STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH I&M'S DSM/EE PROGRAM COST RIDER OF ASSOCIATED COSTS, INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	) CAUSE NO. 45285

IURC
INTERVENOR'S -CAC
EXHIBIT NO. 4
10-15-20 LK
DATE REPORTER

TESTIMONY OF ANNA SOMMER IN OPPOSITION TO

SETTLEMENT BETWEEN I&M AND OUCC

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA

SEPTEMBER 15, 2020

I. Introduction and Summary

Q. Please state your name, employer and business address.

A. My name is Anna Sommer, and I am a Principal at Energy Futures Group. My business address is 30 Court St., Canton, NY 13617.

Q. Are you the same Anna Sommer who previously filed direct testimony in this Cause?

A. Yes.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Citizens Action Coalition of Indiana ("CAC").

Q. What is the purpose of your testimony?

A. I address the Settlement Agreement between the Indiana Office of Utility Consumer Counselor ("OUCC") and Indiana Michigan Power Company ("I&M" or the "Company"). In particular, I respond to certain arguments made by Chad Burnett and Scott Fisher in both their Settlement Testimony and Rebuttal Testimony. I would note that a lack of response to any particular argument in these testimony submissions does not imply that I agree with the Company on that issue.

Q. Please summarize your conclusions and recommendations.

A. I recommend that the Commission reject the OUCC-I&M settlement and require I&M to continue offering its existing DSM program portfolio at the levels consistent with the interim authority until the updated market potential study is published and the IRP in November 2021 is completed in collaboration with I&M's interested stakeholders and OSB. Any program changes in the interim that are supported by the 2021 MPS should be determined by unanimous vote of I&M's OSB.

My primary conclusions underlying this recommendation are as follows:

1. The proposed settlement does not meet the definition of "energy efficiency goals" as prescribed by Senate Enrolled Act 412 in Section (c).
2. I&M's filed DSM plan in this proceeding continues to be inconsistent with its 2018-2019 IRP in terms of the level of savings included in the plan versus the IRP and in terms of the savings selected in the IRP compared to those being offered through the DSM plan.
3. Over the course of at least four years and two IRPs, I&M has failed to adequately document and justify its degradation approach.
4. I&M's degradation approach is not supported by reasonable and documentable facts and results in excluding as much as two thirds of lifetime energy savings from its modeling to the detriment of I&M's ratepayers.
5. I&M can confidently avoid double counting of future energy efficiency ("EE") savings without using degradation and yet refused to do so.
6. I&M has acknowledged that this 2018-2019 IRP is out of date and has told the Michigan Public Service Commission that "trying to process this current IRP may be an exercise that doesn't leave much value in the conclusion in the end, given the current state of affairs."[1]

[1] April 2020 prehearing conference in Michigan Public Service Commission Case No. U-20591.

II. Settlement Does Not Meet Statutory Requirements

Q. Please explain how the Settlement Agreement fails to meet the requirements of energy efficiency goals as defined in Senate Enrolled Act ("SEA") 412?

A. SEA 412 states that:

> *"energy efficiency goals" means all energy efficiency produced by cost effective plans that are:(1) reasonably achievable;(2) consistent with an electricity supplier's integrated resource plan; and (3) designed to achieve an optimal balance of energy resources in an electricity supplier's service territory.*

The Direct and Settlement Testimony Submissions of CAC Witness Dan Mellinger and my Direct Testimony explain why I&M is proposing goals that would fail to capture all, or even close to the majority of, cost-effective and achievable energy efficiency. Additionally, as I described in my Direct Testimony, the Company's planned savings are inconsistent with its 2018-2019 IRP both because (1) there is no adjustment to remove degradation, and (2) the mix of savings selected versus savings picked is entirely different between the 2018-2019 IRP and the DSM plan at issue in this proceeding. Finally, in Section IV of this testimony, I explain why this Settlement would not achieve an "optimal balance of energy resources in" I&M's service territory.

III. <u>The Company Has Failed to Adequately Justify Its Degradation Approach</u>

Q. At page 3 of his Settlement Testimony, Mr. Fisher notes that he does not believe "any of the Director comments suggest the Company's IRP is not reasonable or the Company should modify or redo its 2018-2019 IRP."[2] How do you respond?

A. I disagree with Mr. Fisher because, in my expert opinion, the Director is prohibited from drawing this conclusion under Indiana's IRP rule. The Indiana IRP rule expressly limits the Director's Report to a very narrow assessment of a utility's IRP:

> *(f) The director shall issue a final report on the IRP within thirty (30) days following the deadline for supplemental or response comments.*
> *(g) The draft report and the final report shall:*
> > *(1) be limited to commenting on the IRP's compliance with the requirements of this rule;*
> > *(2) list the areas where the director believes the IRP fails to comply with the requirements of this rule; and*
> > *(3) not comment on:*
> > > *(A) the desirability of the utility's preferred resource portfolio; or*
> > > *(B) a proposed resource action in the IRP.*[3]

Because of this language, I would not expect the Director to express an opinion as to whether a utility ought to redo its IRP or not, because doing so would unavoidably imply an opinion about "the desirability of the utility's preferred resource portfolio" or the "proposed resource action in the IRP."

And, for the same reason, I would not expect the Director to make a wholesale determination as to whether an IRP is reasonable or not. However, with respect to I&M's

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[2] The Draft Director's Report for I&M's 2018-2019 IRP (July 17, 2020) is included as Attachment AS-1.

[3] 170 IAC 4-7-2.2(f), (g).

degradation factors, which are central to the Company's modeling of EE, the Director did observe:

> *The IRP could have also included more information on the development and use of degradation factors. This could have been done in the body of the report or in an appendix. The information provided in the stakeholder presentations was helpful but only up to a point, and does not substitute for a clear discussion in the IRP itself. Even using information from I&M's three-year DSM case (Cause No. 45285), the Director is not clear how EE bundles were developed or how the degradation factors were developed and applied beyond the use of professional judgement by I&M's resident experts.*[4]

I would note that the Director made this statement even after the Commission issued three different data requests for information to clarify I&M's degradation approach in Cause No. 45285.[5]

Q. Do you share the Director's concern that it is "not clear…how the degradation factors were developed and applied beyond the use of professional judgement by I&M's resident experts"?

A. Absolutely. The Company has had more than ample opportunity (quite literally years, as well as multiple stakeholder workshops and rounds of discovery squarely teeing this issue up) to rectify this failure. Multiple requests on the part of the Commission and CAC have been made to I&M for the information showing the development of its degradation factors.[6] Yet, we all still remain in the dark.

This lack of transparency was even present back in I&M's 2016 IRP, showing the recurring nature of I&M's inability to justify how it models EE:

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[4] Attachment 1, page 14.
[5] Note that CAC filed three Notices of Correction to I&M's Responses to these docket entries in Cause No. 45285. This information is included as Attachment AS-2 and Attachment AS-3.
[6] E.g., I&M Response to Docket Entry 3-1 and related attachments; 2018-2019 IRP Stakeholder Process, I&M Response to CAC Informal Discovery Request 1.5 (Attachment AS-4); I&M Response to CAC Data Requests 11-5 and 11-7 (Attachment AS-5).

> *From the narratives provided by I&M, it was not clear how the various models interacted. Moreover, it was not clear how the EE bundles were created and how I&M rolled off EE programs and avoided the double-counting of EE.*[7]

Q. What have you gleaned from these discovery responses and docket entries?

A. I&M cannot and will not provide any quantitative basis for its degradation factors. Its qualitative rationale for the use of these degradation factors is changing and conflicting. For example, in response to Informal CAC Data Request 1.5 in the 2018-2019 IRP Stakeholder Process, I&M stated:

> *The degradation factors were developed in consideration of the expected life, declining effectiveness, and market efficiencies of the various end-use programs and in consideration of the saturation trends in energy efficiency already embedded in the load forecast models. The observed impacts were not linear over time so I&M utilizes a non-linear estimation algorithm to degrade the program savings that are ultimately subtracted from the load forecast.*[8]

But, in I&M's response to Docket Entry 3-01 in this proceeding, the Company states:

> *As explained on page 7 of Mr. Burnett's rebuttal testimony, the rate at which energy efficiency measures degrade is affected by changes in the operational efficiency of the measure, market adoption rates, stipulated vs. verified savings, net-to-gross savings, free ridership, spillover, and other factors. Based on prior experience, including I&M's EM&V process and its residential appliance survey results, I&M recognized that these factors are generally not linear in nature.*

While these are two at least partially conflicting rationales, virtually all of these factors are *already accounted for* in the assumption of effective useful life (measure life), the net-to-gross ratio applied, or baseline efficiency assumptions in the market potential study ("MPS").

Further, I&M has never provided any quantitative support showing how any of these factors would combine to create its degradation factors. There is no documentation

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[7] Final Director's Report for the 2016 IRPs, page 14 (Attachment AS-6).
[8] Attachment AS-4.

in the record showing precisely how the market adoption rates, operational efficiencies, net-to-gross savings, etc., combine to create the degradation factors that the Company uses.

Moreover, for each of the aforementioned variables supposedly supporting degradation, it is useful to ask oneself whether that factor actually changes every year for a measure that has already been adopted. If I bought an efficient refrigerator, does my status as a freerider (or not) change every year? Does the expected useful life of my refrigerator change every year? Would I make the decision to buy the refrigerator (or not) every year (i.e., market adoption rates[9])? For most of these factors, the answer is clearly "no". So these factors could not possibly support a decline in savings to nearly zero by the end of my refrigerator's useful life, as is the impact of I&M's methodology here.

The Company's descriptions of its rationale for degradation may sound sophisticated and complex, as if the Company were thoughtfully considering many factors that go into its representation of energy efficiency savings. But, the reality is that these are merely words with no quantitative documentation to back this up, not to mention the fact that these factors are already accounted for elsewhere in the Company's MPS or IRP modeling. Again, this is all to the detriment of ratepayers, who are being deprived of investment in one of the lowest cost resources available to I&M.

[9] Based on his response to CAC Data Request 6-08(a) (included as part of Attachment AS-5), Mr. Burnett appears to misunderstand the meaning of "market adoption rates" in the energy efficiency context. I use the commonly held meaning (also AEG's definition in I&M's MPS) of the likelihood that a customer will adopt an energy efficient measure.

Q. Can you give an example of where these factors are already accounted for?

A. Certainly. Let's take "net-to-gross savings" as an example. As an initial matter, "free ridership" and "spillover" are key inputs into "net-to-gross savings" so the Company is double counting those in its description in Docket Entry 3-01.

I&M's rationale for using degradation factors is to avoid the double counting of future energy efficiency savings[10] that are already in the load forecast. I&M degrades future utility-sponsored EE savings presented to its IRP model regardless of whether or not I&M then implements a program to capture the explicitly modeled portion of the savings. Put another way, if the model does not select residential water heating, I&M makes no adjustment to its load forecast. In effect, it is assuming that as much as two thirds[11,12] of savings from that bundle will occur regardless of whether residential water heating is a measure incentivized by I&M's EE programs.

It must be the case then that the savings I&M claims are in the load forecast will definitely materialize regardless of the effort (or not) that I&M undertakes to implement utility-sponsored EE. This is the very essence of naturally occurring savings and/or freeridership, and those factors are already accounted for in I&M's MPS and in its application of a net-to-gross ratio to create I&M's EE bundles.[13]

[10] I&M Witness Burnett's Rebuttal Testimony, page 6, line 22 – page 7, line 2.

[11] Because most program savings are modeled in five-year increments in the IRP, there are additional distortions to I&M's EE bundles that decrease lifetime savings to about one third of total savings. But for those additional distortions, which are described at pages 10 – 15 of my Direct Testimony, lifetime savings would have been discounted by about 50 percent.

[12] Based on "Copy of 2018 IM Residential Build Cost w Degradation and Potential Changes v4_Lite R1 052319" and "Copy of 2018 IM Commerical Build Cost w Degradation and Potential Changes v4_Lite R1 052319".

[13] See I&M Witness Walter's Direct Testimony, Attachment JCW-3.

Q. How does the MPS account for savings that will occur regardless of whether I&M implements EE programs or not?

A. The savings that can be credited to any energy efficiency program are relative to the baseline measure at the time an energy efficiency measure is implemented. Thus, it is very important that any credible MPS accounts for existing and future known appliance standards. I&M's MPS accounts for the standards enacted by 2015 (recall that the MPS was completed back in 2016). [14]

Further, the Company has assumed that a 91 percent net to gross ("NTG") factor applies to future energy efficiency as shown in I&M Witness Walter's Direct Testimony, Attachment JCW-3. This means that of all the savings from I&M's energy efficiency programs, 91 percent of total savings would not have occurred but for I&M's EE programs. Clearly, there is a disconnect between the NTG assumption that 91 percent of achieved savings only happen because of I&M's DSM programs and the degradation assumption that only about 33 percent of savings happen because of I&M's DSM programs.

Q. What if the net to gross factor is part of degradation and Attachment JCW-3 is simply showing the removal of this factor to translate this to undegraded savings for this program filing?

A. That is unlikely, but let's assume that is the case. Confidential Figure 1 below shows the savings from one set of measures available from 2020 - 2024 comparing if it were modeled as undegraded savings (the blue bars), degraded savings (the orange bars), and undegraded savings with a 91 percent net to gross ratio applied (white and black striped bars).

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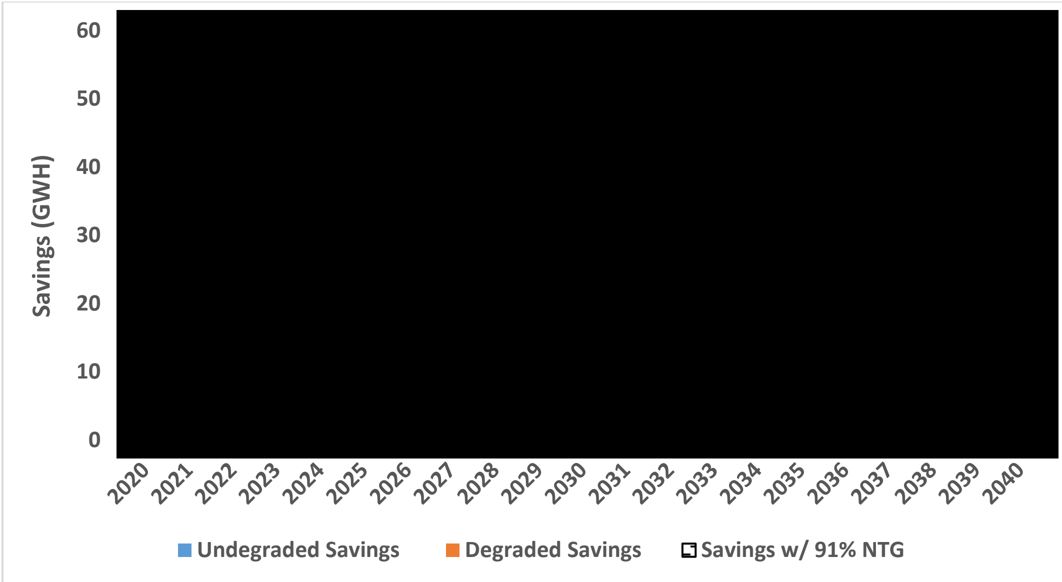
[14] See, for example, page 23 of I&M Indiana MPS, available here: https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/IMReport-ExecutiveSummaryFinal6-2-16.pdf.



Confidential Figure 1. Degradation Removes a Majority of Savings from EE Bundles

The degraded savings (the orange bars) represent nearly two-thirds fewer savings than the undegraded savings. And, with the NTG ratio applied (assuming it is not in the undegraded savings/blue bars already), annual savings are simply adjusted down by only 9 percent in each year (the black and white bars in comparison to the blue bars). That leaves still 58 percent of total savings eliminated from I&M's IRP model for largely unexplained reasons[15] that would have nothing to do with a NTG ratio (see the orange bars in comparison to black and white bars).

Also, the Company's degradation assumptions, if explained by NTG, basically assume that freeridership should be re-evaluated every year of a measure's life and that 99% of customers who participate in EE programs would be free riders by the end. This is nonsensical.

[15] I say "largely" because a minority portion of the difference has to do with additional distortions to energy efficiency in I&M's IRP modeling caused by degradation as described at pages 10 – 15 of my Direct Testimony.

Q. Could this 58 percent drop in total savings for some unexplained reason be due to "expected life, declining effectiveness, and market efficiencies of the various end-use programs"[16] as generally claimed by I&M?

A. No. Expected useful life takes into account declining effectiveness, and both expected useful life and declining effectiveness are already reflected in the measure life assumption made in the 2016 MPS. And, for the same reason, "operational efficiency of the measure"[17] is also accounted for in the 2016 MPS, so that too does not account for this 58% drop in total savings.

Market efficiencies is a nonstandard term that I&M uses. In my expert opinion, this sounds like either the rate at which the market would uptake an energy efficient measure also called "adoption rates" or the efficiency of measures available in the market—but, again, both of these items are also already accounted for in the 2016 MPS. And for the same reason, "saturation trends in energy efficiency" are also accounted for, so that also does not account for this 58% drop in total savings.

Q. Would "stipulated [versus] verified savings"[18] explain the 58% drop in total savings?

A. No. Mr. Burnett relied on Michigan Public Service Commission Staff Witness Karen Gould's definition of this concept:

> *But there are things that the Company can do that would earn them "stipulated savings" based on dollars spent, such as education for their customers or pilot programs, which test new and innovative measures for possible inclusion in future [DSM] programs. Because education to their customers on the benefits of [DSM] behavior and measures are important to the program's success, and because the research an and development of new ways to reduce customer usage through pilot programs are essential to these programs, Public Act 295 (the Act), along with the Commission order*

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[16] Attachment AS-4.
[17] I&M's Response to Docket Entry 3-01.
[18] I&M's Response to Docket Entry 3-01.

> *U-15800 states that the Company can spend up to 3% of their program budget on education and 5% of their program budget on pilot programs, and can subsequently earn up to 3% and 5% respectively of their legislative savings target.* ***These types of savings do not generate actual kWh sales reductions for the Company****.[emphasis added]*[19]

First of all, I&M has not indicated anywhere in this filing that it is asking for an artificial bump in savings for education or pilot programs that will have no measurable impact on program savings. And while the market potential study makes mention of educational components of programs and one pilot initiative, it does not mention an assumed artificial increase in savings for these efforts.

Finally, this is clearly a Michigan concept and, therefore, it would not make sense to adjust all the modeled bundles for something that may apply to only up to 8 percent of savings achieved across 15 percent or less of I&M's sales.[20]

Q. Does I&M's evaluation, measurement, and verification ("EM&V") or its residential appliance survey results[21] explain the 58% drop in total savings?

A. No. A major function of I&M's EM&V is to determine gross and net savings, the difference between the two being the net to gross factor that is already accounted for by using the 91 percent NTG ratio. In my review of I&M's recent EM&V reports, I saw nothing to suggest a nearly linear decline of savings to close to zero over the lifetime of I&M's entire portfolio of EE measures.

And, while Mr. Burnett cites to the 2016 Residential Appliance Saturation Survey and the fact that the penetration of residential LED lighting has increased from 12 percent

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[19] Direct Testimony of Karen M. Gould in Michigan Public Service Commission Case No. U-20359 at pages 4 – 5.
[20] The portion of sales in Michigan based on Attachment JCW-3.
[21] I&M's Response to Docket Entry 3-01.

in 2016 to 35 percent in 2019[22], he completely ignores the fact that this information is already accounted for in the MPS. The MPS vendor, AEG, assumes that the EISA standards for residential bulbs will be in effect in 2020 and that this will result in zero residential lighting savings between 2020 and 2024. The changes from the 2016 to 2019 Residential Appliance Saturation Survey support the need to update the MPS, but do not support I&M's degradation approach because the average efficiency of the existing stock of measures is distinct from the baseline that would be established in the MPS to forecast EE savings.

Q. But isn't "the reasonableness of the degradation factors borne out by the historical accuracy of I&M's load forecasts, which apply degradation factors to the DSM assumptions",[23] as claimed by the Company?

A. No. It has taken months and multiple rounds of discovery to finally get the exact "degradation" adjustments to I&M's load forecast. What is remarkable is just how modest those adjustments are. The degradation adjustment amounts for the IRP forecast are given in Table 1. There are no adjustments in 2022 and beyond. I&M has simply decided that even though prior installed savings persist after this date that because they would become "negative [under this approach], it would raise the forecast (subtracting a negative value) which would imply that the Company's DSM/EE programs caused customers to use more electricity instead of less which would not be accurate or appropriate."[24] And yet somehow this does not raise the question for I&M of whether degradation makes sense at all; it just narrows its application of the methodology to three years.

[22] I&M Witness Burnett's Rebuttal Testimony, page 19.
[23] I&M Response to Docket Entry IURC 3-01 and related attachments.
[24] I&M Response to CAC Data Request 12-04 (included in Attachment AS-5).

Jurisdiction	YEAR	Total at the Gen.	Total at the Meter
IM - Indiana	2019	73.1	66.8
	2020	79.8	72.8
	2021	25.1	22.9
	2022 and beyond	-	
IM - Michigan	2019	10.7	9.8
	2020	8.0	7.3
	2021	2.3	2.1
	2022 and beyond	-	

Table 1*. Degradation Related Adjustments (GWh) to I&M Load Forecast*[25]

Company sales (at the meter) in 2019 were 18,117 GWh. Removing energy efficiency savings based on the 2019 degraded amounts shown in Table 1 only increases I&M's load forecast by 0.22 percent. Similarly, in comparison to forecasted sales in 2020, removing the degraded EE savings only increases sales by 0.45 percent. The accuracy of I&M's load forecast without degradation is well within the range of accuracy given by Mr. Burnett in his Rebuttal Testimony. His graph that purports to support his contention is reproduced here as Figure 3.

[25] 45285_IndMich_Response to CAC 6-02 Attachment 1_03192020 (response included in Attachment AS-5, CAC 6-02 Attachment 1 is Attachment AS-7) and CAC_2-2_Attachment 1 (response to CAC DR 2 is included in Attachment AS-5, CAC_2-2_Attachment 1 is Attachment AS-8). Michigan values at the meter were inferred based on values at the meter for Indiana.

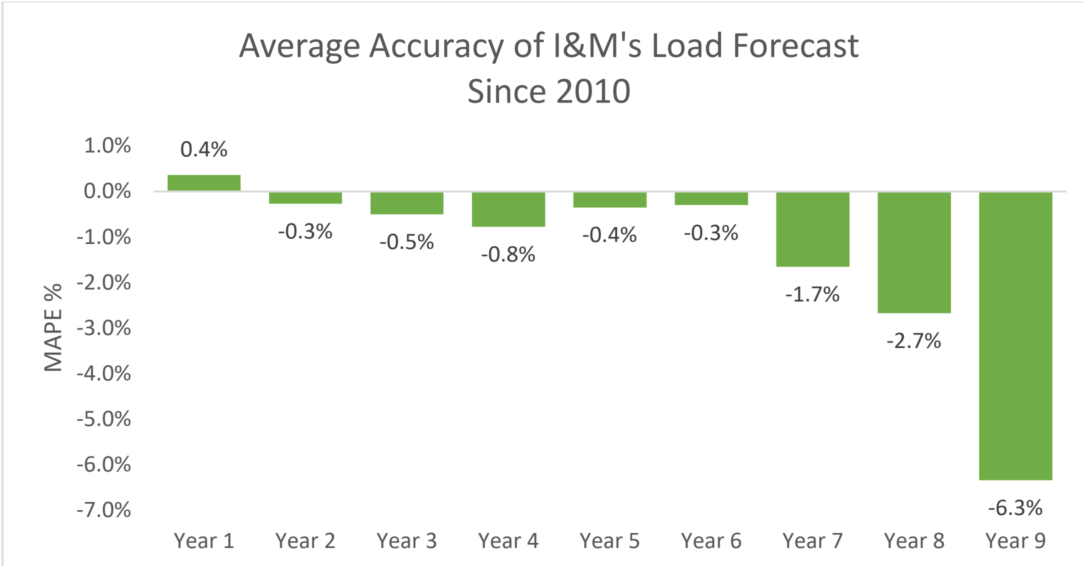

Figure 3. Reproduction of Figure CMB-1R[26]

A change of 0.22 percent and 0.45 percent is well within the average errors given in this Figure. Furthermore, if one looks at the accuracy of I&M's load forecast since 2012,[27] the year that I&M first began to use its current degradation methodology, removing the degradation adjustments looks like a change that is even more in the noise. The range of errors given in Figure 4 is not dissimilar at all to the 2019 and 2020 degradation adjustments.

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[26] I&M Response to CAC Data Request 5-01(included in Attachment AS-5); referenced spreadsheet in this data request included as Attachment AS-3.
[27] I&M's Response to Docket Entry 3-01.

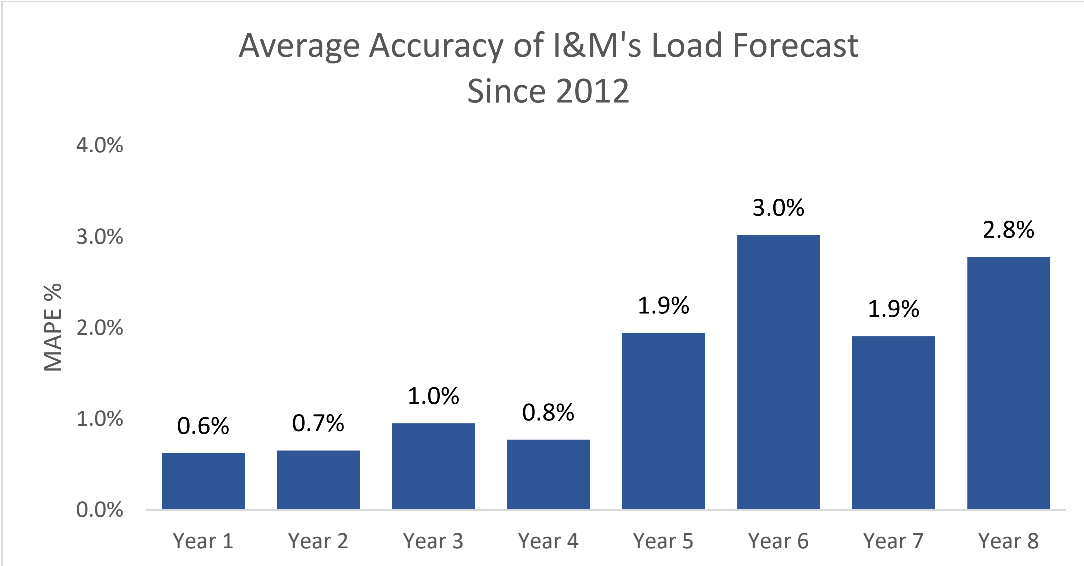

Figure 4. The Accuracy of I&M's Load Forecasts Since 2012

To be clear, I am not suggesting that the Company does not need to make adjustments to its load forecasts to account for utility-sponsored energy efficiency. I am simply pointing out that the historical accuracy of I&M's load forecast is no justification for degradation and that the impact of degradation on modeling of energy efficiency is greatly outsized compared to its impact on I&M's load forecast.

Q. Are you saying, as Mr. Burnett contends you say "that future DSM savings must always be at or above whatever savings amounts I&M was able to achieve historically"[28]?

A. No. Quite simply, my overarching recommendation is that the Company represent EE throughout its IRP in a manner consistent with how those savings actually materialize. This is not a dichotomy about measuring savings differently in the load forecast versus in a DSM plan. This is about a fundamental lack of support for a methodology that has

[28] I&M Witness Burnett's Rebuttal Testimony, page 9.

dramatically greater impacts on modeled energy efficiency than it does on the load forecast, all to the detriment of ratepayers.

IV. The Company's Plan Does Not Achieve an Optimal Balance of Resources

Q. Why does the rationale for the degradation factors matter?

A. Energy efficiency is different than supply-side resources in the sense that its impact ramps up over time. Therefore, rectifying the flaws in I&M's modeling of energy efficiency are, in many ways, more urgent that the flaws identified in my assessment of I&M's modeling of supply-side resources. I&M will have much more difficulty making up lost ground if it waits to correct these flaws until its next program plan filing for 2023. In the meantime, I&M ratepayers will be losing out on the benefits that energy efficiency can provide to defer or reduce the size of future capacity additions. For example, the I&M 2018-2019 IRP preferred plan includes 770 MW of new combined cycle capacity in 2028 which starts out at an annual cost of $[redacted] per MWh and escalates at an average annual rate of [redacted] percent each year.[29] In contrast, if I&M had modeled its energy efficiency in a manner consistent with its representation in the MPS, the weighted average portfolio cost in 2020 would have been $30.20 per MWh. In my expert opinion, it would be illogical to conclude that cutting energy efficiency savings in half at this price in favor of acquiring a significant amount of capacity at a price that is roughly double the cost of energy efficiency strikes "an optimal balance of resources". Again, all of this is to the detriment of ratepayers.

[29] Based on Copy of CASE 9_Base Band Pricing_ 2-Pager Summary_061019 (Attachment AS-9-Confidential).

VI. The Company's IRP and MPS Are Out of Date

Q. Why are the Company's IRP and MPS out of date?

A. Taking these items in reverse order, the MPS is stale simply because it was completed in 2016. As the Director's Draft Report on I&M's 2018-2019 IRP noted, "this dated MPS raises questions about the relevance of the MPS for this IRP."[30]

The IRP is out of date because, as I&M noted to the Michigan Public Service Commission, "trying to process this current IRP may be an exercise that doesn't leave much value in the conclusion in the end, given the current state of affairs" and that "COVID-19 certainly has impacted load not only for I&M but for other utilities throughout the United States and those load changes, in general, call into question the efficacy of the current IRP."[31]

In response to CAC Data Request No. 12-01, the Company said that, "The purpose of the statement was to point out that there was no need to continue litigating under Michigan law the last-completed IRP given that the Company would soon be initiating work on its next IRP."[32] The same rationale ought to apply here. The Commission should order that the Company continue offering its existing DSM programs at the levels consistent with the interim authority in place now, levels which the Commission deemed to be consistent with the prior IRP, because, as the Company states, it will "soon be initiating work on its next IRP". Once the updated market potential study and the IRP is completed in collaboration with I&M's interested stakeholders and its OSB, then the

[30] Attachment AS-2, page 13.
[31] April 2020 prehearing conference in Michigan Public Service Commission Case No. U-20591.
[32] Attachment AS-5.

Company can refile its DSM plan. Any program changes in the interim that are supported by the 2021 MPS should be determined by unanimous vote of I&M's OSB.

Q. Doesn't the "drop in I&M's projected load [make] it that much more difficult to achieve incremental DSM/EE savings but also changes the need for additional DSM/EE"[33] as Mr. Burnett claims?

A. No. Mr. Burnett presents I&M's May 2020 load forecast as justification that EE savings will be harder to achieve given the economic impacts of the COVID-19 pandemic. The parties to this case have not had an opportunity to review the inputs into this new load forecast, which would be afforded if the Commission required I&M to resubmit its plan at the conclusion of its next IRP.

Even more importantly, Mr. Burnett ignores the fact that those impacts are different across sectors as shown in Figure 5.

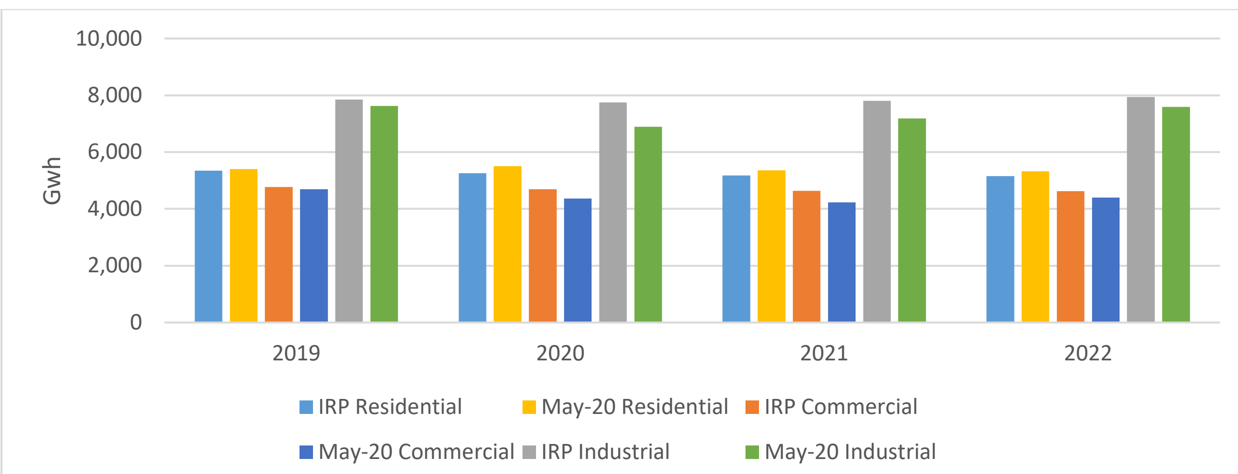

Figure 5. Comparison of IRP Sales Forecast by Sector to May 2020 Forecast

I&M is actually forecasting an *increase* in residential load presumably due to the fact that many customers in I&M's service territory will continue to work from home, keep

[33] I&M Witness Burnett Settlement Testimony, page 2.

their children out of daycare, etc., all of which are activities that increase residential consumption. Forecasted residential sales in the IRP were 5,261 GWh and 5,177 GWh in 2020 and 2021, respectively, while the May 2020 load forecast now predicts sales of 5,509 GWh in 2020 and 5,358 GWh in 2021.

In the commercial sector, I&M is now anticipating a decrease in sales. Forecasted IRP sales were 4,691 GWh and 4,631 GWh in 2020 and 2021, versus 4,369 GWh and 4,227 GWh under the May 2020 forecast in 2020 and 2021, respectively.

The biggest absolute decline in this new load forecast is in the industrial sector from 7,748 GWh and 7,806 GWh (IRP forecast) to 6,895 GWh and 7,182 GWh (May 2020 forecast) in 2020 and 2021, respectively.

Q. Why is the impact to the different customer class sectors relevant to Mr. Burnett's point?

A. As the Company's response to CAC Data Request 3-06 demonstrates, 2,767 GWh of industrial sales have opted out of the Company's EE programs. The forecasted decline in sales is driven largely by the decline in that sector which undermines the suggestion that EE savings will be more difficult to achieve.

Regardless of the sector by sector changes, however, it is important to note that I&M still forecasts that the overall load will recover to a large degree**.** For example, the 2028 total sales in the IRP were 17,823 GWh versus 17,451 GWh under the May 2020 forecast. And as the Company's response to CAC Data Request 12-03[34] acknowledges, even under the low load scenario analyzed by the Company, PLEXOS continues to add hundreds of megawatts of new capacity. While the COVID pandemic is material enough

[34] Included in Attachment AS-5.

to render the IRP out of date, in my expert opinion one cannot conclude that energy efficiency is any less valuable to I&M ratepayers without rectifying the many flaws in I&M's modeling detailed in my Direct Testimony and in this testimony.

VII. Response to I&M Rebuttal Testimony

Q. Is there anything you would like to say in response to I&M's rebuttal testimony in this cause?

A. Yes. Mr. Burnett's rebuttal testimony was very informative in that it revealed just how deeply flawed the Company's rationale for degradation is, which is again to the detriment of ratepayers. Mr. Burnett cites the example that I gave in my Direct Testimony, i.e., "If a customer participates in a program and takes a rebate for a new water heater, they are either a free rider or they are not. Their savings either persist – unchanged – for the entirety of the water heater life, or they are zero for the entirety of the water heater life."[35] He offers Figure 6, below, as his evidence that the "CAC assumption does not align with the assumed efficiency gains in the SAE models and therefore the Company makes a degradation adjustment to the estimated DSM savings to prevent the double counting of energy efficiency in the load forecast."[36]

[35] CAC Witness Sommer Direct Testimony, page 9, lines 2 – 6.
[36] I&M Witness Burnett Rebuttal Testimony, page 13, lines 2 – 5.

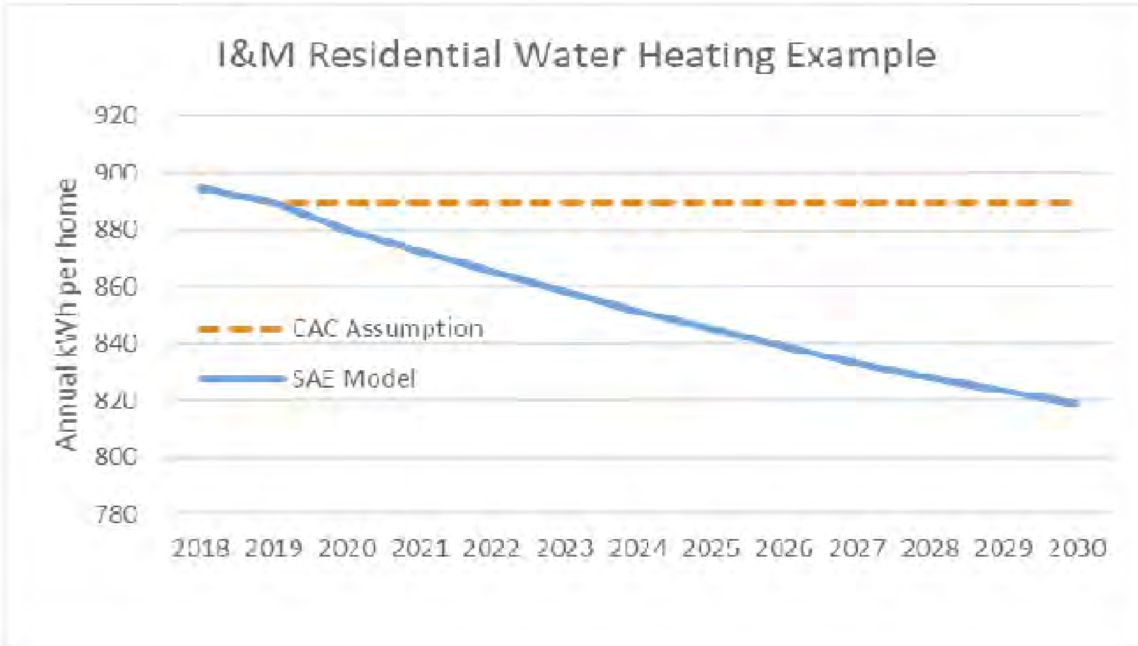

Figure 6. Reproduction of CMB-2R in Burnett Rebuttal

Mr. Burnett's statement and use of this figure do not add up. As an initial matter, Mr. Burnett's example does not even support degradation. Over a 10-year measure life,[37] the statistically adjusted end-use ("SAE") curve declines about 6 percent, whereas I&M's 10-year degradation factor declines by 99 percent.

Second, of course average residential water heating consumption in the SAE model will decline over time, perhaps even in the manner forecasted by the blue line in Mr. Burnett's figure. That is because every year there will be some turnover of existing water heater stock. The newly purchased water heaters will have to be at least as efficient as required by current federal standards. And that will cause the average Annual kWh per home usage for water heating to decline in every year.

[37] Ten years is the measure life I&M assumed for residential water heating as shown in "Copy of 2018 IM Residential Build Cost w Degradation and Potential Changes v4_Lite R1052319.xlsx".

Third, Mr. Burnett's "CAC Assumption" line is too high: the orange line must be measured relative to the current minimum efficiency. If that minimum efficiency level equates to the end point of his blue line, 820 kWh, for example, then the orange line should start at the 820 kWh mark.[38] The savings credited to an energy efficiency measure in this case are relative to the minimum required standard and have nothing to do with the average efficiency of the existing stock of measures.

Simply put, Mr. Burnett is comparing apples and oranges in a manner that is highly misleading—again, to the detriment of I&M's ratepayers who are being deprived of investment in one of the lowest cost resources available to I&M..

Q. To clarify, if the minimum required efficiency changes over time, shouldn't the CAC assumption represented as an orange line shown in Mr. Burnett's figure reproduced above also decline over time?

A. No. Based on his response to CAC Data Request 6-08 (b), Mr. Burnett simply doesn't understand this. He said:

> *Assume this hypothetical heat pump water heater that is rebated in 2021 uses 880 kWh per year. Furthermore assume the market continues to demand higher efficiencies throughout the forecast horizon so that the average efficiency for a heat pump water heater that is purchased in year 5 will only use 840 kWh per year and by year 10, the average water heater available on the market only uses 800 kWh per year. The original program that incentivized the consumer to purchase an appliance that still uses 880 kWh per year would no longer receive credit for energy savings once the market efficiencies surpass the 2021 technology or in this example by year 5.*[39]

[38] Water heater efficiency is measured by "Energy Factor" or "Uniform Energy Factor"—not by annual kWh consumption—so annual energy consumption is not capped at a specific number of kWh per year.
[39] I&M Response to CAC Data Request 6-08 (included in Attachment AS-5).

Energy savings credited to an energy efficiency program are typically not measured relative to the old inefficient equipment (with exceptions such as a custom C&I program). Instead, the savings represent the incremental improvement between a standard new piece of equipment and an efficient new piece of equipment). Nor are they reevaluated every year relative to a changing standard. What matters is the standard in place at the time the efficient measure was installed. I&M clearly agrees with me on this point because otherwise its proposed lost revenue recovery should decline over time on the same schedule as the degradation factors.

Furthermore, given the complexity of setting federal appliance standards it is very unlikely that higher efficiencies will be required every year. But even if the standard could change that frequently, the way to visualize this would be to have a lower, separate but still straight orange line for every year. The savings credited to previously installed measures would not change.

Q. But Mr. Burnett offers multiple examples of other utilities that adjust their load forecasts for energy efficiency, isn't that support for I&M's particular use of degradation?

A. No. If I&M thinks it is my or the CAC's position that no adjustment is needed, then the Company clearly has not understood our concerns. Yes, Itron's SAE model requires an adjustment for future utility sponsored energy efficiency. However, the Company has never presented evidence that any non-AEP utility adjusts for future energy efficiency in an end-use model in a *magnitude* that is similar to the Company's degradation factors. Furthermore and perhaps more importantly, there is a way to perform this adjustment *without distorting energy efficiency modeled on the supply-side*. The fact that the Company continues to attempt to justify degradation is one of the more frustrating aspects of the Company's modeling. I&M can appropriately adjust for future utility sponsored energy efficiency in its load forecast without making any adjustment to its EE bundles; and, in doing so, not only would it assuage CAC's deep objections to degradation, it would increase transparency and readability of its IRP by eliminating a methodology that it has never, over the course of two IRPs, even been adequately documented.

The mere fact that other utilities make an adjustment for future utility-sponsored EE has no bearing on whether the Company's particular method of avoiding double counting is irredeemably flawed. And, I&M's method indubitably is.

Q. **In your Direct Testimony, you raised the issue that even if degradation is appropriate, I&M has still modeled 25 percent fewer savings than it intended. Mr. Fisher contends in his Rebuttal Testimony that the issue you raise applies to "only one of the 29 proxy EE resources" modeled and, that to fix the problem, the Company would "need to develop over 800 EE resources to model".[40] How do you respond?**

A. Mr. Fisher is mistaken. Even if degradation were correct and appropriate, I&M is undercounting EE by 25 percent for _all_ its bundles. That issue is not limited to the example I gave in my Direct Testimony, and Mr. Fisher agrees with me, acknowledging that I am "illustrating the Company's process".[41] Furthermore, the primary reason the Company has to model EE in this way is because of its degradation approach. Removing this flawed approach from its IRP would solve this and many other fatal flaws in its modeling of energy efficiency. I have never said it would be reasonable to model 800 different EE resources

[40] I&M Witness Fisher's Rebuttal Testimony, page 7.
[41] *Id*.

in a model and would be happy to discuss with Mr. Fisher the many ways in which I have seen other utilities limit the number of EE resources modeled without using a degradation approach. I look forward to these conversations as part of the I&M 2021 IRP stakeholder process, which I anticipate will begin soon. CAC has already reached out to I&M requesting an opportunity to discuss the development of its load forecast for use in the I&M 2021 IRP, and I look forward to figuring out a collaborative path forward on all of these modeling issues.

Q. Mr. Fisher also says that the difference between the savings potential modeled in the MPS versus that represented in the IRP model is merely 2 percent. How do you respond?

A. Mr. Fisher is deflecting from the issue that I am raising. The Company's response to CAC Data Request 7-01 confirmed that Mr. Fisher is merely comparing the *first* year savings in the IRP versus the *first* year savings in the MPS.[42] The issue I identified in my Direct Testimony has to do with the *lifetime* of savings modeled setting aside the issue of degradation. Again, Mr. Fisher acknowledges that I have correctly illustrated the Company's process, the result of which is that 25% of total savings (even assuming degradation is reasonable) are missing from the IRP modeling. This is an additional and important flaw that his Rebuttal Testimony does not address.

Q. In his Rebuttal Testimony, Mr. Fisher contends that, "While the EE bundles are proxy resources they are based on the Company's MPS; they align with the retail customer classes; they align with the load shapes within the retail customer classes;

[42] I&M Response to CAC Data Request 7-01 (included in Attachment AS-5); referenced spreadsheet in this data request included as Attachment AS-10.

and they provide a cost and savings level that provides the IRP model over 29 different EE options over a 25 year planning horizon."[43] How do you respond?

A. The selection of the bundles does not align with retail customer classes—this is precisely my point. Mr. Fisher continues to want to have it both ways—a selection of the bundles in the IRP that is radically divorced from the actual plan the Company intends to implement. This conclusion is nonsensical. One does not successfully bake a loaf of bread and then conclude that that success should justify changing 50 percent of one's ingredients to something the recipe does not call for. If the EE bundle savings in the IRP modeling do not have to be representative of potential DSM plan savings, then what is the rationale for the MPS at all? And by what standard could one say that any assumption about IRP EE bundle cost and savings is unreasonable?

Q. Is Mr. Fisher correct that the Company adjusted the IRP savings to arrive at "undegraded savings" for use in the DSM plan?[44]

A. No. In the very spreadsheet Mr. Fisher cites as support for this argument, on the tab "Model Output", one can see the degraded profile of savings are multiplied by the number of units picked and then summed to create a lifetime profile of total savings that is then aggregated together (starting at cell DN99) that is identical to what Mr. Fisher calls the "undegraded savings". There is no adjustment to remove degradation for this DSM plan. This is to the detriment of I&M's ratepayers.

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[43] I&M Witness Fisher's Rebuttal Testimony, page 10, lines 7-11.
[44] *Id.*, page 5.

Q. In his rebuttal testimony Mr. Walter contends that, "The most expensive measure bundle selected in the IRP Preferred Plan is the Commercial Indoor Lighting Maximum Achievable Potential Bundle at a levelized cost of 1.79 cents per kWh…[so] using 2018 and 2019 actual residential sector costs would not have resulted in the IRP selecting any additional energy efficiency."[45] How do you respond?

A. Mr. Walter is very misleadingly using the levelized cost of the Commercial Indoor Lighting Maximum Achievable Potential bundle *before* I&M's many distortions of energy efficiency including degradation are applied. When one takes into account both degradation as well as the fact that this bundle must be selected over a 5 year period the true levelized cost represented in PLEXOS is 3.36 cents per kWh.[46] In contrast, if the IRP modeling had been faithful to the representation given by the MPS, then the weighted average portfolio cost of measures in 2020, for example, would have been 3.02 cents per kWh, materially less than the levelized cost of the most expensive bundle picked in the preferred plan.

Q. In his rebuttal testimony, Mr. Fisher points to a decline in avoided costs as a key driver of the selection of less energy efficiency.[47] How do you respond?

A. Mr. Fisher does not address the many issues related to the MPS and the representation of energy efficiency in the Company's modeling as described in the Direct Testimony submissions of Dan Mellinger and myself, nor does his justification make sense. I would only agree with him in the sense that the Company is undercounting avoided costs as described in the Testimony in Opposition to the OUCC-I&M Settlement of Brian Horii.

[45] I&M Witness Walter's Rebuttal Testimony at page 26.
[46] Based on information in "Copy of CASE 9_Base Band Pricing_ 2-Pager Summary_061019".
[47] I&M Witness Fisher's Rebuttal Testimony at pages 2 – 4.

Setting aside excluded avoided costs, the Company's 2019 forecasted around the clock ("ATC") value of energy in PJM of $28.07 per MWh clearly does not compare favorably to the levelized cost of the most expensive bundle picked in PLEXOS – Commercial Indoor Lighting MAP with a levelized cost of $33.60 per MWh. The model would seemingly be unlikely to pick bundles that are more expensive than this.

But the model does take 770 MW of new combined cycle capacity in 2028 which starts out at an annual cost of $[redacted] per MWh and escalates at an average of [redacted] percent per year. Its cost always exceeds the 2019 ATC PJM prices given in Mr. Fisher's Figure GSF - 1R. In my expert opinion, this nonsensical result is the product of the Company's many distortions of energy efficiency, forcing in certain resources that devalue energy efficiency in the early years of the planning period, and the manner in which the Company modeled future combined cycles as described in my Direct Testimony and its attachments.

V. Conclusion

Q. What is your recommendation?

A. I recommend that the Commission reject the OUCC-I&M Settlement Agreement and require I&M to continue offering its existing DSM program portfolio at the levels consistent with the interim authority until the updated market potential study is published and the IRP in November 2021 is completed in collaboration with I&M's interested stakeholders and OSB. Any program changes in the interim that are supported by the 2021 MPS should be determined by unanimous vote of I&M's OSB.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Anna Sommer, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Anna Sommer

September 15, 2020

ATTACHMENT AS-1

Draft Director's Report

for Indiana Michigan Power Company's 2018-2019 Integrated Resource Plan

July 17, 2020

Dr. Bradley Borum
Director of Research, Policy and Planning
on behalf of the Indiana Utility Regulatory Commission

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Draft Director's Report Applicable to Indiana Michigan Power Company's 2018-2019 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Indiana Michigan Power Company's (I&M) 2018- 2019 IRP was submitted on July 1, 2019. By statute[1] and rule,[2] integrated resource planning requires each utility that owns generating facilities to prepare an integrated resource plan (IRP) and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The IRP Director in the report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.[3]

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of IRP, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting.[4] By identifying uncertainties and their associated risks, utilities will be better

[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7; see also "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm ("Draft Proposed Rule")

[3] 170 IAC 4-7-2.2(g)(3).

[4] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Every Indiana utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors[5] and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. INTRODUCTION AND BACKGROUND

I&M's following statement of purpose is consistent with the integrated resource plan (IRP) statute and rule.

> This 2018-19 Integrated Resource Plan (IRP, Plan, or Report) is submitted by Indiana Michigan Power Company (I&M or Company) based upon the best information available at the time of preparation. This Plan is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. The Plan strives to maintain optionality in meeting I&M's resource obligations to take advantage of market opportunities and technological advancements. Accordingly, this IRP and the action items described herein represent an indicative plan and are subject to change as new information becomes available or as circumstances warrant. *(I&M IRP page ES-1)*

The utility's Executive Summary in its IRP submittal continues to say:

> An IRP explains how a utility company plans to meet the projected capacity (i.e., peak demand) and energy requirements of its customers. I&M is required to provide an

[5] A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

IRP that encompasses a 20-year forecast planning period (in this filing, 2019-2038). This IRP uses the Company's current long-term assumptions for:

- Customer load requirements – peak demand and hourly energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- existing supply-side resource retirement options;
- supply-side alternative costs and performance characteristics – including fossil fuel, renewable generation, and storage resources;
- transmission planning and
- demand-side management program costs and impacts.

In addition, I&M considered the effect of environmental rules and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP also considers the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is considerable uncertainty as to the timing and form future carbon regulation may take. This IRP also evaluates a 'No Carbon' scenario that assumes a future without carbon regulation. To meet its customers' future capacity and energy requirements, I&M assumes the continued operation of its existing fleet of generation resources for a portion of the 20-year plan, including the two base-load coal units at the Rockport Plant, and the two units at the DC Cook Nuclear Plant (Cook). A key assumption in several scenarios is that the Rockport Unit 2 lease expires in late 2022 and Rockport Unit 1 retires at the end of 2028. Other Rockport unit retirement scenarios are also evaluated in this IRP and described in Section 5. Importantly, all of the Rockport IRP assumptions that underpin this IRP are intended for use in this IRP only, as several key decision variables, including the Consent Decree modification and final Unit 2 lease disposition, remain open. Another important assumption in this IRP is that Cook units will operate through the remainder of their current license periods, although the Company may explore future life-extension opportunities. The Company also assumes the continued operation of its run of river hydroelectric and solar plants.

The Company has a portfolio of 450MW of purchase power agreements consisting of four wind farms. During the planning period, these contracts will expire. In addition, the Company is planning to install 64MW of solar resources by 2023, which for this IRP are assumed to be "going-in" or "existing" resources. Another consideration in this IRP is the increased adoption of distributed rooftop solar resources by I&M's customers. While I&M does not have control over where, and to what extent, such resources are deployed, it recognizes that distributed rooftop solar will reduce I&M's growth in capacity and energy requirements to some degree. Importantly, I&M operates within the PJM Interconnection, L.L.C. (PJM) Regional Transmission Organization (RTO), while most Indiana and Michigan utilities operate in the Midcontinent Independent System Operator, Inc. (MISO) RTO. As expected, each RTO has its own capacity planning process that results in different resource planning criteria and assumptions.

> In this IRP, the Company continues to model portfolios that not only add resources to meet its PJM capacity obligation, but also provide zero variable cost energy to enhance rate stability, reduce emissions and further diversify its generation portfolio. *(I&M IRP pages ES-1 and ES-2)*

For this IRP, the key assumption in several scenarios is the status of the Rockport Unit 2 lease, which expires in late 2022, and Rockport Unit 1, which could retire at the end of 2028. Other Rockport unit retirement scenarios are also evaluated in this IRP and described in Section 5. Importantly, all of the Rockport IRP assumptions that underpin this IRP are intended for use in this IRP only, as several key decision variables, including the Consent Decree modification and final Unit 2 lease disposition, remain open. Another important assumption in this IRP is that the Cook units will operate through the remainder of their current license periods, although the Company may explore future life-extension opportunities. *(I&M IRP page ES-2)* I&M analyzed scenarios that would provide adequate resources and minimize costs to I&M's customers over the 20-year planning horizon and selected a *Preferred Plan*. [6] *I&M IRP page ES-3)*

III. FOUR PRIMARY AREAS OF FOCUS

Consistent with the introductory comment, the primary areas of focus include: load forecasting; demand side management (DSM) which includes energy efficiency (EE) and demand response (DR)); risk / scenario analysis; the stakeholder process, and the need for continual improvement such as modeling all forms of distributed energy resources (DERs) and electric vehicles (EVs).

A. LOAD FORECAST

I&M serves approximately 466,000 retail customers in Indiana and 129,000 retail customers in Michigan. I&M has two distinctive peaks occurring in the summer and winter seasons. I&M's all-time highest recorded peak demand was 4,837 MW, which occurred in July 2011; the highest recorded winter peak was 3,952 MW, which occurred in January 2015. The most recent (summer 2018 and winter 2018/19) actual I&M summer and winter peak demands were 4,369 MW and 3,770 MW, occurring on June 18, 2018 and Jan. 30, 2019, respectively. *(I&M IRP Public Summary, page 1)*

Over the next 20-year period (2019 to 2038) I&M is projecting a relatively flat residential customer count growth rate of 0.1% per year. Residential retail sales growth is projected to be flat, commercial sales growth is expected to decline by -0.3% per year, and the industrial class is expected to grow about +0.4% per year. The result is that I&M's retail sales grow at a 0.1% rate per year. I&M's internal energy and peak demand are expected to

[6] The Preferred Plan would: 1) continue the operation of the Cook Units through their current license periods; 2) retain the Rockport Unit 2 until the lease expires at the end of 2022; 3) retire the Rockport Unit 1 at the end of 2028; 4) beginning in 2022, I&M would deploy 3,600 MW of wind and large scale solar by 2038; 5) integrate 50 MW of batteries and 54 MW of microgrid resources by 2028; incorporate 180 MW of energy efficiency and demand response; and anticipates residential and commercial customers will install rooftop solar and other distributed generation.

decrease at an average rate of 0.2% per year, respectively, through 2038. *(I&M IRP Public Summary, page 2)* I&M provided the following graphic to illustrate the load forecasts in the different scenarios (I&M IRP, page 31)

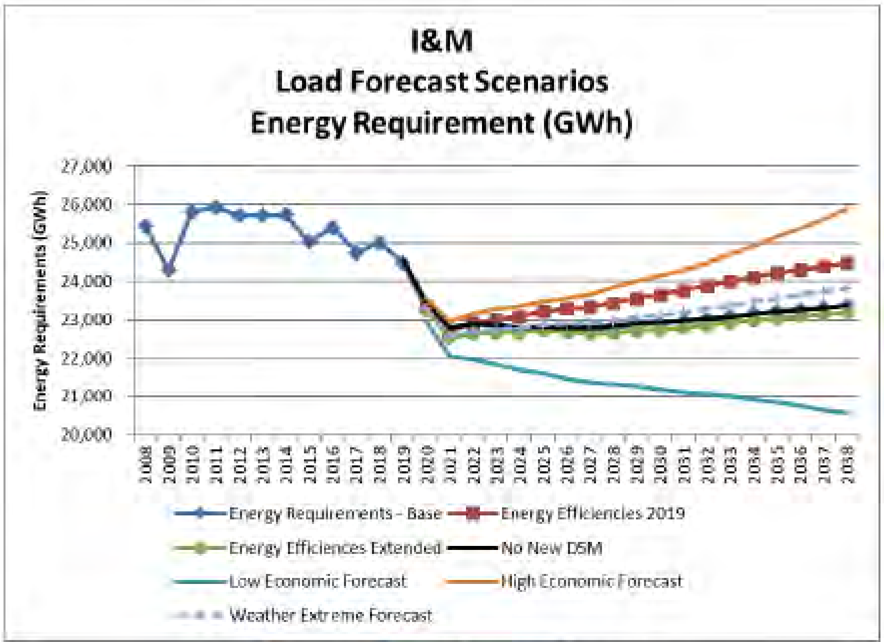
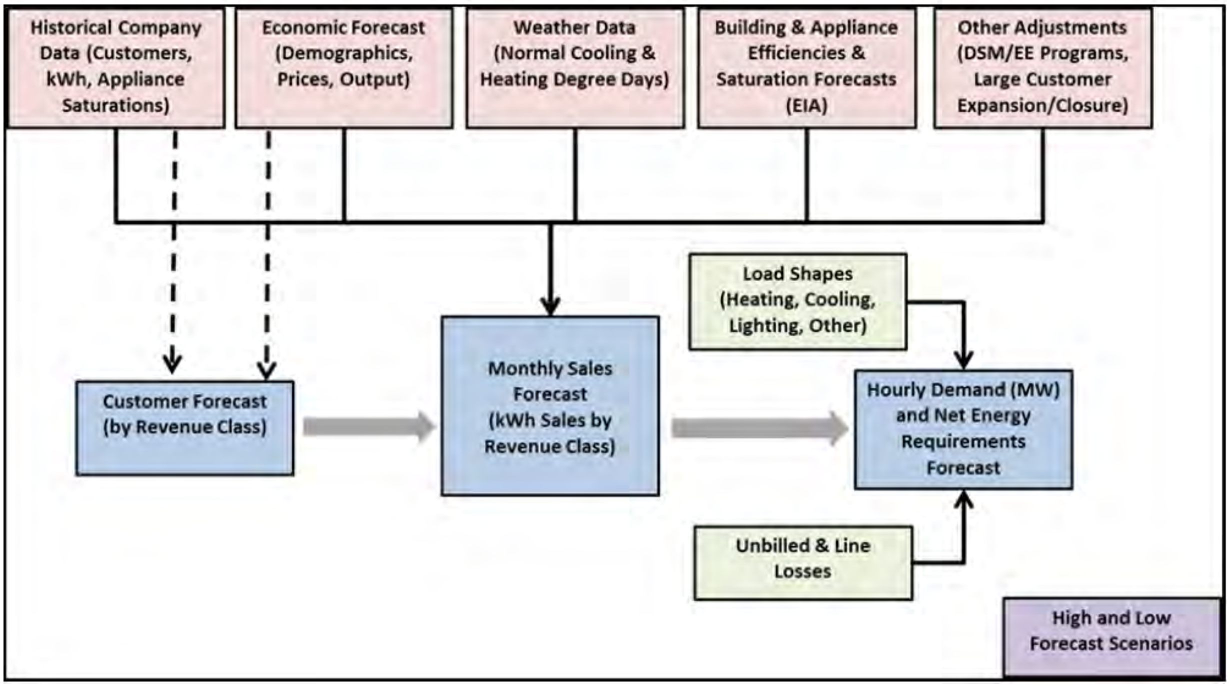


Figure 10. Load Forecast Scenarios

I&M's load forecasts are primarily based on econometrics such as the use of ITRON's Statistically Adjusted End-Use (SAE) model and time series data. A short-term (approx. 24 months) and long-term (approximately 30 years) forecast are prepared. The short-term forecast is an ARIMA (Autoregressive Integrated Moving Average) that considers weather (e.g., heating and cooling degree days) and trends in customer use, and assumes the existing stock of end-uses to be fixed. For industrial customers, factory orders and inventory are included in the ARIMA. I&M believes ARIMA provides more accurate results for short-term forecasts. The long run forecasts attempt to capture structural changes such as changes in end-use, technology, natural gas prices, population/demographics, real personal income, employment, gross regional product, economics, etc. In the long-term, customers can change their appliance/end-uses in response to electric price changes and other factors. Figure 2 (below) is useful. *(I&M IRP, page 10)* The short and long-term models are blended, largely based on professional judgment, to smooth the transition. *(I&M IRP, pages 9-12)* The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2021 the entire forecast is from the long-term models. *(I&M IRP, page 16)*



I&M's load forecast was developed by AEP's Economic Forecasting organization and completed in June 2019. Underlying forecasts include an economic forecast by Moody's Analytics to develop the customer forecast, the sales forecast, the peak load, and internal energy requirements forecast.[7] *(I&M's IRP, page 7)* I&M's IRP also generally discusses the potential for reduced energy use and demand as a result of EE, DR, batteries, microgrids, rooftop solar, distributed generation, and other DERs.

I&M's load forecasts for industrial customers relies heavily on customer service engineers to obtain information from those customers *(I&M IRP, pages 8 and/or 15*) that may alter the large commercial and industrial load forecasts. I&M also uses as explanatory variables its service territory's Gross Regional Product for manufacturing, employment, electric prices, and Federal Reserve Bank (FRB) industrial production indexes. *(I&M IRP, page 15)*

I&M forecasts public street and highway lighting as a function of economic variables such as service area employment or service area population and binary variables. Wholesale

[7] The load forecasts for I&M and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2019. Moody's Analytics projects moderate growth in the U.S. economy during the 2019-2038 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projects regional employment growth of 0.3% per year during the forecast period and real regional income per capita annual growth of 2.3% for I&M's service area. The Company utilizes an internally developed price forecast that incorporates information from the Energy Information Administration (EIA) outlook for the East North Central Census Region for the longer term. *(I&M's IRP, pages 7 and 8)*

energy sales are modeled as a function of economic variables such as service area gross regional product, industrial production indexes, energy prices, heating and cooling degree-days and binary variables. I&M uses binary variables to account for discrete changes in energy sales that result from events such as the addition or deletion of new customers. *(I&M IRP, page 16)*

I&M integrates weather related assumptions as a variable in its load forecast methodology where appropriate, recognizing some electric use is not highly correlated to weather. *(I&M IRP, page 8)*

The demand forecast model is based on a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles, and calendar information.

> The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads. *(I&M IRP, page 17)*
>
> The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. *(I&M IRP, page 17)*
>
> The profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of I&M and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy 2018-19 Integrated Resource Plan requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year). *(I&M IRP, pages 17-18)*

According to I&M, its end-use load forecasting models account for changing trends and saturations of energy efficiency technologies throughout the forecast period. Given that I&M is also administering EE and DR programs to accelerate the adoption of EE technologies, the load forecast needs to be adjusted to account for the impact of these EE and DR programs not already embedded in the load forecast. As a result, I&M applies a “degradation factor” to adjust EE selected in the IRP model to avoid double counting EE savings; once in the load forecast and also in the IRP optimization selecting EE bundles. This will be discussed more in the discussion of Demand-Side Management. (I&M IRP, page 24)

DIRECTOR'S COMMENTS – LOAD FORECASTING

I&M's forecast methodology was well done, the data sources and tools were appropriate for this IRP, and the forecast was well documented both in the report itself and in the appendices. I&M is commended for its stakeholder involvement throughout the process. Especially in the first two stakeholder sessions, I&M provided very good discussions and engaged the stakeholders in better understanding of changing usage patterns and the impact of embedded appliance efficiencies in the forecast.

I&M said there have been only "a limited number of changes in the methodology" since I&M's 2015 IRP *(I&M IRP, page 27)*, but only explicitly mentioned the change involving how the high-low economic growth model is now estimated separately for I&M and each operating company. It would have been helpful for I&M to enumerate any methodological changes. As I&M discussed the changing usage patterns, this is an appropriate predicate for I&M to undertake an evolutionarily significant continuing improvement process to better capture changing usage patterns and demographic changes for all classes of customers. Potential enhancements to I&M's methodology will be discussed in this Report.

I&M's application of the forecast methodology resulted in the construction of a slightly broader range of forecasts than in the previous load forecasts in 2015 load forecast (2015 was 10% below and 11% above the base forecast on page 29 of 2015 IRP compared to this 2018 forecast of 12.4% below and 12% above). Given the limited growth rates, these difference are a bit more significant than the percentages reflect. More discussion of the sensitivities, derived from the Energy Information Administration's (EIA) 2019 Annual Outlook that produced high and low growth scenarios, would have been beneficial. It does appear I&M is being responsive to the Director's suggestion that I&M make greater use of I&M-specific data. Additional details and rationale in the narrative would have been useful.

Questions about how EE affected the load forecast remain. The need to implement a process to avoid the potential double counting of energy efficiency is reasonable. The use of degradation factors to lessen the potential for double counting, even if the factors are estimates, seems appropriate at a conceptual level. However, there are a number of EE-related concerns that will be addressed in the DSM discussion. The Director has some specific comments/questions such as:

1) The Director understands that short-term models do not capture structural changes in the economy but may be more useful to financial forecasts in the near-term. The Director remains unconvinced of the need for "blending" a short- and long-term forecast. Does I&M anticipate changes to reduce the need for the two forecasts?;

2) In the residential forecast *(I&M IRP, page 14)*, I&M describes the "Cooling use variable drivers" but lists Heating Degree Days (HDD). Should this be Cooling Degree Days (CDD) or was HDD used in this model? This occurred in the 2013 and 2015 IRPs as well;

3) The National and Regional economic forecasts *(I&M's IRP, page 7)* are ascribed to be from Moody's Analytics December 2019. We assume I&M meant December 2018;

4) I&M's IRP did not discuss the potential for EVs to increase I&M's energy use and demand as well as changing the load shapes for I&M. While the number of EVs and charging stations may not be significant now, it may become increasingly important to the load forecast. Does I&M anticipate future forecasts and IRPs will provide information on EVs?

5) It is not clear how or why binary variables are integrated into the forecast. For example, is the "addition or deletion of new customers" binary. (e.g., I&M's IRP page 16) In past Reports, the Director has mentioned the use of binaries *may* mask important underlying information. Does I&M anticipate a review of the need for binaries? Regardless, it would be helpful to discuss the rationale in future IRPs;

6) And, with regard to street lighting in specific and lighting generally, I&M's forecast undoubtedly included estimated effects of higher efficiency lights. However, I&M on page 51 of its IRP said efficient lighting could reduce lighting use by 5% by 2033 but it isn't clear this potential was included in their IRP? In future IRPs, will I&M provide additional information on the future of lighting?

B. ENERGY EFFICIENCY

I&M uses the traditional definition of DSM (EE and DR) to encourage efficient energy consumption and to reduce use, especially during peak periods. This section will primarily discuss EE modeling and integration into I&M's IRP resource optimization process due to its relative importance in I&M's selection of resources. Demand response and other distributed energy resources (DERs such as distributed generation, combined heat and power, roof top solar, battery storage, and other customer-owned resources) will be discussed in the demand response and other DER section. I&M's IRP states:

> Programs or tariffs that are designed to reduce consumption primarily at periods of peak consumption are demand response (DR) programs, while around-the-clock measures are typically categorized as energy efficiency (EE) programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.
> Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with I&M's DSM programs that have been approved in Indiana and Michigan prior to preparation of this IRP. *(I&M IRP, page 49)*

I&M stated there is potential for additional or "incremental" DSM beyond the levels embedded in the load forecast as well as Volt VAR Optimization (VVO). For 2019, I&M anticipates 290 MW of peak DSM reduction (total company basis). *(I&M IRP, page 49)* I&M

estimates that EE (including codes and standards) may reduce residential load, commercial load, and industrial lighting use by over 5% by 2033. *(I&M IRP, page 51)* I&M estimates it currently has the capability of reducing peak demand by 272 MW, with most of the potential reduction coming from interruptible agreements. Residential customers are capable of reducing I&M's peak demand by 2.9 MW. *(I&M IRP, page 53)*

The 2018-2019 IRP adds new EE resources in 2020 that are incremental to the programs already approved or pending approval. The consultant firm, Applied Energy Group (AEG), which developed the 2016 EE Market Potential Study (MPS) for I&M, also developed the inputs for modeling the potential incremental EE in this IRP. This input was developed based on the identified EE potential of the MPS. The amount of available EE is usually described within three sets: technical potential, economic potential, and achievable potential.

I&M identified the measures from the MPS that had the most potential savings to determine which end-uses were to be targeted and in what amounts. That resulted in a list of 20 measures for each of the residential, commercial and industrial sectors. Information provided by AEG about the measure costs, energy savings, market acceptance ratios and program implementation factors were used to develop bundles of future EE activity for demographics and weather-related impacts.

I&M then evaluated the selected incremental EE bundles (up to 29 unique bundles) and used the Plexos model to choose the combination of resources that reduces the overall portfolio cost, regardless of whether the resource is on the supply – or demand-side. These bundles were available to be chosen beginning in 2020 and each of them had Achievable Potential and High Achievable Potential characteristics. Each EE bundle had a Levelized Cost of Electricity (LCOE) and potential energy savings, which are offered into the model as a stand-alone resource. After the model determines the portfolio of optimized resources, I&M considers the details of each EE bundle (e.g. participant costs, penetration rates, bill savings, cost effectiveness) that was optimized to develop appropriate EE offerings to its customers.

Demand Response (DR) and other DER modeling

As a member of the PJM Interconnection, LLC (PJM), I&M's contribution to PJM's peak demand, coincident with PJM's peak, serves as the criterion for I&M's resource adequacy obligations. I&M's maximum (system peak) demand is likely to occur on summer days that have the highest average daily temperature which is typically during a weekday, mid to late afternoon. *(I&M IRP, page 52)*

I&M has two customers with interruptible load contracts for interruption during the winter and summer peaks. The interruptible load is considered as a resource that can be used when load is peaking. I&M has agreements with 139 customers that allows the interruption of service only in emergencies. Therefore, I&M's load forecast does not reflect any load reductions for these emergency-only DR customers.

Incremental levels of DR for the residential and commercial sector were respectively modeled based on the Bring Your Own Thermostat (BYOT) program and the "EIS" light interface. I&M mentions that a specific amount of DR resource is offered into the model which may select up to four units of both sectors, in any calendar year, beginning with 2020.

I&M states that the amount of other DERs (including customer-owned distributed resources such as roof-top solar, battery storage, combined heat and power – CHP, microgrids) is, currently, very small. I&M, however, recognizes that all forms of DERs will be increasing with the big question being how quickly. DG, in the form of distributed solar resources, was embedded in amounts in the resource portfolio equal to a Compound Annual Growth Rate (CAGR) of 10.3% over the planning period. CHP resources were made available in the IRP resource selection in 15 MW blocks with an overnight installed cost of $2,300/kW and assuming full host compensation for thermal energy for an effective full load heat rate of 4,800 Btu/kWh.

DIRECTOR'S COMMENTS – ENERGY EFFICIENCY

EE Modeling

I&M's long-term load forecast includes existing EE and incremental EE (including general trends in appliance efficiency standards). Existing DSM programs, particularly EE, are reasonably well-defined. Incremental EE programs are not as well defined. Future DSM is developed following a dynamic modeling process using generic cost and performance data. For the near term horizon of this IRP, currently approved DSM programs through 2019 are embedded into the load forecast. Then, the IRP model selected the optimal levels of economic EE for the years 2019-2038 based on projected future market conditions.

I&M's intention is to model additional EE and DR on the same economic basis as supply-side resources. I&M's PLEXOS model views DSM as non-dispatchable generators. For projecting future EE, I&M developed a company specific Market Potential Study (MPS) using I&M data which is preferable to primary reliance on information from EPRI and EIA that was used in the 2015 IRP.

Unfortunately, the age of I&M's MPS (2016) made it potentially stale by the time this IRP was completed (e.g., the MPS used the 2016 Residential Appliance Saturation survey while the IRP used the 2019 Residential Appliance Saturation survey). It is normal for there to be some delay between when a MPS is developed and when the IRP analysis completed. For this IRP, I&M encountered reasonable circumstances that warranted a greater than normal delay due to the uncertainties of its coal fleet. Nevertheless, this dated MPS raises questions about the relevance of the MPS for this IRP. I&M, to its credit, retained a contractor to update the MPS. It appears this update may be part of a routine annual update from the EIA that captures the effects of legislatively mandated efficiency codes and standards[8] but it is unclear what was updated and how this update affected the IRP results. For example, how different was the load forecast used to develop the MPS from the load forecast in the 2019 IRP?

Since I&M already conducts a Residential Appliance Saturation survey and is deploying advanced metering infrastructure, it should be a relatively small incremental effort to enhance the load research program. Residential, and the creation of commercial surveys, could be enhanced by having experts conduct a comprehensive assessment of appliances/end uses, demographic information, housing and business data. The appliances/end-uses categories enumerated by the data collected by the EIA should be an appropriate foundation for developing a more comprehensive database that would be superior to the data currently available to I&M. The development of enhanced survey instruments is discussed in more detail in the "Future Enhancements" discussion. (Appendix 2, ITRON's SAE model discussion details the information collected by the EIA's *2018 Annual Energy Outlook* (AEO) beginning on page 1888 for residential customers and page 1931 for commercial customers). Collaborating with other similarly situated utilities, particularly those in Indiana, would also increase the quality and credibility of data to support I&M's IRP.

I&M's IRP should have included more information on EE bundle development. For example, were measure costs the most important factor? If yes, how were other factors considered in the development of EE bundles?

The IRP could have also included more information on the development and use of degradation factors. This could have been done in the body of the report or in an appendix. The information provided in the stakeholder presentations was helpful but only up to a point, and does not substitute for a clear discussion in the IRP itself. Even using information from I&M's three-year DSM case (Cause No. 45285), the Director is not clear how EE bundles were developed or how the degradation factors were developed and applied beyond the use of professional judgement by I&M's resident experts. The Director understands that any long-term forecasting exercise is complicated and is as much an art as a science. This is especially the case when trying to account for the real potential of double-counting EE impacts when using the SAE load forecasting methodology. The problem of interaction between the load forecast and future (or incremental utility sponsored) EE must be addressed and there are only so many ways of doing this, none of which is ideal or demonstrably superior (at least at this time with existing computer capabilities, existing databases, and without a better understanding of customers and DERs). The approach

[8] EIA end-use saturation, efficiency and annual appliance usage (UEC – Unit Energy Consumption) are derived from the National End-Use Model System (NEMS). While NEMS generates detailed end-use data, EIA is primarily concerned with the high-level projection of total energy requirements,,, across all end-uses and sectors including transportation. From an electric or natural gas utility forecaster's perspective, it is the underlying end-use and technology level detail that provides insights into how individual residential and commercial customers are using electricity and natural gas, trends in end-use energy consumption, and what these trends imply for future electric and gas usage at the regional level.

selected by I&M is less than intuitive and puts a burden on I&M to be clearer in its presentation of this methodological choice and its application.

A significant driver of the level of EE selected in the modeling process is the projection of avoided costs. The avoided cost projections developed in I&M's IRP are based on regional modeling estimates of PJM's energy and capacity prices over the planning horizon. I&M recognizes transmission and distribution costs can be avoided with DSM but argues it is too location specific for inclusion in the IRP's analysis of DSM resources. As a result, I&M includes zero avoided costs for T&D. But location specific does not mean zero in the judgment of the Director. The question is what level of potential location specific avoided T&D costs should be included in the IRP and appropriately adjusted to reflect the system-wide nature of the IRP analysis. Surely if degradation factors can be developed using professional judgement then it must be possible to develop estimates of potential avoided T&D costs.

The Director believes that improved EE (and other DERs) analysis will require sub-hourly load information to develop load shapes and EE bundles that better reflect the time and locational value of EE. The development of hourly and sub-hourly load data to construct load shapes was briefly discussed at one of the stakeholder sessions *(I&M's IRP, pages 84 and 85)*. Since the IRP rule requires that all forms of resources, including EE and other DERs, are treated as comparably as possible, it is essential that the methodology to develop improved load information for EE and other DERs is clear and there is requisite empirical data to support the analysis. I&M-specific AMI load data is critical but so will be use of data currently being developed by national labs and other entities. This type of information will also be helpful to understand how the time value of EE changes as other DERs become more prevalent on the I&M system.

<u>Demand Response (DR) and other DER modeling</u>

I&M did not place significant effort in evaluating DR programs and even less in anticipating the development of and potential for other DERs to affect I&M's contribution to the PJM system peak demand and PJM's operations. In large part, the lack of DR is likely due to very low avoided costs. Even if T&D costs were included in I&M's avoided cost calculations, it might not move the needle and justify significantly more DR. The paucity of DR and other DERs may also be influenced by the lack of financial incentives from the PJM, and the failure to reflect time-varying costs of providing electric service in retail rates.

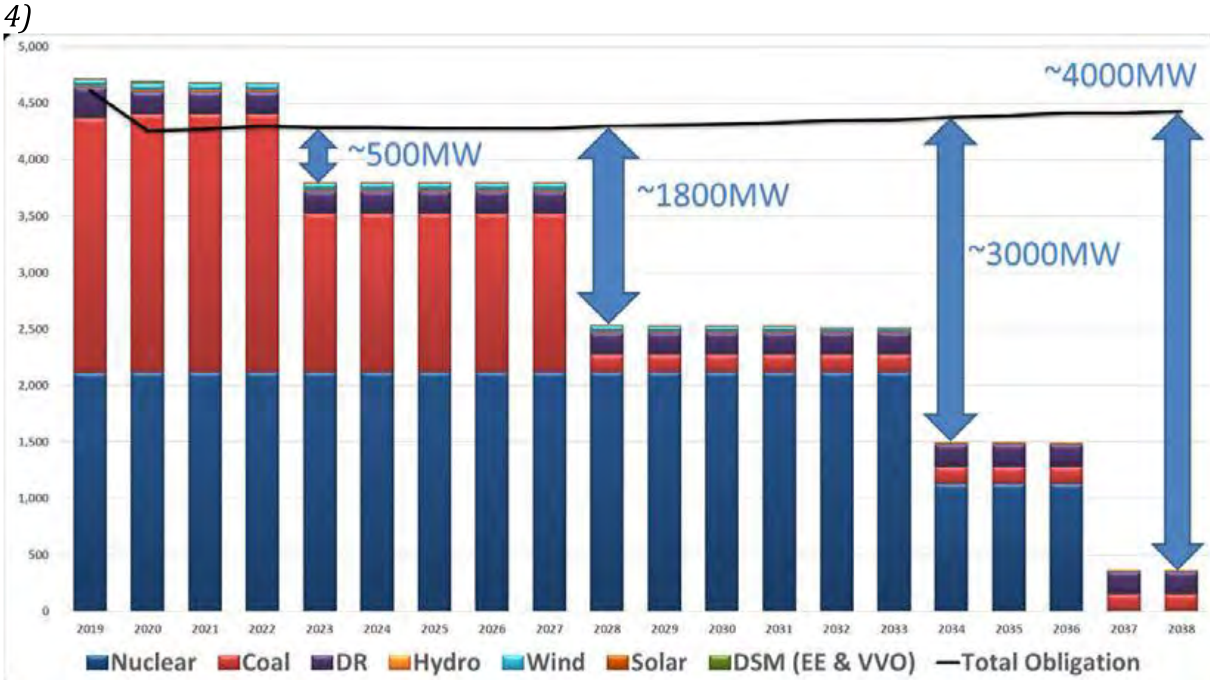
It seems likely that future IRPs will show increasing diversity of resources which may alter traditional concepts of resource adequacy and the calculation of avoided costs. I&M recognized the increasing proliferation of distributed generation (DG), to a large extent, is a function of customers' perception of their electricity costs. *(I&M IRP, pages 55 and 56)* This same observation necessarily applies to the speed with which other DERs are adopted. It is also possible that electric vehicles (EVs) will change the timing and amount of I&M's contribution to the PJM system peak and its operations.

The changing resource mix caused by an increasing penetration of DERs and corresponding changes in load shapes are also likely to affect I&M's distribution system operations and planning in a variety of ways and, in some instances, the changes will be unanticipated. It seems probable that distribution system reliability will, increasingly, be a year-round concern that is accelerated by the changing resource composition, including the ramifications of DERs and EVs.

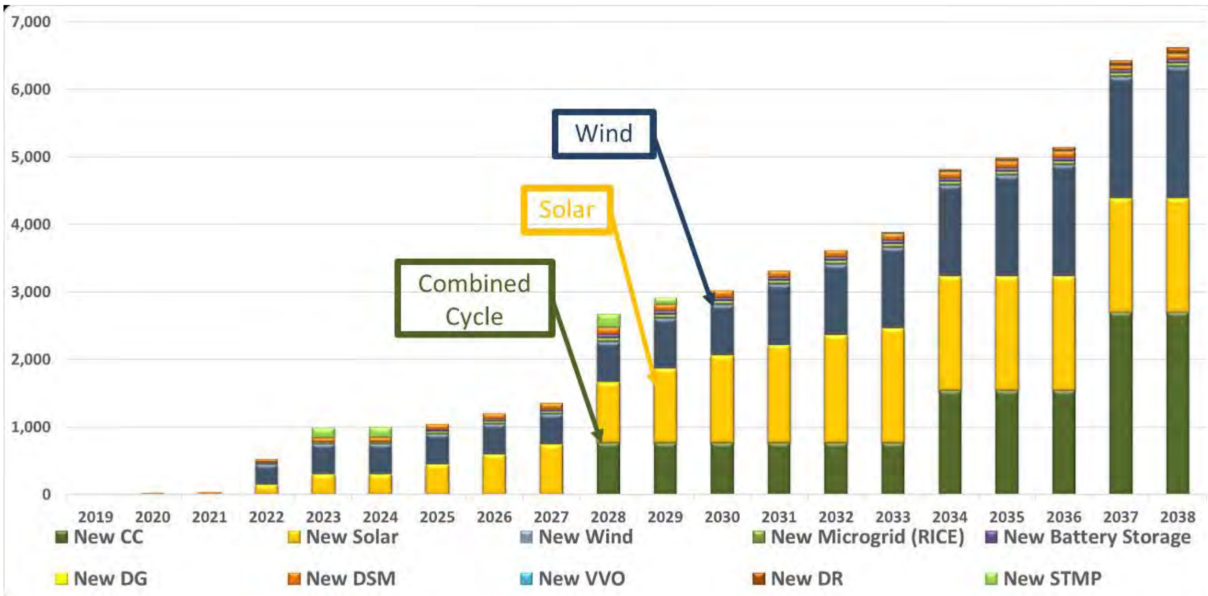
As EVs and a diverse group of DERs become increasingly significant, the ramifications on system load and load shapes must be closely evaluated to understand how the affects influence not just distribution system planning and operations, but also the bulk power system. The interactions of EVs and various DERs will affect the value of specific types of DERs. Improved load shape data will be a necessity but its importance will depend on how rapidly additional DER and EV load is added, their operational characteristics, and where they are located. Effective development of this information will involve a level of company-specific information combined with data available from other sources such as the national labs.

C. RESOURCE OPTIMIZATION AND RISK ANALYSIS

I&M states on Figure ES-1 below, "I&M's assumed "going-in" capacity position (i.e. before resource additions) over the planning period, Through 2022, I&M's existing capacity resources meet its forecasted internal demand. In 2023, I&M anticipates experiencing a capacity shortfall, 484MW, based upon its assumption of the expiration of the lease of Rockport Unit 2. This capacity shortfall is anticipated to increase to 1,762 MW in 2028 upon the retirement of Rockport Unit 1. The retirement of Cook Unit 1 in 2034 and Cook Unit 2 in 2038 further increases I&M's capacity shortfall to 4,060MW." *(I&M's IRP, page ES-4)*



I&M believes it has identified a diverse set of resources to address the capacity deficit position over the planning period. *(I&M IRP, Figure ES-2 and Table ES-1 on page ES-6)* These additions, which include solar, wind, natural gas, energy storage, and EE resources, along with Short Term Market Purchases (STMP,) are expected to eliminate the capacity deficit through the planning period. *(I&M IRP, page ES-5)*



More specifically, the Preferred Portfolio includes the following resources. The Rockport Unit 2 lease expires at the end of 2022 and this IRP analysis suggests that retirement of Rockport Unit 1 will occur at the end of 2028. The continued low cost of natural gas, compared to the price of coal, influenced I&M's resources decisions with the possibility of integrating 2,700 MW of natural gas combined cycle (NGCC) generation including 770 MW in 2028 to replace the existing Rockport units, 770 MW of NGCC generation to replace the Cook Unit 1 in 2034, and 1,155 MW of NGCC in 2037 to replace Cook Unit 2 at the end of their current license periods. I&M also recognized the sharply declining cost of renewable resources, which suggested I&M integrate over 3,600 MW of wind and utility scale solar by 2038. I&M's IRP indicates that 50 MWs of batteries and 54 MW of micro grids might be installed by 2028. I&M also recognized the increasing contribution of other DERs including roof top solar, distributed generation (DG) as well as 180 MW of EE and DR. *(I&M's IRP Public Summary, page 4)*

I&M used the Plexus LP optimization model as the basis for resource portfolio modeling. I&M analyzed 24 scenarios for this IRP in order to test resource selection across varying commodity price and load conditions. The 24 scenarios were divided into five groups and optimized. Group 1 scenarios assumed retirement of Rockport 1 at the end of 2028 and lease termination of Rockport 2 at the end of 2022. A combination of base, high, low, and no carbon commodity price conditions were tested in Group 1. Group 2 scenarios were developed to better understand the dynamic resource selection based on various future conditions related to Rockport 1. Base and No Carbon commodity pricing conditions were modeled all under base load forecast conditions. Battery storage and Mini-Grid resources were embedded in the analysis. Group 3 scenarios were developed to better understand specific resource constraints and their impact on resource slection. Various cases of NGCC additions were modeled and two cases with high levels of renewables were included. Group 4 scenarios considered resource selection based on various loadf and commodity price combinations. Group 5 consists of additional stakeholder-requested options.

For stochastic risk analysis, I&M compared the preferred portfolio to three other optimized portfolios. The three were Case 1 – the Base Case Optimization, Case 7 – Rockport Unit 1 having a Flue Gas Desulferization (FGD) added in 2029 and retiring year end 2044, and Case 12 – High Renewables. The input variables subject to stochastic treatment were natural gas prices, PJM energy prices, blended coal prices, high sulfur coal prices, and carbon prices. For each resource portfolio, 100 random iterations were conducted.

DIRECTOR's COMMENTS – RESOURCE OPTIMIZATION AND RISK ANALYSIS

For I&M, the status of the Rockport units is the keystone to I&M's IRP and affects the near-term and long-term resource decisions with substantial attendant risks. After the status of the Rockport units become more certain, for future IRPs, I&M should be in a position to better identify future reliability, resilience, and economic risks and the attendant costs of their uncertainty beyond the Net Present Value of Revenue Requirements for the scenarios I&M evaluated. The Director appreciates that this IRP was constrained because of litigation and ongoing negotiations. In an attempt to thoroughly analyze the potential resource options available within the limited Rockport options, the company optimized 24 scenarios. While extensive, the analysis is weakened because of several limitations.

1. It appears that I&M did not assess the potential ramifications of the closure of Rockport 1 prior to 2028 combined with lease termination at year end 2022 for Unit 2. Without this information, it is difficult to assess a full range of implications.

2. While 24 cases were developed for scenario optimization, the variations in key parameters were limited. For example, only four scenarios used something other than the Base Load forecast. Cases 1, 5, and 9 had small differences in the conditions modeled. Insights drawn from scenario analysis appear to be limited or are not clearly expressed in the IRP discussion. This is despite the discussion on pages 130 – 131 of the IRP report. Also, the use of 24 scenarios is overwhelming to understand what the results are and how they are interpreted.

3. The optimized portfolios were not compared with each other in an organized manner. No clear criteria was identified and used to evaluate the various portfolios.

4. The IRP document lacks a detailed description of how the Preferred Plan was chosen from the scenario analysis.

5. It is not adequately explained why cases 1, 7, 9, and 12 were selected for comparison and for the probabilistic risk analysis.

6. Why only consider the Revenue Requirement at Risk in the stochastic risk analysis?

7. Though the aggressive build out of renewables may not be practical for I&M in the short-term, the results from the optimization analysis show that adding more renewables would reduce the long-term revenue requirement risk. This type of result should have stimulated more analysis to better understand the trade-offs involved. For example, I&M could have removed the capacity limitation on renewables under preferred Case 9. It may have created a different resource portfolio which may be more economic than the current Case 9 portfolio.

8. It appears that I&M's IRP has an over abundance of wind resources in particular and solar which cause the preferred portfolio to be long on energy. The pricing projections in the scenario analysis seem to be driving these resource decisions. The Director presumes this is done to promote sales (off-system or to select customers). The Director would welcome I&M's comments on whether this is I&M's intention. Did I&M consider the extent to which the economics of various resource portfolios depended on wholesale power sales?

9. Finally, in its analysis of risks, I&M considered four commodity price scenarios ((i.e. Base, High Band, Low Band and No Carbon). I&M also analyzed the effects of a lower and upper band of forecasts to consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. *(I&M's IRP, page 79)* However, this limited risk analysis is not likely to capture the potential risk reductions caused by additional amounts of EE and DR in its preferred portfolio on its load forecast. Similarly, I&M has given little consideration to the potential for other DERs to further mitigate risks. One of the most significant on-going risks for I&M is assessing the value of reduced exposure to market price risk by integrating DERs along with other resources. This is not adequately evaluated by I&M embedding distributed solar in amounts equal to a CAGR of 10.3% over the planning period. *(I&M IRP, page 116)* The Director also believes I&M should consider the potential risk ramifications of increased penetration of EVs within I&M's service territory.

D. THE STAKEHOLDER PROCESS

I&M had an improved (or thorough) stakeholder process. I&M conducted four stakeholder meetings beginning on Feb. 15, 2018. The next meetings were April 11, 2018, Feb. 21, 2019, and May 22, 2019 *(I&M IRP, page 6)*. Several conference calls, one-on-one meetings, and numerous email correspondence occurrd throughout the process. I&M started the process early to accommodate the stakeholders' requests which resulted in greater stakeholder participation, and I&M also made a concerted effort to increase the diversity of stakeholders. I&M made its subject matter experts available to the stakeholders.

As a part of its effort to facilitate stakeholder participation, I&M provided Citizens Action Coalition (CAC) Joint Comenters access to a read-only license for Plexos. This enabled CAC to access model inputs and outputs along with a model manual which aided CAC's understanding of how Plexos works. I&M staff also held multiple meetings on the model with CAC and its consultants and readily answered questions about the model. CAC found this process had limitations but substantially improved its review of I&M's IRP. *(CAC Joint Comments, pages 6 and 7)*

<u>The IRP Schedule Changes</u>
During the IRP development process, I&M sought and was granted three schedule extensions. The first extension request, made on July 26, 2018, extended the filing deadline from Nov. 1, 2018 to Feb. 1, 2019. The reason for the request was to allow additional time for the United States District Court for the Southern District of Ohio ("Court") to rule on a Jan. 8, 2018, Supplemental Motion prospering the Fifth Modification of Consent Decree ("Motion"). The Rockport Plant which is a two-unit, 2,600 MW coal-fired generation facility located in Spencer County, Indiana, is subject to the Consent Decree that resolved a Clean Air Act suit. If granted, the Motion would change the Consent Decree provisions applicable to the Rockport Plant and, therefore, may substantially affect I&M's resource plans. The Motion had not yet been ruled on by the Court at the time of the extension request and the final resolution is still pending at the time of this filing.

The second request, made on Oct. 26, 2018, extended the filing deadline from Feb. 1, 2019, to May 1, 2019. The cause for the request was to allow I&M time to complete the modeling necessary to provide I&M and stakeholders a meaningful opportunity to review the results ahead of the next stakeholder meeting.

The third extension, requested on March 18, 2019, moved I&M's IRP filing date from May 1 to July 1, 2019 to provide additional time to incorporate updates and changes to forecasted inputs and to assess the impact of those changes on the modeling results. *(I&M IRP, page 6)*

IV FUTURE ENHANCEMENTS TO I&M's IRP PROCESSES

The Director appreciates the modifications that I&M has made in response to the 2015 Director's Report *(I&M IRP, page ES-3)*:

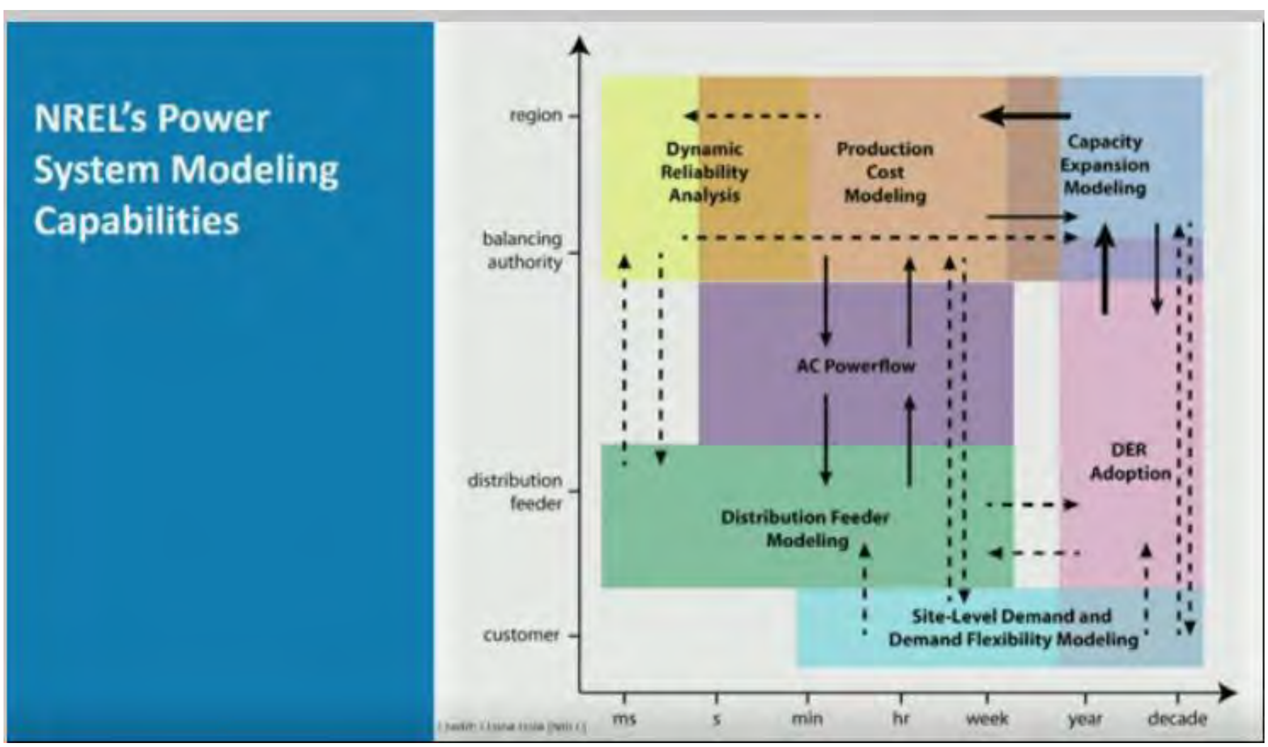
> 1) Uses the most recent load forecast which shows a reduced need for capacity over the 20 year planning horizon. Having a greater range of load forecasts was helpful;

> 2) Incorporates the most recent fundamental forecast developed in 2019; includes updated projections of costs for renewable resources based on Bloomberg's New Energy Finance's (BNEF) H3 2018 U.S. Renewable Energy Market Outlook;

I&M's recognition that, in addition to avoided generation costs, there are also distribution and transmission system avoided costs, should prompt an effort to quantify or approximate the full avoided costs by time and location as a means of reducing distribution system expenses (recognizing that a significant degree of transmission related costs are RTO driven and thus FERC jurisdictional) and improving the reliability and economic efficiency of the distribution system. To say that the avoided costs are zero merely because they are difficult to quantify is excessively cautious.

> The distribution system must have the capacity to safely and reliably distribute central generation resources to end use customers and must accommodate distributed resources as well, whether owned by the Company or by other entities including end use customers. Accordingly, expansions of the distribution system are highly location-specific and dependent upon the unique circumstances of load, interconnected transmission, and connected generation within a local distribution planning area. The concept of distribution-related avoided cost is location specific, based on the load and resource attributes of the specific area under consideration. *(I&M IRP, page 95)*

The NREL graphic below is illustrative of the evolution of IRP to include Distribution System Planning and operations and RTO planning and operations.



I&M's ongoing use of state-of-the-art software is commendable. The Director trusts that I&M continues to assess the evolution of state-of-the-art models and the appropriate data bases required to gain maximum benefits from the advances in modeling,

As stated previously, the Director would like I&M to provide an update in the next IRP process on how I&M intends to fully utilize its data from advanced metering infrastructure, or AMI (software, hardware, and types of information such as load shapes for a variety of different types of customers). This should include the development of a variety of customer load shapes that are more homogeneous than rate classifications. In addition to engaging stakeholders, the Director recommends that I&M engage outside experts (e.g., the National Laboratories). To the extent that the load shapes provide useful information to evaluate EE, DR, and other DERs that can benefit the PJM, I&M may wish to invite PJM to particpate in this process.

To improve I&M's load forecasting (including projections of DERs and EVs), more accurate design of rates and programs for DERs, enhanced resource planning, and improving distribution system planning, the Director urges I&M to develop short-term (e.g., 3 years) and longer-term (e.g., 6 years) plans to integrate AMI data that is supplemented with:

A) End-use load research on selected appliances / end-uses on a sub-hourly basis. This should include data on DERs and EVs;

B) As part of I&M's on-going load research, I&M should conduct regular customer surveys (every three years or so). These should be robust random representative samples of residential and commercial customers to add increased credibility to I&M's load forecast. This information should provide insights into the degradation analysis of EE and how customers perceive DERs in general. This survey data should help I&M gain a more holistic understanding of its customers for forecasting, rate design, DSM, and EVs. The information should involve surveyors that have sufficient expertise to obtain appliance/end-use information that details the age, connected load, condition, housing stock/building information, and demographic data. I&M may want to coordinate with other utilities, the National Laboratories, the Energy Information Administration, etc;

C) Obtain sub-hourly load data and information on distributed energy resource customers, including battery storage and any new technology. Coordination with PJM seems appropriate;

D) Obtain and maintain commercial customer identification using the North American Industrical Classification System (NAICS) to supplement AMI and survey data;

E) Develop a variety of load shapes based on sub-hourly load data that is predicated on a variety of parameters to develop groupings of customers that are more homogenous (e.g., intra-rate class, different usage levels, customers with different types of appliances/end-uses, customers that have different types of DSM, etc.);

F) Develop a more comprehensive approach to avoided costs so that DER evaluation is more accurately based on credible estimates of valuation by time and location. Explore with PJM how DER may be better integrated into PJM's and I&M's planning and operations.

G) Especially with greater reliance on DERs, increasing penetration of EVs and charging stations, and integration of renewable resources, there is an impetus for greater integration of distribution system planning with I&M's IRP, as well as RTO planning and operations. This will require greater involvement with PJM which may include collaborative programs that may be mutually beneficial such as projecting the implications of DERs on both the distribuiton system planning and operations as well as PJM's planning and operations.

H) I&M should also keep track of load shape changes for the system, classes of customers, and groups of customers within a rate class.

Each future IRP should explicitly address the progress on the plan for continued improvements. Because IRP's address both the short and long-run resource assessment, it is essential that the plan address the rate structure changes that are consistent with the strategic plan.

V. STAKEHOLDER COMMENTS

(Director's responsive comments are indented and in italics):

The public input to I&M's IRP has been gratifying. The stakeholder process, despite concerns that it could have been more responsive, deserves much of the credit. The following comments are intended to be a representative sampling of the public input into I&M's 2018-2019 Integrated Resource Plan and stakeholder process. Often similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Clean Grid Alliance (CGA)

CGA's comments address the following points: [1] I&M's ability to meet customer demand and encourage economic development by accelerating renewable development; [2] the importance of third-party data to confirm the cost-effectiveness of renewable generation; [3] the benefits of an "All Source Request for Proposals" on an annual basis; [4] the benefits of I&M's plan to procure a balanced mix of renewable generation; [5] the importance of a well-designed green tariff program; [6]; the reasonableness of I&M's resource planning models; [7] to reasonably account for higher penetrations of renewable resources through hourly and sub-hourly system modeling; [8] to I&M's commitment to battery storage; and [9] the need for transmission planning to deliver electricity from its forecasted generation to its customers at the lowest overall production cost of electricity.

> **Director's Comments:** *At the outset, as an economic regulator, the IURC does not advocate for specific resources. Rather, the IURC's statutory charge is to ensure reliability at the lowest delivered cost reasonably possible. This dual responsibility is, therefore, central to the integrated resource planning rules.*
>
> *We agree with CGA that retaining optionality to the extent reasonably possible is appropriate. As CGA correctly states, the possible addition of natural gas-fired generation in this IRP does not, in any way, obligate I&M to any particular resource decisions. The Director disagrees with CGA that "I&M should advance its renewable purchasing earlier in the plan…to obviate the need to build more expensive gas generation in the later years of the plan…".* (CGA Comments on I&M IRP, page 4) *Building or buying resources that are in advance of the customers' needs may result in higher prices in excess of benefits. It must be considered that the early acquisition of significant renewable resources itself may unreasonably reduce optionality. Also, we cannot know today how the engineering performance and economics of different resource options will change, especially relative to each other, over a number of years.*
>
> *Both NIPSCO and Vectren have made a compelling case for requests for proposals (RFPs) being integrated into their IRPs because the RFPs are intended to result in contracts to buy or build resources to meet near term service and reliability requirements in an economically efficient manner. The several respondents to the all-source RFPs provide excellent price and performance data for the IRPs and, in many cases, vendors provide the delivered cost of electricity that accounts for transmission, congestion, and other transaction costs that are not, always, included in the vendors' proposals. However, RFPs that are not actionable (meaning there is no intent to acquire resources in the near term resulting from the RFP), but are merely used for price discovery for planning purposes, may not result in vendors revealing their true costs. Moreover, this use of an RFP-type process may reduce the number of vendors expressing an interest in responding to actionable RFPs. For these reasons, the RFP should be actionable as a source for better cost information.*
>
> *This Director's Report and previous Director's Reports have urged I&M and all Indiana utilities to utilize advanced Metering infrastructure (AMI) to develop hourly and sub-hourly load shapes to facilitate the integration of renewable resources and all forms of DERs. I&M is installing AMI and the Director expects I&M to improve its planning processes by making effective use of the load data made available through AMI.*

Indiana Advanced Energy Economy (AEE)

Indiana AEE makes four main points: 1) I&M could realize greater savings by deploying more renewable and storage resources and accelerating its development timeline; 2) It should also do this to account for growing, near-term commercial and industrial demand; 3) Demand side resources, such as EE and DR should be more heavily incorporated into this IRP; and, 4) The Commission should closely scrutinize I&M's plan to invest in combined cycle gas plants instead of cost-effective advanced energy alternatives, especially in 2034 and 2037.

> **Director's Comments**: *AEE's comments on accelerating the acquisition of renewable resources are generally consistent with the Clean Grid Alliance and the CAC Joint Commenters' concern about the level of EE. More specifically, AEE believes that I&M used cost data for DERs that are too high which results in a resource plan that is not as cost-effective as it could be. The IRP rule requires utilities to treat EE, DR, other DERs, and renewable resources, on a comparable basis to traditional generation, to the extent reasonably feasible.*
>
> *The Director is thoroughly familiar with the debate about the projected costs of different resources over a 20-year planning period. Not only is there a problem projecting the cost trend of any given technology, but there is the greater complication of projecting the relative costs of numerous resource options over the planning period. There is simply no way to know which projected specific cost or price trajectory is correct. This is the definition of uncertainty. The only way to address this question is to use a range of prices or cost trajectories for the various resources to better understand how this uncertainty impacts resource selection over the planning period. This is an area in which all utility IRPs have improved but need to strive for continuous analytical improvement.*
>
> *For example, the Director would like to see more analysis devoted to understanding or trying to quantify the sensitivity of EE selection in the optimization process to changes in the projected costs of EE. This could also be done with other DERs and renewables more generally. The extent of sensitivity would highlight areas that need to be monitored closely when making resource commitments in the near to middle term.*

Indiana Coal Council (ICC)

The Indiana Coal Council offered several concerns. 1) I&M has not justified the need for the Fifth Modification to the Consent Decree. 2) I&M failed to adequately analyze the potential for extending the Rockport 2 lease and thus undervalued this option. 3) ICC suggests that I&M should have evaluated the efficacy of extending the life of Rockport beyond 2028. 4) I&M has improperly failed to account for the incremental transmission costs and congestion costs in the context of portfolio alternatives before committing to large-scale reliance on utility-scale renewable resources. 5) I&M failed to fully consider the life cycle emissions of any possible future commitment to new natural gas generation facilities

The Director's Comments: *The Director sees many of these criticisms of I&M's analysis as being similar to the Director's criticisms of I&M's scenario and uncertainty analysis discussed earlier in this document. The analysis presented by I&M is not as thorough as it might initially appear. The Director believes there is room for considerable improvement by I&M, but also believes I&M artificially constrained its review to avoid putting in a public forum critical information that might hinder negotiations regarding the possible extension of the Rockport 2 lease.*

Indiana Office of Utility Consumer Counselor (OUCC)

The Director appreciates the OUCC's comments and concerns regarding I&M's IRP. The Director will summarize those comments as follows: 1) Concern about excess capacity if I&M constructs 2700 MW of natural gas combined cycle; 2) A concern that the generating capacity in I&M's Preferred Plan may preempt DSM and other distributed energy projects; 3) The pricing of distributed resources and renewables needs to be re-examined considering: (a) expiring federal tax credits and (b) actual market prices, 4) I&M has not finalized its obligations for Rockport to comply with Combustion Residuals and Effluent Limitation Guidelines; 5) Concern that utilities will delay their IRPs to coincide with filing of rate cases or Certificate of Need cases (CPCN) and, deprive stakeholders of information from the Director's Report and other analysis; 6) A lack of transparency regarding the Consent Decree and the status of the Rockport units; 7) Whether the Rockport 2 unit could operate longer than 2028 if it is economical to do so; 8) The feasibility that DSI might extend the useful life of the Rockport units; 9) The lack of an assessment of an extension of the Rockport 2 lease or reserving a portion of output under a PPA if economical.

The Director's Comments: *With regard to the OUCC's Question 1, I&M's resource plan is overwhelmingly influenced by the disposition of the Rockport units that indicate a 2028 retirement* (I&M IRP, page ES-2) *which coincides with I&M's potential need for other resources. Since I&M's projections for large combined cycle units are several years out, they should be regarded as illustrative of the potential need for resources but not as a fait accompli. I&M's statements that they will maintain as much optionality as possible and consider developing technologies is appropriate.*

> At this time, the Company considers…combined cycle configurations to be the best fit as they most align with historical operating experience and expected output relative to the overall Company's needs. *(I&M IRP, page 99)*…Most importantly, the Preferred Plan does not include a significant investment in new natural gas combined cycle resources until 2028, allowing I&M to modernize its grid and explore new or developing technologies to meet its future capacity obligations." *(I&M IRP, Table 27 on page 131)*

Table 27. Cumulative Capacity Additions (MW) for Preferred Plan

	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Case 9 (Preferred)	BASE	New Solar Firm				76	153	153	229	305	381	458	559	661	737	814	865	865	865	865	865	865
		New Solar				*150*	*300*	*300*	*450*	*600*	*750*	*900*	*1100*	*1300*	*1450*	*1600*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT																				
		New DSM		*19*	*36*	*50*	*62*	*71*	*81*	*89*	*97*	*105*	*96*	*102*	*101*	*101*	*101*	*100*	*102*	*97*	*61*	*86*
		New VVO															9	9	9	9	9	9
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC										770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP					150	150				200	100									
		New DR															14	29	43	58	72	86

Many of the OUCC's comments address limitations in I&M's scenario and risk analysis. The Director believes many of these limitations were self-imposed to address any potential adverse impact on I&M's legal strategies involving the Fifth Modification to the Consent Decree and negotiations involving an extension of the Rockport 2 lease. The self-imposed limits might have been reasonable given I&M's circumstances but it undoubtedly hampered the usefulness of the IRP process. As the Director noted above, the portfolio and risk analysis is not what it should have been.

The OUCC also expressed concern with the trend of Indiana electric IOUs delaying IRP filings to coincide with the filing of a rate case or a certificate of public convenience and necessity (CPCN) filing. (OUCC Comments on I&M IRP, page 2)

The Director appreciates that filing cases for changes in rates, DSM programs, and Certificate of Need cases that are roughly contemporaneous with the submittal of IRPs and the review by stakeholders and the Director's Report, pose real concerns. In the past, particularly with DSM programs, stakeholders expressed concerns that the IRPs were stale and could not provide information necessary to be relied upon. There may also be instances where time is of the essence and the proximity in time between an IRP submittal and a case is unavoidable. Obviously, there is a need to strike a balance. However, this should be a matter for the Commission to decide on a case-by-case basis.

Citizens Action Coalition (CAC), Carmel Green Initiative, Earthjustice, IndianaDG, Sierra Club, and Valley Watch (Referred to as "CAC Joint Commenters")

The CAC Joint Commenters summarize their concerns on Table 1 Page 4 as follows:

1) Energy efficiency potential was unreasonably constrained 2) Significant build constraints were placed on renewables; 3) Wind costs were modeled at higher prices than is justifiable; 4) Solar costs were modeled at higher prices than is justifiable; 4) I&M used an unrealistically low capital cost for gas combined cycled units; 4) I&M did not consider retirement options for all of its coal units; 5) Three 18 MW reciprocating internal combustion engine ("RICE") units were forced in to evaluate "Mini-grid" resources and may have unreasonably depressed the selection of EE; 6) Scenarios and portfolios were conflated in ways that missed important

areas for analysis; and 7) I&M's stochastic analysis is fatally flawed and cannot be relied upon for risk assessment.

Director's Comments: *The CAC Joint Commenters state that I&M undervalued EE by distorting the avoided costs. The Director disagrees in part and agrees with CAC Joint Commenters in part. That is, I&M's use of the PJM energy and capacity markets as a proxy seems to be an appropriate estimation of avoided costs as far as it goes. As I&M correctly states, the complexities of the T&D system pose a daunting task to give effect to the avoided T&D costs. However, the Director believes that an evolutionary effort to quantify avoided T&D systems costs are in the public interest. In sum, trying to capture the dynamic costs of the bulk power market and the avoided T&D system costs should be the objective.*

The CAC Joint Commenters advocate the use of a "decrement" approach to modeling EE. (CAC Joint Commenters Comments on I&M IRP, page 9) *The Director appreciates the intellectual effort to develop the decrement method but does not believe that a prima facie argument has been made that this approach is superior to I&M's modeling of EE. In recent Director's Reports, the Director has expressed concerns with both approaches but also recognizes that, currently, there is no obviously superior methodology. The Director believes that the CAC Joint Commenters and I&M agree that any method should enable EE to be evaluated on as comparable a basis as possible with other DERs and all other resources, which is a limitation of both approaches. As utilities integrate data from advanced metering infrastructure into their planning processes, there may be opportunities for advancement in EE (and other DER and EV modeling) using sub-hourly load shapes and supporting information to better reflect the dynamic changes in the value (avoided costs) of all DERs and other resources.*

The Director believes the analysis of EE had many conceptual complications that warranted more discussion. Chief among these conceptual complications were the development and application of degradation factors and how EE bundles considered other DSM measure characteristics beyond costs. However, the Director cannot overlook the fact that avoided costs are a significant driver of EE selection and similarly for other DERs, and that avoided costs used by I&M in the IRP decreased significantly from the 2015 IRP. This decrease seems reasonable given the changes in the PJM marketplace. As noted earlier, the Director would like to see more analysis of how sensitive resource selections are to changes in the cost of EE bundles and other DERs.

The CAC Joint Commenters contend that the results from NIPSCO's all-source request for proposals (RFP) provides a more accurate assessment of resource costs. (CAC Joint Commenters' Comments, page 9) *The Director has some sympathy with that contention. However, it should be noted that, at least one developer in the NIPSCO RFP was not able to deliver the resources at the prices in its bid. Secondly, the RFP is a snapshot of prices and price adjustments – up or down – should be expected. Vectren, for example, encountered higher prices in its RFP than NIPSCO. In prior IRPs, the*

Director gives considerable discretion to the utility management in assessing the cost of various types of resources, particularly traditional generation. Utilities should, however, be cognizant of the pricing dynamics of these resources. Correspondingly, advocates of greater reliance on renewable resources need to consider the concerns that integration of intermittent renewable resources currently pose reliability and economic concerns.

The CAC Joint Commenters asked I&M to explain how it will own and operate the microgrids/mini-grids and how this would be distinguished from the RICE units serving as peaking resources. (CAC Joint Commenters' Comments, page 24) *In response to an informal data* request CAC Data Request 3.16), *I&M stated: "I&M intends to own and operate the micro grid resources. Each micro-grid will include uniquely configured generation resource(s) and distribution investments to allow the sectionalizing of the distribution system…"*

I&M's recognition of the need for coordinated distribution system planning with IRPs and the wholesale markets is a significant advance in I&M's (and the industry in general) planning. The Director agrees with the CAC Joint Commenters that I&M should engage stakeholders to better ensure these resources are cost-effective and enhance economics, reliability/resiliency.

The CAC Joint Commenters raised concern that in no scenario were the retirements of both Rockport Units 1 and 2 optimized. And in no scenario could the model choose to exit from the Ohio Valley Electric Corporation ("OVEC") contracts for Clifty Creek and Kyger Creek coal units. (CAC Joint Commenters' Comments, page 24)

The Director acknowledges that, ideally and under best practices, I&M should have modeled these units on a comparable basis to all generating units. However, given the significant legal concerns about the future status of the Rockport units, at the time I&M submitted its IRP, I&M was unable to model these facilities. Similarly, there are complicated contractual issues with OVEC prevented modeling. Future IRPs should not be as constrained.

ATTACHMENT AS-2

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH I&M'S DSM/EE PROGRAM COST RIDER OF ASSOCIATED COSTS, INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	**) CAUSE NO. 45285**

<u>CAC'S NOTICE OF CORRECTION TO I&M'S MAY 26, 2020 SUBMISSION</u>

Citizens Action Coalition of Indiana ("CAC") respectfully submits its Notice of Correction to Indiana Michigan Power Company's ("I&M") May 26, 2020 Submission, in which it responded to the Indiana Utility Regulatory Commission's ("Commission") May 18, 2020 Docket Entry. In support thereof, CAC states as follows:

1. CAC Witness Anna Sommer, an expert in resource planning optimization and modeling, submitted testimony in this Cause on January 31, 2020, with certain corrections filed on February 27, 2020. Ms. Sommer testified that there were irredeemable flaws in I&M's 2018-2019 Integrated Resource Plan ("IRP"), upon which this filing is based, and the Commission should reject I&M's reduction of its energy savings goals by approximately 50% in part because of the application of degradation factors to energy efficiency ("EE") bundles modeled in the IRP.

2. In its May 18, 2020 Docket Entry, the Commission requested that I&M respond to the following questions regarding I&M's application of degradation factors and their impact to

EE savings in I&M's IRP modeling and ultimately to I&M's energy savings goals in this proceeding:

> 1. Are degradation factors only applied to historical or currently approved and marketed utility-sponsored energy efficiency programs to avoid energy efficiency improvements reflected in the load forecast from being double-counted?
>
> 2. Are degradation factors applied to energy efficiency bundles included as resource options in the IRP optimization process? Please explain.
>
> 3. If degradation factors are applied to the energy efficiency bundles included in the IRP resource optimization, please provide an example demonstrating how this is done.
>
> 4. If degradation factors are applied to the energy efficiency bundles included in the IRP resource optimization, does the use of degradation factors impact the amount or number of energy efficiency bundles selected by the IRP optimization model? Please explain.

3. While I&M's response to this May 18 Docket Entry provided some of the rationale it has asserted throughout its 2018-2019 IRP Stakeholder Process and throughout this case on the subject, it did not provide all of the rationale I&M has given parties in this case or in the IRP stakeholder process, nor did I&M accurately represent how it actually applied degradation factors.

4. I&M responded to the May 18, 2020 Docket Entry Questions 1 and 2 as follows:

> 1. Yes, the only reason degradation factors are applied to historical and currently approved programs is to avoid double-counting energy efficiency improvements that are already reflected in I&M's load forecast methodology. Please see also the response to IURC 1-02.
>
> 2. Yes, based on the energy efficiency (EE) bundle life, a degradation factor curve is applied. The Company has developed 10-year- and 15-year- EE life degradation factor curves to apply to the EE bundles included as resource options in the IRP. These degradation factor curves were developed by the Company's load forecasting group to avoid double counting energy efficiency improvements already reflected in I&M's load forecasting methodology.

5. First, CAC takes issue with the assertion that I&M is applying the degradation factors to "avoid double counting." I&M may believe that its degradation factors avoid double

counting, but, as I&M itself has said, the primary rationale for its degradation factors was to account for naturally occurring energy efficiency.[1] Secondly, as CAC Witness Sommer explained in her Direct Testimony, the use of degradation factors, which results in a drastic cut to I&M's energy savings goals compared to current goals, is wholly inappropriate for several reasons, especially when considering I&M's purported rationale for doing so.[2]

6. I&M also responded to the May 18, 2020 Docket Entry Question 3 with a hypothetical example of its application of degradation factors to EE bundles, but it does not show or otherwise explain how I&M <u>actually applied</u> the degradation factors to the model itself, which

[1] *See, e.g.*, CAC Ex. 2, p. 5, line 17-p. 6, line 23 (quoting I&M meeting minutes from the third IRP stakeholder workshop and I&M's Response to CAC Data Request 1.5(D) in the 2019 Stakeholder Questions Submitted to I&M). *See also* I&M Witness Burnett's Rebuttal Testimony at p. 7, lines 14-18 ("The Company's use of the term 'degradation' encompasses more than Ms. Sommer's narrow interpretation. <u>In addition to the fact that appliances lose certain operational efficiencies over time</u>, the degradation matrix is <u>also accounting for market adoption rates and other DSM measurement issues (stipulated vs verified savings, net-to-gross savings, free ridership, spillover, etc.)</u>." (emphasis added)).

[2] For example, if I&M is attempting to account for naturally occurring savings, those were already netted out of I&M's market potential study ("MPS") estimate of savings potential. CAC Ex. 2, p. 6, line 27—p. 8, line 2. This amounts to I&M "avoiding double counting" <u>twice</u> and thus severely underestimating the total amount of savings its IRP should have produced. *See* CAC Ex. 2, p. 16, Table 6, for a table capturing I&M's un-degraded savings.

Free ridership is also not a valid rationale for the use of degradation factors. It is clear that the MPS estimates are already net of free riders. *Id.*, p. 8, lines 11-16.

Furthermore, I&M ignores the actual estimated useful lives of its EE bundles in its model (except for behavioral savings) and instead assigned each EE bundle either a 10 or 15-year life, resulting in 25% fewer savings actually modeled. *Id.*, p. 10, line 13-p. 15, line 1.

In addition, CAC would note that market adoption rates, one rationale Mr. Burnett's Rebuttal at p. 7, lines 14-18, claims as supporting the use of degradation factors, have nothing to do with double counting of EE savings. In fact, this is another area in which I&M's degradation factor approach incorrectly <u>doubly</u> penalizes EE savings. The AEG MPS explicitly states that, "To develop estimates for Achievable Potential, we develop market adoption rates for each measure that specify the percentage of customers that will select the highest-efficiency economic option." I&M Witness Cottell Rebuttal Testimony, Attachment AWC-1R, p. 17. There is no justification for using the degradation matrix to adjust for adoption rates again.

is a critical distinction. Instead, please *see* CAC Ex. 2, p. 10, line 13—p. 15, Table 5, which accurately shows how I&M actually applied the degradation factors and the impact to the EE bundles in I&M's IRP model.

7. Finally, I&M responded to the May 18, 2020 Docket Entry Question 4 admitting that its "use of degradation factors reduces the amount of energy efficiency that can be selected by the model" but then goes onto say that "the difference (i.e., reduction) in energy efficiency is already reflected in the load forecast." As Ms. Sommer noted, I&M's use of degradation factors is an out-of-model adjustment to its load forecast. CAC Ex. 2, Attachment AS-2, p. 30. I&M uses the same statistically adjusted end-use load forecast model (Itron) as Duke Energy Indiana, Southern Indiana Gas & Electric Company dba Vectren Energy Delivery, and Northern Indiana Public Service Company,[3] but I&M is the only utility out of those that goes onto apply a "degradation" adjustment to its load forecast. *Id*.

Respectfully submitted,

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[3] CAC would note that it later learned Indianapolis Power & Light Company ("IPL") also used Itron and, similar to Duke, Vectren, and NIPSCO, did not apply a "degradation" adjustment to its load forecast like I&M did here. *See* CAC et. al Comments on IPL 2019 IRP, p. 28, available here:
https://www.in.gov/iurc/files/CAC%20EJ%20Public%20Report%20Version%201.2%20on%20IPL%202019%20IRP--4-22-2020FINAL.pdf.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 5th day of June, 2020, to the following:

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH I&M'S DSM/EE PROGRAM COST RIDER OF ASSOCIATED COSTS, INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	**) CAUSE NO. 45285**

<u>CAC'S NOTICE OF CORRECTION TO I&M'S MAY 28, 2020 SUBMISSION</u>

Citizens Action Coalition of Indiana ("CAC") respectfully submits its Notice of Correction to Indiana Michigan Power Company's ("I&M") June 5, 2020 Submission, in which it responded to the Indiana Utility Regulatory Commission's ("Commission") May 28, 2020 Docket Entry. In support thereof, CAC states as follows:

1. CAC Witness Anna Sommer, an expert in resource planning optimization and modeling, submitted testimony in this Cause on January 31, 2020, with certain corrections filed on February 27, 2020. Ms. Sommer testified that there were irredeemable flaws in I&M's 2018-2019 Integrated Resource Plan ("IRP"), upon which this filing is based, and the Commission should reject I&M's reduction of its energy savings goals by approximately 50% in part because of the application of degradation factors to energy efficiency ("EE") bundles modeled in the IRP.

2. In its May 28, 2020 Docket Entry, the Commission requested that I&M respond to the following questions regarding I&M's application of degradation factors and their impact to

EE savings in I&M's IRP modeling and ultimately to I&M's energy savings goals in this proceeding:

> 2-1. With reference to the table in the response to Data Request No. 1-03, does an energy efficiency bundle input to the Plexos optimization model as a stand-alone resource use the IRP Savings Potential shown in Column C, or does the bundle use the Total Energy Efficiency Savings shown in Column E? Please explain.
>
> 2-2. If the energy efficiency bundle input to the Plexos optimization model as a stand-alone resource uses the IRP Savings Potential shown in Column C, then how does this not affect the amount of energy efficiency selected by the Plexos optimization? Please explain.
>
> 2-3. If the energy efficiency bundle input to the Plexos optimization model as a stand-alone resource uses the Total Energy Efficiency Savings shown in Column E, then at what point is the degradation factor applied? Please explain.

3. I&M's responded to the May 28, 2020 Docket Entry Questions 2-1 and 2-2 as follows:

> 2-1. The energy efficiency bundle input to the Plexos optimization model as a stand-alone resource uses the IRP Savings Potential shown in Column C, in conjunction with a load forecast that reflects the energy savings from Column D. As a result, the IRP includes the Total Energy Efficiency Savings shown in Column E. See also the response to IURC 2-2.
>
> 2-2. The use of the values in Column C as the energy efficiency bundle inputs to the Plexos model does not affect the amount of energy efficiency selected by the Plexos optimization model because the load forecast values in Column D are also used.
>
> The energy efficiency bundle inputs should reflect the level of energy savings (and associated costs) that would result from implementation of those bundles, and should not include energy efficiency savings that would otherwise occur. As described in the response to IURC 2-1, this is accomplished by combining adjusted energy efficiency bundle inputs (as shown in Column C) with a load forecast that reflects the level of energy efficiency that otherwise would occur (as shown in Column D) to arrive at the total energy efficiency savings reflected in the market potential studies (as shown in Column E).

4. CAC has concerns about the accuracy in I&M's responses to Docket Entry Question 2-1 in its June 5, 2020 response. In particular:

a. I&M says in part in response to Docket Entry Question 2-1, "The energy efficiency bundle input to the Plexos optimization model as a stand-alone resource uses the IRP Savings Potential shown in Column C, ***in conjunction with a load forecast*** that reflects the energy savings from Column D." (emphasis added). Although I&M continues to state that its model implicitly accounts for this, there is no specific adjustment for I&M's future energy efficiency in the load forecast. Put another way, there is no number or specific data I&M can point to in its load forecast that verifies what I&M is claiming in this regard.

b. I&M's reference to its response 1-3 to the Commission's May 18, 2020 Docket Entry is misleading in that the table I&M provided has a savings figure of 12,000 MWH, but I&M actually modeled each bundle, at least for the first year before it begins degrading savings each year, at 1,000 MWH. Thus, to answer the Commission's question directly, no, this is not representative of how I&M put the EE bundles into Plexos for a host of reasons, including because no bundle was 12,000 MWH, rather each bundle was only 1,000 MWH.

c. I&M also refers to "Column C" in its Response to Docket Entry Question 2-3 submitted in response to the Commission's May 18, 2020 Docket Entry. Even if I&M had modeled a bundle that started with 12,000 MWH of savings, the savings in Column C are not how these savings were actually modeled for any of the years modeled, except for the first year that each EE bundle was available, i.e., 2020, 2025, 2030, and 2041. In other words, I&M's representation in Column C could only be reflective of the first year of each EE bundle, not for any other years in modeled in PLEXOS. *See* Ms. Sommer's Direct Testimony at pp. 12-15. Even if one assumes the application of degradation is correct, which CAC disputes, I&M did not apply the claimed degradation factor correctly in the PLEXOS model. The problem is that I&M modeled these EE bundles as "available" over a multi-year period. In order to account for the fact that I&M degrades savings each year, without shifting the profile so that each bundle again starts at 1,0000 MWH of savings, I&M simply increased the number of bundles that could be chosen as you move through the second, third, etc. years that any given bundle is available in the model. I&M's presumption was that it could somehow get the same total savings even if those total savings were not spread over the same number of years. But, as Ms. Sommer's testimony demonstrates, this creates another problem; it lowers total savings by 25% from the overall amount of savings I&M intended to model. *Id.*

5. CAC also has concerns about the accuracy in I&M's responses to Docket Entry Question 2-2 in its June 5, 2020 response. In particular, while I&M again implies otherwise, there was no explicit adjustment for I&M's future EE in the load forecast as it relates to the

modeling of future EE savings. I&M cannot point to any number or specific data to demonstrate otherwise.

Respectfully submitted,

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY THROUGH I&M'S DSM/EE PROGRAM COST RIDER OF ASSOCIATED COSTS, INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	**) CAUSE NO. 45285**

CAC'S NOTICE OF CORRECTION TO I&M'S JUNE 15, 2020 SUBMISSION

Citizens Action Coalition of Indiana ("CAC") respectfully submits its Notice of Correction to Indiana Michigan Power Company's ("I&M") June 15, 2020 Submission, in which it responded to the Indiana Utility Regulatory Commission's ("Commission") June 9, 2020 Docket Entry. In support thereof, CAC states as follows:

1. CAC Witness Anna Sommer, an expert in resource planning optimization and modeling, submitted testimony in this Cause on January 31, 2020, with certain corrections filed on February 27, 2020. Ms. Sommer testified that there were irredeemable flaws in I&M's 2018-2019 Integrated Resource Plan ("IRP"), upon which this filing is based, and that the Commission should reject I&M's reduction of its energy savings goals by approximately 50%, in part because the application of degradation factors to the energy efficiency ("EE") bundles modeled in the IRP biased I&M's modeling against the selection of energy efficiency.

2. CAC Witness Dan Mellinger, an expert in energy efficiency and lighting certified by the National Council on Qualifications for the Lighting Professions and a Certified Energy

Manager by the Association of Energy Engineers, submitted testimony in this Cause on January 31, 2020. Mr. Mellinger testified that the level of savings proposed by I&M was inadequate and unreasonable compared to past results, other Indiana utilities, the Company's demand-side management ("DSM") program in its Michigan jurisdiction, and utilities in neighboring states. Mr. Mellinger also testified that I&M relied on an outdated market potential study that does not reflect current technology capabilities, DSM program best practices, or even current programs offered by I&M.

3. In its June 9, 2020 Docket Entry, the Commission requested that I&M respond to certain questions regarding I&M's application of degradation factors and their impact to EE savings in I&M's IRP modeling and ultimately to I&M's energy savings goals in this proceeding, including the following:

> 3.1. Please describe the methodology for how the degradation factors were calculated and how the degradation curves were developed. Please identify any assumptions, and provide any supporting documentation and worksheets.

4. I&M responded to the June 9, 2020 Docket Entry Question 3-1 as follows:

> 3-1. The formula for calculating the degradation factors and the degradation curves is shown on the tab labeled "Degradation" in IURC DR 3-1 Attachment 2, which was provided in discovery to the parties as CAC 2-2 Attachment 1. Please see IURC DR 3-1 Attachment 1 for a copy of the narrative response to CAC DR 2-2. The formula begins with an estimated measure life (5, 10, or 15 years) and applies a non-linear factor to calculate the degradation factors used in I&M's load forecasting and the IRP modeling process.
>
> I&M has used degradation factors as part of its load forecasting methodology for many years, beginning with I&M's implementation of DSM programs. Over time, the methodology for calculating the degradation factors has improved to provide more transparency, granularity, and modeling flexibility, with the current formula (shown in IURC DR 3-1 Attachment 1) developed in 2012.
>
> The current methodology assumes each energy efficiency measure will have a certain estimated life over which the energy efficiency measure will degrade. As explained on page 7 of Mr. Burnett's rebuttal testimony, the rate at which energy

efficiency measures degrade is affected by changes in the operational efficiency of the measure, market adoption rates, stipulated vs. verified savings, net-to-gross savings, free ridership, spillover, and other factors. Based on prior experience, including I&M's EM&V process and its residential appliance survey results, I&M recognized that these factors are generally not linear in nature. To account for this, I&M developed degradation factors and degradation curves that approximate the actual degradation rates reflected in EM&V and the residential appliance survey results. As explained in Mr. Burnett's rebuttal testimony on pages 3-6, the reasonableness of the degradation factors is borne out by the historical accuracy of I&M's load forecasts, which apply degradation factors to the DSM assumptions.

5. CAC has concerns about the accuracy in I&M's June 15, 2020 response to Docket Entry Question 3-1. In particular:

a. First, I&M's reference to reliance on EM&V (Evaluation, Measurement, and Verification) and a residential appliance survey is a new rationale heretofore undisclosed by the Company. As I&M notes, CAC asked a very similar question, "Please provide the source for the degradation rates applied to I&M's load forecast."[1] In response to CAC Data Request 2-2 on November 22, 2019, I&M never mentioned EM&V or a residential appliance survey. However, in this new response to the Commission's June 15 Docket Entry, I&M says, "Based on prior experience, including I&M's EM&V process and its residential appliance survey results, I&M recognized that these factors are generally not linear in nature. To account for this, I&M developed degradation factors and degradation curves that approximate the actual degradation rates reflected in EM&V and the residential appliance survey results." Yet, in recent I&M EM&V reports and the residential appliance survey that would have been available during the preparation of I&M's 2018 IRP, the words "degrade" and "degradation" never even appear. It is also unclear how or why residential appliance findings would be applied to other sectors and measure types.

Moreover, in order for I&M's answer to the Commission's docket entry to make sense, any given measure's savings would have to degrade to nearly zero over its lifetime. Measure savings do not just mystically degrade in this manner – imagine an LED light bulb whose energy consumption would grow over time such that, by the end of its useful life, it consumes as much energy each day as the fluorescent bulb it replaced. And now, imagine an assumption that all LED light bulbs incentivized by I&M behave in this manner. This is simply not a believable level of degradation. If I&M is attempting to account for the persistence of savings, this factor is reflected in a measure's effective useful life ("EUL"), which

[1] I&M included a copy of this narrative response as part of its June 15, 2020, docket entry response labeled as IURC DR 3-1 Attachment 1.

may be shorter than an equipment's technical life due to factors such as early replacement or federal standards.[2] Since the EE bundles modeled in the IRP model include an effective useful life, to also apply a degradation factor would greatly exaggerate the impact of savings persistence.

b. Second, I&M states in this response to Docket Entry Question 3-1 that, "As explained in Mr. Burnett's rebuttal testimony on pages 3-6, the reasonableness of the degradation factors is borne out by the historical accuracy of I&M's load forecasts, which apply degradation factors to the DSM assumptions." In discovery, CAC received a spreadsheet showing I&M's actual adjustment to the load forecast for degradation.[3] On a percentage basis, this adjustment is 0.5 – 1 % of total sales annually but only for 2019, 2020, and 2021. No degradation adjustment is made in subsequent years, i.e. "2022 and beyond".[4]

Mr. Burnett claims that the historical accuracy of I&M's load forecast bears out the importance of applying degradation to its load forecast[5] and cites Figure CMB-1R in his rebuttal testimony as evidence of I&M's load forecasting accuracy. However, in Michigan Public Service Commission Case No. U-20591, which is I&M's pending Integrated Resource Plan case in Michigan, I&M supplied a spreadsheet[6] showing the data used to calculate the averages presented in Figure CMB-1R, which CAC asked about in discovery in this case.[7] Figure CMB-1R shows the average accuracy of the load forecast since 2010:

[2] According to ACEEE, "Measure lifetime or effective useful life (EUL) is typically described as the median length of time (years) that an energy efficiency measure is functional and saving energy (Hoffman et al. 2015; Bordner, Siegal, and Skumatz 1994). Measure lifetime is a function of two components: technical life and persistence." And, "Persistence is the change in savings throughout the functional life of a measure."
https://www.aceee.org/sites/default/files/publications/researchreports/u1902.pdf

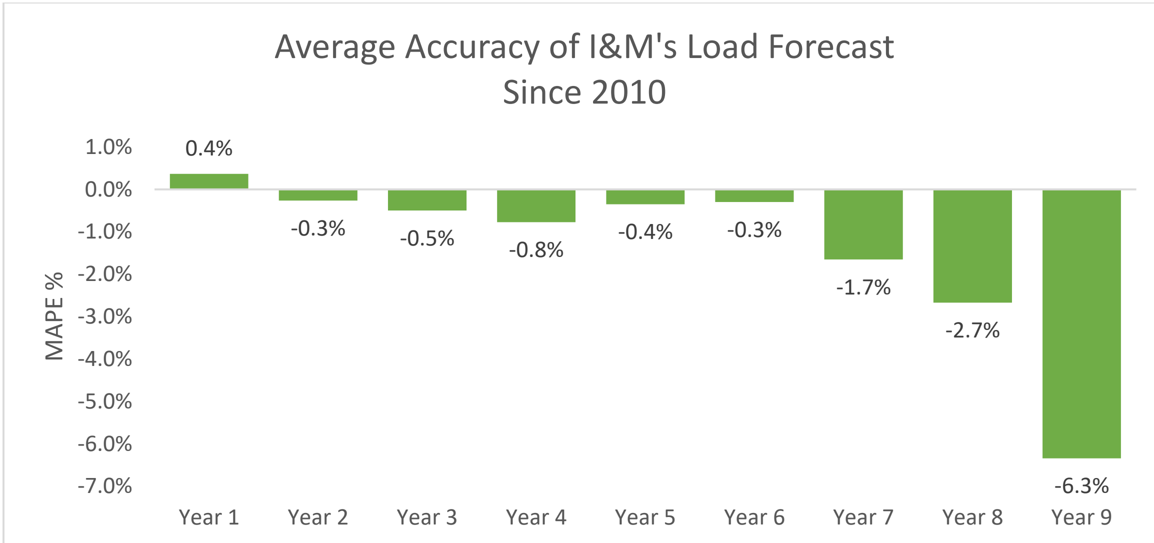
[3] *See* I&M's Response and Attachment 1 to CAC Data Request 6-02, which was produced to CAC on March 19, 2020 (included as Attachment A).

[4] *Id*.

[5] *See*, for example, I&M's Response to CAC Data Request 7-02, which was produced to CAC on March 20, 2020 (included as Attachment B).

[6] *See* I&M's "SC 5-01 WP CMB Rebuttal.xlsx" produced on February 19, 2020 in Michigan Public Service Commission Case No. U-20591 (included as Attachment C). CAC is also submitting Attachment C as an Excel spreadsheet for the Commission's convenience.

[7] *See* I&M's Response to CAC Data Request 5-01, which was produced to CAC on March 19, 2020 (included as Attachment D).



We are flummoxed as to how I&M can conclude that degradation adjustments to its load forecast are essential to accuracy when those adjustments are in the same range as the errors otherwise present in I&M's load forecasts. Moreover, Duke, IPL, Vectren, and NIPSCO all use an approach to accounting for historical energy efficiency that does not rely upon degradation.

Respectfully submitted,

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INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 6
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 6-02

REQUEST

Please see I&M's Response to Sierra Club Data Request 6-21 in Michigan Public Service Commission Case No. U-20591, which is provided with this set of data requests, stating "These numbers are shown in column BO and represent the GWh savings subtracted from the SAE forecast." Please also reference "CAC_2-2_Attachment_1" which was provided by I&M in Response to CAC Set 2 in IURC Cause No. 45285. Please provide the spreadsheet, with all formulas and links intact, that shows the values in column BO of "CAC_2-2_Attachment_1", tab "Indiana_irp", being "subtracted from the SAE forecast".

RESPONSE

As explained in response to CAC 5-10, CAC 2-2 Attachment 1 contains the estimated DSM savings impacts at the meter and what is modeled in the IRP is at the generator for capacity planning purposes. Please see "CAC 6-02, Attachment 1" for the specific DSM amounts that were subtracted from the load forecast that was modeled in the IRP.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 7
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 7-02

REQUEST

Please refer to Mr. Burnett's Rebuttal Testimony at page 5, line 7 through page 6, line 4.

a. Is it Mr. Burnett's testimony that degradation is an essential component of producing an accurate load forecast for I&M? Please explain in detail.

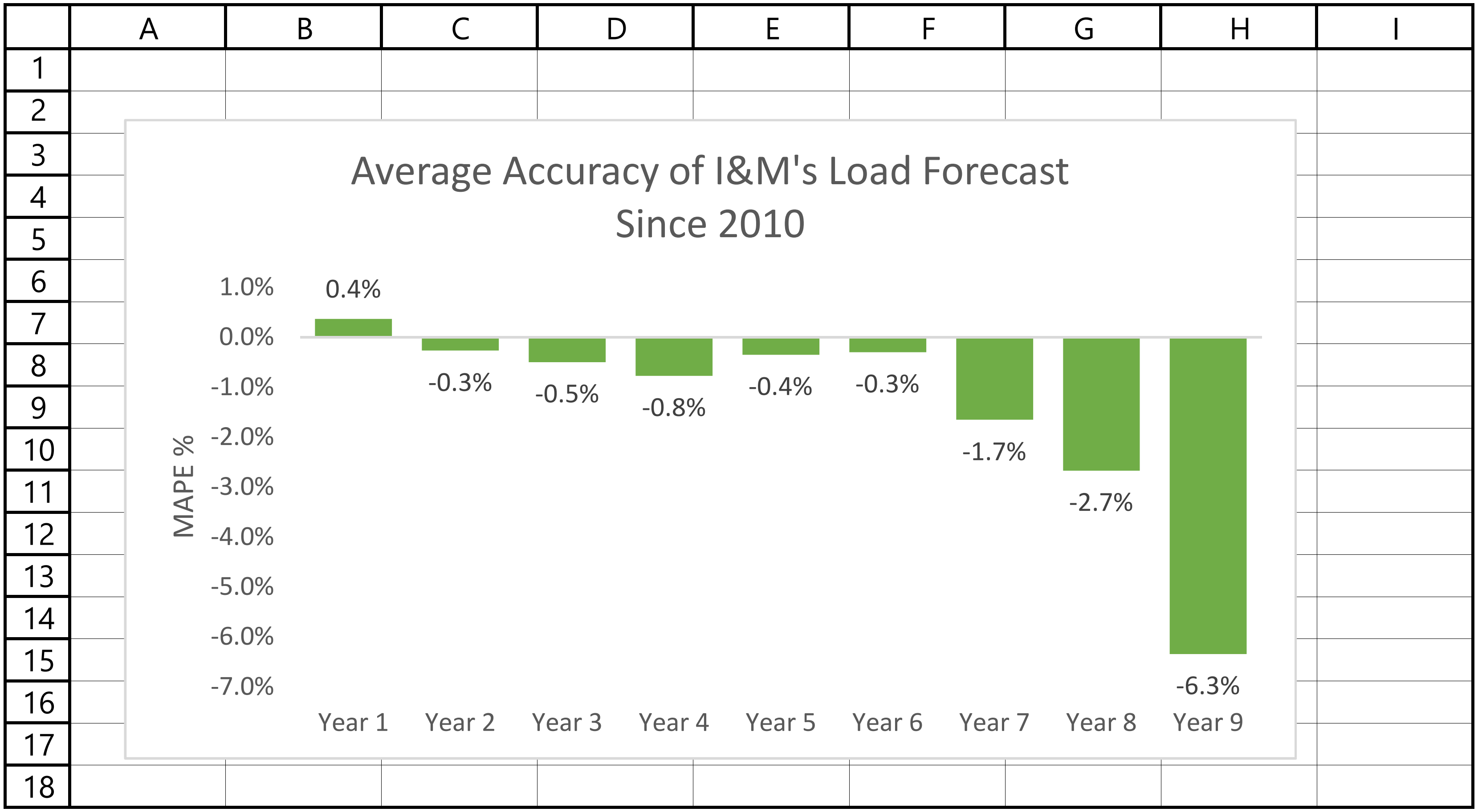
b. If the answer to subpart (a) is "yes", please provide the documentation that supports the assertion that degradation, specifically, is essential to accurate load forecasting for I&M.

c. If the answer to subpart a is "no", what role does Mr. Burnett believe degradation plays in producing an accurate load forecast for I&M? Please provide the documentation that supports your answer.

RESPONSE

a. Yes. The Company's approach to modeling energy efficiency, which includes degradation, is one of many critical components of producing an accurate load forecast. It is Mr. Burnett's testimony, as described on page 6, lines 1-4 of his rebuttal testimony that "the Company's load forecast methodology [which would include degradation of the DSM assumptions] is proven to produce accurate and reliable projections that are useful to planning and setting rates."

b. See Figure CMB-1R on the bottom of page 5 of Mr. Burnett's rebuttal testimony for supporting evidence of Mr. Burnett's accuracy claims.


Average Accuracy of I&M's Load Forecast
Since 2010
MAPE %
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
-6.0%
-7.0%
0.4%
-0.3%
-0.5%
-0.8%
-0.4%
-0.3%
-1.7%
-2.7%
-6.3%
Year 1
Year 2
Year 3
Year 4
Year 5
Year 6
Year 7
Year 8
Year 9

	V	W	X	Y	Z	AA	AB
1							
2		**nkwh**	**kwh09**	**kwh10**	**kwh11**	**kwh12**	**kwh13**
3	**YEAR**	**nkwh**					
4	2005	19,116,134,536					
5	2006	19,178,421,730					
6	2007	19,272,031,988					
7	2008	18,804,044,270					
8	2009	17,993,717,122	19,277,984,738				
9	2010	18,410,765,040	19,611,041,563	18,511,875,245			
10	2011	18,432,885,360	19,886,141,183	19,106,771,780	18,580,045,873		
11	2012	18,392,393,134	20,002,145,663	19,286,457,027	19,048,836,120	18,411,388,920	
12	2013	18,346,153,805	20,127,993,250	19,458,837,528	19,324,195,205	18,446,069,802	18,213,034,403
13	2014	18,469,172,080	20,263,678,186	19,596,941,174	19,148,802,369	18,283,979,395	18,262,747,596
14	2015	18,161,125,332	20,397,473,072	19,738,566,683	18,944,037,643	18,008,391,807	18,292,335,434
15	2016	18,300,418,421	20,531,331,443	19,884,567,982	18,781,333,526	17,791,672,472	18,185,223,268
16	2017	18,163,728,475	20,655,145,943	20,020,875,215	18,622,574,565	17,578,422,431	18,011,448,989
17	2018	18,183,710,039	20,783,809,855	20,159,407,308	18,463,762,461	17,418,754,731	17,922,726,262
18	2019	17,783,267,862	20,918,532,509	20,297,297,271	18,310,983,338	17,302,467,027	17,885,946,919
19	2020		21,060,778,999	20,435,175,672	18,222,729,551	17,281,263,149	17,883,220,461
20							
21							
22							
23							
24			**kwh09**	**kwh10**	**kwh11**	**kwh12**	**kwh13**
25		2005					
26		2006					
27		2007					
28		2008					
29		2009	-6.7%				
30		2010	-6.1%	-0.5%			
31		2011	-7.3%	-3.5%	-0.8%		
32		2012	-8.0%	-4.6%	-3.4%	-0.1%	
33		2013	-8.9%	-5.7%	-5.1%	-0.5%	0.7%
34		2014	-8.9%	-5.8%	-3.5%	1.0%	1.1%
35		2015	-11.0%	-8.0%	-4.1%	0.8%	-0.7%
36		2016	-10.9%	-8.0%	-2.6%	2.9%	0.6%
37		2017	-12.1%	-9.3%	-2.5%	3.3%	0.8%

	V	W	X	Y	Z	AA	AB
38		2018	-12.5%	-9.8%	-1.5%	4.4%	1.5%
39		2019	-15.0%	-12.4%	-2.9%	2.8%	-0.6%
40		2020					
41							
42							
43		Year 1	-6.7%	-0.5%	-0.8%	-0.1%	0.7%
44		Year 2	-6.1%	-3.5%	-3.4%	-0.5%	1.1%
45		Year 3	-7.3%	-4.6%	-5.1%	1.0%	-0.7%
46		Year 4	-8.0%	-5.7%	-3.5%	0.8%	0.6%
47		Year 5	-8.9%	-5.8%	-4.1%	2.9%	0.8%
48		Year 6	-8.9%	-8.0%	-2.6%	3.3%	1.5%
49		Year 7	-11.0%	-8.0%	-2.5%	4.4%	-0.6%
50		Year 8	-10.9%	-9.3%	-1.5%	2.8%	
51		Year 9	-12.1%	-9.8%	-2.9%		

	AC	AD	AE	AF	AG	AH	AI
1							
2	**kwh14**	**kwh15**	**kwh16**	**kwh17**	**kwh18**	**kwh19**	
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13	17,728,395,812						
14	17,611,138,797	18,422,314,777					
15	17,457,238,399	18,341,302,617	17,974,052,049				
16	17,297,744,803	18,239,547,659	17,985,188,012	17,885,619,046			
17	17,150,310,246	18,173,740,104	17,954,527,973	17,871,882,353	18,169,332,174		
18	17,054,445,125	18,135,904,147	18,273,444,186	17,831,049,749	18,080,698,210	18,117,967,826	
19	16,986,561,728	18,137,617,223	18,250,142,812	17,799,194,827	18,125,843,940	17,865,692,100	
20							
21							
22							
23							
24	**kwh14**	**kwh15**	**kwh16**	**kwh17**	**kwh18**	**kwh19**	
25							
26							
27							
28							
29							
30							
31							
32							
33							
34	4.2%						
35	3.1%	-1.4%					
36	4.8%	-0.2%	1.8%				
37	5.0%	-0.4%	1.0%	1.6%			

	AC	AD	AE	AF	AG	AH	AI
38	6.0%	0.1%	1.3%	1.7%	0.1%		
39	4.3%	-1.9%	-2.7%	-0.3%	-1.6%	-1.8%	
40							
41							
42							Avg
43	4.2%	-1.4%	1.8%	1.6%	0.1%	-1.8%	0.4%
44	3.1%	-0.2%	1.0%	1.7%	-1.6%		-0.3%
45	4.8%	-0.4%	1.3%	-0.3%			-0.5%
46	5.0%	0.1%	-2.7%				-0.8%
47	6.0%	-1.9%					-0.4%
48	4.3%						-0.3%
49							-1.7%
50							-2.7%
51							-6.3%

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 5
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 5-01

REQUEST

Please refer to I&M's response to Sierra Club 6-11 in Michigan Public Service Commission Case No. U-20591, "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" which are provided with this set of data requests. Both Excel spreadsheets appear to contain energy forecasts, but no peak load forecast.

a. Please provide the peak load forecast for each year from 2010 to present.

b. Please explain how "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" differ from each other.

c. Please confirm that both "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" are weather normalized

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding and not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M notes that the request seeks information about a data response provided in another docketed proceeding in another jurisdiction. Subject to and without waiver of the foregoing objection, I&M provides the following response.

a. See "CAC 5-1 Attachment 1.xlsx" for the peak load forecasts for each year since 2010.

b. "SC 5-01 WP CMB Rebuttal.xlsx" contains I&M's weather normalized retail sales and retail sales forecasts completed since 2009. "SC 6-11 Attachment 1.xlsx" contains I&M's weather normalized system energy and system energy forecasts (including wholesale) for each forecast completed since 2009.

c. Yes, the data provided in both files are weather normalized.

ATTACHMENT AS-3
Please see separately filed Excel sheet.

ATTACHMENT AS-4

		incremental annual savings in 2019 of 148,484 MWh in its Indiana service territory. That is on the order of 20% more than the sum of the efficiency bundles for "high achievable potential" on slide 18, even though the plan covers only the Indiana portion of the I&M territory and the plan is not spending at levels associated with "high achievable potential". Why is it reasonable to use levels of efficiency in the IRP that are so much lower than what the Company is currently actually achieving or planning to achieve?	IRP. Efficiency levels authorized in Cause No. 44841 were approved as reasonable but exceeded the levels selected in the 2015 IRP for 2019, the extent of which was described by I&M in that Cause.
113	CAC (3/29/19)	113 (CAC 1.5) We are confused about the DSM/EE "degradation" approach used by I&M. a. Could you please explain how the degradation factors by year are developed? From slide 24 of the April 11, 2018 Stakeholder Workshop #2 presentation, they don't appear to be linear over the measure life. b. On slide 23 of its April 11, 2018 Stakeholder Workshop #2 presentation, the Company explains that degradation is needed because "'actual' DSM/EE program savings are measured against a historical base, and the SAE forecast models already account for the changing saturations and appliance efficiencies that are likely to occur in the market…" However, that is not our understanding of how most efficiency program savings are measured. For example, when a customer takes a rebate	<u>113a (CAC 1.5 a):</u> The degradation factors were developed in consideration of the expected life, declining effectiveness, and market efficiencies of the various end-use programs and in consideration of the saturation trends in energy efficiency already embedded in the load forecast models. The observed impacts were not linear over time so I&M utilizes a non-linear estimation algorithm to degrade the program savings that are ultimately subtracted from the load forecast. <u>113b (CAC 1.5 b):</u> We agree there is a lack of consistency with how DSM program savings are measured across the industry. The degradation discussion for the IRP is relative to how things are modeled in the load forecast, not how they are measured in the EM&V process or described in the Technical Reference Manual. In the example provided in the CAC question, the savings are measured against whatever efficiency they could have otherwise purchased in the market (SEER 13).From the load forecast perspective, that is the "historical base" level. Now assume 2years after the purchase was made, only SEER 15 ac units are available in the market, it would be inappropriate to continue to subtract savings that were measured off of the historical base (SEER 13) when someone who is not participating in the DSM program would be able to install the same efficiency (SEER 15) without that incentive, unless the load forecast model is assuming efficiencies are held constant(SEER 13) throughout the forecast horizon.

		for a SEER 15 Central A/C, the savings are measured relative to the SEER 13 that they otherwise would have purchased, not the old SEER 10 that they replaced (i.e. not to a historic base efficiency). Furthermore, once they make a purchase decision, the efficiency results of that decision are "locked in" for the 18 year life of the Central A/C they purchased. That is the case for all efficiency programs targeting "time-of-sale" or new construction purchasing decisions, which is made clear in the Indiana Technical Reference Manual. Why would any degradation of energy savings make sense in such cases? c. The only measures for which the "historic" level of consumption is the baseline from which efficiency savings are measured are true retrofit measures – i.e. measures added to an existing building such as insulation added to residential attics or controls added to existing commercial ventilation systems. However, it also is unclear why degradation factors would be applied to these measures. While it is possible that some homes which get attic insulation through an I&M efficiency program would have eventually installed such insulation on their own, that effect is typically captured in estimates of net-to-gross adjustments. If that is the case, a degradation adjustment would "double-count" the same effect. Also, in our	<u>113c (CAC 1.5 c):</u> See response to part b above. It appears CAC is applying a different definition to 'historic baseline' than is used in the load forecast process. If the Company's degradation approach used in its load forecast was "double counting" as CAC alleges, one would expect the actual loads to consistently come in above the forecasted amounts. That is simply not the case. <u>113d (CAC 1.5 d):</u> There is no double counting of the degradation factors. The baseline projection from the market potential study does include some estimate for the impact of existing and approved changes to building codes and appliance standards but does not account for free ridership and spillover that result from I&M programs. The market potential study does, however, apply a net-to-gross ratio (similar in concept to the degradation factor) when translating from a measure-level to a program level. The IRP inputs are at the measure level which have not been adjusted for free riders and spillover. Therefore the measure level inputs from the MPS are degraded in the IRP modeling so that the output from the IRP can be consistent with the program level outputs, both at a net savings level.

		experience it is likely that only a modest fraction of customers would ultimately install additional attic insulation (and many other pure retrofit measures) on their own over the next couple of decades, not 100% of customers as the degradation factors seem to imply. Why would it make sense to assume that such savings eventually degrade to zero? d.It does seem important that forecasts of future demand take into account savings that will result "naturally" – that is, absent efficiency programs. That would include savings resulting from new federal product efficiency standards. However, it is our understanding that the MPS account for such naturally occurring conservation, including the effects of new building codes and product efficiency standards. In other words, it seems as if the MPS savings estimates, which I&M has degraded, were already "degraded" to adjust for what would have happened absent the programs. Is that not right? If not, it would be helpful to have a discussion to understand why not.	
114	CAC (3/29/19)	114 (CAC 1.6) Please see the attached Indiana-specific Market Potential Study for I&M performed by AEG and the Executive Summary of the entire MPS linked here on I&M's website. Please provide the Michigan-specific Market Potential Study for I&M performed	R114 (CAC 1.6): The company provided of the I&M Report- Michigan Final 6.2.16 as Attachment 2.

ATTACHMENT AS-5

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 2
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 2-2

REQUEST

Please provide the source for the degradation rates applied to I&M’s load forecast.

RESPONSE

Please see “CAC_2-2_Attachment_1.xlsx” for the source of the degradation rates applied to the DSM assumptions in Company's load forecast.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 5
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 5-01

REQUEST

Please refer to I&M's response to Sierra Club 6-11 in Michigan Public Service Commission Case No. U-20591, "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" which are provided with this set of data requests. Both Excel spreadsheets appear to contain energy forecasts, but no peak load forecast.

a. Please provide the peak load forecast for each year from 2010 to present.

b. Please explain how "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" differ from each other.

c. Please confirm that both "SC 5-01 WP CMB Rebuttal.xlsx", and "SC 6-11 Attachment 1.xlsx" are weather normalized

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding and not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M notes that the request seeks information about a data response provided in another docketed proceeding in another jurisdiction. Subject to and without waiver of the foregoing objection, I&M provides the following response.

a. See "CAC 5-1 Attachment 1.xlsx" for the peak load forecasts for each year since 2010.

b. "SC 5-01 WP CMB Rebuttal.xlsx" contains I&M's weather normalized retail sales and retail sales forecasts completed since 2009. "SC 6-11 Attachment 1.xlsx" contains I&M's weather normalized system energy and system energy forecasts (including wholesale) for each forecast completed since 2009.

c. Yes, the data provided in both files are weather normalized.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 6
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 6-02

REQUEST

Please see I&M's Response to Sierra Club Data Request 6-21 in Michigan Public Service Commission Case No. U-20591, which is provided with this set of data requests, stating "These numbers are shown in column BO and represent the GWh savings subtracted from the SAE forecast." Please also reference "CAC_2-2_Attachment_1" which was provided by I&M in Response to CAC Set 2 in IURC Cause No. 45285. Please provide the spreadsheet, with all formulas and links intact, that shows the values in column BO of "CAC_2-2_Attachment_1", tab "Indiana_irp", being "subtracted from the SAE forecast".

RESPONSE

As explained in response to CAC 5-10, CAC 2-2 Attachment 1 contains the estimated DSM savings impacts at the meter and what is modeled in the IRP is at the generator for capacity planning purposes. Please see "CAC 6-02, Attachment 1" for the specific DSM amounts that were subtracted from the load forecast that was modeled in the IRP.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 6
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 6-08

REQUEST

At page 7, lines 15 – 18 of his rebuttal testimony, Mr. Burnett states, "In addition to the fact that appliances lose certain operational efficiencies over time, the degradation matrix is also accounting for market adoption rates and other DSM measurement issues (stipulated vs verified savings, net-to-gross savings, free ridership, spillover, etc.)."

a. What specifically does Mr. Burnett mean by "market adoption rates"? Please explain in detail.

b. For a hypothetical heat pump water heater ("HPWH") rebated by I&M in 2021, how would market adoption rates impact the savings from that HPWH in Year 1 of its life? How would market adoption rates impact the savings from that HPWH in Year 5 of its life? How would market adoption rates impact the savings from that HPWH in Year 10 of its life?

c. Please explain precisely how stipulated vs. verified savings are accounted for in the degradation matrix.

d. For a hypothetical heat pump water heater ("HPWH") rebated by I&M in 2021, how would distinguishing between stipulated and verified savings impact the savings from that HPWH in Year 1 of its life? How would distinguishing between stipulated and verified savings impact the savings from that HPWH in Year 5 of its life? How would distinguishing between stipulated and verified savings impact the savings from that HPWH in Year 10 of its life?

e. What aspect of Itron's SAE model makes accounting for "market adoption rates" necessary? Please explain in detail and provide the documentation that supports your answer.

f. What aspect of Itron's SAE model makes accounting for "stipulated vs. verified savings" necessary? Please explain in detail and provide the documentation that supports your answer.

RESPONSE

I&M objects to the request, and in particular subparts (b) and (d), on the grounds and to the extent the request calls for speculation based on a hypothetical situation. Subject to and without waiver of the foregoing objection, I&M provides the following response.

a. When Mr. Burnett describes market adoption rates, he is referring to the rate at which more efficient technologies become available to consumers in the marketplace.

b. The market adoption rates impact the energy savings that would be credited to a hypothetical rebate program in the load forecast methodology. Refer to Figure CMB-2R of Mr. Burnett's rebuttal testimony. Assume this hypothetical heat pump water heater that is rebated in 2021 uses 880 kWh per year. Furthermore assume the market continues to demand higher efficiencies throughout the forecast horizon so that the average efficiency for a heat pump water heater that is purchased in year 5 will only use 840 kWh per year and by year 10, the average water heater available on the market only uses 800 kWh per year. The original program that incentivized the consumer to purchase an appliance that still uses 880 kWh per year would no longer receive credit for energy savings once the market efficiencies surpass the 2021 technology or in this example by year 5.

c. Stipulated savings are higher than verified savings just as gross savings are greater than net savings. The degradation matrix discounts these stipulated savings and gross measure savings estimates before subtracting from the SAE load forecast that already includes assumptions of continued energy efficiency.

d. See response to part b above for how the savings would change in years 1, 5, & 10 for the hypothetical situation described in part b. The difference is that the stipulated savings would overstate the actual verified savings.

e. The SAE models are designed to capture market trends in appliance saturations and efficiencies. That is why the Company uses the degradation approach to avoid double counting energy efficiency in the load forecast.

f. Refer to Attachment CMB-2R from Mr. Burnett's rebuttal testimony for Itron's explanation for why it is appropriate to adjust the DSM savings amounts within the SAE framework.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC DR 7
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 7-01

REQUEST

Does the worksheet provided with this set of data requests from Michigan Public Service Commission Case No. U-20591 labeled as “SC 5-01 WP-JFT-1_IM IRP EE Modeled v Actual Difference” correspond to Mr. Fisher’s rebuttal testimony in IURC Cause No. 45285 at pages 7 through 8? If not, please provide the spreadsheet with all formulas and links intact that supports Mr. Fisher’s contention on page 8 of his rebuttal that “the Company included an additional 2,600 MWh of available potential than what was identified in the MPS.”

RESPONSE

Yes.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC Set 11
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 11-05

REQUEST

At page 5, lines 20 – 22, Mr. Burnett asserts, “My rebuttal testimony and attachments, as well as the Company’s docket entry responses in this proceeding, provide a robust discussion on how the degradation factors were developed…”

a. To what portions of his rebuttal testimony and attachments precisely is Mr. Burnett referring?
b. If not contained in those referenced materials, what, exactly, was the rationale that I&M used to develop the assumption of a 10 and 15 year degradation curve, and what was the rationale to develop the specific degradation percentages in each year of those curves? Please note that CAC_2-2_Attachment_1 does not provide a rationale for degradation it only applies degradation to historic EE savings.
c. Please provide any spreadsheets, with all formulas and links intact, that document the rationale you describe in response to subpart (b).

RESPONSE

a. Section III of Mr. Burnett's rebuttal testimony contains nearly 14 pages of Q&A's that explain how the Company's degradation approach properly models DSM savings in the IRP. Furthermore, in response to the Commission's 3rd data request, the Company provided a detailed explanation of how the degradation factors were developed.

b. As explained in the Company's response to IURC 3-1, the rationale that I&M used to develop the assumption of a 10 and 15 year degradation curve was that each energy efficiency measure will have a certain estimated life over which the energy efficiency measure will degrade. As explained on page 7 of Mr. Burnett’s rebuttal testimony, the rate at which energy efficiency measures degrade is affected by changes in the operational efficiency of the measure, market adoption rates, stipulated vs. verified savings, net-to-gross savings, free ridership, spillover, and other factors. Based on prior experience, including I&M’s EM&V process and its residential appliance survey results, I&M recognized that these factors are generally not linear in nature. To account for this, I&M developed degradation factors and degradation curves that approximate the actual degradation rates reflected in EM&V and the residential appliance survey results. As explained in Mr. Burnett’s rebuttal testimony on pages 3-6, the reasonableness of the degradation factors is borne out by the historical accuracy of I&M's load forecasts, which apply degradation factors to the DSM assumptions.

c. See response to part b above, the Company's response to IURC Data Request 3-1, and IURC DR 3-1 Attachments 1 and 2.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC Set 11
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 11-07

REQUEST

I&M's June 15, 2020 response to Docket Entry Question 3-1 says, in part, "...I&M developed degradation factors and degradation curves that approximate the actual degradation rates reflected in EM&V and the residential appliance survey results."

a. How does I&M distinguish between "degradation factors and degradation curves"?
b. Please provide the specific documents referenced in this response.
c. Please provide the spreadsheet(s) with all formulas and links intact that document the application of "actual degradation rates reflected in EM&V and the residential appliance survey results" to the creation of the degradation factors and curves.

RESPONSE

a. The terms "degradation factors" and "degradation curves" were both included in the question for Docket Entry 3-1. The Company's interpretation of this distinction is that the degradation factor would be the specific value for a specific year, while the degradation curve would represent sum of each of the individual degradation factors over the expected measure life.

b. See the Company's response to Docket Entry 3-1.

c. See the Company's response to Docket Entry 3-1 and IURC DR 3-1 Attachments 1 and 2.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC Set 12
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 12-01

REQUEST

At page 5 of his Settlement Testimony, Mr. Fisher is asked the question, "…is there a need to modify the Company's 2018 – 2019 IRP?" Mr. Fisher responds, "No. The Company's 2018 – 2019 IRP is a well-developed and reasoned analysis." Please reconcile this assertion with the Company's statement to the Administrative Law Judge in an April 2020 prehearing conference in Michigan Public Service Commission Case No. U-20591 that "COVID-19 certainly has impacted load not only for I&M but for other utilities throughout the United States and those load changes, in general, call into question the efficacy of the current IRP."

RESPONSE

Each statement is accurate, and the two are easily reconcilable when not taken out of context.

First Quote: The Q&A that starts on page 5, line 16 of Mr. Fisher's Settlement Testimony is asking if the Company's 2018 - 2019 IRP should be modified based on the Indiana Director's draft report. Based on the Indiana Director's draft report, there is no need to modify the Company's 2018 - 2019 IRP. The Company's IRP remains methodically and analytically sound.

Second Quote: The second statement was made by Michigan counsel during a prehearing conference for the Michigan IRP docket, U-20591. The purpose of the statement was to point out that there was no need to continue litigating under Michigan law the last-completed IRP given that the Company would soon be initiating work on its next IRP. Of course I&M's next IRP will reflect updated inputs, including updated load forecasts that account for the effects of COVID-19, that may affect long-term resource needs and decision-making. This procedural context, and the potential for long-term impacts, is made clear in the discussion that accompanies the CAC's selected quote.

To the extent the request is attempting to connect the two statements and imply that the Company should update its 2018-2019 IRP to reflect COVID-19 impacts on load for purposes of considering the Company's 2021-2022 DSM/EE targets, such an update is neither necessary nor appropriate. It is reasonable to expect that the reduced near-term load forecasts would likely support a reduced need for supply-side and demand-side resources, as supported by Witness Burnett. This expectation is further supported by the Company's consideration of Case 15 in the 2018-2019 IRP, which analyzed a low load and low commodity price forecast and selected less DSM/EE savings than the Company’s preferred plan. It would be inappropriate to expend the resources necessary to revise the 2018-2019 IRP to confirm an impact to near-term DSM/EE planning that is already known.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC Set 12
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 12-03

REQUEST

Please refer to Figure GSF – 1S at page 4 of Mr. Fisher's Settlement Testimony.

a. What trend would Mr. Fisher expect the blue line on this graph to follow over the course of the remaining years shown on this graph?
b. Please provide, in electronic spreadsheet format, with all formulas and links intact, the most recent PJM AEP price forecast in the Company's possession.
c. In what ways does Mr. Fisher anticipate PJM market prices would influence retirement and new unit acquisition plans contained in the Company's preferred plan?

RESPONSE

a. It is anticipated that AD Hub ATC prices will revert to the prices depicted in the Y2019H1 (solid black line). The deviation experienced in 2020 year-to-date corresponds to the unprecedented loss of load due to the COVID pandemic.

b. See CAC 1-12b - Attachment 1, CAC 1-12b Attachment 2, CAC 1-12b Attachment 3, CAC 1-12b Attachment 4.

c. As described in Section 4 of the IRP, PJM market prices are a key driver in determining the value of all resources; therefore, changes in PJM market prices were considered in the development of the IRP. The impact of changing market prices is shown and discussed in Section 5 of the IRP. Specifically, Case 15, examined both low load and low commodity pricing of the analysis period. The capacity additions from this Case are shown in Table 26, on page 129 of the IRP. the capacity additions from a high level are very similar to the Preferred Plan. The material changes in capacity additions between the Preferred Plan and Case 15 are reflected in the total wind additions are reduced by 1,350MW, combined cycle capacity is reduced by 385MW and demand response resources increase by 65MW all by 2038, as shown in Tables 26 and 27 in the IRP.

INDIANA MICHIGAN POWER COMPANY
CITIZENS ACTION COALITION OF INDIANA, INC.
DATA REQUEST SET NO. CAC Set 12
IURC CAUSE NO. 45285

DATA REQUEST NO CAC 12-04

REQUEST

Please refer to CAC_2-2_Attachment_1, tab “Indiana_irp”, columns BD - BM. Please explain why the formulas in these columns are set to return only positive values. Put another way, why is I&M calculating an adjustment for energy efficiency that only accounts for a positive difference between persisting savings and savings that are rolling off, but returns a zero value where the difference between persisting savings and savings that are rolling off is negative?

RESPONSE

I&M objects to the request on the grounds and to the extent the request, in particular, the second clarifying question adopts a premise with which I&M disagrees. Specifically, the restated question misinterprets both the data and the calculations that are included in CAC 2-2 Attachment 1. Subject to and without waiver of the foregoing objection, I&M provides the following response.

The values in columns BD - BM are the class level cumulative degraded impacts that are subtracted from the Company's sales forecast model output. As described in Company witness Burnett's rebuttal testimony (pg 8), the Company's load forecast models already accounts for some levels of energy efficiency savings in the market place. If the values from CAC 2-2 Attachment 1 were allowed to be negative, it would raise the forecast (subtracting a negative value) which would imply that the Company's DSM/EE programs caused customers to use more electricity instead of less which would not be accurate or appropriate. By only adjusting the load forecast for DSM savings impacts that are positive, it ensures that the overall load forecast captures all of the energy efficiency impacts of the Company's DSM/EE portfolio.

ATTACHMENT AS-6

Final

DIRECTOR'S REPORT

for the

2016 Integrated Resource Plans

Dr. Bradley Borum

IRPs Submitted by

Indianapolis Power & Light Company (IPL)

http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf

Northern Indiana Public Service Company (NIPSCO)

http://www.in.gov/iurc/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf

Vectren (SIGECO)

http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

and

An Update by Hoosier Energy

http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

November 2, 2017

The Final Director's Report for the 2016 Integrated Resource Plans includes the Director's response to comments received from utilities and stakeholders regarding the Draft Director's Report. The Director's specific responses to Indianapolis Power & Light (IPL) are found in Section 2.5, Northern Indiana Public Service Company (NIPSCO) in Section 3.5, and responses to Vectren have been inserted in Section 4.5.

The Director's responses to the Indiana Coal Council (ICC) are in Section 9. Responses to the Citizens Action Coalition (CAC) et al can be found in Section 10. Comments by the Indiana Coal Council and the CAC et are placed at the end of the Final Director's Report since many of the comments are generally applicable to all of the utilities.

The Director sincerely appreciates the excellent analysis conducted by the utilities and the commitment by the utilities' top management and subject matter experts to this endeavor. Because of the increasing importance and complexities of the IRPs, the Director is very appreciative of the contributions by stakeholders, particularly the Citizens Action Coalition et al, the Indiana Coal Council, and the Midwest Energy Efficiency Alliance for their substantive analysis of these IRPs.

EXECUTIVE SUMMARY
2016 INTEGRATED RESOURCE PLANS

Indianapolis Power & Light, Northern Indiana Public Service Company, Vectren, and Hoosier Energy

Purpose of IRPs

By statute[1] and rule,[2] integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (IRP) and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Indiana Utility Regulatory Commission (IURC or Commission) proceedings for the benefit of customers, the utility, and the utility's investors. A key element in achieving this goal, as required by law and rule, is a public advisory process, otherwise known as a stakeholder process. At the outset, it is important to emphasize these are the utilities' plans. The Commission, by statute[3], does not take a position on the relative efficacies of any of the utilities' "Preferred Plans."

An IRP is a systematic approach to better understand the complexities of an uncertain future so utilities can maintain maximum flexibility to address resource requirements. Because absolutely accurate resource planning 20 years into the future is impossible, the objective of an IRP is to bolster credibility in a utility's efforts to capture a broad range of possible risks.[4] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their resource portfolio to maintain reliable service at the lowest delivered cost to customers that is reasonably feasible.

Every utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors,[5] and increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation. Inherently, IRPs are very technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of

[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm ("Draft Proposed Rule")

[3] Indiana Code § 8-1-1-5.

[4] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[5] The primary *driver* of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to *fracking* and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of alternative resource decisions.

The IRPs should be regarded as *snap shots in time* that analyze multiple potential resource portfolios. Because IRPs are usually submitted to the Commission in November, changes occurring after submittal, such as any roll-back of environmental regulations through law, rulemaking, or executive orders (e.g., the Clean Power Plan (CPP)), review of Effluent Limitation Guidelines (ELG) rule, policy emanating from international agreements such as the Paris Accord, newly-discovered natural gas opportunities, and changes in technology do not normally require changes to this IRP unless changes are required by the Commission to support a future filing of a Certificate of Need case or other case. As a result, these resource portfolios should not be regarded as being THE Plan that a utility commits to undertake. Rather, it should be regarded as a road map based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost-effectiveness of various resources, customer needs, etc.) and make appropriate and timely mid-course corrections to change their resource portfolios. Again, it is important that these decisions be made with stakeholder involvement.

Four Primary Areas of Focus

The Director recognizes the complexity of the several elements of IRPs and has selected the following four to highlight:

1) Fuel and commodity price forecasts;
2) Construction of resource portfolios based on the development of a wide range of scenarios and sensitivities;
3) The treatment of Demand-Side Management (DSM) on as comparable a basis as possible with all other resources; and
4) Discussion of the metrics that each utility considered to evaluate the IRPs.

The focus on these four areas is due to the complexity and difficulty of these topics but it should not be interpreted as suggesting that other topics such as the stakeholder process, load forecasting, and integration of customer-owned resources are not important to the credibility of the IRPs and the value to utilities and stakeholders.

General Observations

Perhaps due in part to the increasingly consequential decisions that utilities will be making, and in part to the commitment of the utilities and stakeholders to the IRP public advisory processes as good public policy, Indianapolis Power and Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Southern Indiana Gas and Electric Company (Vectren) have all made significant improvements in all aspects of their IRPs. Indiana utilities are increasingly using state-of-the-art methods and are making continued enhancements to their planning processes. The utilities have all made a concerted effort to broaden stakeholder participation. All of the utilities have offered unprecedented transparency and candor. It is gratifying that the top management of each utility, top staff and subject matter experts have all been made available to facilitate the collegial stakeholder process.

Consistent with the law and the Draft Proposed Rule, each Indiana utility has recognized areas that will be improved in subsequent IRPs. For example, all three utilities recognized the need for improvements in their load forecasting, and IPL is undertaking an ambitious project to utilize "smart meters" (Advanced Metering Infrastructure or AMI) to increasingly rely on its own customers' usage data rather than reliance on information from other utilities. NIPSCO recognized the need to upgrade its modeling capabilities because its current long-term resource model was not capable of integrating probabilistic analysis or performing multiple optimizations of different resources. All utilities are committed to enhancing their stakeholder process. By going from a two year to three year IRP cycle, utilities can increase stakeholder input by: 1) establishing objective metrics to evaluate their IRP; 2) defining the assumptions (e.g., fuel prices, costs of renewable resources, costs of other resources); 3) constructing scenarios to provide a robust assessment of potential futures; and 4) reviewing the resulting resource portfolios.

In the four focus areas, the Director recognizes there is no right or wrong way to conduct the analysis; different approaches have been useful to advance the understanding of the various elements of IRPs but it is premature to standardize.

1. INTRODUCTION AND BACKGROUND

Since 1995, Indiana utilities that generate electricity have submitted IRPs. In 2016 by explicit statute[6] and rule,[7] the Commission requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to their planning as part of their obligation to ensure the reliable and economical power supply to the citizens of Indiana. For several reasons (such as projected low cost natural gas, aging power plants, environmental regulations, decreasing cost of renewable energy resources, energy efficiency, customer-owned resources, and relatively low load growth), all Indiana utilities, in addition to utilities throughout the region and nation, are facing significant resource decisions that will largely remake the resource mix. One of the primary goals of a well-reasoned, transparent, and comprehensive IRP is to narrow the contested issues and reduce the controversy to expedite Commission proceedings for the benefit of customers, the utility, and the utility's investors. For the IRPs submitted on or after Nov. 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule from IURC RM #11-07 dated 10/04/2012 (Draft Proposed Rule), which proposed to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans. The Commission, utilities, and stakeholders collaboratively developed the Draft Proposed Rule, which is available on the Commission's website at http://www.in.gov/iurc/2843.htm

(IPL and NIPSCO submitted their IRPs on Nov. 1, 2016. Also on November 1, Hoosier Energy submitted an update to its 2014 IRP. Vectren was granted an extension to allow for a better understanding of the issues associated with ALCOA and larger customers generally, and submitted its 2016 IRP on December 19, 2016. Links to the IRPs, appendices, and other documents can be found at http://www.in.gov/iurc/2630.htm.

Please note that the links shown below for each utility are public versions of the IRPs and do not include confidential information and most appendices:

[6] Indiana Code § 8-1-8.5-3.

[7] 170 IAC 4-7; *see also* "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: http://www.in.gov/iurc/2843.htm

1. Indianapolis Power & Light Company (IPL)

   http://www.in.gov/iurc/files/ipl%202016%20irp_without%20attachments.pdf

2. Hoosier Energy REC, Inc. (Hoosier Energy)

   http://www.in.gov/iurc/files/Hoosier%20Energy_public%20version_2014%20irp%20update_110116.pdf

3. Northern Indiana Public Service Company (NIPSCO)

   http://www.in.gov/iurc/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf

4. Southern Indiana Gas & Electric Company (SIGECO or Vectren)

   http://www.in.gov/iurc/files/SIGECO%202016%20IRP.pdf

Written comments regarding some of the IRPs were submitted by various entities, including:

1. Citizens Action Coalition, Earthjustice, IndianaDG, Sierra Club, Valley Watch (hereinafter referred to as CAC et al.)
2. Midwest Energy Efficiency Alliance
3. Indiana Coal Council
4. Alliance Resource Partners, LP
5. NIPSCO Industrial Group
6. Sunrise Coal, LLC
7. Joe Nickolick
8. Office of the Utility Consumer Counselor.

Written comments on the Draft Director's Report submitted by the following organizations:

1. IPL
2. NIPSCO
3. Vectren
4. CAC et al
5. ICC

Links to these comments can be found at: http://www.in.gov/iurc/2630.htm

Section 2(k) of the Draft Proposed Rule limits the Director's Draft Report and Final Report to the informational, procedural, and methodological requirements of the rule, and Section 2(l) of the Draft Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

This Draft Report by the Director was issued July 25, 2017. Under the Draft Proposed Rule, supplemental or response comments to the Director's Draft Report may be submitted by the utility or any customer or interested party who submitted written comments on the utility's IRP earlier in the process. 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. The Director would be pleased to meet with utilities and/or stakeholders to discuss the Draft or Final Reports.

1.1 Summary

The 2016 IRPs submitted by IPL, NIPSCO, and Vectren were credible, well-reasoned, and represented a substantial improvement over previous years in all aspects of their IRPs. The utilities are increasingly viewing their IRPs as integral to their strategic planning and having substantial ramifications for their customers, investors, communities, and for policymakers. Certainly all three utilities are facing potentially dramatic changes in their resource mix over the next several years due to the following factors affecting the nation as a whole:

- The aging of the coal and nuclear generating fleets when combined with more stringent environmental regulations accelerate retirement decisions. This is especially true for the smaller and older coal-fired generating units. In the next few years, decisions to retire larger and more efficient generating facilities that have far-reaching ramifications for the each utility's customers, the region, and the nation are certain to require increasingly difficult and rigorous analysis.
- In general, coal and nuclear generating units are having difficulties competing with natural gas and renewable resources in the regional economic dispatch of competitive wholesale power markets. That is, for regional economic dispatch by MISO or PJM, coal and even some nuclear units that serve other states are often "out of the money" and not dispatched as fully as they were as recently as two years ago and therefore unable to recover all of their fixed and variable operating costs. As a result, several utilities have planned to retire substantial portions of their coal-fired units. Nuclear units are increasingly struggling in the current market. Utilities in Ohio, Illinois, and other states are seeking state legislation to have customers subsidize the continued use of nuclear- and coal-fired generators. Against this backdrop of declining natural gas prices and increased cost-effectiveness of renewable resources, utilities evaluating the retention of coal and nuclear units will need to continually reevaluate the value of fuel and resource diversity while maintaining resource adequacy.
- Utilities are facing increasing costs due to maintenance and modernization of infrastructure. These utilities are also projecting low or even negative growth in electric sales, which means the increased costs will be spread over fewer kilowatt hour sales.
- Because the decisions about resources will become increasingly complex, contentious, and difficult, utilities will have to continually enhance their planning processes. In addition to dramatic changes in fuel markets and the cost of renewable resources, utilities will have to consider the planning ramifications of future potentially significant public policy changes, such as the roll-back of some environmental regulations (e.g., the CPP, ELG, Presidential Executive Orders, etc.).

With good reason, IPL, NIPSCO, and Vectren have sought to maintain as much optionality as possible in their IRPs. The Navy uses the phrase "point of extremis" to characterize maximum optionality. That is, waiting to make a very difficult decision until the last possible moment. To this end, the IRP analysis –

including the utility's selection of a preferred resource portfolio – should be regarded as an indicative analysis, in that the results are based on appropriate information available at the time the study was being conducted and does not bind the utility to adhere to the preferred resource portfolio, or any other resource portfolio. If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate. Ultimately, in the instance of a case before the Commission, the Commission, after consideration of testimony, will decide whether additional analysis is necessary to provide the Commission with the requisite information.

1.2 Areas of Primary Focus

The Director's Report of the 2016 IRPs for IPL, NIPSCO, Vectren, and an update by Hoosier Energy will primarily address the four most difficult and significant interrelated topics that were the subject of considerable conversation throughout the stakeholder processes. The four topics are: 1) fuel and commodity price projections; 2) scenario and risk analysis; 3) development of metrics for evaluating the IRPs; and 4) the treatment of energy efficiency on as comparable a basis as possible to other resources.

Utilities, in conjunction with stakeholders, will be evaluating future resource modeling programs, databases, and utility planning processes to continually enhance the credibility of the IRP processes. This continual reevaluation is imperative as decisions become increasingly complex. Just because these other topics are receiving a more cursory review should not be construed as being less important. It is also worth emphasizing that the individual topics being reviewed are all interrelated, which makes clear delineation between the topics impossible. The Director wishes to be abundantly clear that the comments address the methods used in the IRP process rather than the selection of a preferred resource portfolio.

The Director believes this has been the most transparent IRP process to date. The new three-year cycles contained in the more recent draft IRP rules will further reduce concerns and questions by affording stakeholders an opportunity to become more involved in the development of the IRPs from their inception through submittal. Most stakeholder concerns and questions about this and previous IRPs centered on the development of portfolios. This included developing assumptions, selection of appropriate data, construction of scenarios, the use of meaningful sensitivities, and the evaluation of model output and the resulting resource portfolios to reliably and economically meet the needs of Indiana. Stakeholder interest and participation in the IRP processes is likely to intensify as decisions to retire and restructure the resource mix are made.

From the analysis and the stakeholder comments, IPL, NIPSCO, and Vectren made significant improvements to their IRP analysis and their approaches. It is abundantly clear that Indiana utilities, like utilities throughout the nation, are facing daunting issues and there is no easy, single or perfect answer to address these issues. In some respects, Indiana utilities are on the cutting edge of long-term resource planning. The advances made by Indiana utilities should result in lower risk for their customers and investors. As Indiana utilities and their stakeholders realize, however, continued improvements is a goal we all share.

1.3 Presentation of Basic Information

The Director tried to compile the same set of basic information for each utility's IRP and found the task surprisingly difficult. For example, the Director tried to compare for each utility how its portfolio changed from the beginning of the forecast period to how it looked in the last year of the period. This information was presented in terms of generation capacity in either the IRP, appendices, or presentations from the public advisory stakeholder meetings. But comparable information showing how much energy was provided by resource type and how this changed over the forecast horizon was not presented by IPL and Vectren. Some of the basic information was presented by each utility in their IRP but no utility had all of the information in its IRP. Some of the information one utility had in its IRP was not included by other utilities but could be found in the stakeholder presentations. Some of the basic information could not be found in the IRPs, stakeholder meeting presentations, or other technical appendices. Even when utilities presented what appeared to be similar information, a closer examination showed the data was not comparable. Based on comments by the CAC et al., it appears they had much the same experience.

The problem is the IRPs and the associated appendices each provide a considerable amount of information but much is also not available, not well presented or must be laboriously sought and compiled, or is not comparable across utilities. These limitations reduce the usefulness of the IRPs to non-utility stakeholders and can be increasingly problematic over time for utilities, stakeholders, and policymakers. Without being unduly prescriptive, but in an effort to improve the immediate and longer-term value of the IRPs, the Director makes several suggestions that he hopes will serve as a starting point for a discussion that will involve the utilities and numerous stakeholders.

1. Make much greater use of tables and figures comparing resource retirements, additions, and other inputs across both the preferred and candidate portfolios. Examples are on Table 23 on page 131 of Indiana Michigan's 2015 IRP. Another example for consideration is Table 2 on Pp. 11 of the CAC et al. comments on Vectren's 2016 IRP.

2. Include tables showing how inputs or assumptions compare across scenarios. To make scenarios clearer, there needs to be a link of each scenario description to specific inputs. (CAC et al. Comments on Vectren IRP, Pp. 19). For example, which fuel forecasts were used in each scenario should be clearly specified.

3. The first year any resource is available for selection in a portfolio should be presented and the reason why some resources might be available later than others should also be noted. More specifically,

   - The first year a resource can be added to a portfolio;
   - The last year a resource can be added to a portfolio;
   - Limitations on the size of the resource that can be added;
   - The minimum and maximum number of units of a particular resource that can be added; and
   - Performance characteristics of generation facilities including forced outage rates, heat rate profiles, emission rates, and typical maintenance outages.

Also, if the availability of potential resources for model selection varied by scenario, then this should also be clearly presented. As mentioned by CAC et al, for each scenario or portfolio, it is important to note which resource changes are fixed (or set by the modeler) as compared to optimized (chosen by the model based on the constraints set by the modeler). (See pp. 10 of CAC's Comments on Vectren IRP)

4. The non-utility stakeholders would benefit from expanded use of graphics and simple tables. Well-developed graphics would aid a wide variety of audiences.

5. Given that future IRPs are going to be increasingly consequential in their ramifications, we urge all utilities to continue their efforts to improve the clarity and explanatory value of their narratives. With the new three-year cycle for IRPs, we recommend the additional time could be used to good effect to solicit input from stakeholders earlier in the process on the data, assumptions, and the development of scenarios and sensitivities. It is expected that stakeholders will also be active participants in this collaboration. The utilities, with input from their stakeholders, should objectively reassess their modeling capabilities and the databases necessary to make full use of state-of-the-art long-term resource modeling.

2. INDIANAPOLIS POWER AND LIGHT COMPANY

2.1 **IPL'S** Fuel and Commodity Price Analysis for 2016 IRP

Since natural gas price projections and the relationship between gas and coal prices seem to be the primary driver of the IRPs this round, the Director believes more discussion about the assumptions behind the fuel and commodity forecasts and data are warranted. We very much appreciate IPL's willingness to share confidential information from its consultants, which provided a narrative of its fuel and market price projections. However, the narratives did not seem to provide a comprehensive discussion of the complexities of the interrelationships of critical commodities. For example, the production and price relationship of oil to natural gas, natural gas to coal, and fuel prices to MISO market prices.

> *Natural gas/market price correlations – While IPL recognizes potential influences of resource mix changes on market prices, in this IRP correlations between fuel and market prices do not change significantly from recent historic trends. IRP Assumptions, 1.3* page 2

As a result of giving less consideration to fracking as a significant departure from historic trends, it appears that IPL may minimize the complex and changing interrelationships between oil price and production and the production and price of natural gas. To the extent that this concern may be valid, we offer some potential examples but encourage IPL to consider others.

1. Figures 8.40 and 8.41in the Company's IRP shows a somewhat surprising result that coal price became more important than natural gas prices after 2027. This is certainly an interesting scenario but it might argue for construction of a scenario/sensitivity that has a low natural gas price projection.

2. If natural gas price projections are as complex as we believe, this would seem to make estimates of the market price, which is largely dependent on the price differentials between coal and natural gas (the difference between the market price and coal price is sometimes referred to as the dark spread), more difficult. On page 11 of its IRP, IPL states: "*IPL uses a combination of multi-year contracts with staggered expiration dates to limit the extent of IPL's coal position open to the market in any given year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability.*" This seems like a well-reasoned approach but it isn't clear how coal prices varied in the longer-term using stochastic analysis (page 142). Regardless, this IRP analysis, and particularly future IRP analyses, would benefit from more complete discussion of natural gas, coal, and market price intricacies.

3. For IPL, the MISO's economic dispatch and forecast of market prices provide additional data points for consideration. That is, if the projections being used by the MISO show diminishing dispatch of coal-fired power plants, that should be an additional check, but certainly not the only check in determining the reasonableness of the fuel cost assumptions. Similarly, if coal is dispatched more frequently, IPL's planning should be sufficiently flexible to adjust.

The Indiana Coal Council commented that the 2.5% annual escalation rate for coal may be too high. IPL said that might be true but, while they utilized only one coal price forecast, they conducted probabilistic analysis on a wider range of possible forecasts to evaluate their portfolios (IPLs response to Indiana Coal Council on page 1 of the ICC's letter). The Director believes IPL's approach was a reasonable method to address the ICC's concerns. However, we agree with the Indiana Coal Council that it would probably be better to have more expansive scenarios than to rely on sensitivities. As IPL's resource decisions become more difficult, we are confident IPL will be rigorous in its evaluation methods.

2.2 Scenario and Risk Analysis

2.2.1 Models, Drivers, and Scenarios

To IPL's credit, all scenarios were developed in an atmosphere of transparency, and IPL actively solicited input from stakeholders. IPL identified four categories of drivers, which would impact IPL's resource portfolio choice. They are economics affecting load requirements, natural gas and wholesale electric market prices, Clean Power Plan and other environmental costs, and the level of customer distributed generation adoption. IPL considered how these drivers might interact in the future to develop specific scenarios.

1. A Base Case scenario
2. Robust Economy,
3. Recession Economy,
4. Strengthened Environmental, and
5. High Customer Adoption of Distributed Generation
6. Quick Transition

The Base Case included business-as-usual projections for identified drivers trending as currently expected for the study period. Four scenarios were developed by varying projections of the four main categories of drivers mentioned previously. The four scenarios are Robust Economy, Recession Economy, Strengthened Environmental, and High Customer Adoption of Distributed Generation. Another scenario called Quick Transition was formed based on stakeholder feedback. There are six scenarios in total.

The capacity expansion model produced six least-cost portfolios from the six scenarios. IPL then took the six portfolios and modeled them against the Base Case assumptions in the Production Cost Model to examine how each portfolio would fare if Base Case assumptions for the future come to fruition. To better understand the impact of carbon regulation on the Base Case, IPL conducted two deterministic sensitivities on the Base Case by using the Production Cost Model to simulate the Base Case portfolio and dispatched the units subject to different carbon prices. Additionally, stochastic analysis was conducted to assess the financial risk to each portfolio if key variables changed.

Based on the criterion of lowest cost to customers combined with considerations of risk, as well as other economic and environmental impacts, IPL chose a hybrid preferred resource portfolio. The portfolio is a mix of the portfolios from the Base Case, Strengthened Environmental, and Distributed Generation Scenarios. Selecting a Preferred Portfolio that was different from the Base Case, based on IPL's judgment might be regarded as unusual but it is not inconsistent with the IRP draft rule. Selecting a Preferred Plan that incorporates stakeholder and other input demonstrates a flexibility and optionality that the IRP draft rules intended to encourage. Since all of the IRP plans are indicative, they should not be characterized as representing a commitment to adopt the elements of the plan. However, for the integrity of the stakeholder process, the utility's Preferred Plan should be derived from the scenarios that were fully optimized and reflect information developed from sensitivity and probabilistic analyses. A narrative should be sufficiently detailed to track the evolution of the Preferred Plan.

IPL worked with several vendors and utilized multiple models to conduct scenario and sensitivity analysis. The DSM Market Potential Study was conducted by AEG through LoadMap. Load forecasts were performed by Itron using MetrixND. Capacity Expansion Model from ABB was used to develop optimized portfolios under various scenarios. ABB Strategic Planning Portfolio Production Cost Model and Financial Model were adopted to evaluate portfolios by providing present value of revenue requirements (PVRRs) in a Base Case future world.

2.2.2 Issues / Questions

The Director was impressed with the level of scrutiny and in-depth analysis of the computer runs and how the modeling affected the development of scenarios, sensitivities, and, ultimately, the portfolios that were provided by the CAC et al. Giving due regard for stakeholder comments adds credibility, increases understanding, and, hopefully, will reduce the number of contentious issues inherent in the increasing complexity and analytical difficulty of future IRPs. Hopefully, many of the concerns raised by the CAC et al. regarding assumptions, data, development of scenarios, integration of sensitivities, and appropriate metrics for objective review will be addressed earlier in the IRP process consistent with the change in the rule from two to three-year cycles.

All of IPL's optimized portfolios were evaluated under the Base Case Scenario assumptions rather than the assumptions of the corresponding scenarios. IPL argued that the comparison was helpful because it allowed one to see how each portfolio performed under the same set of assumptions. However, in this case, comparison among various portfolios based on the Present Value of Revenue Requirements (PVRR) is less meaningful because the Base Case portfolio has to be the least cost portfolio under Base Case scenario assumptions, according to the least-cost optimization criterion imbedded in the capacity expansion model.

For the probabilistic analysis, IPL evaluated each candidate portfolio under 50 combinations of input variables from random draws using the Production Cost Model. IPL seems to have overlooked changes in the capacity portfolio caused by changes of input assumptions by using this method. Upon reconsideration, would IPL agree that a more appropriate way might be running the capacity expansion model first under each set of assumptions to develop the capacity portfolio and then evaluating the portfolio with consideration of the operation and financial aspects of electrical generating units through the Production Cost Model? With regard to choosing the preferred plan, a more appropriate way might be comparing capacity portfolios derived from different input assumptions first. Resources found in the majority of scenarios might be considered in the preferred portfolio. However, in the end, IPL considered six metrics it regarded as important (page 7 of the Executive Summary) and it is IPL's decision to select a preferred portfolio.

2.3 Energy Efficiency

Like other Indiana utilities, there is a marked improvement in IPL's effort to model demand side management (DSM) in a manner comparable to supply-side resources and to group the resources into bundles that are then entered as selectable resources comparable to supply-side resources in the capacity expansion modeling software. The ability to treat DSM in a manner that is as comparable as possible to other supply-side resources is difficult and there is no single or perfect methodology. Like NIPSCO in this

IRP cycle, IPL contracted the Applied Energy Group (AEG) to use their LoadMap tool to perform a market potential study and Morgan Marketing Partners (MMP) to screen the DSM measures chosen for cost-effectiveness using their DSMore tool. The DSM measures that passed the screening were then grouped into 14 bundles (eight energy efficiency-based and six demand response-based). Seven of the energy efficiency based bundles were further split into three cost tiers.

To estimate the appropriate level of achievable and cost-effective DSM suitable for IPL's service territory, IPL hired AEG to prepare a Market Potential Study (MPS).[8] While the IRP covers the period 2017 to 2036, the MPS started in 2018 and covers DSM opportunities through 2037. A key objective of the MPS was to develop estimates of electric efficiency and demand response potential by customer class for the period 2018 to 2037 in the IPL service territory and develop inputs to represent DSM as a resource in IPL's IRP for the forecast period 2018-2037.

A screening process was used to develop an Achievable Potential for DSM that was used to create the DSM bundles for the IRP modeling. The process starts with all technically possible efficiency measures, or the Technical Potential. AEG prepared a list of available efficiency measures using IPL's current programs, the Indiana Technical Reference Manual version 2.2, and AEG's data base of energy efficiency measures. AEG then applied a cost-effectiveness screen using the Total Resource Cost (TRC) test as the main metric to determine the Economic Potential. This test selects any measure which, if installed in a given year, has a TRC net present value of lifetime benefits that exceed the Net Present Value of Revenue Requirements (NPVRR) of lifetime costs.

AEG estimated two levels of Achievable Potential from the Economic Potential: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. A downward adjustment was applied to the MAP and RAP savings estimates in an amount proportional to the percentage of load that has elected to opt out of efficiency programs.

IPL considered three different DSM bundling options. Option A involved creating the program potential or actual programs - each DSM bundle represented a program. Option B involved creating end-use bundles with similar load shapes that are further disaggregated into cost tiers. Option C used MAP to create bundles based on similar load shape end uses. IPL selected Option B because they thought the method allowed for more creativity in program creation. Also, the cost tiers prevent cost-effective measures from being eliminated because they are bundled with high cost measures, which could happen with Option C. MAP was used to construct the DSM bundle inputs into the IRP.

IPL worked with AEG and Morgan Marketing Partners to create DM bundles using the DSMore cost-effectiveness model. Energy efficiency measures within MAP were bundled by sector and technology to take advantage of load shape similarities among like measures. Bundles were further divided by the direct cost to implement per MWh: up to \$30/MWh, \$30-60/MWh, and \$60+/MWh. IPL decided to use

[8] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

$30/MWh as the top-end of the low cost tier because this is roughly the delivery cost for IPL's 2016 DSM portfolio. It was determined the maximum number of bundles the capacity expansion model could reasonably handle was around 45. To meet this model limitation, IPL decided to split the IRP timeframe into a near-term period that is consistent with its next DSM filing period (2018 to 2020) and a long-term period of 2021 to 2036.

DSM in the IRP capacity expansion model is compared to building new generation or purchasing power to meet load requirements. This is done by giving supply-side characteristics, including load reduction or load shape change potential, and levelized cost in $/MWh and $/MW to the DSM bundles.

2.3.1 Issues / Questions

IPL, despite using the same consultants as NIPSCO, modeled DSM slightly differently than NIPSCO and substantially different from Vectren. In fact, all three companies differed as to how they handled model limitations that constrain how DSM can be modeled in the IRP resource optimization model. For IPL, in dealing with the limitation on the number of resources that the capacity expansion model could handle, it appears IPL reduced the DSM decision points to two years, 2018 and 2021. In 2018, the level of DSM for 2018 to 2021 is chosen. In 2021, the level of DSM for 2021 to 2036 is decided. This is according to the explanation in Section 7.3.3 (page 147) of the IRP main document which reads as follows: "For example, let's say the model picks the Residential Lighting block for the 2021–2036 period. The level of DSM within this bundle is pre-set for this period based on the Market Potential Study. DSM within this bundle is static and will not increase in year 2030, if there is a need for additional capacity to meet the reserve margin." To the degree that this is the case, the treatment of DSM in the capacity expansion decision is not quite on par with the supply-side resources whose decisions are made annually in the capacity expansion model to ensure the resources satisfy the reserve margin requirements.

Another problem area for any utility is to project how DSM costs change over time. IPL's costs per bundle appear to be based on costs contained in the MPS. These costs include incremental measure costs (IMC) of installed DSM measures, which is the difference in cost of a base case measure compared to the cost of a higher efficiency alternative. Other costs that were included were incentive costs and administrative costs that cover vendor implementation costs, EM&V costs, and IPL's internal costs. The administrative costs for modeling purposes were assumed to be 20% of IMC. A measure with an IMC of $10.00 would have an administrative cost of $2.00. IPL assumed future DSM costs escalated by 2.0% annually.

2.4 Metrics for Preferred Plan Development

As noted by IPL in its previous IRPs, IPL primarily used the PVRR of scenarios to compare candidate portfolios. In the current IRP, IPL recognizes that PVRR is important but does not tell the entire story of a portfolio's outcomes. For the 2016 IRP, IPL expanded the number of quantitative metrics in addition to PVRR used to evaluate resource portfolios. IPL used metrics that fit into four categories: cost, financial risk, environmental stewardship, and resiliency. In response to stakeholder feedback, IPL added metrics to measure sulphur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, the percentage of IPL's resources that is distributed generation, and IPL's planning reserves. The following table shows the four metric categories, the individual metrics, and the metric definitions.

Category	Metric	Unit	Definition
Cost	Present Value Revenue Requirements (PVRR)	$MM	The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period
	Incremental Rate Impact (over 5 years)	cents/kWh	The incremental impact to customer rates of adding new resources, shown in five year time blocks
	Average Rate Impact (over 20 years)	cents/kWh	The average 20 year cost impact of adding new resources divided by total kWh sold
Financial Risk	Risk Exposure	$	The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)
Environmental Stewardship	Annual average CO_2 emissions	tons/year	The annual average tons of CO_2 emitted over the study period
	Annual average SO_2 emissions	tons/year	The annual average tons of SO_2 emitted over the study period
	Annual average NO_x emissions	tons/year	The annual average tons of NO_x emitted over the study period
	CO_2 intensity	tons/MWh	Total tons of CO_2 during the study period per MWh of generation during the study period
Resiliency	Planning Reserves as a percent of load forecast	%	Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast
	Distributed Energy Generation	%	Percent of IPL's resources that is distributed generation, shown in five year time blocks
	Market reliance energy	%	Percent of customer load met with market purchases
	Market reliance capacity	MW	Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

According to the IRP, the metrics provide a comparison of how the candidate portfolios differ in terms of cost, financial risk, environmental stewardship, and resiliency. The metrics also show the trade-offs that must be considered when selecting a preferred resource portfolio.

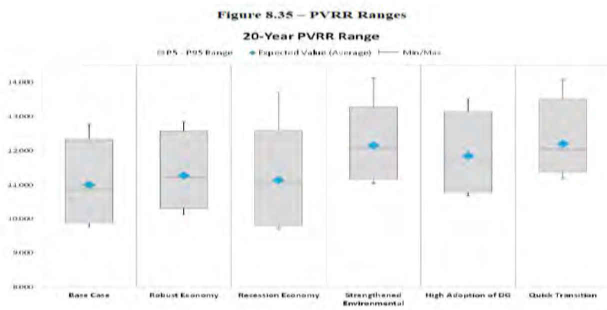
When discussing the model results, IPL introduces a metric/measure that is not mentioned in Figures 7.14 or 7.15 in the metrics development section of the IRP. IPL notes that portfolio diversity is important to mitigate risk of fuel price variation and/or potential fuel shortages. From a cost-mitigation or reliability standpoint, it may not be wise to pursue a portfolio that heavily relies on one fuel (p. 159). The value of fuel and resource diversity is pivotal in this IRP, and it is likely to be a central issue in the future IRPs – perhaps THE central issue for several years. As a result, fuel and resource diversity warrant a much more expansive narrative.

IPL also seems, at least initially, to make a distinction between the metrics used to evaluate and compare the resource portfolios listed above and the quantitative metrics used to review the stochastic analysis results, even though these latter metrics complement the other metrics. According to IPL, the stochastic analysis provides insight into how each portfolio performs against a range of futures. Each portfolio introduces risk by the nature of having varying mixes of resource types, so quantifying that risk and identifying the drivers of that risk helps guide the development of a preferred resource portfolio.

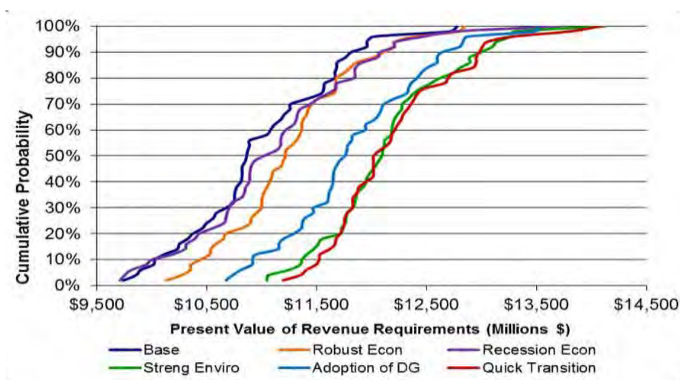
There are several useful metrics presented by IPL to review the stochastic analysis:

1. IRP Figure 8.35 (p. 184) "contains a summary of the range of PVRRs for each portfolio based on results from the stochastic model. The gray box represents the range of PVRRs between the

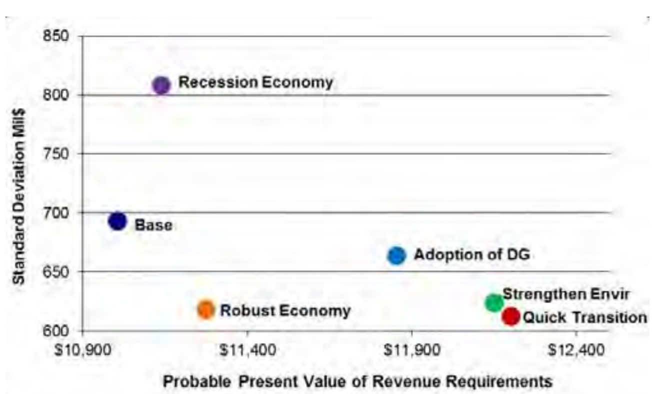
5th and 95th percentiles, which means that 90% of the PVRR outcomes fell in this range. The horizontal bar within that box is the 50th percentile or median value, and the blue diamond is the expected value or average of the outcomes. Two useful comparisons across the portfolios are the expected value and the height of the top of the 5th-95th box."



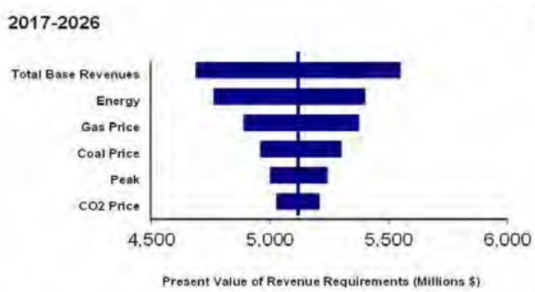
2. IRP Figure 8.36 (p.185), shown below, is a risk profile chart, or a cumulative probability chart. "The risk profile shows the distribution of PVRR outcomes from the fifty stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%." The figure "contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall." (p. 184)



3. IPL also uses a tradeoff diagram (Figure 8.37 on p.186) with the expected value of each portfolio against the standard deviation of the PVRR outcomes as another way to measure portfolio risk.



4. "An additional step IPL took was to identify the drivers of the risk by creating 'tornado charts' in 10-year periods for each portfolio. A tornado chart uses a regression analysis to measure changes in Total Base Revenues – the dependent variable – in response to changes in independent variables such as load, gas prices, coal prices, and carbon prices. The vertical line is the 'Expected Value,' and the 'Total Base Revenues' bar to the left and right of the Expected Value is the range of PVRRs for that scenario. The independent variables on the tornado chart are listed in order of their impact on the PVRR. For example, Figure 8.38 [shown below] shows that the load forecast, labeled 'energy,' has the highest impact on PVRR for the Base Case 2017-2026, and that CO_2 has the lowest impact. However, the changes to the PVRR are not cumulative through the independent variables: the sum of the independent variable horizontal bars will not equal the horizontal bars of the PVRR. Instead, the horizontal bars of the independent variables indicate the magnitude of change to the PVRR due to changes in one single variable." (p. 186)



In the Scenario Metrics Results section of the IRP report (pp. 193-206), IPL summarizes the results of eleven metrics in the four metrics categories. The metrics are further summarized in Figure 8.65 on page 206.

The stochastic analysis is used only in a limited manner in the Scenario Metrics Results section discussion. First, the Risk Profile chart for the Base Case is presented on page 196 but a better figure to use is Figure 8.36 on page 185, because information on the risk exposure of several scenario portfolios is presented in one place which makes for an easy comparison. The Director understands that the Risk Profile for the Base Case is presented to demonstrate how the difference between the expected value (the mean) and the 95th percentile probability is calculated, and that this is the metric IPL uses to evaluate the risk exposure of each portfolio in Figure 8.53 on page 197. This measure emphasizes the probability of higher costs relative to the expected value but also says nothing about the probability of lower costs. The Director believes consideration needs to be given to both the probability of both good and bad outcomes. This is the benefit of Figure 8.36 on page 185. It shows the probability of revenue requirements both above and below the expected value for each scenario portfolio and each scenario is on the same figure.

The Director believes greater use of the quantitative metrics used to evaluate the stochastic modeling results would have improved the comparison of the overall scenario metric results. The addition of the figures displaying the projected annual emissions of NOx and SO2 by scenario was a nice supplement to the metrics for the average annual SO2 and NOx emissions by scenario.

2.4.1 Portfolio Diversity

As noted above, IPL discusses a metric it calls portfolio diversity. IPL notes in the Model Results section that except for the Recession Economy and Strengthened Environmental scenarios, the scenarios result in a diverse portfolio of resources in 2036. Portfolio diversity is also explicitly presented by portfolio in several figures and discussed on pages 161-171. However, in the Scenario Metrics Results section, nothing is explicitly said about portfolio diversity. Perhaps this is because, as IPL mentioned, except for two portfolios, the remaining portfolios contain a diverse set of resources.

2.4.2 Resiliency

At the same time, one of the four metric categories used by IPL is resiliency, which they define as measuring customer exposure to price volatility and market reliance. IPL goes on to note that, "[b]y securing the required planning reserve margin requirement and limiting market reliance for capacity or energy, IPL and its customers can have a high level of resiliency." (p.202) It is clear that the concepts of portfolio diversity and resilience, as defined by IPL, are very similar but also different. It is unfortunate that IPL did not more clearly explore how each concept was interrelated. This would have added to a richer discussion of fuel and resource diversity.

IPL recognizes the risk of technological change and obsolescence in some metrics. One can argue that this is partially reflected in a couple of metrics (especially portfolio diversity) but more explicit discussion would have been helpful. IPL seems to recognize that some level of reliance on the market for both capacity and/or energy can be economic or risky but they do not seem to recognize that long-term resource acquisition embodied in both owned resources and Purchase Power Agreements (PPAs) represent their own forms of risk when all aspects of the electric utility world are changing rapidly and fundamentally.

IPL summarizes the metric results in Figure 8.65 (p. 206) as noted above but states the metrics are not meant to provide answers. Instead, they are meant to show the results in a way that will improve IPL's and stakeholders' understanding of each scenario, provide a comparison of each scenario, and allow IPL and stakeholders to ask questions and dig deeper into the results (p. 193). Despite the comments above, the Director believes the metrics developed and presented by IPL met this objective.

2.4.3 Assessment

IPL demonstrated a substantial improvement in the development and application of metrics to evaluate resource portfolios compared to the 2014 IRP. More importantly, IPL's 2016 IRP included a more explicit and extensive discussion of risks and uncertainties which were better connected to the metrics. The 2014 IRP had an emphasis on PVRR to evaluate alternative resource portfolios with minor recognition of annual air emissions of SO_2, NOx, and CO_2. The 2016 has an improved use of metrics to explore costs in various ways and includes a number of measures of resilience. The specific criticisms discussed above should not detract from the significant actions of IPL to better use more diverse metrics to evaluate resource portfolios.

2.5 Review of IPL's Comments on the Director's Draft IRP Report

The Director appreciates IPL's commitment in several areas in their comments on the Draft Director's IRP report to seek to continually improve even if IPL does not fully concur with the Director's comments in specific areas. IPL implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the IPL staff involved. The Director believes that all involved in the IRP stakeholder advisory process including IPL staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and the Director appreciates the willingness of IPL to explore areas of improvement as we all learn.

What follows are responses by the Director to specific points made by IPL in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in IPL's comments.

2.5.1 Resource Portfolios

IPL: p. 3 **-** IPL suggested an alternative approach to the modeling of scenarios and stochastic analysis in response to comments in the report by the Director and the CAC et al.

The alternative put forth would incorporate stochastics into the capacity optimization upfront. So, instead of developing resource portfolios optimized over five to ten scenarios, the new optimization model being implemented by IPL can select the best portfolio across all the probabilistic simulations. IPL's new modeling system is expected to enable this type of capacity optimization modeling in addition to traditional deterministic scenarios combined with stochastic sensitivities. Some factors such as carbon pricing are difficult to capture stochastically, so IPL expects to rely on multiple methods for developing and evaluating portfolios in the next IRP.

Response: The Director is supportive of evaluating new methodologies. Obviously, however, IPL and the stakeholders will have much to learn as the new modeling system is implemented before any judgment can be rendered as to when and how the different modeling techniques can be most effectively used.

2.5.2 Demand-Side Management

IPL: P. 4 – IPL acknowledged that capturing variability in DSM cost may lead to a more robust analysis. As a follow up, IPL plans to review options to better capture DSM cost variability in the 2019 IRP. IPL went on to say, "the Director's Report was complementary of Vectren and Dr. Richard Stevie's approach in Vectren's 2016 IRP. IPL plans to contact Dr. Stevie and review his methodology."

Response: The Director encourages IPL to explore different ways to capture the range of variability inherent in DSM cost projections. However, the Director wants to be clear that stating the methodology used by Vectren is "interesting" is not intended to be an endorsement. The methodology used by Vectren is conceptually interesting but as noted in the Draft report and follow up comments (see especially the Director's response to Vectren's comments in Section 4.5.5 of this document) there is much additional analysis that must be done and there are numerous questions and issues in need of exploration. IPL is to be commended for their plans to improve the quality of data bases, including for DSM.

3. NIPSCO

3.1 NIPSCO's Fuel and Commodity Price Analysis for 2016 IRP

Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices. The use of a single vendor forecast made the lack of a narrative to articulate the rationale for the forecast more problematic. The fuel forecast narrative is that the price of natural gas and coal is merely a function of demand. This seems to be an over-simplistic explanation to price forecasts for coal and natural gas.

While demand for natural gas and coal are likely to be important variables since much of the "fracking" [9]is for production of oil, it would seem that the production of oil should be a variable in projecting future natural gas prices.[10] Of course, oil prices and production in the United States is likely to be influenced by world-wide events. The export (or import) of Liquefied Natural Gas (LNG) might be an important variable, not just for the quantity but as a reference point for what it tells analysts about future price formation in the natural gas markets.

In the longer-term, NIPSCO should consider technological change in the production of oil, natural gas, and coal. Anecdotally, some coal companies may offer innovative prices that may increase the dark spread. However, the crucial test will be whether short-term coal prices can be sustainable over the longer term.

The CAC et al. raised a significant concern about NIPSCO's fuel and market-price forecasting. Hopefully to address concerns about transparency, analytical rigor, and credibility, these concerns can be minimized in future IRPs by starting the stakeholder process earlier and allowing stakeholders more involvement into the data, assumptions, development of scenarios, and sensitivities. CAC et al. wrote:

> *NIPSCO did not make data developed for it by PIRA available to stakeholders, including its emissions, power, and commodity price forecasts—despite the fact that CAC and Earthjustice have executed a Non-Disclosure Agreement with NIPSCO regarding exchange of confidential information utilized by the Company in its IRP analysis... In a phone call on February 27, 2017, NIPSCO staff* ***indicated that they do possess a narrative explaining and documenting PIRA's forecasts but they could not share it with CAC and Earthjustice. NIPSCO actions in withholding this information are antithetical to transparency and meaningful stakeholder participation****.[Emphasis added] In that same*

[9] Energy Information Administration, Drilling Productivity Report-Key tight oil and shale gas regions, June 2017.

[10] Prior to the development of shale gas, crude oil and natural gas prices tended to move together as they acted as substitutes for each other for various energy demands, such as space heating, electricity generation, and industrial processes. With the development of wet gas fields, that relationship has changed. The prices follow the same general trajectories, with the exceptions of the previously mentioned natural gas price spikes, until 2009, at which point they diverge. With the more moderate oil prices in the past couple years, the positive correlation of the two prices has returned. There appear to be two competing factors affecting the relationship between natural gas and oil prices. On the demand side, they act as substitutes for each other in various processes and end uses. Thus, an increase in oil prices results in an increase in natural gas demand and a corresponding increase in natural gas price. On the supply side, they are co-products in wet gas production. High oil prices spur increased drilling activity, which results in more natural gas supply and lower natural gas prices. From the onset of the shale boom until the drop in crude oil prices, the co-production effect was more significant and the price diverged. With lower oil prices, drilling activity is reduced and the demand substitution effect is more pronounced. The combined effect has been to keep natural gas prices relatively low and stable under both high and low oil prices. SUFG's update to the November 2013 report entitled *Natural Gas Market Study.*

> *call, NIPSCO staff stated that they did not know what the price setting unit was in their Base Case MISO power price forecast.*

The Indiana Coal Council expressed similar concerns and provided information that raised other concerns that NIPSCO's analysis of coal and natural gas price projections could be enhanced.

> *The outlook for natural gas supply, which is clearly the most important consideration in NIPSCO's IRP, is without any depth or context… Without discussion of the respective supply and demand for coal and natural gas, NIPSCO did not (and could not) provide the required discussion of risks and uncertainties for these sources of fuel, as required in the Draft Proposed Rule, §§ 4(23) and (8)(c)(8). More significantly, NIPSCO claims that it does not know what PIRA's assumptions were and PIRA provided no written documents to NIPSCO in support of the forecasts. This is highly unusual. If the forecasts are the consultant's standard forecast, they would come with accompanying assumptions. If the forecasts are customized to the client's request, which is often the case, the specific assumptions would be noted.…. By failing to instruct PIRA as to what assumptions should be assumed in the price forecasts, NIPSCO has no way of knowing whether the assumptions in the price forecasts are consistent with other parts of the IRP analysis. By failing to understand PIRA's assumptions vis-à-vis the price forecast, NIPSCO by definition cannot accept full responsibility for the content of the IRP because it claims no knowledge of what those assumptions are.* ICC pages 4-6 (1.11), (1.13), (1.21), (1.22), (1.23) and (1.24).

In conversations with NIPSCO staff, NIPSCO confirmed its belief that the primary driver of natural gas prices was the demand for natural gas. While this is a plausible theory, given the paradigm change in the natural gas markets, total reliance on changes in the demand for natural gas to dictate the price of natural gas seems problematic. Recent history has shown prices going down as demand for natural gas has increased, largely due to increases in oil production. For example, NIPSCO's assumption doesn't capture the nuanced and dynamic relationships between oil and natural gas markets or whether the historic correlations between natural gas and coal markets are changing. To the extent there are other possible explanations for the changing relationships between coal and natural gas prices, these other possible explanations did not influence the development of scenarios or sensitivities and, as a result, did not result in different portfolios that might have provided NIPSCO with additional valuable insights that might alter future plans.

NIPSCO's assumptions for future natural gas and coal prices led the Indiana Coal Council to observe, "[I]f the case assumed high gas prices, it also assumed high coal prices; if the case assumed low gas prices, it also assumed low coal prices. NIPSCO indicated this was the case because it used "correlated" commodity price assumptions. The term correlated was not specifically defined. Page 7 [2.2] and [2.3].

The Director agrees with the Indiana Coal Council that, "NIPSCO's use of a correlated price forecast between coal and gas prices is not explained." Page 10 [2.7].

While the Director agrees several of the comments of the Indiana Coal Council merit consideration by NIPSCO, according to NIPSCO, the ICC's concerns would not have changed the overall results of NIPSCO's IRP analysis.

The ultimate test is the economic dispatch of coal and natural gas generation in the Regional Transmission Organizations' (RTOs') markets. Over the 20-year planning horizon, NIPSCO recognized the need for *optionality* to provide an opportunity for mid-course corrections if the operations of coal-fired generation cover variable operating and fixed capital costs to permit retention and possible extension of the coal fleet. The *off ramps* that NIPSCO built in could allow for new clean coal technologies to be considered.

The importance of credible fuel price projections become increasingly important because future retirement decisions are likely to be increasingly close calls. Prudence dictates that credible and transparent analysis is essential for assessing reliability and cost ramifications.

3.2 Scenario and Risk Analysis

NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable. The transparency throughout the IRP process afforded to stakeholders was exceptional. NIPSCO provided information that other utilities have not provided. We applaud this openness. To NIPSCO's credit, they were sensitive to the ramifications of these decisions on its employees, communities, and customers.

Resource optimization modeling included a reasonable amount of supply-side and demand-side options; portfolios associated with three planning strategies focusing on least cost, renewable and low carbon emissions, respectively, were identified for each scenario and sensitivity. Especially given what NIPSCO and others knew at the time the analysis was conducted about fuel cost projections and public policy, the analysis was credible. Results were presented in an informative way. However, like other utilities, NIPSCO performed much of the retirement analysis prior to the resource optimization. NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize more resources and reduce the reliance on pre-processing important decisions. NIPSCO contended that its Preferred Portfolio "*aligned with NIPSCO's reliability, compliance, diversity, and flexibility criteria; it almost always had lower costs to customers across the scenarios*." [Page 159].

3.2.1 Models, Drivers, and Scenarios

NIPSCO used the ANN Strategist Proview Capacity Expansion Model to perform the optimization on three portfolios including a least cost portfolio, a renewable portfolio, and a low emissions portfolio (Page 32 of the IRP). The resource alternatives included in this IRP cover 26 demand-side and about 20 supply-side options. Each resource option was individually and fully selectable during each optimization run. The objective of the model is to minimize the Net Present Value of Revenue Requirements (NPVRR).

The first step NIPSCO used in developing the 2016 IRP scenarios was to identify key drivers that could potentially affect its business environment. Then seven long-term commodity pricing cases were developed for the Strategist planning model, taking into consideration the correlations between economic condition, load growth, environmental policy, fuel prices and carbon cost. Those fundamental commodity prices serve as key assumptions for various scenarios in the analysis.

Five scenarios were developed by NIPSCO using different datasets that correspond to specific future worlds. The five scenarios were:

1. Base (B),
2. Challenged Economy (CE),
3. Aggressive Environmental Regulation (AE),
4. Booming Economy (BE), and
5. Base Delayed Carbon (BDC).

Then, a number of sensitivities were developed for each scenario by modifying a single variable each time to analyze the effects of a specific risk on the corresponding scenario. Although each sensitivity focused on a single risk, other related input data were changed accordingly. There were 10 sensitivities in total. In general, NIPSCO did a good job of setting up a comprehensive framework to capture possible futures and address various risk factors. However, there are some inconsistencies in the IRP report regarding the definition of scenarios, which are addressed in detail in the next section.

A separate retirement analysis was conducted before system-wide optimization was performed to identify the future resource mix. Based on the environmental compliance dates and the associated costs to run the existing coal-fired generation units, six retirement portfolios were developed. A combined cycle gas turbine (CCGT) was selected as a proxy for the replacement alternative because of its favorable levelized cost of energy, reliability, dispatchability, and straightforwardness to plan, permit and build. The six retirement portfolios were evaluated across all scenarios and sensitivities and were ranked based on the NPVRR. In addition, the ability of each portfolio to meet Clean Power Plan Compliance Targets, fuel and technology diversity, as well as community impact were considered during portfolio evaluation. A retirement portfolio without any significant difficulties or hurdles for each one of the evaluated criteria was selected as the preferred retirement option. Based on the retirement analysis, NIPSCO's preferred retirement plan is to accelerate the retirement of Bailly Units 7 and 8 and Schahfer Units 17 and 18 and to move forward with compliance investments for its remaining coal units. The entire retirement methodology sounds reasonable. However, some explanations of retirement portfolio design might be necessary to help audiences understand why some older units were set to run to the end of life but some younger units were set to retire soon in a few retirement portfolios to be evaluated. In the seventh page of the Executive Summary, a table lists ages of various coal units owned by NIPSCO. Based on ages shown in the table, Schahfer 17 and 18 are younger than Schahfer 14 and 15. In addition, all Schahfer units are younger than Michigan City. However, for Combination 4 displayed in Table 8-3, which was also the combination chosen as the preferred retirement option after evaluation, Schahfer 17 and 18 were set to retire in 2023, while Schahfer 14 and 15 are set to run to the end of life. In Combination 5, Michigan City was set to run to the end of life, while all Schahfer units were set to retire in 2023.

Results were presented in a clear and logical way. For each scenario, capacity portfolios under the three planning strategies (Least Cost, Renewable Focus and Low Emission) were identified. Numbers of selected resources were listed by technology for each portfolio. Trajectories of annual carbon emissions were depicted by portfolio as well. In addition, energy mixes by planning strategy and scenario were summarized and compared with each other. Summary of NPVRR and DSM selection across the various scenarios and sensitives were provided. A preferred portfolio for the next 20 years was derived from analysis results based on a number of criteria, including providing affordable, flexible, diverse and reliable power to customers while considering the impact to environment, employment and the local economy. In addition, DSM groupings were broken into four categories according to the time of selection across various scenarios and sensitives, providing the basis upon which NIPSCO's 2017 DSM Plan would be determined.

3.2.2 Issues / Questions

In section 8.1.2 titled Fundamental Commodity Prices, descriptions about various commodity cases make sense but seemed to be too simplistic. As discussed in the Fuel and Commodity Price Projections section (e.g., page 15) of this Draft Director's Report, the drivers for the production and price of natural gas and coal seems likely to be more complex than simply the demand for natural gas and coal. However, figures illustrating the long-term projections of the major commodities lacked explanations, which detracted from the explanatory value of the descriptions. The following are some examples.

1. For coal prices in Figure 8-4 on p. 118 and Figure 8-5 on p. 119, the Very High case has a price decrease in the 2022 to 2024 timeframe. Explanations about the driving forces for those outcomes are not obvious and would benefit from a discussion.
2. In Figures 8-7 and 8-8 on p. 120, the on-peak and off-peak power prices show step increases in 2024 in the Base, Low and High cases. As described in scenarios, the carbon price comes into effect in 2023. Why were sudden increases in power prices observed in 2024?
3. Figure 8-9 on p. 121 shows capacity price in $/kW-YR. The specific resource technology is not clear. Is it average capacity price across different technologies? How do capacity price projections shown in the graph correlate with the various commodity pricing cases? A detailed description might need to be added to the report to help the audiences understand the information presented in the graph.

In addition, there seem to be inconsistencies in the description of scenarios presented in different sections of the report.

1. In the Base Scenario Assumptions shown in p. 122, the report mentions that "The average price of Powder River Basin coal is slightly above $1.00/MMbtu by 2035." However, in the coal price trajectories shown in Figure 8-4 in p. 118, no trajectory matches this description. The one closest would be the Base coal price trajectory, but coal price in that trajectory is no more than $1.00/MMbtu in 2035 based on observation. In addition, assumptions about Powder River basin coal price and Illinois Basin coal price were not presented in Table 8-1: Scenarios and Sensitives Variable Descriptions on p. 130. Therefore, there is no way to know exactly which coal price assumption was used for various scenarios and sensitivities.
2. In the Challenged Economy Scenario Assumptions shown on p. 123, it is less clear which Powder River Basin coal trajectory was used in this scenario. In addition, the carbon price increase in 2023 mentioned in the description does not seem to be consistent with the information presented in Figure 8-7 and Figure 8-8.
3. In the Aggressive Environmental Regulation Scenario Assumptions shown on p. 124, the report mentions that "Energy load is increasing at 0.68% and peak demand is increasing at 0.80% (CAGR 2016-2037) annually over the study period." This same load assumption is shown in the Booming Economy Scenario Assumptions at the bottom of p. 124. However, in Table 8-1: Scenarios and Sensitivities Variable Descriptions, "Base Load" is shown for the Aggressive Environmental Regulation Scenario and "High Load" is shown for the Booming Economy Scenario in NIPSCO's explanation.
4. In the Booming Economy Scenario Assumptions shown in the beginning of p. 125, the report mentions that "A national carbon price comes into effect in 2023 ($13.50/ton nominal increasing to $38/ton in 2035)." Table 8-1 on p. 130 shows Base carbon price trajectory for this scenario. However, in Figure 8-6: CO_2 prices shown on p. 119, no trajectory matches the description about carbon prices in the Booming Economy Scenario on p. 125.

There are also some concerns about the DSM modeling mentioned on p. 142. As NIPSCO recognized, due to the inability of Strategist to optimize all 26 DSM groups simultaneously, the demand-side programs were broken down into the various end uses (residential, commercial and industrial) and optimized against an array of supply-side options. One shortcoming of this modeling methodology is a lack of competition among DSM groups of different end-uses, which is highly likely to lead to a portfolio different from modeling all 26 DSM groups simultaneously. Moreover, with the increase in peak demand relative to energy use, it would seem there are opportunities for more demand response that were not modeled. In part, the failure to more comprehensively optimize DSM and to optimize DSM with other resources seems to be a limitation of its current model and should be ameliorated by future models.

In Figure 8-31 on p. 159 the NPVRR for the preferred portfolio appears to be slightly smaller than the NPVRR for the least cost optimal solution, which is not feasible.

Finally, it seems that no scenario or sensitivity covered uncertainties of resource technology cost. Based on information provided at the August stakeholder workshop, capital costs for all technologies increase in nominal dollars at the same rate, based on proprietary consultant information. The reasonability of this is questionable considering that some technologies are less mature commercially (e.g., battery storage) than others.

The Director largely agrees with NIPSCO and its characterization of concerns raised by stakeholders regarding NIPSCO's consideration of retirements of some coal-fired generating units, the dynamics of the natural gas price projections being the primary driver, and NIPSCO's use of Cost of New Entry (CONE) merely as a proxy for the cost of new resources (see below quote).[11] However, the Director is confident that NIPSCO would agree with stakeholders that future IRPs will have to be increasingly rigorous as credible decisions are increasingly difficult and impactful.

> *The Industrial Group and ICC argued that NIPSCO was too aggressive in retiring the four units, while other stakeholders argued that NIPSCO should retire 100% of its coal fired generation almost immediately. NIPSCO endeavors to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet customer needs, and its IRP demonstrates that it does just that. In the retirement analysis, the costs and benefits of continuing to operate the NIPSCO units, including the dispatch costs, recovery, maintenance, retrofitting and continuing to operate the affected units with the appropriate effluent limitation guidelines ("ELG") and coal combustion residuals ("CCR") compliance technologies were compared to costs and benefits of retiring and replacing the units with an alternative. The alternative, CONE, was used for retirement analysis only and was not NIPSCO's selection, but intended to be a conservative proxy for what could be readily built or purchased in the market. This analysis was evaluated across the 15 scenarios and sensitivities discussed with all the stakeholders throughout NIPSCO's 2016 IRP process.*
>
> *While cost to customers is a key decision driver, the decision to retire the four units took into account a variety of factors in addition to customer economics, which caused it to be a "preferred" choice for customers from the Company's standpoint. It is important to highlight that the model showed a lowest cost path of retiring 100% of coal which was not selected as the "preferred" path given these other factors.*
>
> *Even with ICC's comments regarding coal availability and pricing, the analysis would not change dramatically regarding the appropriateness to retire Units 7/8 and 17/18. There must be a balance among continued investment in operations and maintenance ("O&M"), maintenance capital, and maintaining the option to keep Units 17/18 open. However, key*

[11] Response Comments of Northern Indiana Public Service Company to Stakeholder Comments on NIPSCO's 2016 Integrated Resource Plan submitted April 28, 2017, pages 8 and 9.

variables such as environmental regulations can change over time and therefore NIPSCO will evaluate the value of developing a compliance option at Units 17/18 as part of its next IRP. It is important to remember that fuel and technology diversity is important as over-reliance on a single fuel-source may leave a utility and its customers unnecessarily exposed to various operational and financial risks from fuel supply disruptions and/or price volatility. Fuel and technology was quantified by the capacity mix by the end of the planning period.

Despite claims to the contrary, NIPSCO considered long-term gas forecasts in its retirement modeling, but NIPSCO's believes gas prices would need to rise dramatically and stay at a sustained high price to make it economical to continue to operate the units proposed for retirement. This, coupled with the correlated coal forecast, indicates that NIPSCO's Retirement Analysis is appropriate.

Additionally, there were concerns that NIPSCO's retirement path did not consider potential future changes to the ELG. NIPSCO believes that United States Environmental Protection Agency's ("EPA's") ELG rule is consistent with the requirements under the Clean Water Act. The ELG rule is a final rule, and NIPSCO has a responsibility to include it in future resource planning. Although it is possible that there may be changes to the rule which could affect compliance requirements, any changes would be speculative at this time.[12] *If changes to the final ELG rule are propagated, NIPSCO will include and consider any changes in future resource planning.*

Although the IRP is not required to consider factors such as whether or not NIPSCO attempted to sell units it is planning to retire, it does consider if the utility can meet its resource requirements. NIPSCO's IRP meets that standard. In addition, NIPSCO has done an assessment of the market value of the retiring units, and contrary to the ICC's assertions, NIPSCO has been willing to engage with parties interested in purchasing the retiring units.

3.3 Energy Efficiency

It should be noted that NIPSCO's DSM methodology is very similar to that used by IPL. In fact, they both used the same consultants – AEG to prepare a Market Potential Study (MPS) and Morgan Marketing Partners (MMP) to develop the Program Potential based on the MPS and to complete the overall benefit cost results based on the program potential as determined by the MPS.[13]

AEG estimated the technical, economic, and achievable potential at the measure level for energy efficiency and demand response within NIPSCO's service territory over the 2016 to 2036 planning horizon. MMP

[12] NIPSCO recognizes that the U.S. EPA Administrator announced on April 17, 2017, that the EPA issued an administrative stay of outstanding compliance deadlines for ELG and was also petitioning the U.S. Court of Appeals for the 5th Circuit to hold litigation challenging the final ELG rule in abeyance until September 12, 2017. The 2016 IRP was a point-in-time forecast completed in November 2016. Any impacts from the EPA's actions will be addressed in the next IRP.

[13] A MPS assesses how much DSM (energy efficiency and demand response) is potentially achievable in a utility system. A MPS is normally used to estimate the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences.

used the measure-level savings estimates to develop the program potential. The program potential includes budget and impact estimates for the measures. The final budgets and impacts were then run through cost-effectiveness modeling using the DSMore tool to finalize the cost-effective program savings potential. The program potential step also includes information from NIPSCO's 2014 Evaluation, Measurement, and Verification (EM&V) report and applies that information to the Achievable Potential savings amount.

After the savings potential estimation process, the measures were bundled into DSM groupings. A grouping is defined as a bundle of measures with similar load shapes and end uses. Grouping measures by similar load shapes, end-uses, and customer segment (class) allows the IRP model to analyze large groups of measures more efficiently. NIPSCO elected not to further define its groupings by costs per kWh.

Due to a limit on the number of resource options that can be optimized simultaneously in the IRP model, the DSM program groupings were modeled sequentially by customer class (residential, commercial, and industrial). NIPSCO believes the sequentially optimization is comparable to a simultaneous co-optimization of all DSM programs.

3.3.1 Issues / Questions

NIPSCO made a number of improvements to its DSM analysis and the written description of this analysis in the IRP, and the information presented at the public advisory meetings was a very good improvement over prior IRPs. Nevertheless, improvement is an ongoing process as we all learn through experience. For example, NIPSCO also faced model limitations similar to that experienced by IPL and Vectren but chose a different work around. NIPSCO modeled DSM bundles sequentially; meaning that first residential bundles were optimized compared to supply-side resource options, then commercial sector bundles were optimized compared to supply-side options, and lastly industrial DSM options were optimized. Then NIPSCO generally put in the optimization model those residential, commercial, and industrial bundles that were selected in the sequential optimization. It is not clear if the selected combination of residential, commercial, and industrial DSM was locked in as a package in the optimization process or not. If the combined DSM groupings were locked in for the final supply-side optimization, then it could imply that the DSM groupings are not getting quite the same treatment as the supply side resources which are all included together in each scenario run.

NIPSCO discusses program grouping and portfolio budgets but it is not clear if its methodology for development of bundle costs differs much from that used by IPL. NIPSCO developed bundle costs in line with historic program cost allocations across the different budget categories. Each program grouping or bundle budget included categories for administration, implementation, incentives, and other. Administrative costs include NIPSCO staffing costs, planning and consulting costs, and EM&V costs. The "Other" category includes items such as low income measures which are paid by the utility but not classified as an incentive according to the California Standard Practice Manual. "Other" also includes some additional implementation costs for measures with very low incremental costs to include them in the portfolio. However, it is not clear how DSM bundle costs changed over time.

3.4 Metrics for Preferred Plan Development

NIPSCO's stated intent (p.3) is to develop a Preferred Plan that "follows a diverse and flexible supply strategy, with a mix of market purchases and different low fixed-cost generation types, to provide the best balanced mitigation against customer, technology and market risks." NIPSCO sees customer risk from the large concentration of load from its five largest customers. Approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves meets the needs of these five customers. Loss of one or more of these customers would result in a significant decline in billing revenues.

NIPSCO defines technology risk as two separate risks from the perspective of a regulated utility.

Technology risks play a role in inducing market volatility, and they also have the potential to erode the value of existing assets. Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy. To the extent that a utility or its customers are exposed to market risk in general, they are exposed to this aspect of technology risk. Separately, technological and regulatory changes can render specific generation technologies obsolete and can force their premature retirement, such as is currently happening to coal generation. In its report, NIPSCO states:

…Fully avoiding technological obsolescence risk requires avoiding investing in generation, which exposes the utility and its customers to market risk. Investing in generation mitigates or eliminates market risk but exposes the utility and its customers to some amount of technological obsolescence risk.…Balancing these two risks in light of the technology choices available is key to mitigating overall supply portfolio risk. (p. 4)

NIPSCO continues by stating (p. 154) an important component of its supply strategy for the next 20 years is to reduce customer's and the company's exposure to customer load, market, and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply. Another component is to strongly consider cost to customers, while considering all technologies and fuels as viable to provide shorter duration supply. (p. 155)

3.4.1 Retirement Analysis Metrics

NIPSCO's use of metrics to develop its Preferred Plan is applied to two different stages during the planning process, at the retirement planning stage and the optimization stage. The metrics appear to be the same across the two stages. For the retirement analysis, the six retirement portfolios were evaluated across all scenarios and sensitivities for a total of 90 optimization runs. Each model run was limited to the selection of a combined cycle gas turbine (CCGT) as a proxy. In all comparison analyses, the costs of the replacement unit was scaled on a megawatt basis to the same generating capacity as the existing unit by using a replacement capacity value of the CCGT.

Results for the six retirement scenarios were ranked from 1 to 6 with 1 being the portfolio having the lowest cost to customers or net present value of revenue requirement (NPVRR) and 6 having the highest. Figure 8-16 on page 137 of NIPSCO's IRP shows the NPVRR of the base scenario overlaid with range of NPVRR from all the scenarios and sensitivities. NIPSCO noted the magnitude of NPVRR changes depending on the specific scenario or sensitivity but the relative rankings of the retirement combinations generally remain the same within each scenario or sensitivity.

Retirement options under the Base scenario were analyzed to estimate their potential to meet Clean Power Plan compliance targets as shown in Figure 8-17 on page 138. Three of the six retirement combinations did not meet the CPP targets. Each retirement combination under the Base Scenario was also analyzed to show the diversity of each retirement combination. Portfolio diversity was measured as a percentage of forecast installed capacity in 2025. For example, a retirement combination portfolio might consist of 36% coal, 21% natural gas, 14% DSM, 3% renewables, and 26% other resources. Lastly, NIPSCO created a scorecard to show relative differences between the retirement portfolios using a number of quantitative and qualitative measures. The measures are NPVRR, Portfolio Diversity, Impact on Employees, Impact on

Communities and Local Economy, and Environmental Compliance. The scorecard used red, green, or yellow to show how each retirement combination was graded on each of the five measures. A red measure is viewed as worse, a yellow is better, and a green measure is viewed as good.

While recognizing that developing a "score card" to assess the relative importance of different metrics is a relatively new approach in the IRPs, it is not clear how the different measures are weighted in the score card. The score card would benefit from a more detailed narrative to detail those metrics that can be quantified as well as those metrics that do not lend themselves to quantification. For example, is NPVRR more important than the impact on the local economy? If yes, by how much and why? Also, the measure of portfolio diversity is based on installed capacity but might not a better measure be energy? At a minimum, the percentage of energy by fuel type and technology should have been considered. Also, the diversity consideration is limited since a significant resource "need" is shown in five of the retirement combinations but it is unspecified as to the type of resource. The way the retirement analyses were performed, CCGT capacity served as a proxy for other resources the model might have selected if given the opportunity. As noted by the CAC et al., the presentation of a retirement combination scorecard (p. 140 NIPSCO IRP) is qualitative and something of a *black box*. (p. 46 CAC comments on NIPSCO IRP)

3.4.2 Optimization Metrics

In the resource optimization modeling, NIPSCO broke down the DSM resources into residential, commercial, and industrial groups and sequentially modeled each group against an array of supply-side resources. This process was repeated for all 15 scenarios and sensitivities. NIPSCO developed a DSM plan based on these modeling results which was then used to evaluate the supply-side resources. NIPSCO utilized three planning strategies/portfolios, namely least cost, renewable focus, and low emissions portfolios across all scenarios and sensitivities. For the least-cost portfolio the model assessed all supply-side alternatives to develop a least cost plan. The model assessed a renewable focus portfolio by constraining the amount of fossil generation and increasing the amount of renewables. A low emissions portfolio was evaluated where the incremental amount of fossil generation and renewables was constrained to allow other low or non-emitting resources such as nuclear and batteries to be selected.

For each scenario the number of selected resources for each of the three strategies was listed by technology in tables. The trajectory of annual carbon emissions by scenario for each of the three strategies was compared. The cumulative 2015 to 2037 energy mix was also compared by scenario for each strategy. Lastly, the NPVRR by scenario and sensitivities was compared for each of the three portfolios.

NIPSCO notes on page 158 of its plan that it used a number of criteria to evaluate and select its Preferred Plan and that economics played a significant role. However, as noted by the CAC et al., it is not at all clear where the Preferred Plan came from or how it was determined. Nor is it clear how the various metrics were used. All that we can tell is that NIPSCO says it emphasized economics and that it used information provided by other metrics; but we can say little more. It is a problem when NIPSCO develops a Preferred Plan but the connection between this plan and the preceding analyses is murky at best. This should be addressed in the narrative.

Information is poorly presented regarding the components of the Preferred Portfolio such that a reader can read the entire IRP and not have a clear picture of the Preferred Portfolio. For example, Table 8-21 (p. 158) presents the assets retired and added by year over the forecast period. But there are no units of measure to tell the reader, for example, how much DSM is acquired in 2023. The same criticism can be made with regard to purchases. The lack of basic information about the Preferred Plan, combined with the poor discussion relating the Preferred Plan to the IRP's analyses and metrics, makes any evaluation of the Preferred Portfolio problematic at best. Overall, the IRP would have benefited from having one location where each metric was defined and was clearly stated how these metrics, individually or as a group, addressed the three key risks identified by NIPSCO – customer, technology and market risks. The narratives for each of the metrics need to clearly tie back to the important risks on which presumably the company based its IRP.

It is important to note that NIPSCO's planning model is not capable of stochastic analyses so it relied on scenario analyses and sensitivity analyses in preparing its IRP. The result was that NIPSCO's IRP analyses and methodology differed considerably from that presented by Vectren and IPL, both of whom did perform a stochastic analysis in addition to scenario analyses. To be clear, the Director believes stochastic analyses is not a substitute for scenario analyses; rather, they are complements that provide different information which can be combined to hopefully make better resource decisions. The result is that NIPSCO's metrics to compare resource portfolios necessarily differed in several ways from the type of metrics utilized by IPL and Vectren. NIPSCO recognizes this modeling limitation and, to its credit, is in the process of evaluating options to improve its modeling capability.

3.4.3 Assessment

The circumstances NIPSCO encountered developing the 2016 IRP differed considerably from those for the 2014 IRP. As a result, NIPSCO had a much more thorough discussion of risks and uncertainties and various metrics used to evaluate how the different resource portfolios might perform given the future is unknown. The previous IRP had almost exclusive reliance on PVRR to compare the portfolios. That is not to say there was no recognition of other factors, but the discussion of these other factors was much less developed. NIPSCO explicitly included in the 2016 IRP metrics covering portfolio performance in the areas of portfolio diversity, impact on employees, impact on communities and the local economy, and environmental compliance. The various questions or issues discussed above are not meant to detract from the substantial improvement seen when comparing the 2014 and 2016 IRPs.

3.5 **Review of NIPSCO's Comments on the Director's Draft IRP Report**

The Director appreciates NIPSCO's commitment in several areas in their comments on the Draft Director's IRP report to seek to continually improve even if NIPSCO does not fully concur with the Director's comments in specific areas. NIPSCO implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the NIPSCO staff involved. The Director believes that all involved in the IRP stakeholder advisory process including NIPSCO staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and the Director appreciates the willingness of NIPSCO to explore areas of improvement as we all learn.

What follows are responses by the Director to specific points made by NIPSCO in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in NIPSCO's comments.

3.5.1 Demand-Side Management

NIPSCO: P. 7 – Although NIPSCO did sequentially optimize the residential, commercial, and industrial groupings, there were two follow up steps to ensure that it was equivalent to optimizing the whole 26 groupings simultaneously.

Response: NIPSCO's comments do not say what these two follow up steps were nor where they are described if not in these comments.

NIPSCO: NIPSCO is unclear what additional DR programs it could have modeled outside of the AC and water heating programs. Two programs, Curtailment and Interruptible, were not considered in the DSM Groupings, but were included in the IRP, in accordance with the Order in Cause No. 44688. Provided as a whole, this provides a robust amount of DR, but NIPSCO will continue to research additional programs to be considered in future IRP models.

Response: The Director agrees that NIPSCO appears to have done a reasonably thorough review of DR programs but believes it would have been helpful for NIPSCO to have included the Industrial Demand Response DSM Groupings in the IRP. The Director understands the results coming out of the IRP optimization process might have been very different compared to the amount of curtailment and interruptible load agreed to in Cause No. 44688. But any difference and the effort to understand the reason for the difference would have been informative.

3.5.2 Scorecards

NIPSCO: P. 4 –The concept of a scorecard was a significant step towards a more robust decision making process for its customers, employees and stakeholders. As with the introduction of most new concepts, there is progress but also clear opportunities for improvement. In the future, NIPSCO will consider and incorporate appropriate feedback into the scorecard process.

Response: Staff appreciates the willingness of NIPSCO to evaluate opportunities for improvement. Staff agrees there is no one correct way to use or interpret metrics and develop a scorecard. Ideally, objective metrics would be decided at the outset of the IRP process and in consultation with stakeholders to reduce controversy. To the extent reasonably feasible, efforts to quantify the metrics should be considered while recognizing that some measures will be, to varying extents, more subjective.

4. VECTREN

4.1. **Vectren's Fuel** and Commodity Price Analysis for 2016 IRP

Vectren's consideration of multiple fuel price forecasts is very commendable and appropriate given the importance of the decisions that Vectren faces. On Page 74, Vectren said it relied on an averaging of forecasts from several sources[14] to form a consensus forecast for natural gas, coal, and carbon. This single averaged forecast for all commodities constituted the base forecast. Vectren also constructed alternative commodity price forecasts that were phased in relative to the base forecast. So near-term, a natural gas price was limited to a fairly small deviation from the base forecast, and the difference could grow in the medium-term and more so in the long-term.

We understand Vectren considered averaging of higher and lower forecasts but felt that was problematic due to different assumptions and different planning horizons. We will defer to Vectren's professional judgment but hope future IRPs will make use of lower and higher forecasts to provide a more complete scenario analysis. On p. 194 of its IRP report, Vectren describes how stochastic distributions of each of the key variables were developed, with select values that are either one standard deviation above or below the base case values for the variable.

The Director agrees with Vectren that the phasing in of an increasing range of commodity forecasts is appropriate going from the short-, to mid-, and to longer-term projections to capture most expected risks. However, to better understand the risks there is concern that reliance on just one standard deviation that only captures approximately 68% of the expected variation around the mean (expected value) is more appropriate for short-term fuel price forecasts, while for forecasts beyond five years (or so), a wider range of forecasts is appropriate. Two standard deviations to capture about 95% of the expected variation around the mean would seem more appropriate to gain insights on the potential risks of low probability events that are very consequential. As Vectren aptly describes "*stochastic distributions that reflect a combination of historical data and informed judgment tend to capture 'black swan events' that are impossible to forecast but tend to occur quite frequently.*" [Page 194].

Consistent with the previous comment, the Director agrees with the ICC that a higher natural gas price case might have provided useful information. A narrative that is based on widespread anti-fracking policies might provide a plausible, even if unlikely case (note, in Vectren's "High Regulatory" scenario there was at least some reduction in gas supply growth and increased cost due to restrictions on fracking – Page 183). That is, a broad fracking ban is a low probability event that could result in significant price increases for natural gas if realized. Similarly, with new oil and gas assessments upgraded by the U.S. Geological Survey in the Permian Basin just after Vectren submitted its IRP, a lower natural gas price case might also be warranted. However, given Vectren's considerable expertise in natural gas by virtue of being a combination utility, some deference is reasonably accorded.

The Director appreciates the ICC's review of Vectren's IRP but disagrees that "*Vectren's failure to include scenarios without the CPPs (Clean Power Plan) is a serious flaw of its analysis*." The ICC would seem to hold Vectren to an untenably high requirement to integrate new information rather than the intention of the IRP to be a *snap shot in time* based on reasonable assumptions and empirical information at the time the

[14] For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged.

IRP was being developed. While speculation about changes in environmental policies are interesting, the still-unfolding changes in environmental policy are well outside the snap shot in time that Vectren was required to comply with by the draft IRP Rule. This is why the IRPs are done periodically to capture established and emerging trends.

Similarly, because the modeling process takes place over several weeks – perhaps months - the Director would not require Vectren to reconsider projections of natural gas prices based on the U.S. Geological Survey's news release on November 16, 2016 of a massive natural gas potential in the Permian Basin[15] which was before Vectren submitted their IRP which might further reduce the use of coal. Moreover, the ICC noted that the start of Vectren's analysis of the potential ramifications of the CPP didn't occur until the 2021 to 2026 time frame. In the Director's opinion, it was appropriate for Vectren to give some effect to the CPP based on the best information available at the time it was conducting its analysis. Additionally, it is conceivable that some form of CO_2 regulation may occur in the 2021 to 2026 time frame. Regardless of the specific facts that the ICC raised, it is important to memorialize the chronology of events to ensure that Vectren's planning processes were not misconstrued to be deficient regarding the information used in its IRP analysis.

More broadly, the ICC raises an issue that is applicable to all Indiana utilities – specifically, under what conditions should a utility update an IRP in response to significant events or changes in assumptions to important drivers? Nevertheless, it is important to keep in mind the Northwest Power Planning Council principle for its planning process that there are "no facts about the future."

4.2 Scenario and Risk Analysis

Vectren's analysis and processes improved significantly over its last IRP due to the immediacy of some decisions as well as providing for flexibility in making significant longer-term decisions over the next 10 to 20 years. The context for this round of IRPs included concerns about the potential loss of significant customers, largely unforeseen changes in the Clean Power Plan, low natural gas price forecasts relative to coal prices, and a precipitous drop in the price of renewable resources, highlight the need to regard IRPs—as Vectren observed—as a *compass* rather than a commitment to a specific resource strategy. Therefore, as Vectren correctly noted, the IRPs must be resilient to allow for mid-course adjustments in the plan. On page 50 and 51, Vectren articulates its integrated resource planning objectives:

- Maintain reliability
- Minimize rate/cost to customers

[15] November 16, 2016 **USGS Estimates 20 Billion Barrels of Oil in Texas' Wolfcamp Shale Formation.** This is the largest estimate of continuous oil that USGS has ever assessed in the United States. The Wolfcamp shale in the Midland Basin portion of Texas' Permian Basin province contains an estimated mean **of** 20 billion barrels of oil, **16 trillion cubic feet of associated natural gas,** and 1.6 billion barrels of natural gas liquids**.** The estimate of continuous oil in the Midland Basin Wolfcamp shale assessment is nearly three times larger than that of the 2013 USGS Bakken-Three Forks resource assessment, making this the largest estimated continuous oil accumulation that USGS has assessed in the United States to date."*The fact that this is the largest assessment of continuous oil we have ever done just goes to show that, even in areas that have produced billions of barrels of oil, there is still the potential to find billions more*," said Walter Guidroz, program coordinator for the USGS Energy Resources Program. "*Changes in technology and industry practices can have significant effects on what resources are technically recoverable, and that's why we continue to perform resource assessments throughout the United States and the world*."[Emphasis Added].

- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future
- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

The changing environmental regulations warrant emphasis, not only because of the potential effects on the utility's resource decisions, but also because they highlight an inherent difficulty in developing public policy assumptions in IRP modeling. That is, what is the probability of changes in public policy? The question highlights the need to interject more diverse scenario analysis into the IRP process since scenarios and sensitivities are more suitable for addressing the possible ramifications of changes in public policy. Moreover, it adds to the rationale for maintaining maximum optionality. As Vectren stated:

> *While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. SIGECO's preferred portfolio positions the company to meet that expectation. (p. 47)*
>
> *Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided SIGECO with valuable insight on how modeled scenario outcomes can change over time. (p. 52)*

In the Preferred Portfolio *(*beginning on page 33 see also page 44*)*, Vectren mentions greater reliance on energy efficiency, the possible addition of a combined cycle gas turbine in 2024, and solar power plants (2018 and 2019). Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), exiting joint operations at Warrick 4 (2020), and upgrade at Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which it characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the Clean Power Plan (CPP). However, this potential Preferred Plan would significantly reduce Vectren's reliance on coal and result in a significant reduction in CO_2 emissions.

Similarly, Vectren's request for a short delay in the submittal of its IRP in order to better understand the potential implications of ALCOA's decisions is an example of good planning practice, especially given the importance of ALCOA to the Vectren system. To accentuate the importance of ALCOA, Vectren noted on page 203 that "*Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall*." However, given the importance of Warrick to Vectren's resource adequacy and since Vectren did not know the status of ALCOA at the time the IRP was prepared, it would seem reasonable for Vectren to have run at least one scenario that retained the Warrick 4 unit.

The narratives for the scenarios were well reasoned and clear. For the 2016-2017 IRP, Vectren developed its Base Case (not the Preferred Case) predicated on what Vectren considered to be the most likely future at the time this IRP was being developed. This included pre-processing analysis of the retirement of some of their coal-fired generating units to reduce the complexity of the modeling analysis. Vectren also segmented its analysis of all scenarios into short-, medium-, and longer-term (see pages 170-173). This appears to give Vectren more focus on maintaining a high degree of optionality which is commendable. Vectren initially prepared ten additional alternative scenarios that considered input from its stakeholders (ultimately, the number of alternative scenarios were reduced to 6 optimized scenarios). The reduction in the number of scenarios is common. The differences in the scenarios were not sufficient to cause significant changes in the resulting portfolios and didn't provide additional insights that were valuable to Vectren's decision-making processes.

4.2.1 Models, Drivers, and Scenarios

ITRON developed the long-term, bottom-up energy and demand forecasts (see page 170). As discussed in the Fuel and Commodity Price Analysis and on page 74 of the IRP, Vectren developed a consensus base case projection that was informed by several independent firms for development of its analysis. Pace Global also provided future perspectives on the Midcontinent ISO's on- and off-peak prices. Burns and McDonnell and Pace Global provided cost projections for a variety of different resource technologies that, along with other resources, were modeled for economic dispatch using AURORAxmp. Dr. Richard Stevie developed cost forecasts for DSM. Strategist was used as the primary long-term resource planning model. Vectren's objective was to minimize the Net Present Value of all of the scenarios to find the optimum scenario.

Vectren relied on traditional drivers such as the load forecast, appliance/end-use saturation, energy efficiency, weather, economic factors, etc. As stated previously, projections about the cost of natural gas and coal were the primary drivers of this IRP. MISO market prices were also a factor. Known environmental costs and potential environmental costs were a significant driver as well, but it is important to be mindful that the Clean Power Plan had relatively minor effects on the final portfolios.[16] Historically, load growth was the primary driver for long-term planning for Vectren and most – if not all – utilities in the nation. For Vectren, changes in load such as the loss of ALCOA and the development of customer-owned generation by another large customer was a major consideration in this IRP. It is possible that Vectren will see some economic growth but because this is too speculative; the potential for load growth was treated as a scenario with a hypothetical load. Energy efficiency and the potential for other customers to install their own generating resources are also important considerations in this IRP.

Against this backdrop of significant uncertainty regarding environmental rules and dramatic changes in inter-fuel relationships, Vectren's 2016-2017 IRP represents a significant expansion of the number of scenarios and sensitivities from the 2014 IRP and provides a broader range of uncertainties and their attendant risks. Vectren's objective was "to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions." (Vectren 2016 IRP, page 182).

For the 2016 IRP, Vectren developed fourteen portfolios (pages 82 and 83). Seven portfolios (including the Base Case) were optimized, but Vectren concluded the remaining scenarios would not provide sufficient insights to warrant optimization. Below are the 15 portfolios that were tested (Business as Usual, seven optimized portfolios, two stakeholder portfolios, and five diversified portfolios). Vectren hired Burns and McDonnell to find the best possible combinations of resource additions under various scenarios by using the optimization software Strategist. The risk analysis for various portfolios was conducted by Pace Global

[16] Arguably, the accumulation of the costs for environmental rules such as ELG, CCR, MATs, etc, taken as a whole, would have been a more significant driver. However, many of these costs were already *sunk costs* at the time the IRP modeling was done.

using EPIS' AURORAxmp dispatch model combined with Monte Carlo simulation for the selection of possible future states as inputs to AURORAxmp.

1. Business As Usual (Continue Coal) Portfolio (Optimized)
2. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
3. Base + Large Load Scenario Portfolio (Optimized)
4. High Regulatory Scenario Portfolio (Optimized)
5. Low Regulatory Scenario Portfolio (Optimized)
6. High Economy Scenario Portfolio (Optimized)
7. Low Economy Scenario Portfolio (Optimized)
8. High Technology Scenario Portfolio
9. Stakeholder Portfolio
10. Stakeholder Portfolio (Cease Coal 2024)
11. FBC3, Fired Gas, & Renewables Portfolio
12. FBC3, Fired Gas, Early Solar, & EE Portfolio
13. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
14. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
15. Gas Portfolio with Renewables Portfolio

4.2.2 Issues / Questions

Warrick 4 was assumed to be retired in all of the scenarios due to the loss of ALCOA. This raised the question of whether there are any set of circumstances – including MISO market value - in which Warrick 4 would be retained.

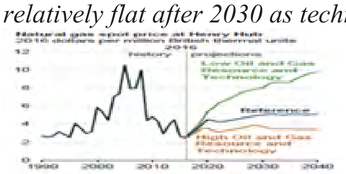
It bears reiterating from the fuel and commodity price discussion that the range of fuel price projections may have been unduly limited by using only one standard deviation from the expected value (mean). The relatively recent (5 years or so) experience in the natural gas industry provides support for a wider range of price trajectories. That is, few analysts ten years ago – even five years ago – would have thought the current price projections for natural gas to be within the realm of reasonable probabilities. Ten years ago, the notion of a *black swan event* might have been ascribed to the current projections for natural gas prices [17] and the attendant ramifications for coal in regional economic dispatch. Given Vecten's appropriate emphasis on maintaining options, having a more robust analysis of natural gas and commodity prices – higher and lower – would seem to be appropriate, especially for the mid and longer-term analysis.

Apart from whether the scenarios provided Vectren and its stakeholders with the most important information to make significant resource decisions, a more fundamental concern is capability of the model to handle the broad array of resource options in a holistic manner. That is, the capacity expansion model had limited ability to simultaneously evaluate and optimize more than a handful of resources. We recognize excessive run times may always be a consideration but the concern goes beyond run time. For example, was the model capable of simultaneously considering DSM, dynamic market conditions for buying and selling opportunities, renewable energy resources, possible new generating resources, and changes to the existing generating resource mix? Would other capacity expansion models be less limiting in their capabilities to conduct several multiple optimizations to better assess all resources and incorporate risk analysis?

Modeling results were evaluated via multiple metrics using a scorecard. The purpose was to find an appropriate balance of all metrics across the several scenarios so the choice of a portfolio performs well across the different metrics. On pages 33 and 44, Vectren identified a Preferred Portfolio Plan that, Vectren contends, balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility (2024), solar power plants (2018 and 2019), and energy efficiency, while significantly reducing reliance on coal-fired electric generation and results in a significant reduction of CO_2 using Mass Compliance limits. In addition to retiring Warrick 4 in 2020, Vectren's Preferred Portfolio also contemplates the potential retirement of Bags natural gas unit 1 (in 2018) and unit 2 (2025), Northeast Units 1 and 2 (natural gas) in 2019, Brown coal-fired units 1 and 2 (2024), FB Culley Unit 2 (2024), and upgrade Culley 3 for compliance with National Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR). Vectren noted the ELG/CCR, which they characterized as the main drivers of closing Vectren coal plants, will be much more difficult to change than the CPP.

While the narratives for the scenarios were well done, the Director is confident that Vectren would agree that there are reasonable scenarios that could result in different portfolios and provide a more robust assessment of potential risks. On p. 81 of the IRP report, Vectren mentioned that the seven optimized portfolios created using Strategist "looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s." Therefore, Vectren continued with self-identified stakeholder portfolios (non-optimized) and the so-called diversified portfolios because "Vectren believes there is value in a balanced portfolio as a way to reduce risk." The

[17] The EIA's Short-Term Energy Outlook (May 8) 2007 stated *The Henry Hub natural gas spot price is expected to average $7.84 per thousand cubic feet (mcf or $7.56 per MMBtu) in 2007, a 90-cent increase from the 2006 average, and $8.16 per mcf ($7.87 per MMBtu) in 2008.* Natural gas reached an all-time high of $15.39 per MMBtu ($15.96 / Mcf) during December of 2005. On June 22, 2017, the Henry Hub Natural Gas spot price was 2. 88 per Mcf ($2.77 MMBtu). In EIA's Annual Energy Outlook for 2017 (page 56), said: *Reference case prices rise modestly from 2020 through 2030 as electric power consumption increases; however, natural gas prices stay relatively flat after 2030 as technology improvements keep pace with rising demand.*



modeling results gave credence to the preferred portfolio being one of the diversified portfolios that was analyzed based on the scorecard evaluation. For Vectren, like all utilities, future IRPs need to critically examine the value of resource diversity and to do so in the context of the MISO and state requirements for reliability and economic benefits.

Two of the optimized portfolios, one from Scenario D: High Regulatory Scenario and the other one from Scenario F: High Economy Scenario, were derived from scenarios with relatively high natural gas prices (please refer to Figure 2.3 on p.78). If the model still chose to invest heavily in gas, it means investment in gas makes economic sense even with much higher gas prices. Wouldn't a better way to test the risk be to raise the gas price to more extreme levels and see what the model selects based on the least cost criterion, rather than subjectively identifying some so-called diversified portfolios to test? More broadly, and while recognizing the number of resource options are more limited for Vectren, the usefulness of the scenario analysis may have been lessened due to the narrowness of the ranges for the important drivers that resulted in portfolios that were not often very distinct from other portfolios.

In addition, according to evaluation results shown in the scorecard on p. 85, Portfolio F actually performed well in terms of creating the right balance between satisfying the competing objectives. While the approach for ranking the portfolios according to several different criteria is good, the distinctions between rankings (red/yellow/green) seemed arbitrary. The arbitrariness of these rankings was subsequently confirmed in a data request by the CAC et al.[18] The arbitrariness, combined with the significant effects on overall rankings, raises concern. For example, the preferred portfolio ranks ninth in terms of NPVRR but gets the same green light as the lowest cost portfolio. While the use of only 3 possible rankings may be visually appealing, it exacerbates the importance of arbitrary distinctions.

Has Vectren done any retrospective analysis to see if their DSM analysis may have been limited by the same inability to optimize DSM and other resources simultaneously? As intimated by comments on Page 80 of the IRP that the iterative nature of Strategist resulted in considering only options that seemed to be viable. More broadly, has Vectren done any analysis to determine if modeling limitations resulted in a more restricted list of resources?

Despite some concerns, Vectren prepared credible and well-reasoned scenarios. As with other Indiana utilities, the degree of analytical rigor needs to be continually enhanced as the decisions become more controversial and difficult.

4.3 Energy Efficiency

Vectren used the same methodology in its 2014 IRP to analyze and model energy efficiency, which is one reasonable approach and is consistent with current practices by some utilities to address this difficult topic. Specifically, Vectren's effort to model DSM resources in a manner reasonably comparable to supply-side resources is similar to the approach taken by other Indiana utilities filing their IRPs in 2016. Vectren starts off with a DSM Market Potential Study (MPS) to assess how much DSM (energy efficiency and demand

[18] CAC et al.'s Data Request 1.20 asked: Please provide the spreadsheet used to develop Figure 2.6 including the metrics measured for each of the objectives and the ranges used to determine whether a particular portfolio has a green bubble, red bubble, partially green and partially yellow bubble, etc. Vectren responded initially: Please see the Risk Analysis section (page 41-70) of the final stakeholder deck presented on November 29, 2016 (included in attachment 3.1 Stakeholder Materials) for details on how the IRP Portfolio Balanced Scorecard was developed. See the legends in the slides for each of the variables where the specifics were provided. In some instances, we used "break points" as the basis for colors.

response) is potentially achievable in its system. The methodology combines a dedicated MPS carried out by the EnerNOC Consulting Corporation in 2013 with a 2014 Electric Power Research Institute (EPRI) study "U.S. Energy Efficiency Potential Through 2035." The sole purpose of the Market Potential Study (MPS) was to construct an annual 2% incremental energy efficiency cap. However the construction of DSM bundles to be offered to the capacity expansion model differs substantially with the other utilities in that it didn't rely on the MPS. Instead of constructing DSM bundles by assembling measures with similar load shapes, end uses, and customer classes, Vectren set an annual cap of 2% of total eligible retail sales from the MPS. It then chose generic DSM savings in 8 blocks of 0.25% of eligible retail sales (not including large customers that have opted out) for each year of the 20 year planning horizon.

The two Market Potential Studies used by Vectren in the IRP estimated the level of Technical Potential, Economic Potential, and Achievable Potential. Technical Potential is the maximum energy efficiency available, assuming that cost and market adoption of technologies are not a barrier. Economic Potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. Achievable Potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. The Market Potential studies were used solely to guide the level of DSM resources to be included in the IRP analytical process as well as the maximum levels that seem reasonable.

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. No minimum level of energy efficiency impacts have been locked in for the planning process. The 0.25% blocks already reflect a 20% adjustment for free riders. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options.

Vectren developed estimates of how the cost of each energy efficiency bundle increases as the penetration of energy efficiency increases. The estimates are based on a study done by Dr. Richard Stevie with Integral Analytics, Inc. The study found that program costs per kWh increase as the cumulative penetration of energy efficiency increases. This means that achieving 1% savings in a given year means that achieving an additional 1% the next year and every year thereafter causes the costs of EE bundles to achieve that incremental 1% to increase by 4.12% each year of the planning period. The starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. A different growth rate in cost is applied to the second set of four blocks. The second set of four blocks is expected to grow at a rate of 1.72%. The lower growth rate in cost applied to blocks 5-8 allows for economies of operation within a given year, while the higher growth rate applied to blocks 1-4 tries to capture the impact on cost over time.

Based on Dr. Stevie's modeling results, high and low energy efficiency cost trajectories were developed using the estimated standard errors of the model coefficients used to develop the Base energy efficiency cost projection. The high and low cost trajectories were created by applying plus and minus one standard deviation to the model coefficients (which would capture about 68% of the variation of outcomes around the "expected value" – or the "mean").

4.3.1 Issues / Questions

Vectren should be recognized overall for its improved analysis and interesting approaches to address a number of difficult issues that arise when evaluating energy efficiency programs. But these interesting approaches also raise a number of questions. Vectren assumed the decision to select any amount of energy efficiency is made in 2018; meaning once a bundle is selected in 2018 that bundle is kept in place every following year through the planning horizon. The implication is that a new set of energy efficiency program participants had to be recruited each year at a cost that increased 4% per year. It is unclear whether the model optimization only considered the cost of the initial year the DSM bundle was selected or if it somehow considered the cost over all the remaining years in the 20 year planning horizon as well. As noted by CAC et al. on page 36 of their comments, it is not clear "whether connecting the initial years' savings to later years would serve to bias the model against selection of energy efficiency that is not realistic." In response, Vectren performed additional analysis which looked at the competitiveness of energy efficiency over a 3-year block from 2018-2020 rather than selecting the block for the entire study period. The results showed that blocks 1-4 in 2018-2020 are relatively similar in cost as a plan with no blocks of energy efficiency under the base scenario. It is not clear to the Director whether the additional analysis performed by Vectren really answers the issue expressed by CAC et al.

Vectren should be commended for making an interesting effort to project how bundle costs changed over time and as program penetration increased. As a starting point, the cost of energy efficiency programs approved in Cause No. 44645 was used for the DSM resource options. Vectren also contracted with Dr. Richard Stevie, VP of Forecasting with Integral Analytics Inc., to evaluate how the cost to achieve incremental energy efficiency savings changes as the cumulative market penetration of energy efficiency increases. Market penetration represents the cumulative achievement of energy efficiency savings as a percent of retail energy sales. The concept is that as market penetration increases and the available Market Potential begins to deplete, the cost to achieve additional program participants may increase.

The analysis was based on the Energy Information Administration's (EIA) Form 861 which contains data by utility on DSM program spending and load impacts. There are a number of limitations when using this data, which Dr. Stevie recognizes and tries to minimize by using the most recent 3 years of data, 2010 to 2012. Another way to minimize data limitations was to look at total annual spending relative to the first year impacts.

The Director appreciates the analysis performed by Dr. Stevie but is concerned that if the adjustments made to correct for admitted serious data limitations is sufficient to overcome the problems being addressed. Drawing strong policy recommendations in such circumstances is probably not warranted. More on this topic is discussed below in CAC et al.'s comments on energy efficiency. Hopefully, future analysis will be more reliant on empirical data derived from DSM effects by Vectren's customers.

4.4. Metrics for Preferred Plan Development

Vectren states the main objective of its IRP is to select a Preferred Portfolio of resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future
- Include a balanced mix of energy resources

- Minimize negative economic impact to the communities Vectren serves

Vectren analyzed 15 portfolios using a number of metrics each of which were given a green color for the best performers, a red color for a worst performer, and a yellow or caution color for something between. A scorecard was used to show the color for each portfolio under seven metrics. The seven metrics were:

- Portfolio NPVRR
- Risk
- Cost Risk Trade-off
- Balance/Flexibility
- Environmental
- Local Economic Impact
- Overall

Most of these metrics consisted of multiple measures.

A. *Portfolio NPVRR* looked at which portfolio had the lowest mean or average costs across 200 modeling iterations. Portfolios within 5% of the lowest expected cost portfolio were given a green color, and portfolios that were 10% or more expensive than the lowest were given a red color.

B. The *Risk Metric* included four different measures, each designed to capture a different risk. One measure of risk was volatility which is the standard deviation of the mean NPVRR. Portfolios whose standard deviation was within 10% of the least volatile portfolio were given a green color. Portfolios that had standard deviations 15% or more than the lowest volatile portfolio were given a red.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is subject to the least market price volatility. Those with less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color.

The third measure assessed is the exposure to MISO capacity market prices. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW received a red color.

The fourth risk measure is remote generation. Portfolios with generation assets located away from Vectren's service territory are thought to be exposed to greater risk of transmission congestion and outages.

C. *Cost-Risk Tradeoff* relates two variables: expected costs and the standard deviation of cost. It is meant to provide a metric of whether a portfolio hedges risk in a cost effective manner. Vectren presented a figure (p. 229) that measured portfolio standard deviation along the vertical axis and expected portfolio cost along the horizontal axis.

D. All of the portfolios would easily meet or exceed the requirements of the CPP. Also, nearly all of the portfolios will reduce SO_2 and NOx levels by over 80%.

E. According to Vectren, balance and flexibility are important objectives to "ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site." (p. 229). Portfolios with the greatest number of technologies are ranked higher than those with fewer technologies. Also, portfolios with more net sales into the wholesale market have the flexibility to adapt to unexpected breakthroughs in technology.

Sub-measures for Balance and Flexibility include the following:

- Percentage of the portfolio consisting of the largest technology in MW (for example wind or gas-fired generation)
- The largest power source (for example a combined cycle unit or a coal-fired unit)
- Percentage reliance of the largest technology to meet energy requirements in 2036 (for example gas or wind)
- Balanced energy metric based on the number of technologies relied on (for example gas, wind, solar EE, coal)
- Market flexibility as measured by net sales into the wholesale market.
- There was also a summary metric based on the other six sub-measures in this category

F. The last metric is local economic impact to the community. According to the IRP, this includes local output reductions and tax losses if local generation facilities are closed. Construction additions and operation of replacement generation was considered.

The customer rates metric, which is actually based on the portfolio's NPVRR, is useful, but is, by itself, limited. Knowing the mean or average NPVRR for one portfolio compared to other portfolios is of limited value without having information on the variability within the metric. Fortunately, Vectren presents information related to costs risks under other performance metrics. The risk metric included, as one element, the standard deviation of 20 year cost NPVRR. Another metric evaluated the cost-risk tradeoff by relating the expected value (or mean) of the 20 year NPVRR for a portfolio to the portfolio's standard deviation.

4.4.1 Risk Metric

Vectren presented three different measures relating to the NPVRR but each was discussed separately with no reference to the other two measures. It is often the case that a portfolio with a higher average NPVRR and a lower variability will be preferable to a resource portfolio with a lower average NPVRR but higher variability. Based on the information presented by Vectren, it is difficult to determine how the portfolios compare. It looks like Portfolio D has the best Cost Risk tradeoff but how the other portfolios compare is difficult to determine, given the information presented. The Director wonders if the cost-risk tradeoff could have been better presented using some other measure such as a cumulative probability chart. The risk probability chart would have shown the distribution of PVRR outcomes from the stochastic draws, showing the outcomes as the cumulative probability of each occurrence between 0% and 100%. The figure contains the risk profiles for each portfolio, with PVRR along the X-axis and the cumulative probability on the Y-axis. For each line, the difference between the bottom left point and top right point on the line is the range which 100% of the outcomes are expected to fall. This type of figure was used by IPL and has been used by other Indiana utilities including IMPA and I&M.

As noted above, the risk metric consists of four separate measures and each receives equal weight. Two of the measures relate to exposure to different aspects of the MISO markets. One measures exposure to the MISO wholesale energy market and the other measures exposure to the MISO capacity market. A third measure considered the risk from transmission issues from remote sources to Vectren which primarily affected those resource portfolios with greater reliance on wind generation.

An obvious question is how the thresholds were developed for exposure to the MISO capacity and energy markets? There is no discussion of thresholds in the IRP itself or the slides for the November 29, 2016 stakeholder meeting that addressed the performance metrics. Especially without a narrative that has been informed by discussions with MISO, it is hard to avoid the conclusion that the thresholds for good levels and bad levels of exposure is arbitrary. Without knowing why the thresholds were set where they are it is difficult to understand the significance when one portfolio receives a green light while another receives a red light. As for the third measure dealing with remoteness of resources to Vectren, there does not appear to be a definition of remoteness. Is it merely any resource that is not directly interconnected to the Vectren transmission system? Are there different degrees of "remoteness"? If yes, on what are these degrees based? If remoteness is based only on whether a resource is directly connected to Vectren's transmission system, then this is a blunt measure. Again, it would seem that MISO would be a good resource to help Vectren quantify the metrics.

4.4.2 Flexibility Metric

The balance and flexibility metric discussion in the IRP differs quite a bit from that in the November 29, 2016 stakeholder meeting presentation. For example, the IRP (p. 230) states that portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology. The November 29 stakeholder presentation says portfolios with higher net sales provide a cushion against higher than expected load, as well as redundancy to quickly adapt to unexpected change. The idea is to reduce the likelihood of exposing customers to wholesale energy market volatilities (p. 72). It is not clear to the Director why higher net sales is protection against unexpected change - be it technological change or something else. For example, higher net sales could also indicate greater sunk costs associated with generation facilities.

4.4.3 Diversity Metric

To some extent, flexibility concerns are addressed by Vectren's diversity metric, which uses four measures. These measures cover both the percentage of energy and capacity requirements satisfied by one technology, the largest single generation source, and the total number of technologies utilized. It is important to note that these measures are based on the projected load and resources for 2036. Again, it is not clear how the thresholds were set for green, yellow, or red classification for the specific measures. Nor is it clear how the summary metric was developed based on the four diversity measures and the net sales measure.

CAC et al. (on pages 47-57) has a number of criticisms of the black box scorecard assessment used by Vectren. Its exercise demonstrates how small changes to the scorecard ranking system implemented by Vectren can result in very different rankings of portfolios. As CAC et al. noted, the scorecard methodology used by Vectren is not robust to small changes in metric assumptions nor is it the only possible interpretation of the data on which Vectren relies. (CAC et. al. comments on Vectren IRP, p. 51) The Director concurs with this criticism.

4.4.4 Assessment

Vectren's circumstance is quite similar to NIPSCO's, in that both utilities are considering the reasonableness of making significant changes to its resource portfolio in the next several years. Similar to NIPSCO, Vectren relied extensively on PVRR to compare resource portfolios in its 2014 IRP, but has made a significant number of improvements in the 2016 IRP. There is an extensive discussion of risks and uncertainties and an explicit effort to have metrics that specifically address these risks and uncertainties to evaluate portfolio performance. Vectren included metrics to measure balance and flexibility of portfolios, local economic impact, cost-risk tradeoff, and environmental compliance. The specific questions and issues discussed above are not meant to detract from the significant improvements in the use of metrics implemented by Vectren in the 2016 IRP. Rather, the questions and issues are intended to further discussion amongst the various stakeholders and Vectren to make ongoing improvements.

4.5 Review of Vectren's Comments on Draft 2016 Director's IRP Report

Vectren implemented numerous changes in the 2016 IRP and the Director has some understanding of the effort put forth by the Vectren staff involved. The Director believes that all involved in the IRP stakeholder advisory process including Vectren staff, Commission staff, and other stakeholders, are in a continual learning process. This is a strength of the IRP process and helps to facilitate the exploration of potential areas of improvement as we all learn.

What follows are responses by the Director to specific points made by Vectren in their written comments on the Draft Director's IRP Report. The page numbers shown below refer to a page in Vectren's comments.

4.5.1 Modeling Resource Options in a Holistic Manner

Vectren: pp. 2-3 – The Director in the draft report raised some questions about the ability of the model used by Vectren to perform complex modeling analysis compared to other models now available. In response, Vectren describes the Strategist model and the how this model was used to effectively conduct the complex analysis involved in exploring the retirement and replacement of existing generation facilities.

Response: Models are all different and it is a weighing of different capabilities that drives which model is most appropriate for the current circumstances. The question is not so much model constraints, but how these constraints are handled by the utility while still making as full use of the model's capabilities. Do different approaches give different results? For example, Vectren's modeling of energy efficiency is very different compared to other Indiana utilities. The evaluation of blocks of energy efficiency over an entire planning horizon instead of several multi-year time periods is one example. Also there is the conceptually odd methodological choice of pricing the fifth block of EE in 2016 at the fourth block price in the year 2036. The narrative for this modeling decision is lacking. That is, it requires more discussion of why this approach is reasonable and does not distort outcomes.

We cannot say whether Vectren's approach to handling model limitations is better or worse than other methodologies but it is an open question that might be better answered as experience is gained over time.

4.5.2 Portfolio Diversity

Vectren: P. 7 – Vectren believes that sound planning bases decisions on circumstances that have some material degree of probability. Determining lower probability scenarios impact on resource alternatives may provide some useful data, but is unlikely to change outcomes. Vectren has also used the phrase "reasonably possible future states."

Response: The Director agrees with Vectren that one measure of the strength of a portfolio is if it does well over a number of scenarios, but it could also suggest that the scenarios were not sufficiently distinct to assess different risks. What seems implausible today can change quickly. For example, just a few years ago, projections of natural gas were substantially higher than current price forecasts. The technological improvements in wind and solar resources have resulted in sharper cost declines than were expected just a few years ago. The difficulty of estimating customer-owned distributed energy resources (DER) is a problem vexing almost all utilities but, as Vectren can attest, there seems little doubt that DER will be increasing. The election of Donald Trump and the resulting effects on environmental regulations was highly unexpected. Also, history is but one sample of what could have happened. Yes, a number of scenarios should be based on "some material degree of probability," but some scenarios should be examined, even if plausible, albeit, unlikely.

Unlikely scenarios can provide useful information when evaluating a preferred resource portfolio and near term resource decisions. Vectren cites an analysis they did not include in the IRP that shows a 50% reduction in coal prices would be required for the IRP optimization models to select coal over natural gas. This is an important piece of information that helps one better understand how strong the results are. Similarly, as Vectren correctly stated, the continued operation of Warrick 4 was not considered to be plausible at the time Vectren constructed their IRP but the situation has changed somewhat.

Vectren: Bottom of page 7, Vectren states "Only the screening analysis used one standard deviation above or below the mean. The risk analysis utilized the full distribution of natural gas prices in the 200 iterations."

Response: Vectren's use of the phrase "screening analysis" in their reply comments is unusual because it is applied to the development of scenarios and the development of resource portfolios based on those scenarios. Staff acknowledges Vectren does not appear to have limited the commodity price ranges to plus or minus one standard deviation when doing the stochastic analysis, but such a limitation was imposed when developing the scenarios. Limitation in the development of scenarios may unreasonably constrain the potential range of resource portfolios that are, then, subjected to the optimization process. And it is these optimized resource portfolios that are then evaluated with the stochastic analysis.

Vectren: Vectren states "the probabilities of these black swan [19]events are so low that it would not have materially changed the risk analysis and the ultimate recommended portfolio."

[19] A black swan event is a metaphor to describe a low probability event with major significance. For utility planning, it is useful to *stress* the system to evaluate the potential ramifications of a low probability event that would have significant ramifications. Because it is unrealistic and prohibitively expensive to try to plan a utility with no probability of failure, it would seem unlikely that any utility would be planned on the basis of a black swan event. The *Polar Vortex* of 2013 / 14 might be regarded as a black swan event. It is also possible that the precipitous drop in natural gas prices in recent years would have been regarded as a black swan event prior to the widespread use of fracking. The term is based on an ancient saying which presumed black swans did not exist, but the saying was revised after black swans were discovered in the wild.

Response: The Director acknowledges that the recommended portfolio might not change. But on p. 194 of Vecren's IRP report they note that black swan events are impossible to forecast, but tend to occur quite frequently. Vectren also argues in the IRP that probabilistic distributions that reflect a combination of historical data and informed judgment tend to capture black swan events.

The Director is open to the possibility that probabilistic distributions based on a combination of historical data and informed judgement may capture many black swan events but thinks many of these types of events are better addressed explicitly in the development of scenarios and the accompanying narratives. Moreover, the portfolios being reviewed are determined before the stochastic analysis is performed. Scenario and stochastic analysis are complements to each other, not substitutes.

Vectren: pp. 7-8 – Vectren clarified that the full distribution of gas prices was used in the 200 iterations for the stochastic analysis.

Response: The Director agrees based on information presented.

4.5.3 Benefits of Flexibility in the Planning Process

Vectren: P. 8 – Vectren South approaches its scenario and risk assessment in a manner intended to maintain flexibility and balance risk. Generally, Vectren South shares the view of the Director in this regard. Draft Report, p. 5. However, Vectren South suggests the Director consider the potential risk that could be created by waiting until the last possible moment to make decisions. Such an approach presents its own challenges. Waiting until the last possible moment to make decisions may place too much emphasis on the present and therefore increase risk because there is no time left to evaluate how trends will work out in the longer run. Options may also be limited because of the time required to obtain replacement capacity or approval to build new facilities. Adequate time is necessary for proper evaluation and planning in order to manage a large project to properly balance cost minimization with reliability and safety.

Response: An appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource. This flexibility allows initial resource analysis to be reversed if there is new information that makes the initial selection less desirable compared to other options.

4.5.4 Metrics for the Preferred Plan

Vectren: P. 12 – There is no threshold for considering what a reasonable maximum exposure to these markets (MISO capacity and energy markets) would be in the analysis. There is only limited experience in these markets to draw upon. That is, there is not enough empirical data to determine what an appropriate level of exposure is in the MISO markets. At this point, the MISO markets are not very liquid and hence can be quite volatile.

The "higher net sales" Vectren South has in mind is the ability to make greater wholesale energy or capacity sales. A utility that lacks sufficient generation resources to serve its load faces significant market risk that can lead to fluctuating prices. The utility also is better able to serve new load in its service territory. On the other hand, a utility that has a reasonable reserve of generation beyond its capacity is able to offer this into the market which, in Vectren South's case, benefits customers and protects it against market risks resulting from changing prices. The utility and its customers are at risk of increases in the cost of purchasing electricity if available energy or capacity becomes scarcer in the market.

Response: The following is a general response to Vectren's comments on metrics for development of the preferred resource plan.

The Director appreciates the explanation of the remoteness metric of a resource located outside the Vectren service territory and the additional discussion provided on some of the other metrics on which the Director had specific questions. The Director also appreciates Vectren's statement, "[w]hile the determination of what constitutes good and bad is subjective, on a relative basis between portfolios, it is an accurate assessment." (p. 12 Vectren comments on Director's Draft Report)

The Director thinks consideration of risks and uncertainties in a long-term planning exercise involving numerous decision points is by definition complex and the "preferred portfolio" as determined by the utility is dependent on many quantitative but also qualitative decisions based largely on the utility's expertise, experience, and judgment. Among the complexities is how the utility weighs the various risks and uncertainties and how they also consider the various metrics used to evaluate the plans. There is no one absolutely "right" way to evaluate these risks and uncertainties and different parties can look at the same information and reasonably derive different choices as to what the preferred portfolio should be.

Nevertheless, the distinction between rankings (red, yellow, green) often appears arbitrary due to a lack of distinction between the ratings. It is also not always clear why something is considered positive or negative. For this IRP, this is especially the case for the metrics involving exposure to wholesale energy and capacity markets, remoteness of a resource from Vectren's service territory, and the ability to make higher net sales which all appear to be very subjective. Surely the risks seen by Vectren vary by degree but, without more definitive thresholds or discussion of how these risks change at different levels of exposure, it appears somewhat arbitrary. It is difficult to have objective metrics without an ability to quantify the metrics so some degree of arbitrariness is unescapable in something as complex as evaluating alternative resource portfolios. Awareness of this circumstance is, however, critical for all IRP stakeholders.

The Director recommends that Vectren, like other Indiana utilities, should consider the establishment of metrics in advance of the IRP process and with the input of stakeholders; recognizing there may be need for some adjustments. To the extent reasonably feasible, the metrics should be quantifiable. However, stakeholders should recognize that some metrics are inherently subjective. Ideally, for those metrics that are subjective (e.g., the value of resiliency or fuel / resource diversity), there should be general understanding about how those metrics will be evaluated and weighted. Mutual understanding of the metrics should reduce misunderstandings as the preferred portfolio is determined.

4.5.5 Energy Efficiency

Vectren: P. 13 **– Vectren responded to questions the Director had on some aspects of how Vectren modeled energy efficiency. One involved how Vectren modeled EE over the full planning period and the other area involved how Vectren projected EE program costs over the 20-year planning period.**

Response: Vectren has several reasonable responses to a number of questions raised by CAC et al. but there are other questions that should be kept in mind if a utility chooses to use the results of Dr. Stevie's study.

1. Stevie's model examines the impact of explanatory variables on direct program spending. The model excludes indirect costs which Dr. Stevie states in his study can add as much as 30 percent to total program spending. Indirect costs includes costs that have not been included in any program category, but could be meaningfully identified with operating the company's DSM programs (e.g., Administrative, Marketing, Monitoring & Evaluation, Company-Earned Incentives, Other). Direct Costs are those costs that are directly attributable to a particular DSM program and include incentive payments provided to a customer for program participation, whether cash payment, in-kind services (e.g. design work), or other benefits directly provided customer for their program participation.

   It is the Director's opinion that the nature of indirect costs means they are likely to grow at a slower pace relative to direct program expenditures due to experience, economies of size, customer awareness / acceptance, etc. Thus, the exclusion of indirect costs from the analysis is likely to overstate the growth in portfolio costs over time.

2. The fundamental problem that Dr. Stevie was attempting to mitigate is the lack of data credibility. The inconsistent data collected by utilities and submitted to the Energy Information Administration's (EIA), adversely affects the EIA's data base. The cumulative MWh data in the EIA data base likely has problems, the extent and significance of which is unknown. The instructions for the 2012 version of Form 861 states the cumulative effects of energy efficiency programs includes new and existing participants in existing programs (those implemented prior to the current reporting year that were in place during prior reporting year), all participants in new programs (those implemented during current reporting year), <u>and participants in programs terminated since 1992 (those effects continue even though the programs have been discontinued</u>) (emphasis added). The instructions go on to say that DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, the cumulative effects should consider the useful life of efficiency and load control measures by accounting for building demolition, equipment degradation, and program attrition.

   It is not clear how individual utilities handle in their EIA reporting the diminishing impact of programs over time. Again, it is almost certain that each utility treats the diminishing effects of DSM differently. Thus, the EIA data may include a program that was in place 20 years ago but no longer has an effect, which would impact the estimated model results.

3. Vectren states there is a great deal of uncertainty in projecting how EE program costs might change over the planning period. Vectren argues that averaging estimated coefficients from the two models analyzed in the study is one way of combining information in a way that appropriately acknowledges the extensive uncertainty.

   The Director agrees that there is a large degree of uncertainty in projecting future program costs but questions in this circumstance whether the averaging of two separate model results is reasonable. The results of the second model raises questions whether it should have been used at all. The second model was estimated using data for only the year 2012, as opposed to the first model based on data for the period 2010-2012. The second model has considerably less explanatory power[20], a marginal significance on the price of electricity, and the program size variable is not significant. The failure of program size to have much explanatory power on program costs calls into question reliance on any of the second model's results.

4. When developing the projected costs of energy efficiency programs through the forecast period, the Director is persuaded that Dr. Elizabeth Stanton, a consultant for CAC et al., is correct that not including the price of electricity affects the projected cost of energy efficiency programs over time.[21] Similarly, it appears that the impact of current or incremental program savings is also excluded. If this assessment is correct, then only the coefficient on the cumulative kWh impacts was used. It can be argued that, if these variables are not going to be used to project the rate of cost change of energy efficiency programs, then perhaps the models should be re-estimated without them (Of course, adding or removing an independent variable will change the coefficients of the other variables. The Director understands that removing these variables will cause other estimation problems). Essentially, the methodology used to project program costs increases over time and saturation levels assumes that the values for electricity price and current (or incremental) kWh savings do not change over the 20 year planning period and thus have no impact.

   Dr. Stevie chose to exclude the price variable for two reasons. First, the price variable was significant only in the first model but not the second so it did not seem appropriate to include the impact of the variable. Second, Vectren's average retail price of electricity has been flat in nominal terms in recent years which means the price is declining in real terms. So if he had included the price it would have increased the cost projection. He chose to be conservative.

   Excluding the price because it was not significant in one form of the model, even though it is significant in the other model, is questionable. Also Vectren's recent price history says nothing about how the price will change over the next 20 years. Ignoring the price of electricity means the energy efficiency program cost projections are based on the assumption of no electricity price changes over the 20 year period. At a minimum, given the resource changes for Vectren over the 20 year planning horizon, it seems unrealistic to assume no price increases for electricity.

The Director continues to believe the analysis performed by Dr. Stevie is interesting but it is not without numerous questions. The EIA DSM data is well-known for many problems that are recognized by Dr. Stevie and the study methodology tries to limit the impact of these problems. But the paper also acknowledges the uncertainty of the results and states that much additional analysis needs to be conducted to feel confident about the relationships affecting energy efficiency program costs over time and as saturation levels change. The additional comments or questions discussed above, whether correct or not, serve to emphasize the extent of uncertainty about the results and how they might best be used.

[20] It is the ability of a model, hypothesis or theory to explain a concept or subject in a credible manner. Or in this case, the ability of the independent or explanatory variables to explain movements in the dependent variable.

[21] See the Direct Testimony of Elizabeth A. Stanton, Cause No. 44927, CAC Exhibit 1, pages 20-21.

5. HOOSIER ENERGY

5.1 Scenario and Risk Analysis

Hoosier Energy filed an update, rather than a full IRP, as part of the change to a three-year IRP cycle. Its update was well-organized and credible.

5.1.1 Models

Hoosier Energy contracted with GDS Associates to perform IRP 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. The model is the same as the one used in 2014 IRP process.

5.1.2 Method

Hoosier Energy started with a Base Case scenario. Eight sensitivities were developed for the Base Case by incorporating different assumptions about load and energy, fuel prices, renewable prices, carbon prices and overnight costs for Combined Cycle and Combustion Turbine construction. In addition to the Base Case scenario, an Environmental Future scenario was developed, which included carbon emissions limits and a limited amount of wind over the 2017 to 2036 timeframe. Seven sensitivities were developed for the Environmental Future Scenario with varying limits on wind and solar and those limits combined with low power and gas prices.

Hoosier Energy reported the least cost plans under each scenario and sensitivity. Nevertheless, it did not reach a preferred resource plan after the analysis. A short-term action plan indicated that the next major resource increment would be required around the years 2023/2024 based on modeling results.

5.1.3 Issues

In Hoosier Energy's IRP analysis, only supply-side alternatives were included in the modeling. The demand-side resource options were predetermined and incorporated into the load forecast. The supply-side and the demand-side alternatives were not evaluated on the same basis in the resource plan process.

Hoosier Energy included a very limited number of scenarios: Base Case scenario and Environmental Future scenario. Usually, a scenario represents a possible future depicted by a set of input assumptions about economy, market condition, load and energy forecast, environmental regulation, and so on. From the perspective of identifying possible future states, two scenarios seem insufficient.

In addition, Hoosier Energy lacked a systematic framework to compare various portfolios. Except cost, no other criteria were established to make comparison. Modeling results were presented in a way less informative, which did not lead to a preferred portfolio plan.

5.2 Energy Efficiency

Hoosier Energy's circumstance is quite different from that of the other three utilities that submitted IRPs this round. NIPSCO, IPL, and Vectren all prepared completely new IRPs consistent with the schedule in the draft IRP rule. Hoosier Energy was scheduled to provide only an update of the IRP with a completely new IRP to be prepared for 2017. This is part of the transition to a three-year cycle for each utility to prepare an IRP going forward.

Hoosier Energy's discussion of demand-side resources is minimal but it appears DSM was reflected in the IRP a couple of different ways. First, DSM resource options were selected and developed as part of the 2013 GDS Associates market potential study and incorporated into the load forecast. Second, GDS developed a 2016 update of its study. Based on the updated assumptions, an additional 3.5 MW of DSM was selected in 2017 in some of the Strategist scenarios. How either step was done is not discussed.

The Director understands that Hoosier Energy was only providing an update to its IRP as requested under the draft rule. He anticipates that Hoosier Energy will have a fuller discussion of how DSM resources are accounted for in their 2017 IRP.

5.3 Metrics for Preferred Plan Development

Hoosier Energy developed two scenarios that were analyzed with Strategist – a Base Case and an Environmental Future. Eight sensitivities were analyzed for the base case and seven sensitivities for the environmental future scenario. Tables for each scenario and sensitivity showed the five lowest cost expansion plans (from the top 100) selected by the Strategist model. The NPVRR of each resource portfolio was the only information presented. No other metrics for plan evaluation was discussed.

Staff understands that Hoosier Energy was only providing an update to their IRP as requested under the draft rule. We anticipate that Hoosier Energy will have a fuller discussion of performance metrics in its 2017 IRP to inform its decision as to the composition of the preferred resource plan.

6. CAC ET AL. COMMENTS

CAC et al. raised a number of concerns as to how the utilities modeled DSM. Attention was especially focused on the use of market potential studies, bundle creation, and the projection of energy efficiency costs over a 20-year forecast horizon. CAC et al. also proposed an alternative DSM modeling methodology that they think avoids many of the difficulties they see with the methodologies used by the utilities.

CAC et al. commented that much of the analysis reflected in the market potential studies is opaque with assumptions that are unspecified or less than clear. (CAC et al. Comments on IPL IRP, pp. 39 – 42) They are also concerned how the market potential studies were used to screen potential EE programs multiple times. (CAC et al. Comments on NIPSCO IRP, pp. 28-30) Essentially, CAC et al. have a number of questions regarding the movement from the MPS to what is included for consideration in the optimization model and how the energy efficiency in the Preferred Plan relates to what occurred throughout the process.

CAC et al. thought Vectren's treatment of DSM was in many respects superior to that done by IPL and NIPSCO. Much of this is the direct result of how Vectren created its DSM bundles compared to the methodology used by IPL and NIPSCO. In CAC et al's opinion, they thought Vectren's approach had beneficial attributes because it "does not rely on such black box elements as 'achievable potential' rates. In addition it does not appear that Vectren performed any cost-effectiveness pre-screening of measures, which generally serves only to result in more screens for the energy efficiency than supply-side measures." (CAC et al. Comments on Vectren IRP, p. 35)

Perhaps CAC et al. reserved their largest concern for how efficiency program costs were projected to change over the 20-year planning period. As noted above, both IPL and NIPSCO assume initial bundle costs similar to existing DSM programs or base information on market potential studies, and each company made assumptions as to the rate of annual escalation in bundle costs. It is not clear on what these annual cost increase projections are based. Vectren's approach based initial bundle costs on programs they are currently marketing, but the rate of cost increase is based on a study done by Dr. Richard Stevie.

CAC et al consultants prepared a paper critiquing the analysis done by Dr. Stevie. (CAC et al. Comments on Vectren IRP, Attachment A) They found that Stevie's analysis:

- is based on highly questionable data sources,
- relies on regression analysis that is sensitive to the inclusion or exclusion of problematic data entries, and seems to depend on unusual choices in variable and model specification, and
- is applied incorrectly and incompletely in the utility filing where the consultants were able to review confidential workpapers.

CAC et al. concludes the "result is higher energy efficiency costs than would otherwise be expected in utility planning and, consequently, less efficiency chosen in optimal resource planning." (CAC et al. Comments on Vectren IRP, Attachment A, p. 3)

To Vectren's credit, they recognize that DSM resource costs are a component of the integration of DSM into the resource plan. The uncertainty around DSM costs, especially considering a 20-year implementation period, means that alternate views of these costs should be examined in the context of the scenario and stochastic risk analyses. (Vectren IRP p. 134)

Vectren developed high and low DSM resource cost trajectories using the estimated standard errors of the model coefficients used in the development of the base case cost projection. These high and low load cost trajectories were created by applying plus and minus one standard deviation error to the DSM costs regression model coefficients. (Vectren IRP p. 135)

The use of high, low, and base DSM costs forecasts is very useful conceptually, but the Director shares CAC et al's concern about the methodology and data used to develop the base case DSM costs trajectories based on EIA data. For example, the costs for an individual DSM block 1- 4 increases by 4.9% per year in the high case, 4.2% in the base case, and 3.4% in the low case. Given low inflation rates all three rates of DSM costs increase translates into substantial increases in the real (meaning inflation-adjusted) costs of DSM. This appears to be inconsistent with other historical evidence. Also, while using high and low DSM cost trajectories is methodologically reasonable to evaluate how sensitive modeling results are to changes in DSM costs, the apparent high increases in real costs over time across all three projections raises questions about how the method was applied and the reasonableness of the results. More fundamentally, the methodology used by Vectren appears to underestimate the role of technological change and changing public attitudes about energy consumption. It is not clear to the Director that this can be adequately captured when using only three years of data. The ideal solution would be to develop a Vectren specific load research – including DSM load research – database, but this takes time. Borrowing data from neighboring utilities and selected utilities that have substantial experience and expertise is a second-best alternative. However, as Vectren knows, borrowing data from other utilities must be carefully done since there are considerable differences in how utilities treat DSM. The lack of uniformity in treatment and reporting of DSM to the EIA is a primary reason that reliance on EIA DSM data is concerning.

CAC et al. recommends moving away from the current approach of using bundles to evaluate the potential for EE in IRP modeling and instead trying to focus on the value of EE. This, they suggest, can be done by moving to an avoided cost proxy for DSM. A utility will use IRP modeling to estimate the value of increasing zero cost decrements of load so that an implicit avoided cost for each decrement is developed. Under this approach, the appropriate level of energy savings is calculated in a DSM proceeding but relies on avoided costs developed from the IRP. This approach eliminates the need at the IRP modeling stage to develop assumptions about the cost and performance of DSM over the 20-year planning horizon. CAC et al. notes the avoided cost proxy requires having portfolios with distinct levels of energy savings but similar resource choices and other input assumptions so that the cost differences between the portfolios is driven by the level of energy savings rather than some unrelated characteristic. (See p. 40 CAC et al's. Comments on IPL IRP and p. 38 of CAC's Comments on NIPSCO's IRP)

The Director shares CAC et al.'s concern about the ability to develop assumptions about DSM bundle characteristics and cost trajectories over a 20-year modeling horizon. As a result, the Director appreciates the alternative methodology proposed by CAC et al. While conceptually reasonable, the idea, however, has to be more fully developed and analyzed using appropriate models so there is better understanding of how use of the technique compares to other techniques of EE modeling being used across the nation.

7. MIDWEST ENERGY EFFICIENCY ALLIANCE (MEEA) COMMENTS

MEEA shared many of the same concerns expressed by the CAC et al. They liked each utility choosing to model EE as a selectable resource but also expressed a number of concerns about the EE modeling methodologies used by NIPSCO and IPL, which are listed below.

1. Each utility used its respective MPS to screen EE programs which MEEA believes unreasonably limits the amount of EE included as an input to the IRP optimization modeling. They prefer the "Technical Potential" be input to the IRP models. (MEEA NIPSCO comments, p. 3)
2. Each bundle was based on individual measures which could be leaving savings on the table that could be achieved with a well-designed portfolio of programs. (p. 2 MEEA NIPSCO Comments)
3. The savings levels are too low. In MEEA's experience it is not uncommon that higher levels of cost-effective energy savings can be achieved as technology, program design, and program delivery mature. (MEEA Comments on NIPSCO, p.4)

MEEA did like IPL's method of separating the bundles into cost-tiers compared to the no-tiers approach used by NIPSCO. They believe bundles based on cost tiers prevent an all-or-nothing selection in the IRP modeling. (MEEA Comments on IPL, p. 2)

MEEA especially liked Vectren's approach to bundle construction, as compared to IPL and NIPSCO. But MEEA had one caveat – the 2% cap on incremental annual energy savings appears to be arbitrary, as do the 0.25% size of the bundle increments. They questioned if the 2% level was too low. Also, they wondered if smaller increments of 0.10% had been used would more energy savings have been selected. (MEEA Comments on Vectren, p. 2) MEEA, in addition, thought Vectren's approach of allowing the model to select EE by cost per kWh in a measure-agnostic fashion avoids limiting what EE is available to the IRP model. This avoids limiting the utility's later DSM planning because it selects savings rather than specific measure types. (MEEA Vectren Comments, p. 3)

According to MEEA, NIPSCO used Version 1 of the Indiana Technical Reference Manual (TRM) in its MPS whereas IPL used Version 2.2. They asked the commission to provide guidance on which version of the TRM should be used in IRP modeling. It is the Director's opinion that the most recent version or data should be used whenever possible. (MEEA Comments on IPL, p. 3)

7.1 Utility Responses to MEEA

Both IPL and NIPSCO disagree with MEEA that their modeling is flawed because they failed to include MPS Technical Potential in the IRP optimization. IPL says they intentionally chose to input MAP in the IRP modeling rather than the lower RAP so as not to limit the amount of DSM available for the IRP model to select. (p. 3, IPL Reply to Stakeholder Comments). NIPSCO states it made a conscious decision to screen EE measures for what was not just possible in its service territory, but also what was practical. (NIPSCO Reply Comments p. 6) In order for the EE bundles to be the most accurate representation of what is available, NIPSCO elected to use the more conservative, but more typical market by also running the EE program potential on all of its measures before including them in the optimization. (NIPSCO Reply Comments, p. 7)

As to the assertion that the savings level is too low, IPL emphasizes that, after opt-outs are considered, the IRP-selected energy efficiency amounts are more than 1% per year of the eligible load. (IPL Reply Comments p. 3) NIPSCO noted that many DSM programs passed the DSM pre-screening process but were ultimately not selected in the model optimization process. As a result, any DSM program that was unable or narrowly able to pass the screening would be highly unlikely to be chosen in the resource optimization. (pg. 2-3 NIPSCO Reply to Stakeholder Comments)

8. GENERAL COMMENTS

8.1 **Fuel and Commodity Price Analysis for Director's** Report on 2016 IRP

The Director recognizes any expectation of precisely accurate forecasts of future fuel and market prices, especially long-term price forecasts, is an impossible objective to attain. Rather, the emphasis should be placed on the plausibility and credibility of different narratives and assumptions that, considered with other factors, provide a broad range of possible outcomes. Given the significance of decisions being confronted by Indiana utilities and their stakeholders, it is important to memorialize the importance of fuel prices—particularly natural gas prices—in relation to coal prices. Similarly, it is important to note that environmental policies affecting coal are changing at the national level but, at this point, it is difficult to anticipate the ramifications. These changes were made after utilities conducted their analysis and generally occurred after the IRPs were submitted. The importance of fuel prices is preeminent in this IRP cycle and warrant well-constructed scenarios, sensitivities, probabilistic analysis, and multiple data sources. Moreover, since Indiana utilities are members of the Midcontinent ISO (MISO) or the PJM, it is also necessary for Indiana utilities to consider market prices and regional resources to maximize the value of their own resources over the 20-year planning horizon.

8.1.1 Construction of Fuel Forecasts

Developing low probability, but highly consequential scenarios, as well as more likely scenarios, is consistent with good industry practice.[22] Similarly, for fuel price projections, forecasts of market energy and capacity costs, load forecasts, environmental regulations and other important variables, especially those that are likely to be primary drivers of resource decisions, should capture a wide variety of assumptions and projections. Analysis of more extreme fuel price assumptions and forecasts should result in different resource portfolios that provide useful insights that could not be provided by too narrow a view.

Just as well-reasoned narratives are essential in the construction of scenarios, it is also imperative that well-reasoned narratives support fuel price projections. Even extreme fuel price forecasts should be supported

[22] The Northwest Power and Conservation Council "Northwest Conservation and Electric Power Plan". The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. (page 3-30). The Regional Portfolio Model (RPM) [A stochastic not deterministic model] uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. [For natural gas prices] These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. (page 8-2). The high and low forecasts are intended to be extreme views of possible future prices from today's context… In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model.(page 8-8). The future is uncertain. Therefore, the ultimate cost and risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the potential cost and risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or risk, and to bracket the range of those uncertainties. (page 15-4). Seventh Power Plan, Adopted February 10, 2016.

by a credible narrative story. For example, what can history—especially recent history—tell us?[23] What combination of factors might cause significant natural gas price escalations (or significant price declines)? What factors, taken together, might cause a significant increase in forecast market energy and/or capacity costs that would alter resource decisions?

To be clear, there is no expectation that the utilities' preferred resource plans will be based on very extreme cases. However, it is important to know the point of inflection when extreme scenarios result in dramatic changes in resource portfolios. For example, what price do natural gas and coal price projections have to reach for utilities to retain their coal-fired generation? Similarly, what natural gas and coal price projections would cause a utility to retire all coal-fired generation? For either of these two examples of high and low fuel and market prices, how does the capacity expansion planning model's selection of other resources change and what are the ramifications?

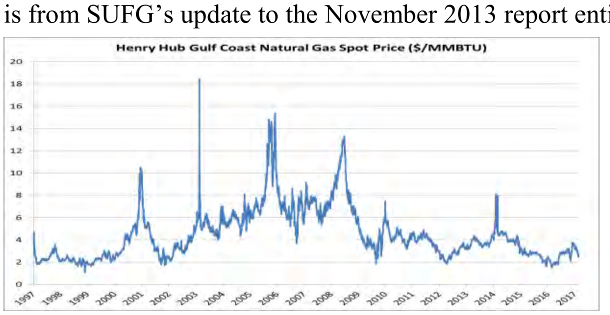
Because business decisions are likely to be increasingly formulated as a result of the IRP process, analysis, and data, and because of the importance of fuel as a driver, utilities should consider using multiple (two or more) independent fuel price forecasts. Ideally, at least one of these forecasts should be a credible forecast in the public domain such as from the Energy Information Administration (EIA). Each of the fuel price forecasts should be supported by a reasonable and credible narrative.

8.1.2 Commodity Forecast Framework

Since the MISO and PJM conduct security constrained economic dispatch to ensure the lowest cost combination of resources are dispatched at any moment in time, subject to constraints, it is essential that Indiana utilities give consideration to a variety of different energy and capacity market price scenarios and sensitivities that could affect their operational and longer-term resource decisions. As with fuel and other forecasts, long-term regional estimates should be supported by credible narratives. For example, regardless of the spread between coal and natural gas prices used in economic dispatch decisions, if a resource is not frequently "in the money" for MISO's and PJM's dispatch, this should be part of a narrative and should be a reference point for the reasonableness of portfolios.

A statewide and regional perspective could provide useful insights and it would be consistent with the IRP statute and draft rules. A statewide (ideally a regional) analysis could provide additional perspectives to

[23] With the exception of a brief spike in early 2014 that was related to an extreme cold spell (commonly referred to as the polar vortex), natural gas prices have remained low since 2013. It should be noted that the 2014 spike was less extreme than those during the winters of 2000/2001, 2003, 2006, and 2008. Horizontal drilling and hydraulic fracturing has allowed the U.S. to capture significant amounts of natural gas from shale formations, where it was previously uneconomic. The result has been a transformation of the characteristics of natural gas prices. This is illustrated by the graph on the following page (data source: Energy Information Administration (EIA)). Information is from SUFG's update to the November 2013 report entitled Natural Gas Market Study. (p. 1).



inform the Commission, policymakers, and stakeholders, and help Indiana utilities assess retirement, retention, and repowering decisions, as well as the potential for future joint projects if technology improvements result in making certain resources economically viable.

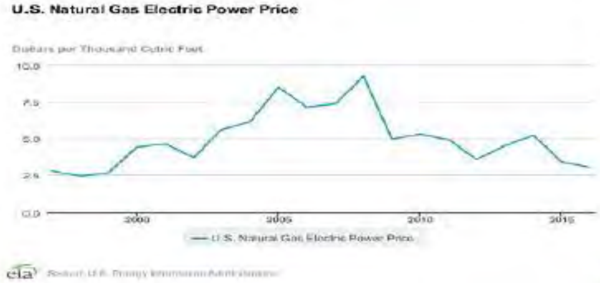
Ideally, Indiana utilities would work with their respective RTOs to consider the broader regional implications of a variety of short, mid-term, and long-run resource options that are comparatively economical and provide appropriate reliability. For example, if a significant amount of coal-fired capacity is being retired in the MISO and/or PJM regions, would this influence retirement decisions for coal units in Indiana?

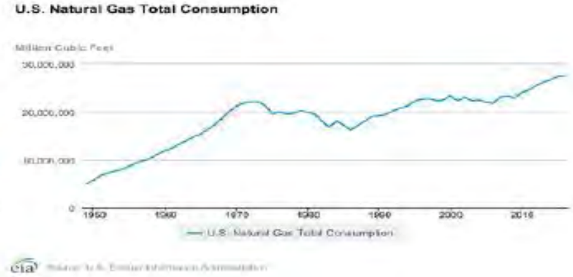
8.1.3 Discussion of Common Issues / Questions

IPL, NIPSCO, and Vectren all used reputable consultants that specialize in energy price forecasts. IPL and Vectren used more than one fuel price projection in their IRPs which seemed appropriate given the importance of fuel prices in this round of IRPs. Especially with the natural gas expertise of NIPSCO and Vectren, as combination utilities, the expectation is higher for well-reasoned narratives to explain the price projections.

To varying extents and owing to the complex interactions of fuel and wholesale electric market prices on load and resources, the narratives offered by IPL, NIPSCO, and Vectren to support their development of assumptions about fuel and wholesale electric market price projections may be too constrained. On page 170 of Vectren's IRP, for example, Vectren said: "…The current over-supply of natural gas continues to dominate the market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rise and gas markets begin to tighten, …Meanwhile coal prices remain depressed in the near short-term as domestic markets remain soft , with a modest price recovery beginning in in 2018." While all of the utilities made similar observations which have considerable merit and plausibility, the fuel and commodity markets seem far more nuanced than traditional supply and demand analysis would offer. For example, none of the utilities advanced an argument predicated on significant technological enhancements and the complex and, often non-intuitive, price elasticity of supply interactions among oil, natural gas, and coal. For future IRPs, foreign trade complexities should also be included in the analysis.[24] It seems that natural gas supplies, for instance, can change quite quickly to changes in the price of oil or natural gas. To the extent that the fuel

[24] According to the EIA (2016), significant improvements in drilling efficiency, well completion techniques, fracturing technologies, and multi-well drill sites (8 to 10 horizontal wells from a single well pad) have substantially increased gas supply.. From 2012 – 2016, well productivity has increased by roughly 300 percent. As a result, natural gas prices are likely to be steadier and less volatile than in the past. As oil and gas producers continue to improve well completion technologies, each well will become more productive and impactful on overall supply.





and market price projections were too constrained, it has an adverse effect on the development of scenarios and sensitives. For example, depending on assumptions for price projections, couldn't reasonable scenarios be constructed for Indiana utilities to address the following types of potentialities?

- Is it possible for natural gas and coal prices to diverge during periods over the 20-year planning horizon?
- Is it possible that reduced customer demand for electricity (perhaps a recession) may not result in lower natural gas or coal prices? Recall the recessions of the 1970s and 1980s where the price of natural gas, coal, and nuclear fuel were very high.
- Would the utilities agree that some level of increased customer demand may not always result in higher coal and/or natural gas prices? Recent history provides an example.
- Are there opportunities for the coal industry, perhaps in concert with the railroads, to lower the delivered cost of coal to a point that may slow the retirement rate of coal-fired power plants?
- Suppose the FERC and the courts reject current attempts by states to subsidize the continued operation of coal and/or nuclear generating units. Does this affect the economics of Indiana generating resources? Correspondingly, did the utilities consider the implications that might result from most utilities retaining much of their coal (and nuclear) generating fleets?
- Suppose state and/or federal law bans fracking in much of the United States. While an admittedly unlikely event, should this be considered in the development of scenarios?
- After the IRPs were submitted, substantial fracking opportunities were discovered (e.g., the Permian Basin). Recognizing the IRPs are a snap shot in time and the IRP analysis was completed before substantial new natural gas potential was public, do the utilities feel the lower natural gas prices projections used in their scenarios might have been even lower?
- Recognizing that the IRPs were developed with the expectation there would be no change in environmental policy, would it have been useful to model a diminished environmental policy?
- What, if any effect, was given to coal and natural gas industry bankruptcies? Did these influence the narratives to justify the fuel price projections?
- What would be the ramifications of lower renewable and EE prices - perhaps due to increased efficiencies beyond those currently projected - on fuel and commodity price forecasts?
- In developing utilities' scenarios and sensitivities from the narratives provided by independent experts for fuel price projections, did the companies' fuel price projections consider international trade and markets for coal and liquefied natural gas exports (imports) over the 20-year planning horizon and the effect on domestic markets?
- What happens to this scenario if trade practices become very restrictive?

Of course there are other potential scenarios. We urge the utilities to give increased consideration to plausible scenarios, including those that have significant ramifications but relatively low probabilities of occurrence. To be clear, there is no intended implication that utilities should run several additional scenarios. Rather, the intention is an expansion of the narratives for the scenarios to have considered a wider range of possible fuel and commodity price projections in the construction of scenarios.

Historically, fuel and resource diversity was also thought to provide greater reliability and serve to moderate volatile commodity prices. More diverse resource portfolios, however, are not necessarily more reliable. The historical price volatility that characterized the natural gas industry for decades may be largely a thing of the past due to fracking, but future prices could be influenced by global markets. Long-term decisions should be informed by an understanding of the dynamics and inter-related complexities of U.S. commodity markets and the influence of global markets. It is incumbent on the utilities to continually evaluate the commodity markets and assess the complex U.S. market interactions while valuing fuel and resource diversity.

8.2. Scenario and Risk Analysis

All Indiana utilities, as well as utilities throughout the nation, are confronting significant uncertainties and risks that seem certain to result in changes in their resource portfolios due, primarily, to projections of low natural gas prices compared to coal. The aging of the existing coal fleet and the very high cost of building new coal-fired generating units poses a significant economic challenge to coal as a fuel source. Even nuclear units in many regions struggle to be cost competitive in the current markets. The rapidly declining cost of renewable resources and the increased capability of the transmission system to carry these resources to distant markets is also a factor. DSM, including improved appliance and end-use efficiencies, is a resource that is likely to be increasingly utilized, even at a time when load growth is minimal or even declining.

Based on these national uncertainties and risks, the Director sees challenges to valid concerns about the rigor and credibility of load forecasting for larger customers in Indiana. Because of the importance of larger customers for NIPSCO and Vectren, in particular, the risks of over- or under-forecasting the demand and energy use of larger customers is important. Especially taken together, changes in the operations and business climate have significant ramifications for these utilities, their employees, customers, communities, and investors.

Each utility said they were taking steps to improve its forecasting for its customers – including the largest customers. These factors heighten the importance of recognizing, assessing, and bracketing the broad range of potential risks and provides opportunities for utilities to develop resilient strategies to minimize adverse consequences of risks. IPL and Vectren made excellent progress in attempting to interject greater use of probabilistic analysis into traditional scenario-based analysis with the recognition that it is a work in progress. Consistent with the IRP draft rule, these initial efforts will mature in future cycles. NIPSCO's efforts to improve its risk analysis were not as successful due to the inability of its models to integrate probabilistic analysis into its IRP. As a result, NIPSCO's IRP was almost certainly not as informative as NIPSCO would have preferred. According to NIPSCO, future IRPs, using more comprehensive state-of-the-art models and improved databases, will not suffer the same limitations.

8.3 Energy Efficiency Issues / Questions

Each of the three utilities is to be congratulated on the significant methodological improvements made so that DSM and other supply-side resource options are treated more comparably. A comparison of the methodologies across the utilities is informative but brings a number of questions to mind.

NIPSCO and IPL used a very similar approach to create DSM bundles, which is in sharp contrast to that used by Vectren. To be clear, the differences in approach should not imply that one method is more efficacious than another. IPL and NIPSCO combined measures with similar load shapes, customer classes, and end uses into bundles. Vectren chose to base bundles on generic DSM savings in eight blocks of 0.25% each year of the planning horizon. The component programs for the blocks developed by Vectren are assumed to initially be those approved in Cause No. 44645.

With regard to Vectren's methodology, every bundle is exactly the same except for costs. More importantly, the load shape of the energy efficiency bundles was exactly the same across the bundles and through time. Vectren used the Strategist default DSM load shape for each bundle which is very comparable to the DSMore load shape used in the 2013 Vectren MPS. In contrast, the bundles prepared by IPL and NIPSCO had load shapes that differed across bundles at any point in time. It is unclear if the load shapes were held constant over time but that appears to be the case. It is not obvious to the Director which approach to developing bundles is superior. Is a uniform bundle, with a uniform load shape, preferable to bundles based on end-use with associated load shapes? Is a resource optimization model going to select a different aggregate amount of DSM based on how these bundles are assembled?

Based on the information available from IPL, NIPSCO, and Vectren, it is not clear that one approach to handle limitations in optimization modeling is superior to another. Certainly, the state-of-the-art computing capability – including reduced run times and modeling sophistication to conduct simultaneous optimization rather than painstaking iterations – has advanced significantly in the last five years. It is likely that models will grow increasingly capable, thus reducing the limitation over time. Regardless of advances in modeling capabilities that are warranted to address the increasingly complex and financially consequential decisions that utilities have to confront in the next few years, the benefits of these new capabilities may not be fully realized until utilities have additional statistically-credible experience to better document the changes in how different customer's use energy and the effects on system peak demand, both within Indiana and across the country, to better inform resource decisions in the future. IPL, in particular, should be commended for its expansive deployment of Advanced Metering Infrastructure (AMI) and its willingness to explore how to more fully develop the information needed for the next generation of DSM analysis.

For Vectren, the different bundle creation processes also demonstrated an entirely different role for - or use of - the respective Market Potential Studies. Vectren's use of identical bundles with a generic load shape was not based in any way on its MPS except to provide indicative information as to the maximum amount of energy efficiency available in its service territory. In other words, Vectren used the MPS to decide if the maximum annual potential savings was 2% or something else. Thus, the MPS was used to decide how many bundles should be considered in any one year which Vectren decided was eight bundles. At this early stage of DSM analysis, the Director takes no position on the efficacy of this approach compared to alternatives except to suggest that the MPS may provide more useful information than was utilized by Vectren.

Both IPL and NIPSCO made extensive use of their respective MPS. Each company used the Market Potential Study to determine the different levels of DSM potential: technical, economic, and achievable. This information was then used by MMP to develop bundles that would be used as resource options in the IRP optimization process. Importantly, the MPS analyses was based on individual measure data and so were the bundles that were fed into the optimization model. The penetration of the measures in each bundle was based on information contained in the MPS.

For both IPL and NIPSCO, MMP utilized the DSMore economic analysis tool to perform a final screening to determine whether the measures coming out of the MPS were cost effective, taking into account utility specific rates, cost escalation rates, discount rates, and avoided costs. Vectren did not perform this step given how they developed its DSM bundles. Vectren instead used its most recent MPS to make sure that Vectren's 2016 levelized DSM cost (the starting point for this analysis) was reasonable.

For all the similarity in overall methodology used by NIPSCO and IPL, there are a couple of differences to note.

1. Both NIPSCO and IPL used the Achievable Potential as determined in their respective MPS. IPL divided the Achievable Potential into 2 levels - MAP and RAP. MAP estimates consider customer adoption of economic measures when delivered through DSM programs under ideal conditions and an appropriate regulatory framework. RAP reflects program participation given DSM programs under typical market conditions and barriers to customer acceptance and constrained program budgets. IPL used the MAP measure estimates to construct the DSM bundles input into the IRP optimization modeling. NIPSCO used a Program Potential based on cost-effectiveness analyses at the measure level by MMP using the screening tool DSMore. Measures that came out of this analyses were combined into bundles by end-use and load shape. IPL also used MMP "to create the DSM bundles using the DSMore cost-effectiveness model."

It appears that NIPSCO used a more conservative version of Achievable Potential than IPL on which it based the DSM bundles. NIPSCO defined Achievable Potential as refining the Economic Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of DSM measures (p. 77). As noted above, IPL used MAP to develop bundles, and MAP estimates consider customer adoption of economic DSM measures under ideal market, implementation, and customer preference conditions, and an appropriate regulatory framework. It would appear that NIPSCO was more conservative because its definition of Achievable Potential is probably closer to IPL's RAP rather than MAP.

2. IPL and NIPSCO both developed bundles by grouping measures by sector, end use, and similarity of load shape. However, IPL went one step further and disaggregated its bundles by the direct cost to implement per MWh. The three price tiers were: up to $30/MWh, $30-60/MWh, and $60 plus/MWh. As IPL noted, creating cost tiers addresses the issue of having highly cost-effective measures lumped into bundles with marginally cost-effective measures. Such a structure could result in some cost-effective measures not being selected. NIPSCO recognizes the potential problem of mixing higher cost and lower cost DSM measures in the same bundle.

Perhaps the most difficult area to compare and try to draw conclusions is how the cost of the bundles were developed by each utility and how the cost varied both across bundles and within the same bundle over the forecast period. CAC et al. expressed concerns the DSM bundle methodologies implemented by each of the utilities required a forecast of DSM bundle cost and performance trajectories over a 20-year period regardless of the specific cost projection methodology used. Vectren used an approach for bundle cost projections that was very different from that implemented by NIPSCO and IPL.

8.4. Metric Definitions and Interrelatedness

The Director appreciates the development and implementation of metrics used by the utilities in their respective IRPs. Our primary interest is to enter into a conversation to further everyone's understanding of the usefulness of individual metrics and how to best consider the metrics and the story they tell in a holistic manner. Clearly some metrics are more directly relevant to the specific risk being evaluated than others and that needs to be better understood. Another issue is how metrics are weighted. Should all risk measures be weighted equally or are there circumstances where a different weighting is reasonable? Also, some of the metrics probably need to be more clearly defined in a narrative so that their limitations and strengths can be better understood. Lastly, the interrelationships between various measures needs to be more fully understood. That is, are some redundant, are some telling the same story from different perspectives, and are other measures more appropriately evaluated only when also considering other metrics? What are the limitations and strengths of using a scorecard based on informed judgment to evaluate the performance of various resource portfolios across a diverse range of potential futures?

Examples of clearer and more specific definitions can be found in the PJM Interconnection report titled "PJM's Evolving Resource Mix and System Reliability," published March 30, 2017. PJM notes,

> *Fuel diversity in the electric system generally is defined as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, fuel supply diversity can be considered a system-wide hedging tool that helps ensure a stable, reliable supply of electricity. (p. 8)*

PJM also says diversity consists of three basic properties: variety, balance and disparity. As each of these properties increase, diversity also increases. PJM defines the characteristics of diversity as:

- Variety is a measure of how many different resource types are on the system. A system with more resource types in its generation mix has greater variety.
- Balance is a measure of how much grid operators rely on certain resource types. Balance increases as the reliance on different resource types in a generation mix is becoming more evenly distributed.
- Disparity is a measure of the degree of difference among the resource types relative to each other. Disparity can relate to the geographic distribution of resource types – generation resources that are evenly distributed across the system are more disparate than concentrated pockets of generation resources. Disparity also relates to operational characteristics of resources – a system with resource types that have different operational characteristics is more disparate than a system with in which all of the resource types have similar operational characteristics. (p. 9)

PJM also defines resilience differently than how this term is used by IPL in its risk metric discussion.

The Director recognizes that the metrics and definitions developed for a region as large as a RTO may not be applicable to a single utility, but the specificity in the definitions used by PJM is worthy of emulation where appropriate. Also, the PJM report makes clear that the relationship between diversity and reliability is not linear. More generally, the costs, benefits, and reliability values of fuel and resource diversity is dynamic and extremely important. Future IRPs should devote considerable attention to developing and interpreting different risk metrics and should be informed by experts and stakeholders.

A critical objective should be a robust or resilient plan. How is this defined? How should it be measured? The utilities seem to be using different definitions but a key common aspect is exposure to the wholesale power market. More specifically, exposure beyond some undefined level is generally thought to be bad but there seems to be little recognition, except for NIPSCO, that length of commitment to a specific resource – particularly one that is capital intensive and long-lived can also be a problem. Steel in the ground eliminates market exposure in a sense but has the downside that the costs are sunk and thus are probably exposed to the highest degree of technological risk. Again, a more detailed discussion of the uncertainties, risks, and ramifications of fuel and resource diversity under a variety of scenarios would be helpful.

9. DIRECTOR's RESPONSE TO THE INDIANA COAL COUNCIL

The Director is pleased that the Indiana Coal Council (ICC), because of its status as an important stakeholder, provided useful and insightful comments in this IRP cycle. The Director agrees with many of the comments made by the ICC. IPL, NIPSCO and Vectren, to varying extents, have also agreed with some of the comments made by the ICC.

At the outset, the Director understands the *ICC does not agree "that natural gas prices will be lower cost in the long-term due to fracking and improved technologies"* and with some of the other analysis conducted by the utilities. Perhaps, if the ICC had participated in the stakeholder processes of the utilities, the ICC's input might have been given specific effect but, at a minimum, the differences of opinion might have been narrowed and misunderstandings about the IRP process might have been avoided. The Director hopes the ICC will avail itself of the next stakeholder processes.

9.1 Fuel and Market Pricing Dynamics

The ICC made the following comment on page 1:

> "*The ICC respectfully disagrees with the statement in the Draft Director's Report (footnote 5) that suggests that every utility and stakeholder agrees that natural gas prices will be lower cost in the long-term due to fracking and improved technologies. At a minimum, that is not ICC's opinion*."

To be clear, footnote 5 of the Draft Director's Report does not suggest that "*every utility and stakeholder agrees natural gas prices will be lower in the long-term.*" Rather, the footnote merely states the fact that the utilities' IRPs found that: *The primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies.*[25]

The Director, IPL, NIPSCO, and Vectren agree to varying extents with some of the comments provided by the ICC regarding the need for greater emphasis on the narratives supplied to the utilities by independent and objective experts. The Draft Director's Report also encouraged utilities to be more expansive in their risk analysis by considering a broader spectrum of fuel prices – including higher natural gas prices and lower coal prices. The Director addresses both of these topics in greater detail below.

If the narratives from the independent experts that were retained by the utilities had provided more details about the drivers for the prices of fuels, and if the ICC had participated in the IRP stakeholder processes, it seems possible that at least some of the concerns raised by the ICC might have been addressed. However, the Director's and the utilities' views were also informed by the following empirical facts:

[25] The complete footnote 5: *The primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies.* As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

A. Coal-fired generating units are not being dispatched as fully as they had been. This is evidenced by reduced capacity factors in competitive wholesale markets facilitated by the MISO. Some utilities have requested subsidies from states to support some generators.
B. The retirements of several coal-fired generating units have been announced in this region despite the recent increase in natural gas prices.
C. The only coal-fired plant under construction in the continental U.S., will probably be cancelled.[26]
D. Against the backdrop of cost overruns and delays at Southern Company's Kemper IGCC unit, it seems unlikely that there will be any new coal-fired generating units being built in the continental United States.
E. The above competitive market-based indicators, combined with a preponderance of confirming studies,[27] add additional credence to the results from the Indiana utilities' IRPs.

The Director agrees with the ICC that expanded analysis of a broader range of coal and natural gas prices would have been informative. Utilities and stakeholders might have found using extreme changes in price assumptions for natural gas and / or coal would provide useful information to determine the point of inflection where changes in price assumptions would affect resource decisions.

The Director believes IPL, NIPSCO, and Vectren fully recognized that planning their systems based upon highly unlikely events / assumptions would not be consistent with good planning. Indiana's utilities' IRPs should continue to recognize the value of fuel and resource diversity, even if they cannot quantify the

[26] Topeka — A controversial plan to build an 895-megawatt coal fired power plant in southwest Kansas now appears to be dead, company officials behind the project have said. In an August filing with the Securities and Exchange Commission, Denver-based Tri-State Generation and Transmission Association described as "remote" the chances that it will ever build the plant, and it said the company is writing off as a loss more than $93 million it has already spent on the project. "*Although a final decision has not been made by our Board on whether to proceed with the construction of the Holcomb Expansion, we have assessed the probability of us entering into construction for the Holcomb Expansion as remote…Based on this assessment, we have determined that the costs incurred for the Holcomb Expansion are impaired and not recoverable."* Lawrence Journal World, Sept 19, 2017.

[27] Trump Administration's "Staff Report on Electricity Markets and Reliability" released by the Department of Energy on August 2017. This recent DOE study is replete with commentary such as:

> *The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation. Low-cost, abundant natural gas and the development of highly-efficient NGCC plants resulted in a new baseload competitor to the existing coal, nuclear, and hydroelectric plants. In 2016, natural gas was the largest source of electricity generation in the United States—overtaking coal for the first time since data collection began. The increased use of natural gas in the electric sector has resulted in sustained low wholesale market prices that reduce the profitability of other generation resources important to the grid. The fact that new, high-efficiency natural gas plants can be built relatively quickly, compared to coal and nuclear power, also helped to grow gas-fired generation. Production costs of coal and nuclear plants remained somewhat flat, while the new and existing, more flexible, and relatively lower-operating cost natural gas plants drove down wholesale market prices to the point that some formerly profitable nuclear and coal facilities began operating at a loss. The development of abundant, domestic natural gas made possible by the shale revolution also has produced significant value for consumers and the economy overall.* (Page 13 – Emphasis added).

value of diversity. Based on the utilities' recognition of the critical importance of fuel price projections and representations made by IPL, NIPSCO, and Vectren, the Director is confident that future IRPs will devote increased effort to capture the complexities of fuel price dynamics.

> "*For a utility to craft a resource plan without consideration of the complexities of the natural gas market (including plans to address the volatility) is problematic for customers.* Comments of the Indiana Coal Council on the Draft Director's Report for the 2016 Integrated Resource Plans, Page 2 of their letter.

Again, the Director, IPL, NIPSCO, Vectren will, to varying extents, agree with the ICC's comments that the natural gas markets are becoming increasingly complex. The Director is confident that utilities not only recognize the increasing complexities but will insist that narratives supplied by independent experts for future IRPs reflect the degree of uncertainty and complexity inherent in fuel price forecasts. The Director believes the analysis conducted for this IRP by IPL and NIPSCO especially combined with the commitment to continued enhancements, should help allay concerns.

> **IPL**
> *IPL agrees that the interrelationship between commodities and power markets will continue to evolve with the changing landscape of natural gas production and demand, the changing national and regional resource mix, and stagnant regional load growth projections. The forecasts and projections have a major influence on the portfolios generated as part of an IRP process, and IPL is committed to enhancing robust modeling techniques and discussing assumptions in an open and transparent manner as part of the stakeholder process. IPL is confident that ABB's Reference Case methodology is consistent with forecasting best practices and relies on fully integrated energy models that ultimately build up to the power prices used in the production cost modeling. In the next IRP, IPL will commit more to fully describing the fundamentals underlying the forecasts used.* Indianapolis Power & Light Company Reply to Director's Report on the 2016 Integrated Resource Plans August 28, 2017, Page 2.
>
> **NIPSCO**
> *The Director expressed concern that NIPSCO's fuel price projections do not capture the 'nuanced and dynamic relationships between oil and natural gas or whether the historic correlations between natural gas and coal markets are changing.' NIPSCO takes note that the Director also noted that NIPSCO needs to do more than simply have a correlated price forecast. NIPSCO accepts the Director's observation and will do so in future IRPs.* Northern Indiana Public Service Company's Response to the Director's Draft Report on NIPSCO's 2016 Integrated Resource Plan, Page 1
>
> *NIPSCO has engaged a consultant that independently forecasts fuel prices using an integrated market model. Moreover, the consultant intends to provide underlying assumptions, alongside benchmarking to publicly available forecasts, to support its analysis. NIPSCO also notes the Director's agreement that several of the Indiana Coal Council's ("ICC") comments merit consideration. To that end, NIPSCO has had follow up meetings with the ICC to discuss its concerns.* Page 2

Director's Summary of Fuel and Market Pricing Dynamics
These increasing complexities and interrelations of the natural gas market and the resulting fuel price projections is one of the four primary focal points of the Draft Director's Report. These complexities and interrelationships were also addressed in the other topics; particularly in the construction of scenarios,

sensitivities and, ultimately, in the resource portfolios. Particularly as the resource decisions become increasingly close calls, the Director is confident that Indiana utilities and their stakeholders will appreciate the importance of independent, objective, and comprehensive fuel and market price projections and will insist on well-reasoned narratives.

9.2 Scenario Development and Risk Analysis

> *The ICC is confused by the Commission's position that the IRP is limited to being "a point in time analysis". While the revised Rule 7 has not been finalized, every draft version that ICC has seen contains a new Section 10 which specifically addresses Major Unexpected Change following that publication of the IRP… ICC respectfully requests that the Draft Director's Report consider more forceful language related to the limited validity of IRP findings acknowledging that no material actions should be taken without new analysis at the time of a filing and include reconsideration of what has turned out to be dated findings.* [Page 3 of the ICC letter]

The Director believes the ICC may misunderstand the purpose of the IRPs and any concerns are premature. The Director reiterates on page 5 of the Draft Report "*With good reason, IPL, NIPSCO, and Vectren have sought to maintain as much optionality as possible in their IRPs… To this end, the IRP analysis – including the utility's selection of a preferred resource portfolio – should be regarded as an indicative analysis, in that the results are based on appropriate information available at the time the study was being conducted and does not bind the utility to adhere to the preferred resource portfolio, or any other resource portfolio. If there is information to support a different outcome in a matter before the Commission after an IRP used to support a resource decision is completed, the utility should assess whether an update to the IRP is appropriate. Ultimately, in the instance of a case before the Commission, the Commission, after consideration of testimony, will decide whether additional analysis is necessary to provide the Commission with the requisite information."*

9.3 Continued Improvements in the IRP

> *The ICC is surprised by the standard to which the Commission is holding for the utilities which have submitted IRP's. A "better than last time" performance should not be acceptable if there have been significant flaws in their analyses, be it with respect to assumptions and/or methodology.* Page 3 of the ICC letter.

The draft rules recognize that IRPs (e.g., the data, analysis, methods, computer capabilities, and stakeholder process) are evolutionary in the quest for continual improvements rather than the impossible requirement for utilities to accurately project optimal resource requirements over the 20 year planning horizon. The Director disagrees with the ICC's characterization on pages 3 and 4 of their letter that the utilities had "*significant flaws in their analyses, be it with respect to assumptions and / or methodology."* The Director stands by the well-deserved comment that utilities have made continual enhancements to their IRP processes.

9.4 ICC's Suggestion for Commission Consideration

> *The ICC strongly believes the utilities' and the Commission's consideration of the broad public interest can be improved upon and should include an analysis of the resource plans' impact on the state economy.* (Page 4 of the ICC letter)

This is a matter for the Commission to consider, consistent with its statutory authorities. Moreover, in addition to the proposed draft IRP rules, the utilities gave considerable consideration to the potential ramifications for their employees, customers, and communities.

SUMMARY

The Director cannot over-state the technical complexities inherent in the development of credible IRPs. The comments offered by stakeholders that participated in the process, as well as those offered by the ICC, highlight the daunting task. The Director takes this opportunity to commend IPL and NIPSCO for their commitments to make future enhancements to subsequent IRPs.

10. Director's Response to the CAC et al

10.1 Stakeholder Process

Stakeholders, like the CAC et al, that have participated in the IRP process for several years and have made significant contributions to the IRP processes have commended Indiana's utilities for substantial improvements in all aspects of the IRPs, including the stakeholder processes. The Director and utilities agree with the CAC et al that, future enhancements to the stakeholder process are desirable. As the Director noted:

> *All utilities are committed to enhancing their stakeholder process. By going from a two year to three year IRP cycle, utilities can increase stakeholder input by: 1) establishing objective metrics to evaluate their IRP; 2) defining the assumptions (e.g., fuel prices, costs of renewable resources, costs of other resources); 3) constructing scenarios to provide a robust assessment of potential futures; and 4) reviewing the resulting resource portfolios.* Page 3 of the Draft Director's Report.

Beyond the CAC et al's contribution to the IRP processes, it is incumbent upon all other stakeholders to make an effort to understand the complexities of IRP to provide well-reasoned input. It was commendable that utilities, on their initiative, provided a primer on long-term resource planning to help stakeholders increase their knowledge of the processes. For the benefit of stakeholders, utilities should continue to provide information on the building blocks of long-term resource planning. For stakeholders that have expertise and experience in IRP, utilities might consider a *deeper dive* into some of the elements such as the inputs for the IRP, how the models work and constraints on their operations, and how difficult topics such as DSM and Distributed Energy Resources (DER) are modeled.

There are limits to what can be done in a stakeholder process to facilitate education beyond starting earlier to permit greater sharing of information and limiting - to the maximum extent possible – the withholding of information due to proprietary and confidentiality concerns. The Director appreciates the increased burden on the utility as well as stakeholders. However, the improved processes should reduce controversies or, at least, focusing the areas of controversy more narrowly. To reiterate:

> *The utilities have all made a concerted effort to broaden stakeholder participation. All of the utilities have offered unprecedented transparency and candor. It is gratifying that the top management of each utility, top staff and subject matter experts have all been made available to facilitate the collegial stakeholder process.* Page 2 of the Draft Director's Report.

10.2 Formatting Material

The Director is pleased that IPL, NIPSCO, and Vectren have made substantial enhancements to the content and clarity of their IRP's but agree with the CAC et al's comment that "*utilities [should] endeavor to present basic information in a more readable and accessible fashion*." (Page 1 of CAC et al's comments) The Director appreciates the utilities commitment to make continued improvements. From the inception of the IRP process in Indiana, the Director has been reluctant to be too prescriptive in how the IRPs should be formatted. However, there is some core information that the utility, the Commission, the OUCC, stakeholders, the RTOs, and others would like to have available in the IRPs and in formats (narratives, graphics, tables, and mathematics) that are informative and easily understood. The Director welcomes suggestions.

10.3 **Referencing Stevie's section we share many of the concerns**

Comments made by the CAC et al regarding the interesting work done by Dr. Dick Stevies' were excellent and very much appreciated. The Director agreed with many, but not all, of the concerns raised by the CAC et al. For a more detailed discussion, the reader is invited to read the Director's response to Vectren.

10.4 Metrics

The Director agrees with the CAC et al that the metrics used to evaluate the efficacy of the portfolios should be improved upon but recognizes this is the first time that metrics have been expressly detailed. Especially given the newness of the metrics, the Director recommends all Indiana utilities, with input from stakeholders, consider establishing metrics early in the stakeholder advisory IRP process. Stakeholders should recognize the possible need for adjustments to the metrics as the modeling proceeds. To the extent reasonably feasible, the metrics should be quantifiable. However, stakeholders should recognize some metrics are inherently subjective (e.g., the value of resiliency or fuel / resource diversity) but this should not mean that there is no effort to gain a general understanding about how those metrics will be evaluated and weighted. Ideally, mutual understanding of the metrics will reduce misunderstandings as the utilities' preferred portfolio and the other portfolios are assessed.

10.5 Modeling

The Director agrees with the CAC et al that all models (e.g., long-term planning models, DSM models, forecasting models, financial models) have limitations or constraints. Stakeholders and the Director would appreciate as much transparency as possible to understand the limitations of specific models. It is not obvious to the Director that these modeling limitations don't adversely affect the results compared to an idealized model with no such limitations. Nor is it apparent to the Director that alternative methods of working through the model limitations don't provide different results. The run times are greater for models that rely on multiple iterations rather than those models that have greater capability to conduct simultaneous optimizations. Ultimately, it seems likely that modeling a single bundle of all resources would enable more comparable treatment of all resources than multiple iterations of multiple selected bundles of resources. As the computer capabilities expand current modeling constraints will be reduced. Of course, it is the discretion of the utility to evaluate, compare, and value the different strengths and weaknesses embodied in different models

10.6 The Future of IPL Stochastic Analysis

The CAC et al raised a potential concern that IPL may be placing too much reliance on stochastic analysis at the expense of scenario analysis. A statement by IPL in their comments on the Draft Director's Report might cause further concern for CAC et al:

> *IPL could accommodate showing a similar table in the next IRP, but believes that the probabilistic modeling effectively accomplished the same thing in a more robust manner by showing how each portfolio performed across 50 simulations using alternative assumptions, not just the three to four drivers that changed with each scenario. An alternative approach to each of these methods would be to incorporate stochastics into the capacity optimization up front. Rather than generating five to ten*

> *portfolios from deterministic scenarios, the optimization engine would select the best portfolio across all of the probabilistic simulations.* <u>*IPL's new modeling software is expected to enable this type of capacity optimization modeling in addition to traditional deterministic scenarios combined with stochastic sensitivities.*</u> *Some binary factors such as regulation or carbon pricing are difficult to capture stochastically, so IPL expects to rely on multiple methods for developing and evaluating portfolios in the next IRP.* (Page 3) – Emphasis added.

But the Director trusts that IPL recognizes that some planning analysis is best suited to scenario analysis and IPL's inference that their new long-term resource planning models will facilitate probabilistic analysis is not to the exclusion or detriment of scenario analysis. More broadly, for all Indiana utilities, the Director has tried to emphasize that scenario and probabilistic analysis are complimentary rather than being substitutes or mutually exclusive.

ATTACHMENT AS-7
Please see separately filed Excel sheet.

ATTACHMENT AS-8
Please see separately filed Excel sheet.

ATTACHMENT AS-9-CONFIDENTIAL
Please see separately filed Excel sheet.

ATTACHMENT AS-10
Please see separately filed Excel sheet.