DRAFT REPORT

OF

THE INDIANA UTILITY REGULATORY COMMISSION

ELECTRICITY DIVISION DIRECTOR

DR. BRADLEY K. BORUM

REGARDING 2014 INTEGRATED RESOURCE PLANS

Date of the Report: March 3, 2015

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 2014, 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, 2014. The four are:

1. Indianapolis Power & Light Co.
2. Northern Indiana Public Service Co.
3. Southern Indiana Gas & Electric Co. (Vectren)
4. Hoosier Energy

Written comments on the integrated resource plans were submitted by the following and others:

1. Citizen Action Coalition, Earthjustice, and Sierra Club
2. Synapse Energy Economics, Inc.
3. Hoosier Environmental Council
4. Office of Utility Consumer Counselor
5. Valley Watch
6. Jean Webb

The draft report by the Electricity Director was issued March 3, 2015.

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

According to the Draft Proposed Rule, the Director shall issue a final report on the IRPs within 30 days following the deadline for submitting supplemental or response comments.

GENERAL CRITIQUE OF THE 2014 INTEGRATED RESOURCE PLANS OF HOOSIER ENERGY, INDIANAPOLIS POWER & LIGHT COMPANY, NORTHERN INDIANA PUBLIC SERVICE COMPANY, and VECTREN / SOUTHERN INDIANA GAS & ELECTRIC COMPANY

While every major business dedicates substantial effort to forecasting demand for their products and planning to meet their customers' needs, few industries are as important as the electric system which has been called the most complex man-made system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The urgency for continual and immediate improvements are heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and new technologies. To this end, the IRP draft rules anticipate continual improvements in all facets of the planning processes of Indiana utilities. It is clear that utilities have made substantial progress but, given the importance of long-term resource planning, much work remains to be done.

As with the prior Director's Report, this Report also places considerable emphasis on the importance of robust risk analysis in IRPs. The Commission staff has encouraged the utilities, in collaboration with their stakeholders, to develop scenarios and sensitivities that not only provide a likely future but also *stressing* the system by exploring lower probability scenarios and sensitivities that have a high potential cost if realized. The staff has encouraged utilities to caveat all analyses; particularly those having a low probability as *illustrative* so that no party will suggest this is a likely future. In all instances, the staff urges utilities and stakeholders to develop an internally consistent narrative. This Report will have greater emphasis on load forecasting because of its integral relationship with the long-term resource plans of each utility. Consistent with the previous Director's Report, this critique will also stress the importance of stakeholder input, assessing the potential for new technologies, and increasingly sophisticated critical thought to the long-term potential for energy efficiency, demand-response, renewable energy resources and other distributed generation.

Perhaps the most gratifying outcome has been the improvements in the Stakeholder Process. All of the utilities made a concerted effort to encourage participation and there were significant numbers of people that attended (as a guesstimate 30 -60 people on average) with additional participation by phone. Utilities generally had one-on-one conversations with some stakeholders and in some instances utilities conducted conference calls with multiple stakeholders. In short, the utilities went to considerable effort to provide access to the meetings. The Commission staff was gratified by comments from the utilities that they would try to find ways of increasing access and stakeholder participation. Without exception, the utilities' top officers and subject matter experts attended the sessions, which provides strong evidence of the utilities' commitment to their IRP processes. The utilities were gracious hosts and provided good information that benefited the process. Despite efforts by the utilities to encourage participation by large customers and the importance of electricity for these customers, very few large commercial and industrial customers participated. The credibility of the IRP would benefit from the perspectives of large customers.

These IRP filings, stakeholder comments, and the Director's Report conclude the first cycle of IRPs under the new proposed IRP Rule. The Commission staff hopes that the next cycle of IRPs will build on each utility's prior work and make continual improvements to enhance the IRP's credibility and insights.

COMMON CONCERNS

LACK OF RISK ANALYSIS

All Indiana utilities noted they had either completed their IRPs or their analysis was too far along to accurately assess the risk implications of Greenhouse Gas (CO_2) compliance. While the Commission staff acknowledges that the proposed draft rules were not issued until June 2014, the staff believes that it would be prudent for the utilities to consider a broad spectrum of possible implications for the EPA rule and other environmental regulations (probability with consideration to joint probability). It is especially important to consider a broad range of risk associated with CO_2 in conjunction with other environmental rules because of their potential for accelerating the deactivation of some power plants and other aging of utility infrastructure.

In addition to the risk analysis of Green House Gas and other environmental regulation, utilities should do more to consider a more expansive spectrum of natural gas price projections. IF the long-term projected low-cost price trajectory of natural gas occurs, it seems likely to further accelerate retirements of some generating units. A high natural gas price forecast might be expected to have the opposite results. Regardless, a wide range of natural gas prices should also be considered in the scenarios and sensitivities.

The utilities did not seem to give adequate consideration to the significant declines in the cost of renewable resources and other forms of distributed generation. This may have been one factor in the limited reliance of renewable resources and distributed generation.

In short, it is precisely because the utilities don't know, with any reasonable certainty, what the potential risks are that a fuller spectrum of risks should be evaluated as part of a credible Integrated Resource Planning process.

Especially after the IURC staff, in an effort to encourage the utilities to think more expansively about potential risks, assured Indiana utilities that scenarios and sensitivities that are intentionally intended to analyze the outer bounds of probability won't be used against them, the Commission staff hoped to see a more robust analysis of various potential risks. The IURC Staff suggested they refer to these and all scenarios and sensitivities as *illustrative* or hypothetical for the purpose of a comprehensive assessment of risk. The IURC staff doesn't expect greater risk analysis to be additional work because the IURC expects that the prudent management of Indiana utilities probably required their staff to prepare more expansive risk analysis of the potential ramifications of CO_2 compliance and other risk factors under a variety of scenarios and sensitivities. That is, the Commission staff believes the utilities could provide much of the analysis prepared for their management as part of their IRP.

In one instance, a utility (NIPSCO) developed a Base Case and just one so-called scenario which, they contend, is sufficient for analyzing complex risk issues. The IURC staff disagrees that two scenarios would be sufficient. The Commission staff also disagree that the change case constituted a separate scenario since it didn't result in a different resource plan that was subjected to optimization. Rather, the other scenario appears to be a combination of sensitivities to compare to the Base Case. NIPSCO performed a number of sensitivities on three alternative resource plans but the sensitivities are not always true sensitivities and verge on being scenarios. This is especially the case for the Aggressive Environmental Regulation scenario. We note that the language used by NIPSCO indicates they can't decide if it is meant to be a scenario or a sensitivity. Regardless, the CO_2 spectrum of potential prices deservers more discussion in all of the utilities IRPs.

The Commission staff, while not wishing to be prescriptive, invites utilities and stakeholders to consider whether it would be beneficial to the process to have reasonably consistent definitions of important concepts such as how to construct a base case (a/k/a, business as usual or reference case), Scenarios (a/k/a Futures), and Sensitivities.

For the construction of the Base Case, the Commission staff would like to propose the following working definition. The Base Case would be regarded as the status quo case that includes only known events and expected trends (e.g., forecasts of fuel prices, economic forecasts, estimated future capital costs, most expected load forecast). The Base Case should describe what the utility (with input from stakeholders) would expect the world to look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws / policies affecting resources that aren't known and measurable. That is, the Base Case should not include a *preferred portfolio* of resources beyond those with a very high probability of being implemented in a relatively short time period. The narrative for the base case should also discuss the anticipated uncertainties that would be addressed in scenarios and sensitivities. A Base Case should probably not include federal or state legislative or regulatory changes that are not certain or, subject to the utility and stakeholders' opinions, have a very high probability. At the time of the 2013 and 2014 IRPs, for example, it might have been reasonable for the Base Case not include the Clean Power Plan rules for carbon dioxide however it would be reasonable to expect utilities to construct a scenario and sensitivities that would attempt to bracket the potential risks of the Clean Power Plan rule. For the 2013-2104 IRPs, the utility and its stakeholders might (or might not) wish to continue existing policies, such as DSM, renewable portfolio standards, or investment tax credits for renewable energy projects, beyond their statutory expiration / sunset date. Any generation or other resources, beyond those that are certain or almost certain – say over the next three years or so, should be added by the capacity expansion planning model to satisfy reliability constraints rather than *hard-wiring* specific types of units at any specific time which would diminish any claims of "optimality." Care should be taken to avoid a bias resulting from unusual or cyclical events such as extrapolating that either an economic downturn or extraordinary inflation is expected for the entire planning horizon. Because the Base Case is foundational and because of the complex interrelationships, it is imperative utilities construct a narrative to explain their rationale for the Base Case and the change cases- scenarios should also have consistent and well-reasoned rationales.

With regard to construction of Scenarios, again, the Commission staff does not wish to be prescriptive so we invite utilities and stakeholders to comment on the following general description of scenarios. The utilities and stakeholders should collaborate in the selection / development of key drivers and construct well reasoned and consistent narratives to create alternative scenarios or futures that result in different resource mixes and that bracket the Base Case with a broad range of alternative scenarios. Perhaps it would be useful to think of them as "book-ends" that, at the extreme, stress the system by examining low probability but high consequence outcomes. The Commission staff believes this is the type of analysis that utilities probably already construct for their managements so they can make prudent and informed decisions. To encourage candor, expansive consideration of risk, and objectivity, there should be no misunderstanding that these extreme cases are hypothetical and illustrative and DO NOT represent the utilities' judgment of the most likely future.

Sensitivities for each future Scenario should provide a basis for a well reasoned narrative that allows the utility and stakeholders to isolate the individual affects of each distinct sensitivity on the scenario. By way of examples, sensitivities for each future might consider the ramifications associated with different load growth forecasts, a broad range of potential cost associated with environmental regulations (e.g., CO_2 costs might range from $0 to $50) to better reflect the current uncertainties, different potential amounts of renewable energy – especially to better assess the potential implications of 111(d), a range of possible penetrations of distributed generation, differing amounts of energy efficiency – especially to better assess the implications of 111(d), differing fuel costs, different capital cost projections, and etc. Sensitivities should be integrated into to each scenario individually to enable the utility and stakeholders to understand the incremental affects of each sensitivity on each of the scenarios. As with each alternative scenario (future) and to encourage an expansive assessment of risk, the utility may wish to offer the disclaimer that these sensitivities are for informative and illustrative purposes only.

Utilities seemed to layer on resources such as energy efficiency, demand response, renewable resources, customer-owned, and other distributed resources on top of the utility's preferred resource plan rather than allowing the expansion planning models to objectively select the most cost-effective resources. In some instances, this appears to have been accomplished by restrictive assumptions and data that would not result in a resource plan that was significantly different from the utility's preferred plan.

To reduce the potential for intentional or unintentional bias in the construction of the base case and the different scenarios / sensitivities, it is important to include the stakeholders in these decisions. There should be no resource decisions that are baked into the analysis prior to the stakeholder involvement. For resources that the company believes have a certainty or a high probability of being developed, the utility should be able to make the case to the stakeholders rather than taking unilateral decision to include those resources.

Recommendations

In general, the Commission staff encourages utilities to provide the range and depth of information they would provide to their management so reasoned decisions about long-term resources can be made. (1) The Commission staff continues to suggest utilities consider several scenarios and sensitivities with, what might be characterized as "bookends" that constitute the high and low cases with different resource mixes. These distinct scenarios should result in different resource build-outs. (2) Each of the scenarios and their sensitivities should have a narrative that is internally consistent and within the realm of possibility but may be relatively low likelihood but with significant ramifications. (3) Since trying to optimize these decisions, to the extent reasonably feasible, is a difficult undertaking, the Commission staff urges utilities to adopt state-of-the-art planning tools, processes, and databases. With increased computing capabilities and software, it is increasingly possible to optimize two or more resources. Improved databases are essential to effectively utilize advanced software. (4) These scenarios and sensitivities should be driven by the stakeholder process but with considerable education and guidance by the utilities.

Indiana utilities should consider utilizing more probabilistic analysis to provide an additional perspective or to be injected into the current planning processes. Probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more comprehensive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods, may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contribution of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a compliment to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severity.

LOAD FORECASTING

To varying extents, all utilities recognized there seemed to be a paradigm shift to low (or even negative) load growth. Despite the recognition of important implications of load forecasting for resource planning, only IPL offered suggestions on measures they intended to take to improve the *believability* or *credibility* of their load forecasting.

Even without, what appears to be, a major change in how much electricity customers use, the forecasting of all utilities could be improved to reduce risks by, among other things, incorporating price effects (elasticity) on energy use and more detailed information on the changing uses of electricity. One utility (IPL) in particular used a 10 year load forecast and was going to extrapolate for an additional ten years even though they had information such as a 20 year forecast of the effect of energy efficiency on their company's energy use.

As important as industrial customers are to IPL, NIPSCO, and Vectren, there was little evidence that their knowledge of their customers had a meaningful effect on the forecasts. This short-coming was particularly noticeable for NIPSCO where the number of customers and the industrial electric use and demands were constant from 2015-2035. Despite the projections for low natural gas prices, the improvements in technology, and customer attitudes toward their ownership and operations of their own resources, the utilities seemed reluctant to consider that these customers may install combined heat and power or take other actions to reduce their use of utility generated power.

Commercial customers, as noted by the utilities, are extremely diverse. Yet, for forecasting purposes and despite having some end-use information by NAICS (customer classification), it's not at all clear the utilities utilized this information in preparing their forecasts. To the extent of this failure to segment commercial customers (e.g., by type, end-uses, building information, employment / demographics, usage level), utilities are missing an opportunity to tailor their rates and other offerings to their customers. Grocery stores may, for instance, be interested in advanced refrigeration technologies. Schools might be interested in rates that encourage energy efficiency and recognize that, for some schools, operations are at very low levels during the peak summer months. Municipal water pumping loads may also be interested in some form of peak load pricing. Some customers may be early adaptors of technology. Even if the utility doesn't deem a customer-owned resource to be cost-effective, there are some customers that will install the technology anyway.

Similarly, the diversity of residential customers does not seem to be captured in the utility forecasts. The level of use *may* have a bearing on the customers' interest in energy efficiency, demand response, and ownership of their own resources.

Without exception, the utilities could have done more to explain their forecasting methods and how they are integrated to develop a cohesive company forecast and narrative.

Recommendations

Suggestions for consideration: (1) As with the resource plans, the Commission staff suggests utilities consider several scenarios and sensitivities for the load forecasts. These different load forecasts might also be thought of as "bookends" that constitute the high and low cases. (2) Each of the scenarios and their sensitivities should have a narrative that is internally consistent and within the realm of possibility but, at the extreme, would stress the system. (3) These scenarios and sensitivities should be driven by the stakeholder process but with considerable education and guidance by the utilities. (4) The initial forecast should be done without including DSM / DR (especially hardwiring the amount into the load forecast), and other resources being subtracted from load. This would enable DSM / DR and other resources that survived the benefit cost analysis to be compared on a more comparable basis.

AVOIDED COST CALCULATIONS

The contrasting information for DSM was interesting. NIPSCO's detail on avoided cost calculation is commendable (Section 5). In contrast, IPL had very limited information on avoided cost calculations and their estimates of avoided cost raised more questions about their calculation of avoided cost. The Commission staff believes there should be more commonality in the elements and processes for calculating avoided cost. While historically with favorable resource balances (some might refer to as excess capacity), the avoided cost calculations were not as important because the amount of avoidable costs were relatively small. However, with the potential for dramatic changes in the composition of resources (including customer-owned generation, demand response, and energy efficiency) and the attendant increases in the cost of electricity, avoided costs are increasingly no longer a trivial matter. Lower costs and improved technologies for DSM / DR / and customer-owned generation also should be considered in evaluating resource alternatives to utility-owned resources.

The Commission staff invites comments on the process for calculating avoided costs and the integration of those calculations into the IRPs.

DEMAND-SIDE MANAGEMENT AND DEMAND RESPONSE

In general, the Commission staff (and stakeholders) found that utilities did not give as much consideration to DSM and DR as we expected; especially since these might be compliance options for the Clean Power

Plan and to mitigate cost increases if there is a dramatic change in the State's resource mix. Certainly, DSM and DR warranted more expansive analysis in the scenarios and sensitivities. For all the utilities but especially NIPSCO and IPL, there needs to be more of a story (rationale) for the amount of DSM that is being forecasted by the utilities. In the next IRP, to reflect SEA 340, the Commission staff would like to have a separate analysis of commercial and industrial customers that did not opt out from Core Plus DSM programs.

CUSTOMER-OWNED AND DISTRIBUTED GENERATION

None of the utilities gave much affect to the potential for more customer-owned or distributed generation. Too often, utilities included past experience as a predictor of future penetration of customer-owned and distributed generation. As with utility-owned resources, these resources were largely baked-into the utilities resource planning based on the utilities belief that these were not cost-effective at the time their IRP was prepared. It is, of course, possible that the utilities are correct. However, it would behoove utilities to give greater consideration to the ramifications that they are wrong and more customer-owned and distributed generation becomes available which would reduce the utility's need for building / purchasing resources. There are also important implications for resource adequacy (both positive and negative).

Stakeholders correctly noted substantial declines in the cost of wind and solar resources that may not have been given due consideration by the utilities in their IRP analysis. It is also possible that customers' perceptions of cost-effectiveness are different than a utilities' perception and will install facilities that the customer deems to be cost-effective. It is also possible that a customer will install resources for *resilience* to protect against outages. In some instances, customers may have an interest in the technology and don't care whether their decision is cost-effective, schools and universities are examples.

INCORPORATION OF PROBABILISTIC METHODS

The Commission staff is concerned that there is too much reliance on deterministic methods that do not permit a more robust consideration of risk. At the extreme, deterministic methods leave the impression that the utilities have "put their thumbs on the scale" as a means of supporting their preferred resource plan. Probabilistic analysis is, by definition, more useful for examining some aspects of risk. To be clear, the Commission staff is not advocating probabilistic methods to the exclusion of deterministic methods. Rather, probabilistic methods would provide an additional perspective to deterministic methods that are prevalent in Integrated Resource Plans.

STAKEHOLDER PROCESS

One of the purposes of the IRP process was to expedite the acquisition of new resources and to do so with less acrimony by having utilities and stakeholders better understand the decisions and the alternatives. The Commission staff believes better mutual understanding will enhance public confidence in the decision-making processes.

The Commission staff's primary concern is that too many long-term resource decisions were baked-in (aka hardwire) to the IRP process rather than allowing their sophisticated modeling, with appropriate input from their stakeholders, to select the appropriate resources. While the utilities' decisions may have been correct, the process would have benefited from letting the modeling verify the outcomes.

Additionally, the utilities could do more to inform and educate their stakeholders. At the outset of the stakeholder process, it would facilitate the collaborative work by discussing goals, providing an over-view of the current system and how planning is done that considers regional resources and environmental policy, defining terms, detailing the models, discussing the likely significant drivers and how to develop logically consistent narratives for "futures" or "scenarios" as well as the sensitivities applied each. For example, having a discussion of the primary drivers of the load forecasts and the resource plans would help stakeholders focus on the most important issues.

With the potential for significant effects on industrial customers, the Commission staff hopes large commercial and industrial customers would participate in each utility's IRP process to better ensure that their perspectives are considered in the planning process. For example, the IRP process would benefit by knowing about efforts to reduce use or to generate some of their own power. By participating in the process, hopefully, future proceedings would be less contentious by stakeholders, utilities, and Commission staff being better informed.

EMBRACING NEW TECHNOLOGIES, TOOLS, AND PROCESSES IN AN EFFORT TO ENHANCE THE CREDIBILITY OF THE IRPS

The Commission staff is cognizant of the challenges of conducting objective and comprehensive long-term resource planning. However, with dramatic improvements in computing capabilities, planning software[1], and greater opportunities to improve databases (e.g., Advanced Metering Infrastructure, collaborative projects with other utilities, and the work of the National Laboratories and others), there is every reason to expect continual improvements in the IRP process and the credibility of the analysis. While deterministic analysis has its place, the planning processes should make greater use of probabilistic analysis.

In constructing 20 year (or longer) resource plans, it is common for the utilities to do much more in-depth analysis at some interval (say every 4 or 5 years). However, with some new long-term planning tools and because of improved computing power, it is now possible to do the detailed analysis each year.

REGIONAL FORECASTS

Because of the potentially significant ramifications on resource mix throughout the Eastern Interconnection and the overlapping objectives of the IRP process with the planning done by RTOs, utilities should encourage their Regional Transmission Organizations to have 20 year (or longer) planning analysis and participate in efforts to improve the quality and quantity of analysis. There should be no debate that Indiana utilities need to consider transmission and operations facilitated by the RTOs and RTOs cannot engage in transmission planning or conduct efficient operations without knowing the available resource mix. To a considerable extent, utilities and the RTOs should have common cause to develop credible load forecasts, give due consideration to energy efficiency, demand response, customer-owned generation, and other forms of distributed generation.

The Indiana Utility Regulatory Commission takes its responsibility seriously for ensuring the reliability of the electric system in Indiana. For this reason, the IURC staff would have the utilities provide additional tables that are consistent with the information provided to their respective RTOs. While the IURC staff has been loath to be prescriptive in formatting, the IURC staff would welcome suggestions on a uniform report format.

CONFIDENTIAL INFORMATION SHOULD BE REASSESSED

Some utilities declared publicly available information such as data from the United States Energy Information Administration as being confidential. In some instances, important tables, graphs, and charts omitted information that would have been helpful to stakeholders. In still other instances, basic formulas (e.g., load forecasting) were held as confidential. If the information is publicly available, the information should not be regarded as confidential. When proprietary or confidential information is used, it is incumbent upon the utility to attempt to provide proxy information. For example, if the utility relies on propriety fuel price forecasts, the utility should make an effort to find fuel price forecasts that are in the public domain that may approximate the proprietary data (Vectren did this to good effect). The utility is free to caveat the information accordingly. Alternatively, the utility might combine several different sources which could include proprietary data. This combination might be referred to as a *consensus*

[1] By way of examples, utilities should consider work being done using probabilistic methods rather than virtually total reliance on deterministic methods. Computer programs now exist that would permit utility planners to co-optimize resources such as transmission in comparison to generating resources. This type of modeling construct can also enable planners to assess demand response and other customer resources in comparison to the utilities' preferred resource plan. In assessing whether a transmission solution is preferable, instead of total reliance on deterministic methods that solve for reliability requirements (LOLE for resource adequacy or N-1 and beyond contingencies), a probabilistic model can better answer is transmission or some other resource (or combination of resources) more beneficial.

forecast but the utility is free to say that it is a proxy for the information they used in constructing their cases and sensitivities.

NARRATIVES

Each scenario and its sensitivities should have its own narrative that details an internally consistent story of the plausibility of the scenario and the ramifications or *take aways* for each different resource mix. To gain useful insights on the different risk factors, following the modeling runs, there should be a retrospective analysis of the scenarios – particularly the most interesting scenarios. This data mining expedition may serve as guidance for the future IRPs, assess the quality of the modeling, provide guidance on data sources (both those used in the analysis and other sources), and insights on improving the stakeholder process.

OBSERVATIONS REGARDING
IPL's 2014 IRP AND PLANNING PROCESS

1. RISK ANALYSIS WAS TOO CONSTRAINED

IPL worked with *Ventyx* and used its Capacity Expansion model. The Capacity Expansion simulation uses a minimum revenue requirement planning criteria to evaluate generation technologies based on a given set of future landscape assumptions. Explicitly speaking, the model calculates the incremental present value of revenue requirements ("PVRR") for multiple resource expansion plans and selects the resources and timing that result in the lowest present value.

METHOD

IPL identified three drivers that were viewed to have the largest impact on future plans, along with having a great deal of uncertainty linked to them: environmental regulation, natural gas prices, and load variation.

IPL considered four environmental landscapes around costs and timing of effective dates for proposed CO_2 regulation – EPA Shadow Price (Base), ICF Mass Cap (Environmental), Waxman-Markey (High Environmental) and No CO_2 (Low Environmental).

IPL considered five fuel forecasts of NG prices – Base Gas Prices, High Gas Prices Landscape, Low Gas Prices Landscape, Environmental Prices Landscape and Mass Cap Prices Landscape. IPL considered three demand and energy forecasts for load sensitivity – Base Load Forecast, High Load Forecast and Low Load Forecast.

Derived from the three key drivers, IPL created eight scenarios to screen the capacity expansion resources. The eight scenarios are as follows:

A. Base – Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast

B. High Load - Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and High Load Forecast

C. Low Load - Ventyx Base Gas/Market Prices, EPA Shadow carbon price starting 2020 and Low Load Forecast

D. High Gas - Ventyx High Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast

E. Low Gas - Ventyx Low Gas/Market Prices, EPA Shadow carbon price starting 2020 and Base Load Forecast

F. High Environmental – Ventyx Environmental Gas/Market Prices, Waxman-Markey proxy Ventyx Fall 2013 carbon price starting 2025 and Base Load Forecast

G. Environmental – Ventyx Mass Cap Gas/Market Prices, Mass Cap ICF carbon price starting 2020 and Base Load Forecast

H. Low Environmental - Ventyx Base Gas/Market Prices, no carbon policy and Base Load Forecast

Resource options included in capacity expansion modeling were NGCT, NGCC, Nuclear, Photovoltaic and Wind turbine. Additionally, the model was used to determine if and/or the early retirement of the four units at Petersburg was economic in each scenario. Each one of the eight scenarios produced one capacity expansion plan.

Based on the results of the capacity expansion modeling, five plans were created to be tested for future landscapes (six of the eight future landscapes) in order to evaluate a range of resource options and combinations of resources. Under each future landscape, the first and second least cost plans among the five were identified.

A separate sensitivity analysis was performed in regard to wind resources. One case considered lower Locational Marginal Price of wind based on the historic price of wind produced from Lakefield. The second case reduced the expected capacity factor for new wind resource to 25% based upon Lakefield's historic capacity factor. The third case considered wind purchases from Clean Line Energy with 50% capacity factor at a cost of $45/MWh. The last case considered utility scale batteries on wind resources.

Based on quantitative analysis results combined with considerations of risks associated with resource planning, IPL chose Plan 1 as its Preferred Portfolio. This portfolio eliminates the need for new generation in this IRP planning period. IPL did mention that the company would continue to analyze the benefits of additional renewables to its portfolio between now and 2020 when uncertainties pertaining to wind resources and Clean Power Plan resolve in the future.

ISSUES AND CONCERNS

A. At the outset, a consistent and detailed narrative to explain the rationale for the scenarios or the sensitivities is lacking.

B. The DSM programs were incorporated in the load forecast and the programs were not allowed to change in the resource expansion modeling. As a result, only supply-side resource alternatives were considered in the modeling.

C. The relationship between the five resource plans created by IPL for further analysis and the initial resource plans developed for each of the eight scenarios is not obvious. For example, one scenario had Petersburg 1, 2, and 4 retiring in 2020 and another scenario had Petersburg 1 retiring in 2024. But three of the five plans created by IPL for additional analysis locked in the retirement of Petersburg 1 and 2 in the year 2024 and the other two plans created by IPL had no retirements. The creation of the plans for further analysis appears to be arbitrary which creates serious doubt about the conclusions IPL derives as to the preferred resource plan.

D. The PVRR analysis on the resource plans created by IPL was done over a 50 year planning horizon when original eight scenarios were done using a 20 year planning period.

E. The inclusion of carbon prices or taxes in the scenarios is confusing. On page 51 IPL states the EPA shadow pricing landscape "applied EPA's shadow prices to IPL's coal unit emissions above the Indiana target emission rate commencing in 2020 using a fixed ($/kW) cost based on the CO2 building block shadow prices." This implies that IPL did not properly include the carbon price as a variable cost which would affect the dispatch of units. Inclusion of a variable cost as a fixed cost biases the results. If our understanding is accurate than it raises concerns about how carbon is modeled in other scenarios and casts additional doubt on the robustness of the company's analysis.

F. The high and low Load Forecasts, as discussed further below, were not designed for IPL's IRP analysis.

G. The analysis of Distributed Generation was also baked into the analysis and it was unduly constrained. The model should have been allowed to objectively select DSM. Moreover, IPL acknowledges their planning models are not sufficient for analyzing demand response or DG (page 102). *IPL recognizes the installed costs for solar are decreasing, however, modeling limitations do not allow dynamic costs to be included.*

H. Consistent with IPL's comment *modeling limitations do not allow dynamic costs to be included* and a prior concern raised by the Commission staff, IPL's planning process might benefit from probabilistic analysis in addition to their current modeling analysis that is deterministic. While the Commission staff recognizes that deterministic planning is traditionally used for analysis of long-term resource planning and resource adequacy, the Commission staff would ask IPL to consider using probabilistic analysis to provide additional insights. Co-optimization of different resources might also be used to provide additional perspectives on long-term resource requirements.

I. The Commission staff appreciates IPL's recognition of the on-going need to critically examine new models and their data requirements**.** In addition to IPL's recognition that improvements in their load forecasting are warranted, ideally, IPL (and other utilities) would use chronological load shapes with discrete time intervals rather than load duration curves for a more detailed analysis of the potential for demand response. Additionally, models that co-optimize demand response with other resources are likely to provide more credible results. IPL mentions on page 129, *that they continuously seek to upgrade their capability to model their transmission system. Including computer software and data collection.*

Given that the EPA's proposed draft rules for the Clean Power Plan didn't come out until late in the IRP development process, it is understandable for IPL not to include an in-depth analysis of those rules in the IRP. IPL used the EPA shadow price for the Base Case and four of the scenarios (page 54). For the High Environmental scenario, IPL's use of the Waxman-Markey Climate bill (a/k/a the American Clean Energy and Security Act of 2009 (and some combination of other bills) *may* be a reasonable proxy for the upper bound of the CO_2 risk in the Environmental Scenario. For the Environmental Case, for example, it is possible that all environmental regulations – including carbon dioxide - will be more rigorous than IPL anticipated. At a minimum, joint probability should be considered in the narrative of the different scenarios and sensitivities.

IPL's IRP might have asked the question: What would be the ramifications to IPL and its customers if the price for CO_2 compliance / mitigation was higher than the previously proposed legislation? Does IPL agree that, if CO_2 regulation sustains legal challenges, is there a reasonable probability that a market will develop? If so, IPL might have considered a more expansive range of CO_2 prices. The relatively narrow risk band was seemingly inconsistent with IPL's comments on page 5 and other statements [2] that "*The future impacts on IPL's generation resources to continue to be uncertain amidst potential legislation and U.S Environmental Protection Agency ("EPA") regulations*."

On page 109, IPL recognized avoided costs are expected to rise as more restrictions on coal-fired production are implemented which will result in higher resource costs. Yet, despite IPL's recognition, there is limited effect given to gauging the spectrum of potential risk associated with all of the environmental regulations and the higher avoided costs didn't appear to be reflected in IPL's analysis. If our understanding is accurate, failure to recognize the potential range of risks is especially surprising because it is against the backdrop of the significant ramifications that MATS is, according to IPL, having on IPL and IPL's customers.

As the Commission staff reads IPL's IRP, IPL's relatively constrained risk analysis may give the impression that IPL put its thumb on the scale to justify IPL's pre-ordained resource decisions rather than

[2] On page 38 IPL enumerates the potential for additional EPA action on SO_2, NO_X, coal ash, and other pollutants. On 39, IPL states: *At this time, we cannot predict the final outcome of the Clean Power Plan as it is currently a proposed rule, the impacts may include decreased dispatch of coal-fired generation, increased dispatch of natural gas, and renewable generation, and increase demand side efficiency measures.* On page 105, …[W]*hile the ultimate disposition of the rulemaking is unknown, it is prudent for IPL to actively plan for the eventuality that this rule, or other carbon constraints, will result in an increasing role for energy efficiency.*

letting the model solve the resource decisions using objective data and assumptions. In the first round of optimization, the model retired the Petersburg units individually (Figure 4.10 on page 57). IPL clearly biased the results when it created five resource plans where the retirement of Petersburg 1 & 2 was forced in 2024. See the five resource plans created for further review in Figure 4.11 on page 59. Had IPL asked, "Under what conditions, would these units not be viable (selected by the model), the concern for bias would have been avoided.

Probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more comprehensive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contributions of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a compliment to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severit**y.**

In sum, the Commission staff noted that the different scenarios did not produce dramatically different resource mixes of both utility-owned and customer resources. In part this seems to be due to *layering on* different sensitivities rather than truly integrating the changes into the different scenarios. In part, this is also due to the constrained risk analysis. If IPL was to truly stress their system and develop book-end scenarios to better capture the full range of potential risks, the Commission staff would have expected greater differences in the resource mix. The Commission staff understands IPL's long-term expansion planning model to be deterministic which, as IPL recognizes, does not generate an optimal solution since it isn't designed to evaluate different resource options simultaneously. However, there are some models that do this. Future IPL IRPs might examine the potential for this modeling.

Especially after the IURC assured IPL that scenarios and sensitivities that are intentionally intended to analyze the outer bounds of probability (to stress their system) would not be used against IPL, the Commission staff hoped IPL would have had a more robust analysis of various potential risks.

Synapse Energy Economics, Inc. on behalf of Sierra Club (page 1) *"The Company's planning methodology has evolved slightly during the stakeholder process, largely in response to stakeholder comments – including from the Sierra Club. However, IPL's modeling approach for the 2014 IRP continues to be limited in both its structure and assumptions, This section summarizes problems with the Company's chosen plan, as well as with the Company's treatment of scenarios, resource choices, and treatment of off-system sales. Subsequent sections address key flaws in the underlying assumptions.. Ventyx provided assumptions for energy, capacity, and natural gas prices, and IPL developed carbon prices and load forecasts. Ventyx then performed capacity expansion modeling to determine the Company's portfolio..over 20 years…We discuss further how the carbon price was not applied properly in scenarios 1 through 5, disproportionately favoring the generation of coal in these scenarios. The capacity expansion modeling results showed that it was economic to retire Petersburg unit 1 in 2024 in the Environmental scenario. In most scenarios, no capacity is retired or built until 2030…IPL claims these plans were 'created to represent the results of the capacity expansion model,' However, unlike in the capacity expansion plan modeling, the unit retirements are fixed in each of the five plans chosen by IPL. Simply put, IPL chose to either retire both or not retire both Petersburg 1 and 2 in each of these five* *plans, rather than letting the model run without IPL's fixed treatment of these resources. Despite not being the lowest cost plan in any scenario, IPL chose Plan 1 as its 'preferred portfolio.'*

- ***IPL's Preferred Portfolio (Plan 1) is Based on Flawed Modeling***
- ***The structure of the scenarios does not allow for unit-by-unit evaluation***
- ***The Company dismisses Plan 2 because of the uncertainty surrounding wind, even though this is the lowest cost plan under most scenarios.***
- ***The Company continues to model off-system sales as if 100% flows directly to ratepayers ..***

In Section 3 The Company's carbon price is not applied properly in most scenarios "*as a result, the Company's analysis biases the results towards continued operation and investment in its coal fleet. Future Enviornmental spending is not all included in IPL's modeling. The Company provided a range of estimates for compliance with upcoming environmental regulations such as Coal Combustion Residuals (CCR), Effluent Limitation Guidelines (ELG). Cooling Water Intake (Section 316 (b) of the Clean Water Act, Cross-State Air Pollution Rule (CSAPR), and National Ambient Air Quality Standards (NAAQS). However, it appears that most or all of these future costs were not included in the IRP modeling."* On page 10, Synapse sates *"It also appears that the Company's eight modeling scenarios failed to account for all of the potential costs associated with these environmental compliance obligations."*

"After the capacity expansion modeling, IPL evaluated five portfolios (Plan 1 -5) under multiple scenarios of natural gas and carbon prices. This analysis was limited to simply testing five portfolios against different commodity price variations... the IRP lost the opportunity to review how different explicit variable changes impact the choices of portfolio..By only changing gas and carbon costs, individually, it is impossible to see the results with combinations of risks (e.g., High Gas / High Environmental)." On page 9 Synapse explains that the Base, Low Gas, and High Gas scenarios only apply carbon costs as a fixed cost rather than as a variable cost. As a result, dispatch of coal units aren't affected. This favors coal-fired units in the dispatch. (page 9)

With regard to IPL's consideration of wind resources, Synapse states: "*Given that the Company's original Plan 2 was the lowest cost plan – even with conservative assumptions for wind performance – it should not dismiss the addition of an entire resource type based on such vague and insufficient reasoning." (page 7)*

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 1 state: "*The most recent revisions to the IRP rule were intended to recognize the increasing regional interconnectedness of Indiana utilities, and to facilitate a collaborative process for evaluation of the potential ramification of a range or risk and uncertainties facing the electric sector, such as increasingly stringent environmental regulations (including region of green house gas emissions) and increasingly low –cost and available demand-side renewable resources…[A]s detailed, the three utilities* [NIPSCO, IPL, and Vectren]..*each undervalue, and in some cases disregard, clean, low-cost energy and resources by failing to analyze demand-side and supply-side resource alternatives on a consistent and comparable basis."*

The OUCC (page 1) observerd "*The utilities did not demonstrate in a clear manner whether these qualitative elements [e.g., political outlook, risk, portfolio mix, and human behavior] were considered and, if so, how they were accounted for in the modeling process. It also is unclear whether the utilities' modeling considered the availability of renewable resource at peak load or the need for and cot of available back-up energy through spot or long-term contracts for purchased power*."

COMMENTS ON LOAD FORECASTING

IPL uses econometric and statistically adjusted end-use modeling. The Residential sales forecast is a product of a residential customer forecast multiplied by a residential use per customer forecast from the monthly statistically adjusted end-use model. Sales are a function of heating, cooling, and other end-use variables. The intention is to capture the interactions of end-use intensity projections, household characteristics such as the size of the home, real income, electricity price, and heating / cooling degree days. The customer model is a linear regression model driven by total households in Marion County.

Unlike most utilities, IPL does not model Commercial and Industrial forecasts separately. Instead, the model forecasts Small Commercial and Industrial and Large Commercial and Industrial customers. Sales forecasts for Small C&I and Large C&I customers also use statistically adjusted end-use models. However, instead of the *average use* concept used in the Residential forecast, both the Small C&I and Large C&I use aggregated sales. According to IPL, this is done because of the relatively greater heterogeneous nature of C&I customers compared to Residential customers. The C&I forecasts are designed to capture equipment saturation and efficiencies, commercial and industrial output, energy price, and heating / cooling degree days. The economic driver for the Small C&I customers (rates SS and SH) is Indianapolis Non-Manufacturing Employment. The economic driver for the Large C&I customers is Non-Manufacturing Employment for rates SL and PL and Indianapolis Manufacturing Employment for Rates PH and HL.

The monthly peak demand forecast is generated from a monthly peak model which is a hybrid of econometric drivers and energy efficiency impacts. The peak model uses the same economic drivers as the energy model while average temperatures / degree days associated with historical peak days are used.

IPL used the high and low bands from the SUFG's 2013 IPL forecast as the IPL high and low band forecasts.

IPL's external data sources are reasonable but should continually be evaluated. Weather data from NOAA, economic and demographic data from Moody's Economy.com, end-use saturations and efficiencies from EIA and Itron that were modified for IPL"s service territory are all good sources of information.

ISSUES AND CONCERNS

- Is the Commission staff's understanding correct that average temperatures are calculated from daily minimums and maximums? If so, why didn't IPL use a 24 hour average? What base temperature is used for CDD and HDD? In attachment 6.9 (Peak Forecast Drivers and Input Data), it appears that 50 degrees is used for HDD. Is this correct? If so, how was 50 degrees chosen?

- IPL uses the most recent 30 year averages of monthly CDD and HDD "normal." By placing Normal in quotes, is the Commission staff's inference accurate that this is not really a normal but, rather, a simple average? If so, perhaps using a true Normal would be better.

- IPL said that data constraints in "economic data availability" was the reason the original forecast was only for 10 years rather than the 20 years required by the IRP Rule. The Commission staff has never encountered this before. Could IPL please clarify?

- IPL recognizes there may be a significant change in the amount of electricity consumed by its customers over the short and longer term that may not be as credibly captured by using only econometric models; so IPL (Itron) also uses end use modeling. The Commission staff isn't, however, sure how the EIA information (and other) is actually integrated into the residential and commercial forecasts. The Commission staff would appreciate a discussion of the integration of

Itron – EIA data into the forecast. The Commission staff would also like a discussion of when and how IPL's intends to integrate price elasticity in the forecasts. Commission staff believes that IPL agrees that one of the needed improvements for the entirety of the load forecast is the integration of price effects (price elasticity). With potentially significant changes in IPL's cost and resulting rates, it is increasingly important to be able to anticipate the extent to which customers will reduce their use (including energy efficiency, demand response, and customer-owned generation). Knowing when customers use electricity and when they reduce their use is increasingly important to a credible load forecast that has a consistent narrative.

- On page 146, IPL states "The inclusion of more drivers generally causes a collinearity problem which degrades the predictive power of the model. The Commission staff suggests that multicollinearity affects the significance of individual drivers but it doesn't affect overall model accuracy. If our interpretation of multicollinearity is correct, it should not be used as a reason to keep important drivers out of the model. Moreover, from the Commission staff's perspective, the C&I forecasts may be too simplified. IPL should consider whether it is possible to increase the credibility and explanatory capabilities of the forecasting models to stratify the Commercial and Industrial customers into more homogenous groups which, then, may entail different (perhaps more) drivers. Regardless, continual effort should be made to improve the quality of data that supports the drivers.

- As an example of reevaluating the model specifications and consideration of different groupings for C&I customers to make them more homogeneous, the "output" measure used for the C&I models appears to be manufacturing and non-manufacturing employment. Have other measures – such as some measure of *gross product* – been tried? If so, what were the results? The large C&I model uses manufacturing employment as a driver for the PH and HL rates. Since manufacturing employment can be a problematic driver for sales because, as manufacturing processes become automated, manufacturing employment and sales typically move in opposite directions.

- On page 145, it states that "*simulation models are then created to convert billing cycle information into a calendar month format.*" Because credible system planning is predicated on consistent chronological information and increasing granularity, the Commission staff would like more explanation of these simulation models, how they are used to do the conversion of billing data to calendar data, and a discussion of the efficacy as to continuation of this practice.

- There is no mention of *other sales* categories such as street lighting, public authorities, or even station use. Does IPL not have these sales categories? If the Commission staff's interpretation is correct, in addition to concerns for the lack of comprehensiveness and questions about the credibility of the forecast, the Commission staff believes this category of uses has significant opportunities for energy efficiency, demand response, and distributed generation that are missing from IPL's planning.

- Commission staff would like more detail on the Peak Demand forecast (page 147). It isn't clear how the peak demand was developed. In Section 7 – Attachment 6.9 for example shows the Peak Model including a variable "Aft09." Would IPL please tell us what this variable is and how it is integrated into the model? The Peak Model also appears to include 2 specific day dummy variables although the Excel is formatting the cells incorrectly and showing them as numbers. What are these variables?

- Also, with regard to the Peak Model, the selection of peak day weather is unclear as is the "Normal / Weather _ Data" tab in Attachment 6.9 (Peak – Forecast Drivers and Input Data) .xlsx. Why was 2001 used.

- While the Commission staff is gratified by IPL's use of forecasts generated by the State Utility Forecasting Group as an impartial expert source, hopefully IPL would agree that, for future IRPs, IPL should develop their own high and low load forecasts. It is Commission staff understanding that SUFG high and low forecast bands are driven by changes in growth assumptions but IPL appears to interpret the bands as representing economic uncertainties, inclusion of DSM, as well as technological and behavioral changes. If this is IPL's understanding, it is inaccurate. Rather, SUFG's forecast bands are based solely on changes to real personal income, non-manufacturing employment, and Gross State Product. If the Commission staff correctly characterizes the SUFG forecast, we would like to know if this misunderstanding of the SUFG's forecast may have been the cause of IPL having the same DSM forecast in all three cases. In other words, if IPL knew the purpose and limits of the SUFG forecast, would IPL have made more of an effort to appropriately incorporate DSM and other risk factors into the high and low forecasts? This could have important implications for the IRP. Again, if the Commission staff is accurately characterizing the SUFG methodology, did this become a limiting factor in the IPL forecast since there was only about 200 MW difference between the high and low load forecasts for 2034 (pages 52-53 and on page 141)? Regardless, since the SUFG forecasts were not prepared for the purposes of IPL's IRP, the use of the SUFG forecasts may not fit well with stakeholder driven process and the range of forecasts.

- Because the load forecast is a keystone for the planning process, the Commission staff hopes the next IRP and stakeholder process will devote more attention to the development of a more credible load forecast.

- On page 139, for example, IPL states *Energy sales have consequently recovered since the recession, but have not mirrored the overall growth in economic parameters. This is in part due to the structural shift in energy-consumption induced as a result of increasing appliance – efficiencies*. This low load growth in IPL's baseline forecast is depicted on page 142 Figure 4D.4. Given that IPL recognizes the importance of significant changes that are likely to affect long-term load forecasting and resource planning as well as the recognition that improvements in forecasting and planning take time, the Commission staff was disappointed there wasn't more discussion of how the load forecasting process would be improved. Hopefully, IPL will offer a plan for improved load forecasting processes, databases, and modeling in their next IRP.

2. CONSIDERATION OF DSM

The Commission staff is not clear on how the DSM studies done for IPL were integrated into the IRP. In 2012, IPL received from the Applied Energy Group (AEG) a complete market potential study entitled *Energy Efficiency Market Potential Study and Action Plan.* Since the completion of the MPS and Action Plan, Senate Enrolled Act 340 was passed which has significant ramifications for DSM in Indiana. This state policy change resulted in IPL re-engaging AEG to update the Action Plan and to create a longer-term (2018-2034) DSM forecast. The 2015-2017 Action Plan was based on an update to the 2012 MPS. This Action Plan accounts for *"elimination of IURC annual savings targets and the opt-out provision for large customers to identify cost-effective achievable DSM potential."* Quantitatively this means the Plan accounts for 1.1% percent of sales per year (page 106). IPL also expects sales after DSM adjustments to grow at a compound annual growth rate of .7% which is lower than the 1.24% growth rate of sales before any DSM adjustment over the next 3 years. In this case DSM addresses 42% of the estimated load change (page 23). Hence, "*the DSM evaluation for this IRP is driven by a more traditional analysis that identifies market potential for cost effective DSM*" (page 97). IPL continues by saying it expects achievement of approximately 456 GWh savings by the end of 2014 which is approximately the prior cumulative Commission targets for the end of 2014 (page 98). We take IPL's comments that this DSM study is based upon information known today and that future public policy, including the Clean Power Plan and Indiana's legislative direction, will likely affect IPL's projections of the appropriate level of

DSM beyond 2017 such that future IRPs will be more in-depth and comprehensive; especially given the longer-term potential for energy efficiency as a compliance measure. Is our understanding correct?

Hopefully, rather than layering in the additional 10 years of energy efficiency analysis, future IRPs will fully integrate energy efficiency into the IRP modeling and let the model decide resource choices objectively.

ISSUES AND CONCERNS

- DSM was baked into the analysis instead of allowing it to compete with supply-side or resources or other customer-side resources. Does IPL agree with the assessment?

- While not an uncommon practice, treating DSM (and other customer-owned resources) as reductions in load (reducing the Net Internal Demand) rather than as a resource has implications for resource adequacy calculations and, as a result, for the evaluation and integration process with other resources. The Commission staff invites IPL and others to discuss the appropriate treatment of DSM (and other resources).

- IPL recognizes that avoided costs are starting to rise (page 109) but it's not clear how avoided cost information is used in forecasting the potential effects of energy efficiency. The Commission staff would welcome IPL's comments. The Commission staff agrees with IPL (page 108) that if DSM programs are not justified in states like California and New York that have higher electricity costs, these programs won't be cost-effective in Indiana.

- How many customers are projected to opt-out in the future (numbers, percent of total usage etc)? How was this number projected?

- How many customers are projected to participate in each program? In the description of each program the number of participants wasn't specified in the IRP text or the Attachment 4.1.

- Is there a potential for a double counting problem when considering some measures that overlap between each other? Is this something that IPL considered in the DSM Plan?

Synapse Energy Economics, Inc,on behalf of Sierra Club (page 17) believes the AEG analysis understates the amount of DSM reasonably available and it fails to give due regard to studies around the nation. Synapse cites residential new construction as an example saying that this has been a success elsewhere and there is no reason to expect it would not be successful in IPL's service territory. Synapse also suggests IPL could do more to "reengage" large customers that have opted out due to SEA 340. In sum, Synapse suggests the Company should pursue all cost-effective DSM and should allow the model to evaluate supply-side and demand-side resources on a consistent and comparable basis and to select it as a resource rather than hardwiring the impact of EE as the utilities did in the 2013 IRPs. (page 20)

Mary Moriarty Adams, City County Council "I also believe in the importance of reducing energy demand and urge you to work with the Indianapolis Office of Sustainability and the City-County Council to develop cost-effective programs that encourage and incentivize energy efficiency and conservation in Indianapolis.

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on pages 5 and 6 "*A core requirement under the IRP Rule is that energy efficiency and other demand-side resources must be treated on equal footing with supply side resources…Put simply, energy efficiency must be treated as a true resource that can be selected whenever cost-effective, rather than a hardwired adjustment to the load forecast that cannot compete with other resources..IPL incorporates efficiency in its net internal demand (NID) forecast, which is set before supply side options are evaluated through scenario resource modeling..Simply put, IPL 'does not optimize energy efficiency by letting efficiency compete with supply-*

side resources. In sharp contrast to IPL's five evaluations of alternative supply-side plans, the commenters said *The Company did not evaluate a single resource plan that included more efficiency than what IPL included in its NID forecast.*

3. DISTRIBUTED AND CUSTOMER-OWNED GENERATION

IPL adopted Rate REP (Renewable Energy Production) and Net Metering programs to motivate customers to install distributed generation. Under the REP program, IPL was authorized to purchase all of the energy produced by the customer-sited solar, wind, or biomass systems and IPL, in turn, receives the Renewable Energy Credit (RECs). At present, IPL has 66 MW of solar distributed generation on its REP rate. IPL has 8 commercial and 43 residential Net Metering customers as of September 1, 2014 with a total name plate rating of 240 kW. The increase in the number of customers is attributable to the decline in the cost of these technologies – particularly solar panels, interest by customers, and IPL's DSM incentives (expired at December 31, 2014).

ISSUES AND CONCERNS

- On page 78, IPL seems to recognize that there is a potential interest nationally and within Indiana that may not be justified by using cost-effectiveness tests. Nationally, IPL noted on page 94, *The total U.S. market grew more than 120% in 2010 –from 349 MW to 782 MW – and included approximately 48,000 photovoltaic ("PV") systems. These were mostly rooftop systems, but there were also a significant number of utility-scale projects, with eight projects greater than 10 MW.* For IPL's service territory, *IPL has experienced a large influx of early adoption of DG solar due in large part to its feed-in-tariff, Rate REP as describe in Section 4 A. Additional DG is not included in the short-term forecast absent further financial incentives.* The need for greater consideration of customer-owned and other distributed generation was noted by stakeholders during the various meetings. However, with little explanation, beyond a general statement that IPL expects to see little growth in customer-owned generation due to Indiana's climate, IPL asserts that distributed generation will not affect their resource planning. As a result, IPL on page 49 states that solar is projected as being a constant 30 MW from 2015 through 2034; despite IPL's recognition that the costs are declining and interest is increasing.

- The Commission staff, however, believes that the response by customers suggests that customers may wish to install distributed generation for reasons other than the utility's cost-effectiveness tests;

- In addition to a need for a consistent narrative, the Commission staff also believes that a more expansive – but still objective and reasonable - risk analysis (including higher CO_2 prices, relatively low natural gas prices, different avoided cost to reflect the changing composition of the resource mix, declining cost of technologies) would be appropriate. Moreover, given the composition of IPL's service territory, the downtown area – including major buildings, high tech industries, IUPUI, city – county facilities including water and waste water treatment, and the hospital complexes may be good candidates for a bolder vision for CHP, micro-turbines, and other customer-technologies. If IPL's relationship with their large customers is as good as they say it is, their input could be very valuable. In sum, IPL should have been able to construct a scenario and sensitivities that would have resulted in a plausible resource plan where customer-owned generation would beneficially affect IPL's resource planning. To be clear, such a resource plan may not be the *preferred* plan or the most likely. However, in the Commission staff's view, it should have been given thoughtful analysis.

- IPL's capacity avoided costs are $87 (in 2014 dollars) throughout the entire planning horizon. A more in-depth analysis of avoided costs might result in more Distributed Generation in the long-term resource mix. IPL, in contrast to some other utilities, hasn't provided a comparable level of detail about the elements that go into their avoided cost calculations (Discount Rates, System

Losses, Electric Generation Capacity (summer), Transmission & Distribution Capacity Cost, Energy Cost, and MISO Ancillary Charges.

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 8 "*IPL appears to view renewable resources as fundamentally different from other supply-side resources. According to IPL '[r]enwables technologies represent a resource that primarily targets potential future requirements for GHG regulation, and specifically any federal or state RES legislation. IPL at 80*". On page 29, commenters said "Although solar costs are declining and IPL has experienced a large influx of early adoption of solar generation, IPL believes its service territory will see little growth in distributed generation ("DG"). IPL IRP at 78, 95. IPL should provide a more detailed discussion of DG in its IRP, explaining its position in light of current cust and technology trends.

4. STAKEHOLDER PROCESS

The commitment of IPL's top management and their subject matter experts is highly commendable. The proposed IRP rules only require two stakeholder meetings but, to IPL's credit, they went above the required minimum effort by holding three stakeholder meetings between May 16 and October 10, 2014.

ISSUES AND CONCERNS

- After attending several stakeholder meetings over the last two years, the Commission staff believes that, as part of the stakeholder education process, IPL (and other utilities) should consider devoting more time to a primer on long-term resource planning and the role of stakeholders. The spirit of the proposed IRP rule is for stakeholders to be intimately involved in all aspects of the scenarios and sensitivities used in the development of the IRP. In addition to understanding how scenarios and sensitivities are developed, the stakeholders will need to have an understanding of major elements of the process such as load forecasting, the data sources, different resources, and the analytical tools to be used. Since the expertise of the stakeholders will vary, it is important to define important terms and incorporate charts, tables, and graphics. By way of example, graphics such as load shapes and load duration curves can be used explain how DSM / DR, customer-owned generation, and utility-owned generation affect IPL's resource requirements.

- The stakeholders should have been more involved in identifying the key drivers and constructing the various scenarios and sensitivities to those scenarios**.** Such involvement ultimately leads to greater understanding on the part of all participants**.** Beginning on page 8, IPL's IRP said: "IPL identified three key drivers most likely to impact its preferred resource portfolio: (a) CO2 prices as a proxy for pending environmental legislation related to greenhouse gas ("GHG") emissions, (b) gas/market prices, and (c) load forecast differences due to economic and DSM impacts. Eight (8) scenarios were indentified based on combinations of these drivers. While these seem to be well reasoned, these were significantly different than the drivers that were mentioned by stakeholders.

- The initial discussions on May 16, 2014 such as "Introduction to IPL and the Integrated Resource Planning Process" might have been extended to provide more of a primer. With education and dialogue, the differences might have been sharply reduced. Regardless, it would have been better for the stakeholders and IPL to, collaboratively, determine the drivers. By way of example, some stakeholders argued that IPL should have given more importance to customer-owned resources and energy efficiency. It would seem appropriate for IPL to offer expert advice and rationale for what IPL believes are the drivers that have greater relative importance. This, in turn, may stimulate conversation that would assist IPL in developing "book-ends" that stress the IPL system to bracket potential risks and delve more deeply into more probable risks.

- To increase the value of stakeholder participation, especially participation by industrial customers and large commercial customers, IPL should avoid “hardwiring” too many assumptions into the planning process. While IPL’s expert judgment may be best, it is better to explain the rationale but involve the stakeholders in the decision process and let the models select the resources without putting a thumb on the scale. A more vigorous stakeholder process may cause customers to be more engaged in solutions.

- As part of the stakeholder education process, IPL should consider using more load shape and load duration curves to explain resource planning and how DSM / DR, customer-owned generation might affect IPL’s resource requirements. The Commission staff believes that better graphics could be used to explain difficult concepts.

- As part of the initial stakeholder meeting for the next IRP, it would be useful to provide the stakeholders with a context for planning that includes the MISO such as the planning reserve margin, the importance of broad diversity, transmission planning, security constrained economic dispatch, etc .

CAC, Sierra Club, Indiana NAACP, Indianapolis Green Congregations, Ms. Linda Porter, and Larry Kleiman, Hoosier Interfaith Power & Light wrote *“Though we appreciate IPL’s efforts to allow for engagement by stakeholders, we offer suggestions for improving the IRP process going forward. In particular, the meetings were designed to be overly heavy on presentations by IPL staff and its consultants with insufficient opportunity to engage in dialogue, In the future, we suggest that time be allocated for stakeholder presentations and dialogue between IPL staff and stakeholders. The lack of such constructive dialogue contributed to insufficiently robust discussion of certain issues, such as solar energy, demand-side management and other sustainable energy options. Further, we suggest that, in the future, IRP meetings should start earlier in the year and ther should be more than three meetings scheduled. Finally, we suggest IPL consider holding some meetings in the evening to allow more people to attend.* Comments of Organizations and Individuals that Participated in Indianapolis Power & Light’s 2014 Integrated Resource Plan and Stakeholder Process.

5. THE ORGANIZATION OF THE IRP

The IRP had a lot of useful information.

ISSUES AND CONCERNS

- The Commission staff recognizes that the IRPs are evolutionary and we certainly don’t want to be prescriptive on how the organization of the Report. However, from the Commission staff’s perspective, IPL’s IRP was not an easy read.

As stated previously, some of the material in the IRP was more difficult due to the amount of important information that was contained in the confidential filing. For future IRPs, the Commission staff hopes IPL will be more judicious about the information that is contained in the confidential filing.

OBSERVATIONS REGARDING

NIPSCO's 2014 IRP AND PLANNING PROCESS

IRP PURPOSE

In Section 1 of NIPSCO's IRP, NIPSCO states: *Our goal is to develop a resilient and cost-effective resource portfolio that takes into account changing and uncertain business climate. There are five factors that have the greatest potential to influence customers' energy needs and resource portfolio decisions:*

1. Global and local economy

   NIPSCO notes that the *industries* [in their service territory] *follow economic cycles and are tied to the global economy. As such, NIPCO's planning assumptions are heavily dependent on its ability to accurately forecast future economic activity.*

2. Environmental requirements

   A large portion of the next decade's increases in customer costs are expected to be driven by environmental compliance investments.

3. Energy Commodity Prices

   NIPSCO noted the increased production has resulted in *competitively priced* natural gas which, along with renewables will replace some of the retiring coal-fired power plants. As the MISO resource portfolio for power generation begins to shift away from coal, rising energy and capacity prices are expected.

4. Regulatory and legislative

   NIPSCO cited SB 560 (2013) which allows utilities to seek recovery of costs for projects related to a long-term plan for transmission, distribution, and storage as well as Senate Enrolled Act 340.

5. Technology

   Energy source availability, technical feasibility, commercial availability, economic attractiveness, and environmental compatibility are considerations for assessing resource options.

1. <u>RISK ANALYSIS IS TOO CONSTRAINED</u>

Commission staff expected NIPSCO to present risk analysis that is as comprehensive as the analysis they present for their management. Unfortunately, this did not occur. This was disappointing; especially since the Commission staff, during stakeholder meetings, offered assurances that scenarios and sensitivities that are intentionally intended to analyze the outer bounds of probability / plausibility won't be used against the Utility. In sum, the staff hoped to see a more robust analysis of various potential risks; including those that had a low probability but high potential for cost and reliability ramifications.

NIPSCO uses the Strategist expansion planning module PROVIEW from Ventyx. The model simulates real world operation of NIPSCO's generation, transmission, and distribution system. The simulation has the capability to determine the cost and reliability effects of various resource plans. All feasible plans that satisfy the constraints within Strategist are ranked based on the Net Present Value of Revenue Requirements (NPVRR). The long-term resource plan that has the lowest NPVRR is selected as the preferred case.

To derive the best case, NIPSCO used market value to initially screen the supply and demand-side resources to limit the total number of options that can be examined at one time and within a single analysis. Each option was valued using a discounted cash flow. Only options with a positive discounted cash flow and a benefit - cost ratio of greater than 1 passed the initial screen. Any resource combination that passed the screen was eligible to be included in the resource plan development.

NIPSCO then used PROVIEW to examine the following:

1. **Gas Plan**: This included self-build supply-side peaking and intermediate options only;
2. **DSM / Gas Plan**: Gas Plan mixed with DSM options excluding the industrial direct load control (DLC);
3. **DSM / Gas / DLC Plan**: The Gas Plan mixed with all DSM options including industrial DLC:
4. **DSM / Non Gas Plan**: Coal and nuclear mixed with DSM options;
5. **DSM / Gas /Renewable Plan**: Renewable resources mixed with DSM options;
6. **DSM / Renewable Plan**: Renewable resources mixed with DSM options;
7. **Early Retirements Plan**: Early retirements of Bailly 7 and 8 were included in the DSM / Gas Plan.

These plans were evaluated under the same set of assumptions identified as the SLOW ECONOMIC IMPROVEMENT SCENARIO, considered NIPSCO's Base Case assumptions. The DSM / Gas / DLC Plan was the least cost expansion plan among the seven alternatives mentioned above. DSM / Gas was the second lowest cost option. However, since the potential to increase industrial Direct Load Control, characterized as unlimited curtailments and short notice interruptions was unknown when filing the Plan, the DSM / Gas Plan was designated as the Base Case. The resource expansion plan of the Base Case called for a new Combined Cycle Gas Turbine in 2023 and another CCGT in 2035.

NIPSCO developed another *scenario* named "Aggressive Environmental Regulations" which was treated as sensitivities to the Gas Plan, the DSM / Gas Plan, and the DSM / Gas / Renewable Plan. The Aggressive Environmental plan included increased environmental regulation compliance costs, higher natural gas prices, and increased electric prices. It also included a 5% Renewable Portfolio Standard (RPS) by 2020. NIPSCO opted for a deterministic approach for sensitivity analysis – using single point estimates: expected, best, and worst for the input variables. This deterministic approach was extended to intra-variable correlations. Tested sensitivities included: high and low load growth, high construction cost escalation, high and low commodity market conditions, and aggressive regulation; but, curiously for an "Aggressive Environmental Regulations" case, there was no carbon price before 2025 and the range was not as significant as it might have been in an objective risk analysis. In other words, the Commission staff would have thought NIPSCO would have asked the question, at what price for CO2 would there changes start to occur in the resource plan(s).

ISSUES AND CONCERNS

- Ideally, alternative plans would be constructed through the modeling of each scenario to develop the corresponding optimal resource plan. Based on sensitivity results shown on page 121, it seems that no alternative analysis was conducted for the "Aggressive Environmental Regulations" scenario. Thus, no optimal plan was developed based on the assumptions in this scenario. Instead, NIPSCO only tested the three lowest cost plans developed under Base Case

Assumptions [3] *(or reference case)* using the assumptions in the "Aggressive Environmental Regulations" scenario.

- None of the three tested plans are optimal under the Aggressive Environmental scenario. Moreover, none of these three plans were subjected to any stress testing. In essence, because of the structure of the scenario and the lack of an optimal plan produced by the Aggressive Environmental Scenario, NIPSCO only developed a Base Case with different sensitivities.

- Fundamentally, and notwithstanding the complexities mentioned by NIPSCO on page 106 and the limits of dynamic programming NIPSCO mentions on page 108 that limits the total number of options that can be evaluated at one time, the Commission staff disagrees with NIPSCO's use (definition) of Scenarios and Sensitivities. Commission staff does not believe that NIPSCO's methodology of comparing a so-called alternative scenario, which Commission staff believes are really sensitivities, to a base case (or reference case) can credibly assess the potential extent of the diverse array of risks that NIPSCO may address over the next 20 (or more) years. Moreover, in the opinion of the Commission staff, the second scenario (the Aggressive Environmental) isn't really a scenario at all. The Commission staff believes that each scenario should result in a separate optimized resource plan. Instead, NIPSCO treated the Aggressive Environmental as a sensitivity to the base plan. The Commission staff believes NIPSCO's approach is at variance with, what we believe to be, common utility practice.

  The Commission staff is cognizant of the modeling complexities NIPSCO discussed on page 106 but this should not paralyze the analytic process. Other utilities construct multiple scenarios and sensitivities. Certainly, computing capabilities, reduced run times, the increasing sophistication of long-term planning software, and the ability of utility planners to screen and organize inputs (such as the PROVIEW model used by NIPSCO), have all contributed to the ability of utility planners to analyze complex and data-intensive problems in a relatively expeditious and comprehensive manner. In view of NIPSCO's concerns about the complexities, NIPSCO may wish to reconsider the use of more probabilistic analysis.

- While this is NIPSCO's IRP, input from stakeholders during the selection of scenarios and sensitivities might have assisted NIPSCO's planners. Would NIPSCO be amenable to including stakeholders in the formulation of the BAU, scenarios, and sensitivities for the next IRP?

- NIPSCO (page 96) *At this time, it does not appear likely that widespread GHG [Green House Gas] reductions will be required until, at a minimum, the latter half of this decade. NIPSCO is*

[3] The Business as Usual Case (a/k/a Base Case or Reference Case) might be regarded as the status quo case that includes only known events and expected trends (e.g., forecasts of fuel prices, economic forecasts, capital costs). The BAU should describe what the utility (hopefully with input from stakeholders) would expect the world to look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws / policies affecting resources that aren't known and measurable. That is, it should not include a *preferred portfolio* of resources beyond those with a very high probability of being implemented. The narrative for the base case should also discuss the anticipated uncertainties that would be addressed in scenarios and sensitivities. A BAU should probably not include federal or state legislative or regulatory changes that are not certain or, subject to the utility and stakeholders' opinions, have a very high probability. At the time of the 2014 IRPs, for example, it might have been reasonable for the BAU to not include the Clean Power Plan rules for carbon dioxide. For the 2013-2104 IRPs, the utility and its stakeholders might (or might not) wish to continue existing policies, such as DSM, renewable portfolio standards, or investment tax credits for renewable energy projects, beyond their statutory expiration / sunset date. Any generation or other resources, beyond those that are certain or almost certain – say over the next three years or so - should be added by the capacity expansion planning model to satisfy reliability constraints rather than *hard-wiring* specific types of units at any specific time. Care should be taken to avoid a bias resulting from unusual or cyclical events such as extrapolating that either an economic downturn or extraordinary inflation is expected for the entire planning horizon.

estimating that a price on carbon will not be established prior to 2025 due to the current economic and political environment, in addition to the time required for a widespread program to be developed and implemented. The Commission staff understands the proposed draft rules for the EPA's Clean Power Plan was issued in June 2014 which was after NIPSCO and other utilities were well underway with their IRP process. For this reason, the Commission staff did not expect an in-depth analysis of the potential ramifications because the price of carbon dioxide and the mitigation plans were not known. However, the Commission staff believes it would have been reasonable to expect scenarios and sensitivities with different prices for CO_2. Also, given the significant risks, the Commission staff would expect that NIPSCO might want to do *what ifs* for implementation dates before 2025. Even if 2025 is a reasonable date for CO_2 prices to be established, that is still well within the 20 year planning horizon that NIPSCO should be evaluating. Such a scenario and sensitivities would have enabled NIPSCO to conduct at least a preliminary assessment of potential risks of CO_2.

- During the stake*holder meetings, NIPSCO expressed concern that a very high carbon price may cause some industrial customers to leave. However, this concern, then, should be reflected in scenarios and sensitivities that objectively assess this risk. With the prospect for relatively low natural gas prices, is there a potential for some industrial customers to switch some of their electric use to natur*al gas? If the potential for reduced electric use wasn't given explicit consideration, can NIPSCO offer a rationale?

- NIPSCO should give consideration to incorporating more probabilistic analysis into the IRP. From the perspective of the Commission staff, probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more *comprehe*nsive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contributions of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a complement to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severit**y.** Probabilistic analysis better reflects the reality that multiple things simultaneously are always changing and many factors are moving in opposite directions. For example, commodity prices might have a general increasing trend (or not) over a period of time but they will fluctuate, sometimes extensively, around the trend.

In summary, while NIPSCO stated "*Our goal is to develop a resilient and cost-effective resource portfolio that takes into account changing and uncertain business climate,"* there is very little indication that this goal was given proper effect in the construction of scenarios and sensitivities. The Commission staff would ask NIPSCO to consider developing Scenarios and Sensitivities that are based on the world not turning out as they anticipated. This would, then, result in the development of viable alternative plans that would be preferred if the future looks different than NIPSCO expects or hopes for.

The OUCC (page 1) observed "The utilities did not demonstrate in a clear manner whether these qualitative elements [e.g.,, political outlook, risk, portfolio mix, and human behavior] were considered and, if so, how they were accounted for in the modeling process. It also is unclear whether the utilities' modeling considered the availability of renewable resource at peak load or the need for and cost of available back-up energy through spot or long-term contracts for purchased power."

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 1 state: "*The most recent revisions to the IRP rule were intended to recognize the increasing regional interconnectedness of Indiana utilities, and to facilitate a collaborative process for evaluation of the potential ramification of a range of risk and uncertainties facing the electric sector, such as increasingly stringent environmental regulations (including regulation of green house gas emissions) and increasingly low –cost and available demand-side renewable resources…[A]s detailed, the three utilities* [NIPSCO, IPL, and Vectren]..*each undervalue, and in some cases disregard, clean, low-cost energy and resources by failing to analyze demand-side and supply-side resource alternatives on a consistent and comparable basis."* On page 27 commenters contend "*NIPSCO only evaluates a narrow range of potential future carbon prices, containing no serious evaluation of the sensitivity of alternative resource portfolios to potential carbon prices. NIPSCO itself acknowledges that '[r]evised or additional laws and regulations could result in significant additional operating expense and restrictions on NIPSCO's facilities and increased compliance costs. Moreover, such costs could affect the continued economic viability of one or more of NIPSCO's facilities. Yet despite the magnitude of this potential risk, NIPSCO did not model any carbon price scenarios or sensitivities which evaluate the potential impact of the... proposed 'Clean Power Plan'…NIPSCO's base case scenario…assumes that the Clean Power Plan will not be implemented as proposed...and ultimately replaced with a carbon price of $20 / ton that takes effect in 2025. NIPSCO also evaluates a sensitivity to its base case scenario in which it assumes that no carbon price takes effect during the planning period. The only other variation on carbon prices that NIPSCO models is in its Aggressive Environmental scenario which incorporates the assumption that a carbon price of $20/ton takes effect in 2020, in tandem with assuming significantly increased costs from a range of other environmental regulations…By evaluating only a narrow range of potential carbon prices, the NIPSCO IRP fails to account for the economic risks to its generating fleet… Accordingly, the NIPSCO IRP does not analyze how 'candidate resource portfolios performed across a wide range of potential futures.*" (page 28)

On page 10, L*ike Vectren, NIPSCO in its IRP does not consistently evaluate retirements of its existing coal-fired generating units on a level playing field with other, potentially less expensive, resources. Although NIPSCO does not provide a detailed explanation of this in its IRP, NIPSCO appears to have failed to model the possibility of retiring each of its units…On the contrary, NIPSCO appears to have placed an arbitrary constraint on its modeling of retirement alternatives, hardwiring its model to assume that while Bailly Unit 7 could be retired as soon as 2016, the model did not have the option to consider retiring Bailly Unit 8 until 2026 and did not have the option of retiring Michigan City Unit 12 until 2030.. In addition, NIPSCO did not model the possibility of retiring any of the Schahfer facility during the planning period.*

2. LOAD FORECASTING

As a general observation, the Commission staff believes more of a discussion of load forecasting would benefit the stakeholders and Commission staff. This would include a more detailed discussion of how the forecasts are done (e.g., the integration of the two residential forecast methods, the integration – if any – of the results of the residential, commercial, and industrial forecasts to enhance the narratives of each).

On Table 6-1 page 77, NIPSCO subtracts a constant 377 MW of DSM from Internal Net Demand. Notwithstanding NIPSCO's comments on page 87 that "All...DSM energy options…were considered in resource optimization," since NIPSCO has a constant DSM reduction over the forecast horizon, it seems likely that the DSM programs and their effects on NIPSCO's load shapes was not analyzed in-depth then integrated into the base forecast. If this is an accurate characterization, this means DSM was not evaluated like other resources. While treatment of DSM is often treated as a reduction in load, this may not be efficacious. This also is likely to affect other resource decisions and resource adequacy calculations. If there is agreement on this treatment of DSM, it would be useful for NIPSCO to discuss its future treatment of all resources as part of its plans for improving the explanatory value of future forecasts. The following is intended to provide more specificity for the Commission staff's comments.

NIPSCO (page 18) states that the 2014 energy and demand forecasts uses an econometric approach to forecast long term energy sales and peak hour demand.[4] The discussion could be clearer.

For the residential customer forecasts, the drivers appear to be appropriate but additional discussion as to how the variables such as housing stock is integrated into the long-term forecasts would be beneficial.[5]

The Commercial energy usage model is a function of the number of commercial customers, county retail sales (the Commission staff isn't sure how this works for commercial customers that aren't in retail businesses), energy price, and cooling degree days (but apparently not heating degree days).

For industrial customers, the Commission staff appreciates that forecasting industrial usage and demand is difficult; especially beyond a couple of years. The Commission staff also appreciates the sensitivity that industrial customers have to sharing significant business information and NIPSCO's recognition that 1% of their customers constitute more than 50% of their load. However, *informed judgment* is not an ideal way to forecast demand and energy sales for such an important part of the NIPSCO system. As NIPSCO noted, these customers can cause very large and rapid swings in demand. Even reliance on judgment doesn't account for the constant demand for this class of customers.

To enhance the narrative for the residential and commercial forecasts, does NIPSCO project employment for the industrial customers and the economic ramifications for NIPSCO's service territory?

The Peak Demand forecast is a regression model using energy sales by class, cooling degree hours, heating degree hours, and relative humidity at peak hours as drivers. More of a narrative of this would be beneficial.

ISSUES AND CONCERNS

The Commission staff invites NIPSCO and stakeholders to respond to the following:

- What base temperature is used for CDD and HDD?
- NIPSCO uses the 1976 -2010 average for both CDD and HDD as normal weather. Is this truly a simple average or is it a true normal? Why use 35 years? This 35 year period seems unusually long and NOAA's official "normals" are based on 30 years. NIPSCO might wish to consider going to even shorter periods to better account for warming trends.
- Do we understand correctly that the weather normalization procedure uses regression models of 10 years of monthly kWh / customer / day on CDD / day and HDD / day plus additional terms for some month CDDs and a trend variable as deemed appropriate? If our understanding is correct, what does "*additional terms for some month CDDs"* mean and how does it affect the model?

[4] *The forecast employs data representing service area demographics and economic data, saturation and efficiency information, electric energy sales by class, price of energy and average monthly and peak hour weather. Residential usage is related to end uses and efficiencies, and real per capita income. Commercial activity is captured with actual county retail sales. Prices for typical electric bills are used in both the residential and commercial econometric models to measure customer behavior in reaction to changing prices*. (page 18)

[5] NIPSCO notes the average home has 33 kW of connected load and an estimated 18 kW might contribute to the coincident demand. The components of this demand consists of a *typical residential demand breakdown* by type appliance: Central A/C has a peak demand of 6 kW, water heater 4.5 kW, electric range /oven 8.0 kW, clothes dryer 5.0 kW, Dishwasher 2.0 kW, lighting, fans, and other appliances 7.5 kW. (page 68)

- HDD was not a driver in the commercial forecast model. Did NIPSCO make an attempt to include it? If so, please detail the effort. If no attempt was made to include HDD, please explain the rationale.

- NIPSCO produces weather normalized historical energy for residential and commercial customers only. NIPSCO does not produce one for industrial customers because, according to NIPSCO, *"industrial varies very little with weather."* While this may be correct, the Commission staff would like to know if NIPSCO has done an objective analysis of whether industrial loads are affected by temperature and humidity. The Commission staff would be surprised if there was no affect. Regardless, for credibility, the Commission staff believes it would be appropriate to weather normalize.

- The long-term Residential forecast uses historical and forecast saturations and efficiencies from Itron and EIA. Was the Itron – IEA data tailored to NIPSCO? Has NIPSCO conducted a statistically valid independent analysis to verify the data?

- The Residential forecast is a multiplication of the number of projected customers times residential use per customer. Customer count is also listed as a driver in the use per customer model. This is confusing and the Commission staff is concerned about the appropriateness of this. Could NIPSCO please explain?

- Both the longer-term Residential and the Commercial forecasts are partially a function of the historical customer attrition rate. This assumes that historic attrition rates will continue into the future. Especially since we experienced a recession and slow economic growth for a few years, is this reasonable? Has NIPSCO conducted any analysis of whether this driver is stable? If so, over what period was it stable? More discussion of the rationale would be helpful.

- NIPSCO correctly notes that the Commercial class is a very diverse rate class which would seem to provide even more compelling reason to develop homogenous sub-groupings by North American Industry Classification System (NAICS) or Standard Industrial Classification Codes (SIC Code), usage, and other groupings. Would NIPSCO agree that sub-groups might increase the explanatory value of the load forecasts, improve the credibility, and provide better insights regarding DSM, DR, and customer-owned generation?

- NIPSCO's projection that the number of industrial customers and their demand will be constant throughout the entire forecast horizon strains credulity. What is the narrative to justify this? At a minimum, the Commission staff believes this is inconsistent with historical information. It also seems to ignore the potential for these customers to generate their own power (e.g., CHP), to participate in Demand Response (which was also projected to be flat), or to install equipment that uses less electricity; especially with relatively low price projections for natural gas and the potential for major changes in NIPSCO's and the region's generating fleet. Given that industrial load is about half of NIPSCO's total load it is a huge assumption that the number of customers and their demand will be flat which has significant consequences. With this huge uncertainty, it is surprising there are no scenarios (and only single sensitivity) with higher/lower load growth.

- If the Industrial sector is indeed flat throughout the entire forecast horizon, shouldn't this have ramifications for the commercial and residential classes? How is this integrated into the residential and commercial forecasts? Has NIPSCO considered a transition from informed judgment to an econometric approach? While the Commission staff recognizes the sensitivity, after a couple of years don't customer plans become more available?

- It would seem that the industrial and commercial forecasts would have a bearing on the number of residential customers and their incomes but this and other interrelationships are not obvious from the descriptions in the IRP.

- Street lighting, Public Authority, Railroads, Company Use, and Losses are forecast using current levels and anticipated trends. Has NIPSCO made an effort to use a regression model at least for street lighting (recognizing the increasing use of more efficient lighting as a reason for closer examination) and Public Authority? Other utilities do this.

- Forecast bands are calculated with underlying model predicted values along with a statistically estimated 95% confidence interval around those values. High includes GWh sales reflecting industrial expansions currently being developed in NIPSCO's service territory. It's not clear to Commission staff how this is done. Is this *on top* of the 95% band? Is the low band purely statistical while the high band includes (or entirely) informed judgment?

- An on-going concern for NIPSCO and all utilities is the continual enhancements to the databases to support state-of-the-art load forecasting. For discussion purposes, the forecast captures the "average" customer but, aside from simplicity which has merit, would there be advantages to stratifying by usage or other groupings to provide greater intra-class information? That is, by constructing sub-groups wouldn't the explanatory value of the forecast improve? Wouldn't this information be helpful in assessing the potential for DSM, DR, and customer-owned generation as well as the design of rates?

- Why is the high, low, and most expected load forecasts included in the confidential information?

In summary, the Commission staff believes more description of the load forecasting process would be beneficial.

3. <u>CONSIDERATION OF DSM</u>

The Commission staff commends NIPSCO for *adopt[ing] a culture change that encourages conservation and efficiency* (page 42) and will continue to offer DSM programs. There was a good discussion of DSM programs as currently constituted (DSM savings on Table 5-12 on page 51 and Table 5-15 showing MWh savings on page 53). NIPSCO noted that, for this IRP, no industrial customers were presumed to opt out of DSM under SEA 340 (page 52). This is an interesting decision and such a Base Case will be useful for future comparisons but, since this is improbable, it may pose problems for the IRP analysis.

NIPSCO hired Applied Energy Group (AEG) to identify DSM that would be appropriate (Appendix G) for 2016-2035. AEG uses DSMore [6] to model the programs. Programs that passed the initial benefit / cost screen are bundled into heating, cooling, and lighting. However, the narrative would be improved if there was more clarity on the methodology used to incorporate DSM in the optimization process. Beyond a brief presentation of results, the discussion of DSM is very limited and focuses more on descriptions of the programs than projected results and the attendant rationale. For example, on pages 3 and 5 of AEG's report, there seems to be a substantial and increasing difference between NIPSCO planned DSM and the "Achievable Potential." This may be justifiable but it would certainly benefit from a narrative to explain the rationale. [The graphics in the AEG report are very good].

AEG identified energy efficiency measures based on factors like census data, population growth, age of the housing stock, current technology, and projected technology (pg 51). These were subjected to a screening process performed by NIPSCO using DSMore. These programs were, then, subjected to the five common cost-effectiveness tests. The energy savings of the programs seem to be used as an input

[6] NIPSCO characterizes this model as a "*Modeling tool for EE and DSM that correlates weather, loads, and prices on an hourly level.*" This model helped assess the benefits (or avoided cost) of the appropriate conservation measures against their cost (page 59). This tool values DSM using a risk based approach where the relationship between prices and loads is derived. After the DSM programs were evaluated, the conservation measures with benefits lower than their costs were dropped from consideration. The screening process first aggregated by end use, then by sector, and then run through the Total Resource Cost Test and the Utility Cost Test. NIPSCO projected the annual costs for the period 2016- 2035 for each aggregated end use sector where avoided cost accounts for energy, capacity, T&D, and ancillary services cost.

into the PROVIEW (PRV) module. This module is a resource planning optimization model that determines the least cost balanced demand and supply plan for NIPSCO. Finally, the Model determines the cost implications of adding resources to the system or the effects of modifying the load through DSM programs (Appendix D, page 15).

Given that NIPSCO's final Scenario noted the benefits of Industrial DLC, it's a bit surprising that additional industrial and large commercial DLC would not have been beneficial.

ISSUES AND CONCERNS

The Commission staff invites NIPSCO and stakeholders to respond to the following:

- In general, NIPSCO's 2014 IRP does not provide a very good explanation about the methodology used to identify and integrate DSM programs in the resource planning process. The Commission staff would welcome NIPSCO's response to the Commission staff 's concern that DSM seems to have been *baked into* the IRP and merely been layered on-top of NIPSCO's preferred resource plans rather than being truly integrated into the planning process. The constant demand reductions for the Industrial class add to our concern. If the Commission staff's understanding is correct, this is very concerning since the IRP intends that DSM compete with other resources for inclusion in the IRP on as comparable a basis as possible.[7]

- It's unclear how the eligible customers for some of the proposed 2015 DSM programs were selected. Furthermore, there is no information related to the number of participants in each program and how they were projected into the future. Given that the forecast has variables for number of customers and their usage, this seems to be inconsistent treatment.

- There is a vague explanation as to how the 2014 and 2015 programs were selected. It's not clear that they were subjected to a screening process or benefit cost test. Could NIPSCO please clarify?

- How were the projected annual costs of each DSM measure calculated? There is no explanation on how these costs were determined. Furthermore, there is a need for calculation on how the projected escalation factor adjustment used in the avoided cost calculation was achieved.

- Again, while assuming no large customer opt out has some potential benefits, this decision could have significant implications for the projected energy savings and avoided costs of the programs (page 52). Furthermore, this assumption is inconsistent with the Commission staff's understanding of the development of a Base Case (a/k/a Business as Usual or Reference Case). Since the Senate Enrolled Act 340 which allows large customers to opt out was passed during the development of the IRP and since this legislation was supported by large customers, continuing to include them seems unduly optimistic. Did NIPSCO also assume that large commercial customers would also opt out?

- AEG reported results (Appendix G) that left the Commission staff unclear as to what is included in the baseline forecast. Moreover, the graphs show that "NIPSCO with DSM" projection is above the baseline forecast in the Commercial and Industrial sectors (page 30) but this projection twice crosses the baseline in the Residential sector scenario. What is the rationale for this outcome?

[7] The Commission staff appreciates the difficulty of comparable treatment of DSM with utility generation. This problem MAY be ameliorated by the use of next generation long-term resource planning tools that co-optimize DSM with traditional generation resources and, purportedly, are capable of utilizing more discrete time intervals to better capture DSM and the operations of generating resources on a comparable basis. The Commission staff suggests that NIPSCO may wish to consider these tools that have more granular information and rely more heavily on probabilistic analysis rather than deterministic analysis. These tools need not be considered as a replacement, at least initially, but as providing another perspective.

- Were free riders considered in the DSM modeling process? The Commission staff couldn't find any information.

- According to NIPSCO, DSM had negligible effects on T&D requirements. From the Commission staff's perspective, while we have no reason to doubt NIPSCO's assessment, we hope that NIPSCO will periodically assess the avoided T&D costs especially as the quantity and quality of information from Smart Grid and AMI becomes more available.

- NIPSCO affirmed potential benefits for inclusion of 122.9 MW incremental Industrial DLC (NIPSCO described the parameters as: curtailment and short notice interruptions with at least ten minutes notice. Curtailments were assumed to be unlimited in quantity and duration, and limited to no more than one interruption per day, no more than 12 consecutive hours, no more than three consecutive days during week days, and no more than 200 hours per rolling 365 days). Page 116 Has NIPSCO considered the conditions under which additional DLC might be procured?

- Consistent with a concern the Commission staff raised in the Load Forecasting comments, what is the status of deployment of efficient street lighting within NIPSCO's service territory?

- IPL and I&M is instituting *Conservation Voltage Reduction* (CVR). Has NIPSCO given consideration to a similar effort?

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 17 states "NIPSCO has not demonstrated that it utilized all economical DSM. NIPSCO projects a 50% decrease in energy savings in 2015 as compared to last year. Then on page 11 noted it wasn't clear which DSM programs NIPSCO screened. *"It appears that the screened measures include those identified as achievable in the DSM Study but the IRP also states all DSM Core Plus programs were evaluated for inclusion in the IRP..."* Commenters also noted a difference between the IRP and the Study and asked for NIPSCO to explain the difference.

4. RESOURCES

Table 6-1 has the assessment of Existing Resources vs Demand Forecast and Table 9-3 is a Summary of Supply and Demand-Side Options that was considered. With the recognition that NIPSCO doesn't need resources in the near term, it was gratifying to see (beginning on page 80 and confidential information in Appendix 1) that NIPSCO provided some very good information on different generating resource options including renewable resources. The discussion of using levelized cost screening using various capacity factors on pages 88 and 109 is appropriate; providing they also used sensitivities to assess the implications of changes in construction cost and / or changes in capacity factor. Similarly, with variable O&M, it would be especially appropriate to use sensitivities to examine the implications of different fuel prices (beyond the fuel escalation rates on page 88) on the selection of NIPSCO's "Self Build Traditional Resource Analysis." Ideally, some of these scenarios and sensitivities involving NIPSCO self-build resources would be co-optimized with DSM, DR, customer-owned generation, and other resources - including transmission.

NIPSCO's discussion of other resource attributes (page 93) such as reliability at the time of peak demand, the ability to use the resource for ancillary services,[8] and the ability of the resource to reduce congestion and marginal losses was interesting but it isn't clear to the Commission staff how NIPSCO used these and if there was a potential for biasing the resource decisions in favor of traditional utility owned resources. Does the resource planning model have the capability to consider these attributes? The Commission staff would appreciate getting NIPSCO's perspective on this matter.

[8] Reactive power, contingency reserves / black start spinning reserves.

To increase the value of stakeholder participation –particularly increased input from industrial and commercial customers, NIPSCO should avoid "hardwiring" (e.g., the "self-build" plan) too many assumptions into the planning process. While NIPSCO's expert judgment may be best, it is better to explain the rationale but involve the stakeholders in the decision process and let the model do its thing. In this regard, the stakeholder process would benefit from a more complete airing of various risks.

5. REGIONAL CONSIDERATION

On page 92, NIPSCO has a good discussion of the implications of resource adequacy for NIPSCO's resource planning.[9] Given the Commission has responsibilities to ensure resource adequacy and in addition to the Resource and Demand projections throughout the 20 year planning horizon, the Commission would like NIPSCO (and other Indiana utilities) to provide the same Resource Adequacy information to the Commission that they provide to the MISO (appropriate consideration will be given to confidential information) and to the North American Electric Reliability Corporation.

The Commission staff would observe that the 7.3% Planning Reserve Requirement is substantially less than historic (Pre MISO) Planning Reserve Margins that were often well in excess of 20%. The lower reserve requirements due to coordinated operations, efficient transmission, and load and resource diversity result in huge capital cost savings for NIPSCO's customers and should provide a rationale for coordination in development of future resources. Beyond the significant operational and resource planning benefits and comments about participating in MISO processes, it isn't clear how NIPSCO integrates its planning process with MISO's planning process. In discussing its resources, on page 35, NIPSCO noted that 40% of MISO generation is coal-fired. Half of these would require substantial retrofits to comply with EPA rules (We believe this is without GHG rules that came out in June 2014) and may be retired due to the high cost. While MISO's south region is expected to have a 5 GW surplus by 2016, MISO's north and Midwest regions are forecast to have a 2 GW short fall. As a result, MISO is conducting studies to determine what can be done to transfer the capacity from the south to the north and Midwest.

NIPSCO states that MISO currently has 12,500 MW of wind resources in its region and an additional 15,000 MW in the study queue and accommodates Demand-Side resources. Did NIPSCO raise this topic because they are considering expanding their access to these resources in the next IRP? By way of examples, wind may be a cost-effective compliance measure to help satisfy new environmental requirements that should be more certain in the next IRP. NIPSCO also states there is 377 MW on interruptible tariffs that are registered with the MISO as a *Load Modifying Resource* to retain its resource adequacy benefit. Does NIPSCO intend to make efforts to increase this?

6. NATURAL GAS AND COAL

Based on the optimistic projections for natural gas supply and price, it is surprising that NIPSCO didn't have a more expansive analysis of natural gas in their Scenarios and Sensitivities. NIPSCO notes (page 36) "*The discovery and exploitation of North American shale gas resources appears to have fundamentally altered the price relationship between coal and natural gas. Natural gas prices have declined and remain low while coal prices have continued to rise with higher mining costs, rail transportation costs, and increased governmental regulations related to the mining of coal…coal still enjoys an economic advantage over natural gas, current and future environmental regulations may jeopardize…" (page 37)*

[9] *A minimum Planning Reserve Margin will ensure a minimum level of resource adequacy. The MISO UCAP planning protocol was used. To ensure that the correct criteria was employed, the Company constrained the 2014 IRP optimization so that no resource mix would be accepted that achieved a Planning Reserve Margin of less than 7.3% for years 2014-2035. Based upon NIPSCO's generation fleet reliability, NIPSCO's targeted UCAP planning reserve margin of 7.3% is roughly equivalent to a traditional Planning Reserve Margin of 9-12% using the Installed Capacity ("ICAP") planning protocol. An adequate minimum Planning Reserve Margin will minimize loss of load hours and the system's reliance on emergency energy... (page 92)* _ Emphasis added

NIPSCO has firm capacity on the interstate pipeline for Sugar Creek. On page 39, NIPSCO discusses its policies for Requests for Proposals. *To date, NIPSCO has entered into electric generation supply agreements that extend no longer than one year but is always evaluating the value and benefits of longer term agreements.* A bit more discussion of the rationale would be useful.

7. CUSTOMER-OWNED AND DISTRIBUTED GENERATION

For NIPSCO, customer-owned and other distributed generation is composed of Net Metering and participants in their Feed-In-Tariff (FIT). These programs were developed and made available to customers to promote distributed generation; particularly renewable resources.

Based on significant customer response to NIPSCO's *Feed-In Tariffs* for renewable energy, the Commission staff would like to know if NIPSCO has done a forecast of the potential for customer-owned and other distributed generation? NIPSCO's three year pilot feed-in-tariff (FIT) to promote customer-owned renewable power was approved by the IURC on July 13, 2011 with a cap of 30 MW (beginning on page 62). There are now 29.7 MW enrolled. NIPSCO's Phase II (Electric Rate 665) has expanded the resources by about 24.7 MW with an additional 16 MW being allocated to smaller renewable energy projects. At present, NIPSCO lists the following resources:

- PV solar generation: 15.50 MW
- Wind generation: 1.98 MW
- Biomass-fueled generation: 21.06 MW

NIPSCO states that an additional .19 MW of PV solar, .11 MW of wind generation, and 10.95 MW of Biomass-fueled generation would be added in 2014. Has this occurred?

ISSUES AND CONCERNS

NIPSCO's optimistic comments about the potential for customer-owned and other distributed generation seem to be inconsistent with the relatively modest amount projected in the IRP. Especially for industrial and large commercial customers, a reasonable case could be made that declining costs of technologies, increasing customer interest, declining cost of natural gas, the potential for CO_2 prices to be significant, and the potential changes in NIPSCO's generating fleet with attendant costs might result in an alternative resource plan that may warrant consideration.

ELECTRIC VEHICLE PROMOTION

Based on NIPSCO's positive experience EV and NIPSCO's efforts to cultivate early adopters of new technology, it is a bit surprising that a similar thought process wasn't considered in customer-owned resources. Moreover, with NIPSCO's positive experience with time of day rates for EVs, does NIPSCO plan to offer more time-differentiated options? One of the more revealing aspects of the NIPSCO EV promotion is that the time-of-day rates do have an effect on customer usage patterns. Specifically, customers avoiding peak periods for the *free* energy between 10 PM and 6 AM. [Cause 44016 approved NIPSCO's *In-Charge Electric Vehicle Pilot* program]. As of July 31, 2014, NIPSCO received 221 enrollment requests and the average usage for charging is 206 kWh per month.

8. STAKEHOLDER PROCESS

The Commission staff commends NIPSCO for its conduct of the two in-person stakeholder meetings. It is particularly commendable that NIPSCO's top management and subject matter experts attended the sessions and stayed throughout. This commitment should be well-received by stakeholders. NIPSCO also conducted a webinar, several meetings with groups of stakeholders, and one-on-one meetings with individual stakeholders. NIPSCO also performed several analyses for stakeholders. The Commission staff would be interested in NIPSCO's perspective on whether there are valuable synergies from having more broad stakeholder collaborative meetings than the two. Would that, for example, help NIPSCO and stakeholders better focus their requests for scenario and sensitivity analysis?

ISSUES AND CONCERNS

- It is the Commission staff's interpretation of the structure of the analysis that NIPSCO hard-wired or predetermined the resource mix that it deemed to be most-cost effective. The selected resources may be the right decision but it may have benefited from greater consideration of stakeholder input. Comments such as the following (on page 119) would have benefited from stakeholder input rather than being unilaterally decided by NIPSCO. "*The Base Case for the 2014 IRP was based on a best reasonable projection or expected case view of future economic, demographic, and energy use conditions...the second scenario developed for the 2014 IRP assumed higher commodity prices, a renewable portfolio standard implemented in 2020, and higher costs to comply with pending EPA regulations and a carbon cost is assumed to be implemented in 2025".*

- To help stakeholders make informed decisions that would have reduced the need for NIPSCO to make important foundational decisions, the stakeholder process would have benefited from a better understanding of the risk factors faced by NIPSCO and a better understanding of the elements of IRP. For example, from a risk perspective, NIPSCO could have analyzed a broader spectrum of future natural gas prices, carbon dioxide prices, the timing of carbon regulation, energy efficiency - especially with 111(d) stressing the importance of EE as a compliance measure, renewable energy – again as a compliance measure for 111(d), and customer-owned generation (even if NIPSCO doesn't believe some customer-owned generation is cost-justified, it seems likely some customers will go forward with the projects for non-economic reasons). NIPSCO, for example, might consider different "learning curve" sensitivities that incorporate different prices for various technologies.

- While the Commission staff appreciates NIPSCO began the IRP process before EPA issued its draft rules on June 2, has NIPSCO considered developing strategies to ramp up 111(d) compliance measures such as Energy Efficiency and Renewable Energy? It would seem this would be an appropriate risk analysis that should have been considered by all stakeholders.

The Sierra Club Hoosier Chapter commented favorably on NIPSCO's stakeholder process *"The process used by NIPSCO by far was one of the most open and participatory of the ones we have been involved in and we believe should provide a model for others moving forward in the second round of plans this year. The following five points illustrate why the process deployed by NIPSCO was exceptional : 1) NIPSCO offered multiple meetings with individual stakeholders to discuss various drafts of the plan, answered questions about the modeling and assumptions underlying the model and followed up promptly with responses throughout the year; 2) All meetings were held in the NIPSCO service territory which allowed customers and stakeholders in the area to attend; 3) NIPSCO held more than the minimum two public meetings by adding a third public meeting in response to requests for more review when it became apparent that stakeholders were not satisfied with the two meetings as required by the rule; 4) In addition to the three general public meetings and numerous individual stakeholder meetings, NIPSCO agreed to run models of various scenarios and sensitivities as requested by the Sierra Club to further analyze higher carbon costs, early retirements of existing generation facilities and accompanying net revenue requirements of scenarios beyond the minimum number they had initially set up; 5) Upon our request, on several occasions, NIPSCO made key personnel available who were doing the modeling and who provided detailed answers to our questions regarding the model itself which went above and beyond requirements."*

OBSERVATIONS REGARDING
VECTREN's 2014 IRP AND PLANNING PROCESS

IRP PURPOSE

"The Integrated Resource Plan (IRP) process was developed to assure a systematic and comprehensive planning process that produces a reliable, efficient approach to securing future resources to meet the energy needs of the utility and its customers. The IRP process encompasses an assessment of the range of feasible supply-side and demand-side alternatives to establish a diverse portfolio of options to effectively meet future generation needs." page 20

The Commission staff appreciates Vectren's voluntary adherence to the proposed Rules, establishment of a stakeholder process, the retention of outside experts to assist Vectren and its stakeholders, and a good recitation of the broad range of risks confronting the Company. However, given the risks identified by the Company in Chapter 1, the Commission staff believes it would be consistent for the purpose statement to be expanded to give greater explicit effect to risk analysis throughout the IRP. While perhaps intended by the statement a "*range of feasible supply-side and demand-side alternatives,"* this might be read as being unduly limiting since the concept of "feasible" changes over time in response to cost, efficiency, customer needs, and other risk factors. The Commission staff would ask utilities to *stretch the risk and feasibility envelopes* by considering some scenarios and sensitivities that stress their systems and consider risk factors that have low probability but significant economic and / or reliability risk ramifications.

1. RISK ANALYSIS WAS TOO CONSTRAINED

MODELS

Vectren uses the optimization software (Strategist) developed and supported by Ventyx to find the best possible combination of resource additions — both supply-side and demand-side alternatives, that result in reliable service at the lowest cost to customers over the twenty year planning horizon. According to Vectren, the optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the Net Present Value (NPV). Power purchases and sales are included in the NPV analysis as well.

METHOD

Vectren started with twelve scenarios – three basic portfolio themes compared against the capacity needs of four energy forecasts. The three basic portfolio themes are "A" – Base (serve customers with existing resources & DSM), "B"- FB Culley 2 Unit Retirement Scenario (shut down FB Culley 2 in 2020) and "C" – Renewable Portfolio Standard. However, Vectren did not mention what criteria the company used to narrow down to the three portfolio themes. The four energy forecasts are Base Demand Forecast, Low Demand Forecast, High (modeled) Demand Forecast and High (large load) Demand Forecast. The difference between the two high demand forecasts is slow steady growth or a large step up. In the High (modeled) Demand Forecast, economic growth was increased from approximately 1% in the Base Demand Forecast to 2%, and population growth was increased from about 0.3% to 0.5%. The High (large load) Demand Forecast is the same as the base case, with the addition of a large customer in 2018. Assumptions regarding existing purchased power, fuel prices, environmental costs and financial costs are consistent across the twelve scenarios.

The Renewable Portfolio Standard (RPS) plan was the most expensive one among the three portfolio themes no matter which demand forecast was used because the RPS called for new generation to be built and additional energy efficiency programs to satisfy the renewables requirement. The cost of serving customers with existing resources, compared to that of retiring FB Culley 2 in 2020, was slightly higher under the Low, Base and High (modeled) Demand Forecasts. But retiring FB Culley 2 prematurely, in the event of a large customer addition (High (large load) Demand Forecast), could be very costly to customers. Due to the risks associated with prematurely retiring FB Culley 2, Vectren intended to serve customers with existing generation in the near term. The company did mention that the plans would be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Each plan resulted from scenario analysis was tested against six risk factors respectively to determine which plan was the lowest cost over a wide range of possible future risks. The six risk factors were natural gas prices, coal prices, electric energy market prices, carbon prices, capital costs of new resources, and regulation cost. Ranges of the six factors were set by Vectren based on various sources. The upper and lower bounds of each risk factor produce two sensitivity analyses for each scenario for all risk factors except the regulation cost. The high regulation cost uncertainty only adds one test of including the capital cost for a cooling tower at FB Culley in 2022 for each scenario.

ISSUES AND CONCERNS

A. It is not clear how Vectren determined the three basic portfolio themes.

B. Although Vectren developed twelve scenarios to factor in distinctive possible futures, none of the scenarios take into consideration different trajectories of natural gas price, electricity market price and carbon price when developing the optimal resource plan.

C. In regard to sensitivity analysis, the range of carbon prices picked by Vectren is between \$10.3/ton and \$15.5/ton. The upper bound of carbon price came from the Synapse 2013 mid case CO2 pricing. The problem is that the choice of the upper bound of the carbon price was relatively low. It is noted that RPS is only slightly more expensive than the other two portfolio themes in all sensitivity analyses conducted by Vectren. It was also mentioned by Vectren that high carbon price had the greatest influence of stress tests on NPV based on stress test results. Therefore, when carbon price is high enough, RPS portfolio might easily become the optimal plan. This possibility was totally ignored by Vectren.

D. Vectren mentions a significant uncertainty is large customer adoption of combined heat and power to generate some or all of the customer's electricity requirements but fails to address this issue in its risk modeling to further understand the potential implications.

It appears the Scenarios were primarily intended to confirm Vectren's preferred long-term resource plan rather than to undertake an expansive assessment of relatively low probability but potential high risk / significant consequence outcomes. It would be perfectly appropriate for Vectren to caveat extreme cases as being illustrative or hypothetical for the purpose of stressing the system and to admonish stakeholders not to characterize such analysis as representing Vectren's judgment of endorsing these more extreme cases.

It is a bit surprising that Vectren didn't take the opportunity to develop something akin to "book-end" risk analysis since Vectren enumerated factors that could affect the Company in the short run including the Clean Power Plan, early retirements of coal-fired units due to MATS, and the age of some units. Given that the EPA's proposed draft rules for CO_2 didn't come out until late in the process, the Commission staff would not expect an in-depth analysis of the ramifications of the rule but an expansive analysis of the potential risk should have been undertaken. Table 10-8, shows the "High" case of \$15.5 per ton for CO_2 and a low case of \$10.3 per ton. Vectren noted that a high carbon price resulted in the greatest stress on the NPV analysis, so it isn't surprising this low price of \$15.5 per ton did not provide any significant insights regarding resource build-outs. For example, at what price would carbon prices have to be for the RPS portfolio to become the optimal plan? What CO_2 price level(s) would cause major changes in all of the resource plans? Other factors such as a broader range of natural gas prices, lower prices for renewable energy sources could have also resulted in a larger risk bandwidth to stress the Vectren system but these were not explored.

On page 189, Vectren mentions access to 30 MW (UCAP) of Ohio Valley Electric Corporation (OVEC) throughout the entire 20 year planning horizon. Given the age of the OVEC facility and the potential ramifications of reliance on that resource with CO_2 regulation, would Vectren agree that even some minor changes in assumptions might result in the elimination of this resource in the IRP? In other words, how tenuous was the inclusion of this resource in Vectren's IRP? The Commission staff assumes that Vectren would not be able to answer this question due to the limited analysis of risk. Is this assumption correct?

On page 211, Vectren discusses important risk factors in the decision to retire Culley 2. Specifically, (1) How Indiana intends to implement CO_2 guidelines, the EPA's Clean Power Plan. (2) Uncertainty about customer load due to the installation of a large co-generation unit. (3) The possibility of a new large customer addition, (4) Uncertainty around capacity shortfalls within the MISO market. Given this recognition of risk surrounding Culley 2 (beginning on page 196 through page 211) that showed retirements in some scenarios, how tenuous was Culley 2 in the IRP analysis? In short, wouldn't even a more slightly expanded treatment of risk result in Culley 2 being retired? In sum, it seems likely that narratives could be constructed that produced a different set of plausible, feasible, cost-effective, reliable, and resilient set of resource plans if Vectren would have had incorporated slightly more risk analysis into their IRP.

For the Base Case (a/k/a Business as Usual or Reference Case), rather than "baking in" a preferred resource portfolio, it would be strongly preferable to work with stakeholders to construct a Base Case that allows the model to solve for resources beyond the first three to five years . That is, the Base Case should only include those resources that have a very high degree of certainty within the next few years. For alternative scenario analysis, it is important for Vectren – in concert with its stakeholders – to develop a consistent and well-reasoned narrative for each scenario and the sensitivities.

As with other utilities, Vectren may be too reliant on deterministic analysis and might want to incorporate more probabilistic analysis into their long-term planning processes. For additional perspectives on risk, the Commission staff would encourage Vectren, and other Indiana utilities to consider alternative or supplemental planning tools and to develop the requisite databases to support new state-of-the-art planning tools.

The Commission staff would ask Vectren (and all Indiana utilities) to consider injecting more probabilistic analysis into the long-term planning; at least as a supplement to its current practices. Probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more comprehensive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods, may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contributions of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a compliment to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severit**y.**

The Commission staff commends Vectren for utilizing both public and private information on key drivers. Combining several sources – including Vectren's in-house expertise for financial assumptions is very appropriate. Providing public domain fuel price data for the public version and also considered other sources – including proprietary sources to provide a more robust forecast of this important driver. (Pages

190- 191). Similarly, Vectren's use of public domain estimates of inflation was appreciated and, taken in total, the complimentary use of public and private information enhance the credibility of the analysis.

The OUCC (page 1) observerd "The utilities did not demonstrate in a clear manner whether these qualitative elements [e.g.,, political outlook, risk, portfolio mix, and human behavior] were considered and, if so, how they were accounted for in the modeling process. It also is unclear whether the utilities' modeling considered the availability of renewable resource at peak load or the need for and cot of available back-up energy through spot or long-term contracts for purchased power." The OUCC also mentioned on page 5 that Vectren should use the Indiana Technical Resource Manual (TRM) until actual Evaluation, Measurement, and Verification (EM&V) results are aviable to determine savings for individual measures. Once available, company-specific EM&V results should be used.

The OUCC raised concerns about whether the retention of Culley 2 (page 4) was properly considered in the context of all of the environmental regulations.

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 1 state: "*The most recent revisions to the IRP rule were intended to recognize the increasing regional interconnectedness of Indiana utilities, and to facilitate a collaborative process for evaluation of the potential ramification of a range or risk and uncertainties facing the electric sector, such as increasingly stringent environmental regulations (including region of green house gas emissions) and increasingly low –cost and available demand-side renewable resources…[A]s detailed, the three utilities* [NIPSCO, IPL, and Vectren]..*each undervalue, and in some cases disregard, clean, low-cost energy and resources by failing to analyze demand-side and supply-side resource alternatives on a consistent and comparable basis."*

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 8 states that Vectren failed to examine the economics of retiring existing units other than FB Culley 2. "*Vectren's IRP treats certain existing resources preferentially, which violates the requirement to evaluate all resource on an even playing field. Vectren's IRP modeling only examined one plan in which FB Culley 2 is retired in 2020.* On page 20 "*Vectren fails to mention its modeling results showing that in the vast majority of modeling runs, retiring FB Culley 2 is the least-cost option."*

The CAC (at page 8) *"criticizes Vectren for not modeling retirement of units other than FB Culley Unit 2 in its IRP and contends that since some modeling supported retirement of FGCulley Unit 2 as early as 2020, the modeling may have yielded similar results for other units."*

Valley Watch, Inc on page 1 states "Vectren South's 2014 IRP does not say that its customers pay the fifteenth highest electric service delivery rates in the nationand has a plan to reduce those costs to the captured ratepayer.

2. COMMENTS ON LOAD FORECASTING

On page 32, "*The demand forecast considers historical electric demand, economics, weather, appliance efficiency trends (driven by federal codes and standards), population growth, adoption of customer owned generation (such as solar panels), and Vectren DSM energy efficiency programs (such as appliance rebate programs)."* Specifically, the demand forecast is a monthly linear regression model based on heating, cooling, and base energy use requirements from the sales model for each class. Vectren uses a statistically adjusted end-use model for residential and general service loads, an econometric linear regression model for large loads, and a simple trend analysis model for street lighting. For purposes of risk analysis, the low and high forecasts are developed by modifying assumptions for conservation, distributed generation adoption, economic drivers, population, and large customer additions. For the IRP, Vectren used two versions of the high load forecast. One included the addition of a large customer in 2018 and the other changed the model drivers.

The Residential forecast is the result of a residential customer forecast multiplied by a residential use per customer forecast that is developed from the monthly statistically adjusted end-use variables to capture (heating, cooling, and other). The model is intended to capture the interactions among the variables to construct end-use energy intensity projections for the Evansville Metropolitan Statistical Area (MSA) and to interact with household characteristics such as size and income, electricity price, and heating / cooling degree days.

The General Service (GS – Commercial) forecast is a result of a monthly statistically adjusted end-use model in which sales are a function of heating, cooling, and other end-uses. The model is intended to capture the interaction among these variables, a commercial economic variable (gives equal weight to commercial employment and non-manufacturing output), real electricity price, and Heating Degree Days – HDD / Cooling Degree Days - CDD.

The Large (Industrial) forecast is based on a generalized monthly regression model in which sales are driven by manufacturing employment and output (a weighted combination of real manufacturing output and manufacturing employment), cooling degree days, and monthly binaries that capture seasonal load variation and shifts in data. From the comments about the possibility of a new large customer and the uncertainty about another large customer installing co-generation, it's clear that the risks associated with large customers are significant.

The street lighting forecast is predicated on a simple exponential smoothing model with a trend term.

Vectren had a good use of graphics to help illustrate the demand and energy use of its different customer classes. This type of graphic should be particularly helpful to the stakeholders.

AREAS FOR DISCUSSION

At the outset, Vectren's external data sources are reasonable including the use of NOAA, Moody's for Economic and Demographic data, saturations and efficiencies from EIA as modified by ITron for Vectren's service territory. However:

1) The CDD and HDD weather data from NOAA is calculated from daily minimum and maximum for Evansville. Why didn't Vectren use a 24 hour average?

2) The footnote on page 73 stating *The large sales model also includes CDDs* is confusing in the context of the sentence.

3) Residential model is estimated over January 2003 – December 2013. Why only 10 years? Were longer periods tried? If so, what were the results and concerns?

4) The Residential forecast uses historical and forecast saturations and efficiencies from Itron and EIA. Was the Itron – IEA data tailored to Vectren? Has Vectren conducted a statistically valid independent analysis to verify the data?

5) What is the estimation period for the General Service and Large customer models?

6) The Large Sales Model lists "output" as a driver. What is the measure of output used? This appears to be regional manufacturing GDP growth based on page 74 but it would be clearer to specify it in the model description as well.

7) On page 140, the IRP states the forecast will be affected by "organic energy-efficiency trends." For the sake of clarity, what is meant by "organic" in this context and how is that different from other energy efficiency?

8) Street lighting is modeled as a simple linear trend. Has Vectren considered constructing an econometric specification for street lighting? With increased efficiencies, it would seem appropriate to consider this.

9) Regarding the development of "High" and "Low" forecasts discussed on page 69, were the changes to the economic drivers based on internal company judgment or were they provided by Moody's Economy.com?

10) Also on page 69, it states that in the "High" (modeled) case, economic growth was increased from approximately 1% to 2% and population growth was increased from about 0.3% to 0.5% yet there was no mention of the changes to the drivers of the "Low" forecast. Could you please provide those?

11) The Commission staff would also like to have a better understanding of the interactions among the Residential, GS, and Large customers. Perhaps, this could be provided in the narrative.

12) The Commission staff would appreciate a discussion of what steps Vectren intends to take to improve the databases, specification of variables, models, and processes (including more stakeholder involvement) in the next IRP and beyond.

3. <u>CONSIDERATION OF DSM</u>

The Commission staff appreciates Vectren's statement of a *culture change* in their support for energy efficiency (page 131), the recognition that *"a cost-effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process"* (page 172). The Commission staff also commends Vectren for being the only utility to make a concerted effort to <u>treat DSM as a resource</u> rather than baking in an estimate in the load forecast. As evidenced by Vectren's comments, they have an appreciation that energy efficiency is another element of risk that may alter Vectren's long-term resource plans and, therefore, warrants additional scrutiny. On page 121,Vectren highlights that 25 MWs of demand reduction will increase to 40 MW in 2014 and the 130,000,000 kWh savings will increase to 188,000,000 kWh.

Beginning on page 129, the IRP discusses the significant ramifications of federal and state policies to promote energy efficiency. At the federal level, Vectren identified the EPA's Clean Power Plan proposed draft rule as well as the amended minimum efficiency standards (Appliance and Equipment Standards Program) issued by the U.S. Department of Energy that includes residential air conditioners and heat pumps. At the state level, Vectren cited their recently approved 2015 DSM plan (1 year) that was the result of the Senate Enrolled Act 340 removal of the mandatory statewide CORE DSM programs and the attendant PHASE II energy savings goals. This IRP includes energy efficiency programs for a savings target of <u>1% of eligible annual savings</u> for 2015-2019 and .5% thereafter "*for customer load that has not opted out of DSM programs*" (page 172). The IRP projects that 70% of the large C&I customers will opt out and not participate in the energy efficiency programs. Vectren, however, said it has revised its 2015 Plan to adjust for an 80% opt-out level effective January 1, 2015.

Especially in retrospect more stakeholder involvement would have been beneficial. However, Vectren should still be commended for the process used in developing their 2015 Plan which used the framework of the programs offered in 2014 (including the retention of EnerNOC Utility Solutions to conduct a Market Potential Study (MPS – The 2012 MPS is contained in the Technical Appendix D) which established a baseline for 2011 through 2023. Vectren, in formulating it's 2015 Plan and the benefit / cost analysis used in the IRP, relied on the Recommended Achievable potential scenario in the MPS as guide for developing the 2015 Plan (page 135) which was supplemented by the expertise of Vectren's DSM program managers and outside experts.

Vectren's modeling included the different tests such as the Participant Test, Utility Cost Test, Ratepayer Impact Measure, and Total Resource Cost Test (page 137) with the programs that passed input into the integration analysis as a resource (page 169). The bottom-up approach used by Vectren / EnerNoc described on page 134 seems to be very appropriate but a discussion of the process that supported the conclusions would have been beneficial. It's clear there was considerable effort in obtaining the data to support a bottom-up approach but the effort may go unnoticed due to a lack of a good discussion about the approach.

Vectren created savings blocks based on 0.5% of eligible sales considering the adjusted projection that 80% of the Large Customers would opt out (rather than the 70% originally assumed) of the utility sponsored DSM programs. Vectren identified the maximum level of potential additional DSM being 2% of total eligible sales. The 2% includes 1% of embedded savings plus 1% of incremental DSM modeled in 2018 – 2019. Beyond 2019, the model was limited to selecting 1.5% . That is, 1% embedded DSM and .5% of total eligible sales for additional DSM. The total is consistent with Building Block 4 of the Clean Power Plan 111(d). In the MPS, EnerNOC estimated the *"Levelized costs of energy saved began at approximately 3 cents / kWh for the first available block in 2015 and increased to 6.4 cents/kWh for the last available block in 2034"* (page 172).

AREAS FOR DISCUSSION

1) The Commission staff is gratified by Vectren's comment that "*a cost effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process.* However, we were concerned that the 1% embedded DSM and the .5% incremental amounts of DSM were a cap after 2019. Allowing the expansion planning model to select cost-effective DSM under more expansive risk analysis might have produced significantly different results that would have been plausible.

2) There seems to be a contradiction between the statements:*"The framework for the 2015 Plan is a continuation of programs offered in 2014, at a savings level of 1.2% of sales"* (page 134) and *"DSM energy efficiency programs included in the base sales forecast are available to all customer classes at a targeted level of 1% eligible annual savings for 2015 – 2019* (page 171). Why are these percentages different?

3) Notwithstanding the comment *"if the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), a given measure is considered in the economic potential,"* and page 1-2 of the EnerNOC study which provides some idea of the specific test, there was no obvious explanation for the costs and benefits primary test parameters used to decide whether or not to adopt a specific energy efficiency measure since there was no discussion of the other cost-effectiveness tests beyond the TRC.

4) How big are the groups considered to indentify the measurable savings in the Residential Behavioral Savings Program? The Commission staff believes that the size of the groups could affect estimates of energy / demand savings and the expected cost of the program (page 162).

5) From the IRP (page 69 Table 5-2), the origin of "NET DSM" number for 2014 and 2015 is not clear. Since the baseline forecast estimated by EnerNOC was only used to guide the design of the 2015 DSM Plan, there should be an explanation of the type of adjustments that were made to estimate these numbers. Furthermore, the IRP states that the *RECOMMENDED ACHIEVABLE* scenario was used as a guide for the 2015 Plan but the energy savings values specified in that Scenario are far off of the ones used in the IRP.

6) While Vectren seems to acknowledge that DSM is dynamic and innovations may spur additional DSM programs (page 152), there is concern that Vectren's DSM savings goals and comments seem to imply that once *the low hanging fruit* are picked that some current programs may no longer be cost-effective. If the Commission staff's understanding is correct, we would like to have some examples**.**

7) The comments regarding avoided cost on page 139 warrant more discussion. Particularly, if a more expansive risk analysis was conducted and there were substantially different resource plans and different Reserve Margins. Even without plans that might justify different avoided cost calculations, within the MISO facilitated markets, is it still appropriate to use Simple Cycle Gas Turbine as the proxy for avoided cost?

8) Again, the bottom-up approach has intuitive appeal but it would have benefited from more discussion of the benefits of this approach and the process.

9) Greater discussion would have been useful of the assumption on page 172 of the increasing levelized costs of blocks of energy saved over the forecast horizon.

The OUCC, on page 2, that Vectren hardwired DSM resources and reducing the expected load by the predetermined level of DSM prevents evaluation of DSM with other resources on a consistent and comparable basis.

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 8 states: *"As with IPL, Vectren hardwired a base level of DSM into the load forecast…The IRP is unclear as to how the Company developed its base DSM forecast…Vectren also projected that the cost of energy efficiency more than doubles over the twenty-year plan. Vectren stated these costs were based on its potential study and 2015 plan, but the derivation of the cost assumptions over the planning period should be further explained."* CAC et al, also observed that Vectren's DSM opt-out and cost assumptions raise concerns because it leaves a substantial amount of cost-effective energy efficiency *on the table* and do not assume that any will opt back in if there were improved industrial offerings or a self-directed program. On page 15, "*Vectren's declinng savings projection does not reflect all economical DSM."*

Hoosier Environmental Council cites several studies such as those from the American Council for an Energy Efficient Economy and Lawrence Berkeley Laboratory to support their argument that energy efficiency was the lowest cost resource, has the least risk, and might play a significant role in compliance with the Clean Power Plan (pages 1 and 2).

Ms. Jean Webb said: "*Vectren has reduced their efforts in the Direct Load Control (DLC) program*." Vectren, at the time of their last rate case (Cause No, 43830) claimed 25 MW of DLC. In the 2014 IRP, Vectren only projects 17 MW for DLC. Likewise, Vectren is deemphasizing interruptible power. In their 2011 IRP, Vectren projected 35 MW to 50 MW but then the projection drops to 28 MW in the 2014 IRP.

4. <u>DISTRIBUTED, RENEWABLE, AND CUSTOMER-OWNED GENERATION</u>

The Commission staff commends Vectren for their enumeration of the potential types of customer-owned and other forms of distributed generation, but believes that Vectren, as with most other Indiana utilities, may not fully appreciate the potential for Customer-Owned and Distributed Generation in their service territory. Vectren noted, for example, on page 211, that the uncertainty surrounding installation of a large co-generation unit might be a significant factor in the decision to retire Culley 2 sooner than in Vectren's preferred plan. Vectren also noted the potential addition of another large customer on page 211. Has Vectren considered how its resource planning might be altered if this customer decided to locate in Vectren's service territory but elected to install some generation? Suppose, other large customers decided, for any number of reasons (e.g., their perceived cost savings, reliability, quality of service, interest in a specific technology) that they would install some resources to reduce their reliance on Vectren? Is this a Black Swan event that doesn't warrant consideration?

The Commission staff believes that, given the potential for significant changes in the resource mix due to declining cost of some technologies, the potential for innovations, lower natural gas prices, environmental policy, and the need to replace much of the current resources during the planning horizon, that some customers will install their own generation with varying degrees of regard for whether the utility believes the customer-owned technology is cost-effective. The IRP (page 85 and page 69 – Table 5-2) shows the primary distributed and renewable generation are wind, solar, and biomass with only solar showing growth (wind and landfill are held constant) throughout the 2014-2034 planning horizon.[10] Solar generation in the Base Case is 1 GWh in 2014 and increases to 106 GWh in 2034.

The Commission staff believes that, especially over the 20 year planning horizon, some of the other technologies Vectren mentions should be given greater scrutiny. These include technologies that may be adopted sooner such as combined heat and power (CHP) for some customers as well as technologies that may be more likely to be adopted in later years such as small wind turbines, energy storage, fuel cells, micro-turbines, micro-grids, and combinations of these technologies.

Comments from CAC, Earthjustice, Indiana DG, and Sierra Club on page 10 states "*IPL considered wind energy that could be delivered into Indiana when the Clean Line high-voltage transmission line linking Kansas to Indiana is completed. IPL noted that the Clean Line transmission project will make wind with a 50% capacity factor available in Indiana..which is nearly double the 27% capacity factor wind that Vectren modeled.*" On page 29, commenters express concern that Vectren did not provide an adequate citation (beyond citing NAVIGANT) for the assumptions it relied upon to develop its solar forecast.

The CAC asserts that Vectren failed to evaluate the most economical renewable resources, particularly out of state wind like wind farms in Kansas. (page 3).

HEC contends that Vectren did not explore the potential for other types of of customer-site distributed generation like CHP to meet future base load and peak load needs. Vectren acknowledges that customer sited CHP can be an efficient way to serve certain types of loads. However, the ultimate decision about these systems lies in the hands of the customer and their unique situation.

Ms. Jean Webb said *"The 2014 IRP considered a new build of a 50 MW solar facility…however, it didn't look at Purchased Power Agreements (PPAs) for solar."*

5. INTEGRATION OF NEW TECHNOLOGIES

Vectren provided a discussion of Smart Grid and AMI (including better information that would improve the credibility of the IRPs and resource evaluations) that was useful. While extolling the benefits of Smart Grid and AMI, Vectren has – thus far – concluded that it would not be cost-effective. Given the successful implementation by other utilities, the Commission staff urges Vectren to continually assess the benefits and costs.

6. APPROPRIATE RECOGNITION OF THE REGIONAL CONTEXT FOR LONG-TERM RESOURCE PLANNING

Vectren did a good job of explaining their involvement with the Midcontinent ISO and how the operations and planning conducted by the MISO affect Vectren's planning and operations. The Commission staff appreciates Vectren's understanding that MISO's long-term planning and Vectren's Integrated Resource Plan are intertwined and the MISO facilitated markets provide greater reliability and

[10] Vectren's "High" case shows a 40% growth per year from 2014-2025 and a 15% per year growth rate for 2025-2034. The "Low" case has a 34.1% growth per year and 12.8% for the period 2025-2034. The Base Case uses a simple average annual growth rate of the high and low cases in each year. Based on analysis by Navigant Consulting, a **PEAK DEMAND CONTRIBUTION** of 38% is used. The rationale is that the optimal solar output for a given solar panel occurs at noon in late spring through early summer. Therefore, a factor of 38% is applied to each year's solar forecast to derive the contribution of solar to the Vectren system's peak demand.

lower costs (e.g., regional economic dispatch, access to a vast array of resources to provide greater resource diversity, load diversity, lower reserve margins, and the ability to facilitate compliance with complex environmental rules) than would be possible without the MISO.

On page 187, Vectren discusses the Unforced Capacity (UCAP) *minimum* Planning Reserve Margin (PRM) based on MISO's projected need. For the year 2014, MISO set 7.3% as a UCAP PRM. However, with the potential for significant changes in the resource mix, does Vectren believe the RA should be re-evaluated? In this regard, the Commission staff is interested in how Vectren intends to incorporate the analysis being conducted by the MISO regarding the ramifications of environmental regulations; particularly 111(d) into Vectren's IRP analysis.

If Vectren had conducted a more rigorous analysis of risk (particularly increased CO_2 prices) that would have resulted in different resource expansion plans, would Vectren's comments on pages 179 and 180 change? On page 180 Vectren states "*No transmission facilities were identified due to proposed generation interconnections, transmission service requests, or energy resources in this IRP process*." On page 179, Vectren contends that "…This reliability measure [expected net interchange] indicates that additional import of transmission capacity is not needed for our generation to serve our load. However, the table [9-1] does not reflect several other factors such as potential purchases or sales. The table reflects total generation capability and not a reasonable economic dispatch under all conditions. It is likely that renewable energy resources may be imported using the transmission system in lieu of running local generation. It is assumed that the gas peaking turbines would likely not be dispatched during some near peak summer conditions, in which it is not only possible, but likely that the expected interchange could be importing 300-400 MW.

Regarding comments on page 175, "*The primary criteria for assessing the adequacy of the internal Vectren transmission system were (1) single contingency outages of transmission lines and transformers during peak conditions, and (2) selected double and multiple contingencies. Interconnections were also assessed by examining single, double, and multiple contingencies.*" First, to be clear, is our understanding correct that for contingency analysis of (1) and (2) that this is predicated on the peak conditions on specific transmission elements (which are likely to be non-coincident) rather than system peak coincident demand? Further, isn't Table 9-1 based on net interchange capability at the time of system peak demand? If so, does Vectren's analysis of transmission or other resource needs change if the analysis is based on coincident peak demand rather than the maximum demands on the various transmission elements?

Especially since transmission is typically based on the demands on specific transmission elements while system planning is based on coincident peak demand, a concern arises that investment in transmission and other resources may be based on different metrics. For transmission planning, resolving system contingencies is deterministic –as required by NERC - but determistic methods don't address whether other resources might be more cost-effective in resolving the contingency. For this purpose, probabilistic methods might be used to supplement deterministic methods. Has Vectren considered supplementing traditional deterministic methods with probabilistic methods? The Commission staff notes that NERC is considering probabilistic methods to provide an additional perspective to current deterministic planning analysis and has started to collect data to assist their consideration.

For both reliability and economic reasons, especially if there are proposals for substantial amounts of new transmission to facilitate broad regional trading of renewable energy to comply with environmental regulations including 111(d), does Vectren anticipate working with MISO to consider probabilistic analysis of transmission proposals to better ensure that all alternative resources are appropriately considered with the goal being cost-effective while also ensuring reliability?

On page 189 Vectren mentions potential changes in the distribution system, has Vectren, given consideration to using DSM, DR, customer-owned, or other distributed generation to beneficially alter these plans? IPL and I&M are instituting *Conservation Voltage Reduction* (CVR). Has Vectren given consideration to a similar effort?

The Commission staff has considerable regard for Vectren's expertise in natural gas and is familiar with recent studies that demonstrate natural gas delivery is not likely to be a major issue for Indiana. For these reasons, the Commission staff would like Vectren's comments on how the MISO (and others) is addressing natural gas procurement issues to ensure reliability; especially if there is a substantial change in the generating fleet. In addition, have the ramifications of the Polar Vortex in 2014, the protracted cold weather in February 2015, the relatively low price trajectory of natural gas prices, and the potential for more intermittent resources that might require additional natural gas generation to firm-up intermittent capacity caused Vectren to change any of its natural gas procurement practices such as purchasing more firm pipeline capacity?

7. TREATMENT OF PROPRIETARY INFORMATION

The Commission staff commends Vectren for using both propriety and public domain data sources. Using public domain information (or blended data to prevent disclosure of proprietary information) is helpful to the stakeholder process and to the credibility of the analysis. The Commission staff appreciates the candor of top Company officials during the stakeholder meetings and their due recognition of pending matters before the IURC. The Commission staff believes that Vectren recognizes that the process benefits from an open process and comported themselves accordingly.

8. INCORPORATION OF NEW MODELS, DATABASES, AND PROCESSES

The Commission staff recommends that Vectren assess the potential benefits from injecting more probabilistic analysis into their planning processes and considering models that are specifically designed to optimize resources with much more granular detail throughout the entire planning horizon. This suggestion for considering greater use of probabilistic analysis is not meant to be a replacement for the deterministic methods that permeate the current planning processes. [11] Rather, probabilistic analysis is intended to provide different insights that may better inform all aspects of the IRP.

Especially with the continued use of Scenario Analysis, the Commission staff encourages Vectren to redouble their efforts to provide a consistent narrative to explain the different resource expansion plans that emanate from the IRP process. The stakeholders should be invited to assist in developing coherent and consistent narratives. To be of the greatest help to Vectren, the stakeholders should be active participants in the construction of the Scenarios and Sensitivities.

9. SHAREHOLDER PROCESS

Vectren is to be commended for the commitment of its top management and its subject matter experts throughout the stakeholder process. While the proposed IRP rule requires at least 2 meetings, Vectren, to its credit, scheduled three.

After attending several stakeholder meetings over the last two years, the Commission staff believes that, as part of the stakeholder education process, Vectren (and other utilities) should consider devoting more time to a primer on long-term resource planning and the role of stakeholders. The spirit of the proposed IRP rule is for stakeholders to be intimately involved in all aspects of the scenarios and sensitivities used in the development of the IRP. In addition to understanding how scenarios and sensitivities are developed, the stakeholders will need to have an understanding of major elements of the process such as load forecasting, the data sources, different resources, and the analytical tools to be used. Since the expertise of the stakeholders will varying, it is important to define important terms and incorporate charts, tables, and graphics. By way of example, graphics such as load shapes and load duration curves can be used explain how DSM / DR, customer-owned generation, and utility-owned generation affect IPL's resource requirements.

[11] Vectren uses the optimization software (Strategist) which is highly regarded. The software was developed and is maintained by Ventyx to find the plan that results in the lowest Net Present Value of Revenue Requirements and deterministically satisfies the reliability requirements.

10. THE ORGANIZATION OF THE IRP

The Commission staff recognizes that the IRPs are evolutionary and we certainly don't want to be prescriptive on how the organization of the Report. Because this is an *integrated resource plan,* the Commission staff is well aware there will be overlaps. We hope Vectren and other utilities will consider how other utilities have done their IRPs and adopt formats that they believe will advance the stakeholder process and the readability of the IRPs.

OBSERVATIONS REGARDING

HOOSIER ENERGY's 2014 IRP AND PLANNING PROCESS

IRP PURPOSE

"The IRP will enable Hoosier Energy to expect the lowest possible power supply cost, at a targeted level of low market and low business risk, for its member distribution systems, while seeking a high degree of generation and transmission reliability. In developing this resource plan, Hoosier Energy considered alternative types of generation (supply-side) and end-consumer usage modification (demand-side alternatives to seek an optimal blend of capacity resources.

The process has led to a plan that seeks to minimize member-system power supply costs and risk while maintaining a high degree of system reliability. In addition, the Hoosier Energy Plan seeks to maintain sufficient flexibility to react to changes n member system needs, load forecasts, legislative and regulatory mandates, new technologies, and market price volatilities. The Plan will be reevaluated periodically to ensure that the recommended course of action are having the desired effect and continue to the best alternatives." (page 11)

OBSERVATIONS

The Commission staff recognizes the structure of Hoosier Energy and its members are different from vertically integrated electric utilities. The structural differences pose problems for coordinating the long-term development of demand-side management, demand-response, customer-owned generation, and other forms of distributed generation. As a result, integrated resource planning is more difficult. The Commission staff also recognizes there are some potential advantages due to the ability of member cooperatives to tailor their programs more precisely to their members. Notwithstanding the differences, the significant risks that the Hoosier Energy system will be confronting are, with few exceptions, the same as those faced by Investor-Owned Utilities (IOUs). Due to the statutory requirements for the Indiana Utility Regulatory Commission to ensure reliability – including Resource Adequacy and at the lowest cost reasonably feasible, the Commission staff's comments will hold Hoosier Energy to the same standards as those of Investor-Owned Utilities.

The Commission staff fully appreciates that projecting load and resource requirements over a planning horizon of 20 years is unlikely to be spot on. Rather, the Commission staff expects utilities to provide narratives that provide a rationale for several different "Scenarios" (a/k/a "futures) and "Sensitivities" (such as significant changes environmental regulations such as CO_2 prices, changes in the resource mix over a broad region, changes in natural gas prices, changes in the cost of alternative technologies, changes in the efficiencies of technologies, changes in the load forecasts, economic and etc). Hoosier Energy would benefit from insights derived from several Scenarios and Sensitivities that result in distinct resource plans. These plans, at the extreme, might be regarded as "bookends." To be clear, the Commission staff does not expect Hoosier to defend any alternative scenario as being endorsed by Hoosier Energy. To this end, we would encourage Hoosier (or any utility) to characterize the more extreme cases as illustrative or hypothetical.

The Commission staff encourages Hoosier Energy and other Indiana utilities to explore Scenarios and Sensitivities with a wide range of potential risks in order to stress the system. That is, to examine the potential resource ramifications that, at the extreme, are considered to be low probability but significant consequence cases. Hoosier Energy by way of examples, at what price level do CO_2 prices cause a different resource plan? At what point do events such as the Polar Vortex (or other periods of very cold temperatures over an extended period of time) that would cause Hoosier Energy (or any other utility) to reconsider the use of non-firm transportation contracts for natural gas supply?

Again, the Commission staff would like to see a comprehensive, internally consistent, and robust narrative analysis of the various risks and their effect on the resource planning.

1. RISK ANALYSIS IS TOO CONSTRAINED

Despite Hoosier Energy's enumeration of significant risks on page 74 and this specific statement of risk associated with environmental regulations on page 12, *"A major factor in the development of the Plan was the effect of potential legislation and / or regulatory changes. For example, additional environmental restrictions have the potential to dramatically affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level of Hoosier Energy's existing and future generating stations. The Plan was structured to be flexible enough to incorporate not only existing regulations but also possible future restriction."* the Commission staff believes Hoosier Energy did not engage in a robust analysis of risk or conducted a planning analysis that would have been able to credibly assess the various risks Hoosier identified on page 74. .

Beginning on page 51, Hoosier Energy discusses several environmental regulations that will affect reliability and the cost of delivering power to its Members and their consumers. For example, *"Compliance with the MATS rule will be costly and will likely force retirement or fuel conversion of a large amount of coal-fired generating capacity in the Midwest, including Indiana. The impact of these retirements is likely to tighten reserve margins the Midcontinent ISO for the next several years."*

Hoosier Energy also stated "*EPA released the proposed green house gas rules for existing plants in June 2014 and this new regulation represents a primary risk to consistent operation of coal-fired facilities… EPA project the rule will cost between $7.3 and $8.8 billion by 2030…"* (page 33). Hoosier Energy goes on to articulate a compelling case for comprehensive long-term planning due to the significant risks faced by the electric utility industry and their customers. *"MISO developed an analysis of the EPA proposal that was discussed with stakeholders on September 17, 2014. The current analysis provides some insights on the cost of implementing 111(d), but it appears to be a high-level view and therefore lacks some significant cost items. Hoosier Energy will encourage MISO to quantity the additional costs of new transmission development, natural gas pipeline development (including the cost of firm transportation and supply), and heat rate improvements at existing power plants…). Inclusion of these and perhaps other requirements would make this a more complete analysis."* Just as Hoosier Energy argues for more detail, the Commission staff believes Hoosier Energy should provide more in-depth analysis of the risks within their IRP. Hopefully, Hoosier Energy is providing heat rates and other information to the Midcontinent ISO to enhance the MISO's analysis.

On page 61 Hoosier Energy comments that "*With the Midcontinent ISO Market development, the industry continues to transition to financial products and these market purchases are now primary risk management tools."* While the Commission staff believes this strategy is appropriate, the IRP would benefit from more of a narrative regarding the risk analysis that Hoosier Energy conducts to assess this strategy on an on-going basis.

Hoosier Energy's treatment of non-traditional resources such as demand-side management as an adjustment to the load forecast rather than having it compete with traditional resources is a matter of concern because it may not capture all of the benefits of this resource option.

With the sharply declining cost of wind and solar as well as technological advances, it would seem that these resource options should be increasingly cost-effective in future years. It's not clear how Hoosier Energy's IRP integrated the declining costs and increasing efficiency into the IRP. More broadly, the failure to give adequate consideration to demand response, customer-owned generation and other forms of distributed generation are matters of concern because – as Hoosier Energy notes, these resources increase diversity and thereby reduce risks. They may also be lower cost alternatives.

Based on the Commission staff's review of Hoosier Energy's IRP, it appears the "Preferred Plan" (see page 76) was largely predetermined. While there were distinct differences among the resource plans, there were considerable commonalities but none resulted in retirement of most of the coal-fleet by 2034 as might be expected if there was a Scenario that stressed the system. Again, the Commission staff recognizes that DSM and other customer-owned and distributed resources is primarily a responsibility of Hoosier Energy's Member Cooperatives. However, if Hoosier Energy would have a more integrated planning process that would have permitted a comprehensive analysis of all resources and a more detailed narrative of risks (such as an expansive consideration of potential CO_2 prices, lower prices for solar and wind, a more robust risk analysis of natural gas prices), the Preferred Plan may have been different.

The Commission staff would ask Hoosier Energy to consider injecting more Probabilistic analysis into the long-term planning; at least as a supplement to its current practices. Probabilistic analysis is likely to be more objective and comprehensive than deterministic approaches because probability analysis can assess the frequency, duration, and severity of events. For this reason, probabilistic analysis may provide an additional perspective for benefit – cost analysis of a variety of resource options which, in turn, provides a more comprehensive and insightful narrative. For example, probabilistic analysis of lower probability but high consequence events such as the "polar vortex" may provide a more useful narrative because deterministic methods may overstate the concern and lead to unnecessary and costly responses. Probabilistic methods, may also provide more insight into the contribution of renewable resources, distributed generation, demand response, and energy efficiency since deterministic methods often look at pre-determined contribution of these resources to the summer (or winter) peak demands. Since NERC is also considering incorporating more probabilistic analysis in their assessments as a compliment to deterministic methods, this may add to the rationale for greater use of probabilistic method in IRPs. For the IRP process, explaining outcomes in a probabilistic context may aid stakeholder understanding because it addresses frequency, duration, and severity. In contrast, solely using deterministic analysis of a worst case scenario may appear to be unnecessarily bleak because it lacks parameters of frequency, duration, and severit**y.**

The OUCC (page 1) made a similar observation by saying "The utilities did not demonstrate in a clear manner whether these qualitative elements [e.g., political outlook, risk, portfolio mix, and human behavior] were considered and, if so, how they were accounted for in the modeling process. It also is unclear whether the utilities' modeling considered the availability of renewable resource at peak load or the need for and cost of available back-up energy through spot or long-term contracts for purchased power."

LONG-TERM CAPACITY EXPANSION PLANNING MODELS

Hoosier Energy contracted with GDS Associates to perform analysis by using the Strategist Integrated Planning System developed by *Ventyx*. The model simulates production operations of all combinations of potential resource additions, then compares across those combinations to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. Hoosier Energy's salient observation on page 95 is important. *The Strategist model runs hundreds of scenarios to select an optimal, or least cost, combination of resources. It does not consider any other factors such as risk, potential market changes, regulatory or environmental considerations etc., Management must evaluate the model results in conjunction with judgment about these other factors."*

METHOD

Hoosier Energy started with a Base Case, which uses its base load and energy forecasts paired with base expectations of fuel price growth purchased from *Ventyx*. Two sensitivity cases were created for different load growth expectations – High Load Growth Case and Low Load Growth Case. Additional two sensitivity cases were developed taking into account risks associated with natural gas price. The High Gas Price Case was based on the high gas price forecast obtained from *Ventyx* and increased power prices as well. The Low Gas Price Case was based on the low gas price forecast obtained from *Ventyx* and decreased power prices. Finally, there was one case named Federal Environmental Legislation Case, which was based on the *Ventyx* Federal Environmental Legislation Scenario which was fashioned off a combination of bills introduced in the 112th Congress related to greenhouse legislation. In this case, gas prices, market prices, and CO_2 emission costs were all changed.

Each one of the six cases mentioned above produced one optimal resource plan. There were six optimal plans in total. It seems that Hoosier Energy chose the optimal plan from the Base Case as the preferred resource plan as shown on page 96 of the document, which included a peaking unit purchase of 200 MW to meet short-term needs before 2020, followed by 300 MW of Combined Cycle capacity in 2022, 100 MW of Combustion Turbine capacity in 2031, and the purchase of 50 MW of Wind Power in 2034. The company also outlined strategies which would allow it to retain flexibility should load expectations, market prices and emissions regulations change.

ISSUES AND CONCERNS

- In Hoosier Energy's integrated resource analysis, only supply-side alternatives were included in the modeling. In addition, the number of supply-side alternatives was limited – Integrated Gas Combined Cycle, Natural Gas Combined Cycle, Natural Gas Combustion Turbine, peaking unit purchase, wind power purchase, and solar power purchase. Apparently, there was no consideration of partnering with other utilities in baseload resource development. Notwithstanding Table 15 on page 60, there seems to be a failure to treat Demand-Side Management, Demand Response, and customer-owned distributed generation on a comparable basis to resources is concerning.

- The Commission staff appreciates Hoosier Energy's role as a Generation and Transmission utility that has a limited role in its Member's retail programs, but we are concerned that a predetermined level of DSM was baked-into the IRP and was not, therefore, treated on a comparable basis to supply-side resources that would have allowed the generation expansion planning model to solve for the least cost resources.

- The supply-side and the demand side alternatives were not evaluated on the same basis in the resource plan process. The retirement decisions for Ratts units were hardwired in the modeling process as well.

- Hoosier Energy did not perform any sensitivity analysis for the optimal plans identified by Strategist. However, sensitivity analysis was necessary because the Strategist model runs did not take into consideration risk factors. It is mentioned in the document:"The Strategist model runs hundreds of scenarios to select an optimal or least cost, combination of resources. It does not consider any other factors such as risk, potential market changes, regulatory/environmental considerations, etc. Management must evaluate the model results in conjunction with judgment about these other factors."

- It is less clear how Hoosier Energy would factor in various risks into the resource plan process without a systematic sensitivity analysis.

- On Page 95, Hoosier Energy outlined 5 strategies to pursue in the future without mentioning what methods the company used to develop those 5 strategies. It is also hard to tell what action Hoosier Energy planned to take, the 5 strategies, the preferred resource plan or some other plan. It would be better if Hoosier Energy explains clearly what they plan to do with the analysis results.

2. <u>LOAD FORECASTING</u>

Hoosier Energy's Residential Sales Model is the summation of each individual member's econometric model. Each member's model has three equations which are solved simultaneously. The three equations include: average use per consumer per month, real average residential price of electricity, and the number of customers.

The average use per consumer per month equation is a function of average per use lagged, real average residential per capita income, HDD, CDD, and other variables such as alternative fuel prices or agricultural production. The real average residential price of electricity equation is a function of use per customer, actual real cost to operate and maintain the distribution system excluding wholesale power costs, and the average real wholesale cost of electricity paid by the cooperative. The residential customer equation is a function of population and other variables that may affect customers.

Hoosier Energy's Commercial, Industrial, and Other Sales Model is the summation of the individual member's results for those classes and is largely based on a judgmental approach. The reasoning for using an informed judgment approach seems to be the erratic nature of the historical load and the fact that growth in these classes is highly dependent upon new business developments rather than past patterns which requires local knowledge all of which makes using an econometric approach difficult.

Hoosier Energy gathers historical coincident and non-coincident summer and winter peaks and total annual electric sales for each member. A "coincident factor analysis" is performed to calculate load factor, seasonal adjustment factor and coincident factors which are then used along with information from the REMC/REC representatives to forecast each member's system peak demand. The member system demands are then aggregated; a 60-minute to 30-minute time ratio adjustment and an estimate loss factor are applied to ultimately arrive at Hoosier Energy's system peak.

High and low bands as well as "severe" and "mild" weather bands were constructed around the base forecast. In the high and low bands residential differs by population, real per capita income, and fuel prices while C&I differ by variation in number of customers and energy growth rates. The weather bands make use of the maximum and minimum annual degree days in the historical period. Two peak demand bands are constructed for each energy scenario, one based on historical average load factors and the other based on extreme annual system load factors.

Hoosier's external data sources seem reasonable but the Commission staff always encourage utilities to continually evaluate both internal and external the data sources. Operating statistics are from the Rural Utilities Service (RUS Form 7 and Bulletin 1-1). Weather data is from NOAA. Fuel prices are from EIA, US Department of Energy, and the American Gas Association. Agricultural variables are from Purdue University and the US Department of Agriculture. Other variable sources include STATS Indiana and the Illinois Department of Commerce and Economic Opportunity.

ISSUES AND CONCERNS

- The demand-side resource options were predetermined and incorporated into the load forecast. This makes comparable treatment of DSM with other resources impossible. The Commission staff believes the long-term resource planning model should be able to select from a menu of all resources including demand-side management.

- In the residential customers model one of the drivers listed is "Other variables that may affect customers". What are some examples of these variables and why not specify them?

- The material describing the "60/30 time factor ratio" is confusing and could be made clearer and easier to understand.

- The section on page 22 called "Individual System Demands" should be presented before the preceding section "Hoosier Energy System Demand" for greater clarity. The Commission staff would also like to know what effect, if any, is given to forecasting Hoosier Energy's contribution to the MISO forecasted system peak (we recognize this is difficult) and how Hoosier handles the different time zones.

- Hoosier Energy's forecast weather bands are based on the maximum and minimum annual degree days in historical period. Why use the extremes? Perhaps something like 10% colder and warmer would be more reasonable and meaningful.

- With regard to Table 6 on page 39, the Commission staff would appreciate more of a narrative on constructing the peak demand data. In addition to the trend to lower energy usage, the Energy Information Agency and several utilities have noted a trend in recent years that has the peak demand growing more rapidly than energy usage. This has important implications for load forecasting, for DSM, Demand Response, and customer-owned generation. To be clear, the Commission staff is not saying that this phenomenon is universal. Rather, we suggest that it is something to consider.

- Hoosier Energy correctly notes that Commercial, Industrial, and other loads area very diverse. However, the Commission staff notes that, on page 10 "*The consumer mix on the Indiana portion of the Hoosier Energy system changed slightly over the 2001-2011 period...The Commercial and Other sector remained constant…Hoosier Energy experienced significant growth in sales to the Industrial classification between 2001 and 2011.*" Given the relative stability in the Residential, Commercial and Other, and the significant increases in the importance of Industrial, the Commission staff would like to know if Hoosier Energy's members have considered grouping Commercial and Industrial customers into more homogenous sub-groupings by North American Industry Classification System (NAICS) or Standard Industrial Classification Codes (SIC Code) for forecasting purposes? Has Hoosier considered other groupings such as by usage levels within the current classes?

- There was no mention of what efforts Hoosier Energy anticipates making to its load forecasting program to improve the credibility of the forecasts. Given the risks that Hoosier Energy acknowledges throughout the IRP, there is little evidence that Hoosier is making an effort to reduce a major area of uncertainty – the load forecasts. The Commission staff appreciates Hoosier Energy's rationale for use of econometric forecasts and agrees with the concerns for other forecasting methods mentioned on page 27, however, that should not dissuade Hoosier Energy from continual reassessment of different methods. A properly specified end-use forecast with the requisite data has the intuitive appeal of providing a more credible narrative (e.g., perhaps better capturing of energy efficiency for appliances / end-uses).

  As discussed on page 38 (the Residential End-Use Survey) and because of the Member systems closeness to their consumers, Hoosier Energy has an opportunity to obtain demographic and end-use data that Investor-Owned Utilities would find more challenging. To supplement the results from the email and phone surveys has Hoosier Energy and its Member cooperatives considered conducting a representative and random in-person surveys – perhaps with personnel that can accurately assess the load, age, and condition of major appliances / end uses, house structure, and the household demographics? Have Hoosier and its Members considered in-person surveys with commercial and industrial customers to obtain more detailed and accurate information to enhance the load forecasts, customer rates and programs, and the IRP? With regard to the RUS Residential End-Use Survey, has Hoosier Energy done any correlations with EIA or other data sources?

3. <u>RESOURCES</u>

On page 14, Hoosier Energy states it continues to "*add cost-effective renewable resources to its resource portfolio. In addition, Hoosier Energy has added 18 MW of renewable generation since 2011, with plans, which have been budgeted and approved by the Board, to add an additional 51 MW by the end of 2016. Hoosier energy performed an analytical review of its potential long-term resource options and filed the* *assessment with the IURC in April 2012. As a result of this study, the decision was made to idle Ratts Unit 1in 2014 and Ratts unit 2 in 2015*." Hoosier Energy current generation fleet has approximately 1,750 MW of capacity. This includes 1,080 of coal-fired capacity and 670 MW of natural gas-fired capacity. (page 43 and Table 9 on page 44).

The Commission staff agrees with Hoosier Energy's perspective that power purchases, such as the 250 MW (three separate agreements) from Duke Energy, can provide beneficial diversity and reduce risks.

ISSUES AND CONCERNS

- On page 43, Hoosier Energy notes there are no anticipated changes to the two unit coal-fired Merom Station (1982 and 1983) except for changes required by more stringent environmental restrictions and has not included any planned changes to this facility in the IRP analysis. More narrative of the planned changes in response to more stringent environmental regulations would be appreciated since this goes to the risk analysis that Hoosier Energy faces.

- Again, the Commission staff agrees with Hoosier Energy that power purchases can provide beneficial diversity and, thereby, reduce risks. We also recognize power sales, such as the one to Wabash Valley Power Association (WVPA) provide benefits. However, the combination of the power sales and purchases pose some measure of risk that is not clearly discussed in the IRP.

- Given Hoosier Energy's structure and the relationships that their members have with their consumers, the Commission staff believes that there should be more information about the potential for customer-owned and other forms of distributed generation than were evidenced in the IRP. The Commission staff contends that utility cost-effectiveness tests don't entirely explain consumer motivation to install their own resources or participate in demand response programs. It appears that these resources were not given comparable treatment to traditional resources and power purchases.

4. REGIONAL CONSIDERATION

The Commission staff is pleased that Hoosier Energy recognizes that their Integrated Resource Plan and the planning conducted by the Midcontinent ISO are inextricably intertwined. The MISO facilitated markets provide greater reliability and lower costs (e.g., regional economic dispatch, access to a vast array of resources to provide greater resource diversity, load diversity, lower reserve margins, and the ability to facilitate compliance with complex environmental rules) than would be possible without the MISO.

Hoosier Energy mentioned (page 12) "…*Hoosier Energy expects to continue to fulfill its future resource needs through a combination of company-owned generation, long-term purchases and sales, and short-term purchases and sales. While the Midcontinent ISO has brought liquidity and transparency to the wholesale market, the availability and price of market power can be volatile especially during peak periods as electricity requires instantaneous production / consumption and there is currently no capability effectively store it. Therefore, while power purchases may, at times, be a least cost alternative, ownership of generation is a necessary component of this least-cost plan."*

On page 33, Hoosier states *"As a FERC-approved RTO, MISO is responsible for the provision of reliable electricity to its footprint. MISO is uniquely positioned to identify reliability concerns that may result due to the accelerated retirement or reduced output of existing units, increased reliance on natural gas CCs, additional renewables, and the short compliance timeline. MISO should identify reliability issues, develop transmission solutions, and estimate these costs. A combination of these two analyses would provide a more complete picture of the challenges faced by this region to comply with 111(d)."*

ISSUES AND CONCERNS

- Other than considerable reliance on the MISO, it is not clear how Hoosier Energy's IRP addresses the risks associated the reliability and cost risks associated with the environmental regulations.

- On page 54, Hoosier Energy states *"Summer and winter gas service to the Worthington, Lawrence County and Holland stations is secured on a short-term basis. In 2011, Hoosier made an economic decision to serve the Lawrence County and Worthington facilities with interruptible pipeline capacity, rather than firm capacity Hoosier continues to utilize the natural gas providers' firm pipeline capacity to serve the Holland natural gas facility. Hoosier Energy assumes adequate pipeline capacity is available to serve the requirements of all current and potential gas fired generating facilities."* (page 55). Against the backdrop of the Polar Vortex during Hoosier Energy's preparation of the 2014 IRP and the cold weather in late February 2015 and just as Hoosier Energy has asked the MISO, to assess the risks of natural gas availability and deliverability, the Commission staff would like to have Hoosier Energy provide a narrative of their risk analysis that concluded the efficacy of non-firm gas was appropriate for some units.

5. <u>ENERGY EFFICIENCY AND DSM</u>

Hoosier Energy states their intention to continue "*…implementation and penetration of the demand response and energy efficiency programs identified as cost effective in the 2013 Demand Side Management Report."* (page 13) By way of context, the 2013 Report built upon a 2009, the report entitled "Energy Efficiency & Demand Response Potential Report for the Hoosier Energy Member Territory" which was performed by GDS Associates and Summit Blue Consulting firms. This study provided a description and analysis of DSM programs that were recommended for the Hoosier Energy (HE) system. This study was updated in 2013 to help the company manage existing and develop new DSM programs and represents an integral component of HE's 2014 IRP.

In 2013, Hoosier Energy jointly with GDS Associates, Inc. updated the 2009 study to reflect the current benefits, costs and other major assumptions (IRP, p. 12). For this 2013 DSM study, GDS updated the major global assumptions and avoided cost assumptions to reflect the current conditions of the HE territory. Assumptions like inflation and discount rates, avoided cost of generation energy and capacity were lowered with respect to the 2009 study. Other updated assumptions were related to the forecast of electric retail rates used when fuel switching occurs and avoided costs of water that represent a benefit to EE programs that reduce water consumption. For example, updates of the avoided costs were needed because the cost effectiveness of the DSM programs is performed using the Total Resource Cost (TRC) test as the primary test. In the end, HE asserts that, after the appropriate demand-side resource options were assessed, the identified DSM levels were incorporated into the load forecast employed by Hoosier Energy in this IRP (p. 87).

The information that is presented in the IRP's appendices includes detailed description of the current DSM programs being implemented in the analysis. Furthermore, the GDS report clearly explains the changes in assumptions and steps considered to update the 2013 DSM study. However, there is limited discussion on the methodology or procedure used to incorporate DSM savings levels, including Avoided Costs (Table 13 on page 55) into the Hoosier Energy's integrated modeling system.

ENERGY EFFICIENCY MODELING METHODOLOGY

The 2009 report presents results obtained from the evaluation of additional opportunities for DSM programs in the Hoosier Energy member territory. The evaluation process estimated DSM technical, economic, achievable and program potential savings by the year 2028 for the residential and commercial/industrial sector. The program potential savings is based on the achievable potential resources but is estimated to reflect the goals of the program design and fit the allowable budget (GDS

2009 study, p. 37). GDS delivered a portfolio of recommended DSM programs that includes the electric savings levels achieved in the program potential scenario.

The results of this study were obtained by sector using a bottom-up approach through a customized potential assessment computer models and cost effectiveness criteria specified by HE. In order to define eligible measures and project future measure penetration, customer end use information was collected through surveys with random samples of residential households and commercial/industry facilities. These on-site surveys provided information regarding the current saturation of electric appliances and equipment and baseline levels of energy efficiency. These estimates were calculated based on a market penetration scenario that targets the installation of high efficiency equipment in 40% of the available market between 2009 and 2028. Then for determining the cost-effectiveness of the eligible program the Total Resource Cost (TRC) test was performed including the cost of the programs and the avoided cost projections for energy and capacity. The avoided energy cost component accounts for the cost associated with the generation of electricity, while the capacity component consists primarily of the capital costs of facilities (GDS 2009 study, p.16). Finally, the portfolio of the cost effective DSM programs were analyzed to develop estimates of overall costs, benefits, net benefits, and benefit cost ratio. In total, 13 recommended programs were presented by GDS in this analysis.

This methodology explained above was also used in the updated 2013 DSM study with only some changes to reflect current benefits, costs and other major assumptions. For this IRP, HE affirms it has prepared a list of resources, and all associated cost and operational parameters to plan a portfolio of resources, that were included in Hoosier Energy's integrated system modeling process. Also HE mentions that the resource assessment and resource integration analysis was produced using the Strategist Integrated Planning System which has the capability to simulate production operations and develop least cost expansion plans (p.79).

ISSUES AND CONCERNS

- Only the Total Resource Cost Test (TRC) is used to determine the cost effectiveness of the DSM program or measure in the GDS study. There are, however, other tests that are appropriate to use in order to analyze other important factors of these programs. Did Hoosier Energy and its member cooperatives consider the use other tests like Utility Cost Test (UCT), Rate Impact Measure test (RIM), Participant Cost Test (PCT), etc.? At some point, Hoosier Energy and its member systems may wish to compare their results to other Indiana utilities. To the extent that different cost-effectiveness tests are used, that will make comparisons difficult. Moreover, IF energy efficiency is deemed to be an important compliance measure for new environmental rules, Hoosier may need to demonstrate a credible Evaluation, Measurement, and Verification protocol that will be difficult to do without a comprehensive assessment regime.

- In the GDS report, the estimation of potential savings is based on a targeted savings and budget level. There is little mention about the targeted savings used to determine the appropriate DSM measures. Are these total targeted savings (a percentage of sales) or per measure savings? A more complete narrative would be beneficial to the Commission staff and, we believe, to Hoosier Energy's membership.

- What is the number of participants considered per measure? No mention was provided on the numbers of residential customers that beneficiated from the programs.

- In the commercial/industrial sector, was the forecast used to project "building stock decay and new construction" (GDS 2009 study, p. 60) included in the 2009 DSM study updated for the 2013 study? How would the recent economic or policy changes affect those projections?

- There is no mention on how this plan will account for the potential reduction in savings due to SAE 340 that allows customers to opt-out of utility sponsored DSM programs.

- As mentioned above, there is limited discussion about the process of incorporating the values of energy efficiency programs into the load forecast. Also, there is no clarity in presenting information about the DSM historic and future values used in the IRP report.

- Energy efficiency programs were pre-determined instead of being allowed to compete with supply-side resources in the IRP. By not allowing energy efficiency to compete with supply-side resources, it is – by definition – impossible to assert that the resource mix approached optimization.

  The OUCC (page 2) agrees with the Commission staff's assessment that Hoosier hardwired DSM resources into the IRP, thereby preventing comparable treatment.

6. <u>CUSTOMER-OWNED AND DISTRIBUTED GENERATION</u>

Despite Hoosier Energy's comments on page 13 "*Hoosier Energy will continue to purse cost-effective, renewable resources in the future including wind, solar, landfill gas, hydro, and coalbed methane generation facilities. These resources are smaller than typical supply-side resources, which provide diversity and risk mitigation advantages,"* The discussion of distributed generation in the IRP is minimal. The Hoosier Energy IRP briefly mentions distributed generation in Chapter 3 and 4 of this IRP. In Chapter 3, Hoosier Energy listed the Distributed Generation Purchase Tariff as one of its optional wholesale tariffs at page 48. To be qualified for this Tariff, customers need to have qualifying distributed generation facilities with 50 KW to 2,000 KW nameplate rating. Hoosier will pay $0.053 per KWh for excess electricity. In Chapter 4, the report lists options for distributed generation alternatives to meet its peaking power requirements, namely wind, solar photovoltaic, diesel generators and small gas turbines. The installed costs for those alternatives are listed as follows:

- Solar PV: $2,500-$4,000 per kW

- Wind: $2,500-$8,000 per kW

- Diesel or gas turbines: $1,000 per kW depending upon a number of factors.

Hoosier Energy also states in the IRP (beginning on page 63) that given the higher capital cost, the economics of distributed generation do not compare favorably to central station power without a customer specific need for increased reliability and/or an economically advantageous fuel source. In Chapter 6, Hoosier Energy provides a complete list of resource options considered in this IRP. Among those options, 50 MW from wind and 10 MW from solar are listed as renewable resource options.

As for renewable resources, Hoosier Energy adopted a Renewable Energy Program and set a goal to secure 2% of total energy generated from renewable resources by 2011 with additional resources going forward matching 5% of member energy growth. In 2014, Hoosier Energy reset the target of obtaining 10% of member energy requirements from renewable resources by 2025. Hoosier Energy lists its renewable generation facilities as follows:

- Clark-Floyd Landfill methane gas-fired facility with 3.4 MW capacity;

- Story County wind project: Hoosier Energy has rights to 25 MW though a 10-year purchased power agreement;

- Dayton Hydro facility in Dayton IL: a 20-year power purchase agreement to procure 3.6 MW of generation annually.

- Osprey Point Renewable Energy Station: 3 MW capacity in 2013 and will produce 13 MW when at full capacity; this facility produces power from coalbed methane.

- Orchard Hills landfill gas generation facility is under development with 16 MW capacity and expected online in 2016;
- Livingston Renewable Energy Plant at IL with 15.6 MW capacity.
- There are seven small-scale solar facilities and three small-scale wind facilities across Hoosier Energy's southern Indiana service territory under development.

ISSUES AND CONCERNS

Again, despite Hoosier Energy's statements in their Short-Term Action plan on page 13 and its retrospective mention of the very similar 2011 Short-Term Action Plan, there are number of issues with Hoosier Energy's discussion regarding renewable energy and distributed generation in the IRP as follows:

- It is not clear what the current total production capacity of distributed generation Hoosier Energy is, and neither its forecast growth for the study period;
- Hoosier Energy's IRP mentioned it considered distributed generation as options to optimizing integrated resource planning. However, the IRP does not provide any detailed information on the future growth or changes of those renewable resources.
- The discussion of new technologies (page 65) suggests that these may become viable in the future yet this was not given effect in the IRP.

7. PROPRIETARY DATA

It would be beneficial to the reader to minimize, to the extent possible, the use of confidential or otherwise protected information. To the extent that public domain information (e.g., EIA) is close to the proprietary data (e.g., fuel price forecasts), Commission staff encourages the use of this data with the caveat that the data used in the IRP is somewhat different and the differences might produce different results.