BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (“VECTREN SOUTH”) FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY (“CCGT”); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS (“CULLEY 3 COMPLIANCE PROJECT”); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH’S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 ET SEQ., 8-1-8.5-1 ET SEQ., AND 8-1-8.8-1 ET SEQ.

DIRECT TESTIMONY OF
TYLER COMINGS
ON BEHALF OF
CITIZENS ACTION COALITION, SIERRA CLUB, AND VALLEY WATCH
AUGUST 10, 2018

PUBLIC VERSION—CONFIDENTIAL INFORMATION REDACTED
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1. **INTRODUCTION AND PURPOSE OF TESTIMONY**

Q Please state your name, business address, and position.
A My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 44 Teele Avenue, Somerville, Massachusetts.

Q Please describe Applied Economics Clinic.
A The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University’s Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups and government agencies on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q Please summarize your work experience and educational background.
A I have 13 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, New Jersey, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42. Prior to that, I conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is included as Attachment TFC-1.

Q: On whose behalf are you testifying in this case?
A: I am testifying on behalf of Citizens Action Coalition of Indiana, Sierra Club, and Valley Watch (“Joint Intervenors”).

Q: Have you testified in front of the Indiana Utility Regulatory Commission previously?
A: Yes. I testified in Cause No. 44339 which involved Indianapolis Power and Light’s application for a Certificate of Public Convenience and Necessity (CPCN) to construct the Eagle Valley natural gas plant.

Q: Have you filed comments on Integrated Resource Plans (IRPs) in Indiana?
A: Yes. I co-wrote comments on Duke Energy Indiana’s 2013 IRP and Indianapolis Power and Light’s 2014 IRP.
Q What is the purpose of your testimony?

A My testimony mainly addresses the assumptions and modeling methodology employed by Southern Indiana Gas and Electric Company (“Vectren” or the “Company”) in its petition to construct a new natural gas plant near the A.B. Brown coal plant and continue operation of the F.B. Culley 3 coal unit.

Q Please summarize your testimony.

A Based on my review of the Company’s petition, its responses to data requests, and modeling conducted by Witness Clack, I conclude the following:

1. The Company’s plan is neither low cost nor low risk according to its own analysis. The Company conducted several modeling steps using multiple models, starting with the 2016 IRP process through the filing of this petition. However, it chose to ignore lower-cost, lower-risk portfolios in favor of its preferred plan. Moreover, its resource decision is largely based on assumptions and modeling that are now two years old.

2. Even if the Company had chosen a low-cost, low-risk plan based on its own analysis—there were many flaws in the Company’s modeling approach to the point that it should not be used to make a resource decision. Perhaps most notably, the Company’s plan exposes ratepayers to significant market risk. Despite relying on the wholesale market for low-cost energy in recent years, the Company is speculating that it will now make significant net sales outside of its territory to support major investments. Many decisions made throughout the process were biased in favor of the Company’s plan including: the underestimation of demand response potential (and by extension an overestimation of the Company’s generating capacity need), overestimate of renewable costs, a highly flawed risk assessment with arbitrary scoring methods, and a limited solicitation for choosing a new resource.
Q What are your recommendations?

A I recommend that the Company’s petition be denied. The Company has not provided sufficient justification for its choice to build a new natural gas plant and to continue operation of F.B. Culley Unit 3. Its modeling contained many flaws and even that flawed exercise did not show that this plan was low cost or low risk. At the very least, the Company should be required to conduct a new, more reasonable and up-to-date analysis, prior to a final Commission decision on whether to approve its petition.

Should the petition be granted, given the excessive market risk involved in the Company’s plan, the Commission should condition any approval by putting in place protections for ratepayers. The Company is asking that ratepayers fund a speculative, risky investment venture in place of other lower cost, lower risk alternatives. The Company should be held accountable if this investment does not pay off.

Conditional approval should include: 1) limiting capital costs charged to ratepayers for the natural gas plant to those presented in this filing; 2) applying credits to ratepayers for off-system sales revenue that were projected in this filing but do not materialize; 3) exempting ratepayers from environmental compliance costs for F.B. Culley Unit 3 over and above what is included in this filing.

2. SUMMARY OF THE COMPANY’S PLAN AND METHODOLOGY

Q Please summarize the Company’s preferred expansion and retirement plan in this cause.

A Vectren says that it intends to retire A.B. Brown Units 1 and 2, F.B. Culley Unit 2, and Warrick Unit 4 by January 1, 2024. Additionally, it intends to bring 4 MW of solar online in 2018 with an additional 50 MW in 2019. It also intends to

1 Similar conditions were imposed by the West Virginia Public Service Commission (WVPSC) in approving the Pleasants coal transaction. See: Case No. 17-0296-E-PC. WVPSC. Commission Order, January 26, 2018. (Attachment TFC-20).

2 Cause No. 45052, Petitioner’s Exhibit 1 at 8, lines 3-5.
bring a 800 to 900 MW natural gas combined cycle unit online starting in 2024. And finally, the Company proposes to invest in environmental compliance at F.B. Culley Unit 3 in order to extend its life through at least 2036, the last year of Vectren’s modeled planning period, and perhaps even later than that. This portfolio is referred to as “Portfolio L” in Vectren’s 2016 IRP and as “Preferred-7F5F” in the Company’s updated Strategist modeling.

Q What analysis did the Company conduct to support this plan (“Portfolio L” and later “7F5F”)?

A The Company conducted the following analytical steps:

1. Strategist modeling analysis performed for its 2016 IRP;
2. a risk assessment and scorecard performed by Pace Global, using the Aurora model, for the 2016 IRP;
3. updated Strategist modeling performed after the 2016 IRP submission;
4. updated scorecard by Pace Global, excluding some of the original risk factors but using the original 2016 IRP Strategist modeling results (#1);
5. a request for proposal (RFP) that only resulted in natural gas bids, including self-build proposals from the Company; and
6. modeling using PROMOD performed by Burns and McDonnell to evaluate select responses to the RFP, used to support the Company’s choice of a self-build natural gas plant.

These steps are discussed in more detail below.

Q What objectives did the Company seek to achieve?

A Matthew Rice describes the 2016 IRP analysis as seeking to address “reliability, cost, flexibility, risk, environment, balance, and economic impact.” These

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3 Vectren Petition, p.8.
4 Vectren Response to ICC Data Request 3.10 (Attachment TFC-2).
5 Cause No. 45052, Petitioner’s Exhibit No. 5, p. 15, lines 20-23.
6 Cause No. 45052, Petitioner’s Exhibit No. 6, p. 6, line 23 to p. 7, line 4.
objectives were purportedly addressed in the risk assessment conducted by Pace Global—provided as part of the 2016 IRP.

Q Did the Joint Intervenors file comments on the 2016 IRP?
A Yes. A report authored by Anna Sommer and Elizabeth Stanton was filed on the Joint Intervenors’ behalf on April 17, 2017, which was subsequently updated on July 26, 2017 with corrections to Exhibit A submitted on August 7, 2017. Joint Intervenors also provided extensive comments on the Director’s Draft Report on the 2016 IRPs, which ultimately produced the Director’s Final Report on the 2016 IRPs. I have reviewed these documents in preparation for my testimony.

Q How was the 2016 IRP analysis updated for this current filing?
A Vectren updated its 2016 IRP’s coal and gas price forecasts, MISO energy and capacity prices, solar photovoltaic (PV) costs, energy efficiency (EE) costs, and the solar capacity credit. The Company removed the option for Strategist to consider early retirement, conversion, and refuel options for coal units and assumed extension of Warrick Unit 4’s operating life through 2023. Additionally, Vectren asked Pace Global to rework its scorecard analysis based on feedback from the IURC Director’s Report on Vectren’s 2016 IRP.

Q Please describe the use of the Strategist model in this case.
A Strategist is primarily a capacity optimization model that produces portfolios of energy resources over the long-term. Once portfolios are chosen, they can be dispatched by the model but not at an hourly level—as other models can. In this case, the Company used the model both to choose between limited sets of

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7 Cause No. 45052, Petitioner’s Exhibit No. 5, p. 4, lines 2-3.
13 Cause No. 45052, Petitioner’s Exhibit No. 5, p. 15, lines 15-17.
resource alternatives as well as to simulate the operation of fixed portfolios of
different resources—arriving at a net present value cost of each portfolio.

Q Please describe the use of the Aurora model in this case.
A The testimony of Gary Vicinus describes the Aurora modeling that was conducted
as part of Vectren’s 2016 IRP. No further Aurora modeling was conducted for this
Cause. In the 2016 IRP, Aurora was used to test a fixed set of portfolios that were
developed from the Company’s Strategist modeling. Pace Global used Aurora to
perform stochastics on each portfolio. Mr. Vicinus ultimately arrived at an
average portfolio cost in terms of net present value.

Q Did the original 2016 IRP modeling using the Strategist and Aurora models
lead the Company to decide which type of natural gas plant it would
procure?
A Not directly. The Company’s modeling in its 2016 IRP using Strategist and
Aurora models was used to justify the Company’s decision on a type of portfolio,
Portfolio L, which included a generic natural gas combined cycle plant. The
decision of what precise natural gas resource to procure was then analyzed in the
PROMOD model, which looked at only select responses to the Company’s RFP,
which were limited to natural gas resources.

Q Please describe the PROMOD model.
A PROMOD is a dispatch-only model, meaning that it simulates the operation of
power plants but cannot select a resource portfolio as Strategist can. However, its
dispatch simulation is more detailed than can be performed in Strategist.
PROMOD can simulate hourly, chronological dispatch while Strategist relies
upon a load duration curve using “typical” time-slices, frequently one week per
month, which is then extrapolated into an annual figure.

Q How did the Company evaluate natural gas resource options?
A Vectren used PROMOD to compare different natural gas resource options. The
Company evaluated:
different vendor operational and cost quotes, to compare congestion relative to Vectren South customer load associated with a new combined cycle facility built in different locations, and finally to compare discrete project options in an overall net present value comparison similar to the 2016 IRP.14

PROMOD was used to evaluate four gas procurement options—including two self-build options and two procurement options outside of Vectren’s territory.15 The two self-build options were a 668 MW CCGT and 808 MW CCGT (both located at the A.B. Brown site). The other proposals were for Vectren to either own 63 percent of a MW CCGT, or partially own and partially procure through a PPA 63 percent of that same CCGT (located in ).16

Q Was the Company’s chosen resource the lowest cost in the PROMOD modeling?

A No. The smaller of the two self-build options (a 668 MW plant) was lower cost than the larger plant (808 MW) pursued by the Company.17 The two non self-build options were shown to be more expensive due mainly to congestion costs, according to Burns and McDonnell.18

Q What is your overall opinion of Vectren’s modeling in support of its filing in this Cause?

A I have several concerns with specific inputs and other modeling assumptions made by Vectren that I detail later in my testimony. My overall opinion, however, is that the process was too convoluted to yield a sufficiently transparent or credible result. Figure 1 and Figure 2, below, show two flowcharts of Vectren’s 2016 IRP created by Vectren’s internal auditors.

14 Cause No. 45052, Petitioner’s Exhibit No. 6, p. 6, line 24 to p. 7, line 4.
15 Cause No. 45052, Petitioner’s Exhibit 6, Attachment MEL-1 (Public), pp.107-108.
16 See Cause No. 45052, Petitioner’s Exhibit No. 6, Attachment MEL-1 (Confidential) at pdf page 87 and MEL-1 (Public) p. 1.
17 Cause No. 45052, Petitioner’s Exhibit 6, Attachment MEL-1 (Public), pp.107-108.
18 Cause No. 45052, Petitioner’s Exhibit 6, Attachment MEL-1 (Public), p.105.
The first flow chart shows that, in Vectren’s 2016 IRP, Pace Global produced market prices using the Aurora model and inputs provided by Vectren, such as fuel prices. The power prices were then fed into the Strategist modeling. The Strategist modeling produces a mix of portfolios that were then fed back into Aurora for “risk analysis” (see Figure 2) which then led to the selection of the preferred portfolio.

These flow charts are focused on the 2016 IRP modeling, so do not even reflect the updated Strategist modeling, the results from the natural gas bid responses to the RFP, or the additional PROMOD modeling analyzing certain bids from the RFP performed by Burns & McDonnell. The more models (and iterations of modeling) used, the more difficult it is for the Commission and stakeholders to

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19 Vectren Attachment ICC DR 1 5.3-R1, p. 7 (Attachment TFC-7).
20 Id.
follow the Company’s process. While it is not unusual for a utility to rely upon outside modeling to develop key inputs like power and capacity prices, the use of so many models in the actual selection of the preferred portfolio creates ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan.

Setting aside any issues with Vectren’s inputs or its methodological approach, Vectren’s preferred portfolio is neither least-cost nor least-risk based on its own analysis using multiple models (as I will discuss in the next section). Moreover, Vectren does not clearly lay out how it considered all of this modeling in its decision-making. In particular, Vectren does not articulate how it weighed cost versus risk with respect to its final decision-making. Pace Global’s “balanced scorecard” (setting aside its flaws), which purports to balance cost and risk, does not resolve this issue because it pertains entirely to the 2016 IRP modeling and not to Vectren’s modeling done subsequent to the IRP.

Q Were coal retirement decisions based on the 2017 updated modeling?

A No. In the updated modeling, Burns and McDonnell removed the Strategist model’s ability to economically retire units endogenously—meaning the model could not choose when to retire a resource on an economic basis. Instead, coal retirement decisions were hard-wired into the model. Witness Rice stated that this was “because the initial modeling adequately addressed the best timing for retirement and the viability of the coal refueling options.”21 In other words, the Company chose not to re-evaluate the coal retirement decision and continued operation of F.B. Culley Unit 3 in light of more up-to-date assumptions.

Q What did the initial modeling in the 2016 IRP conclude was the lowest cost plan?

A The initial modeling in Strategist for the 2016 IRP showed that retiring all coal units and replacing them with natural gas units was the lowest-cost option.22

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21 Cause No. 45052, Petitioner’s Exhibit No. 5, p. 10, lines 16-19.
22 Id. p. 10, 16-17.
Company’s decision to not retire F.B. Culley Unit 3 was based more on the Company’s judgment than on modeling—as I will discuss in more detail below.

3. **BASED ON ITS OWN MODELING, THE COMPANY’S PREFERRED PLAN IS NEITHER LEAST-COST, NOR LEAST-RISK**

Q  Did the Strategist modeling for the 2016 IRP show that the preferred plan was the lowest cost?

A  No. Vectren’s 2016 IRP Strategist modeling, again setting aside any flaws, showed that Vectren’s preferred plan, Portfolio L, was not the lowest cost plan and very close in cost to several other portfolios. Figure 3 shows the net present value (NPVs) of each of the 15 portfolios that were passed on to Pace Global for its scorecard risk analysis.

Figure 3: Net Present Value of 15 Portfolios in Vectren’s 2016 IRP - CONFIDENTIAL

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23 From the Confidential Strategist files provided through informal discovery during CAC’s review of Vectren’s 2016 IRP.

24 See pages 526 – 534 of Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1 for a description of the resources contained in each of these portfolios.
Q Was the Company’s preferred plan the least cost portfolio in Pace Global’s 2016 analysis?
A No. Under Pace Global’s analysis, using the Aurora model, the Company’s preferred plan (Portfolio L) ranked 9th out of 15 portfolios evaluated in terms of least cost NPV—below the median portfolio cost.25

Q Was the Company’s preferred plan the best portfolio when looking at cost and risk together?
A No. Pace Global looked at the “cost-risk trade-off” of the 15 portfolios—shown in Figure 4. The preferred plan (Portfolio L) was neither the lowest cost nor the lowest risk, as shown in the chart below (cost is on the x-axis and risk is on the y-axis):

![Cost Risk Trade Off](image)

Figure 4: Cost-Risk Trade-off in 2016 IRP Portfolios26

Q On what basis did Pace Global support the Company’s preferred plan?
A Pace Global evaluated several risk factors including capacity purchases, number of technologies, economic impact, and environmental impact (among others). It then applied weights to each factor and developed a score on a 0 to 10 basis (10 being the best possible score). Pace Global found the preferred portfolio had the

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25 Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1, p. 280.
26 Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1, p. 231.
highest score of any portfolio but the next two portfolio scores were both within
one percent of that score—as shown in Figure 5 below.

Figure 5: Pace Global’s Assigned Scores for 2016 IRP Portfolios

Q  Do you agree with Pace Global’s methodology in assessing portfolio risk?
A  No. Pace Global’s risk analysis uses arbitrary thresholds to evaluate certain risks
and employs arbitrary weighting of risk factors. I will explain these issues in more
detail in the next section.

Q  Did Vectren’s 2016 IRP preferred portfolio, Portfolio L, look any more
preferable from a cost perspective in Vectren’s 2017 updated Strategist
modeling?
A  No, in fact it was one of the expensive portfolios (highlighted in black)
examined by Vectren in its updated modeling—see Figure 6 below.

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27 Cause No. 45052, Petitioner’s Exhibit No. 7, Vicinus workpapers.
Did the Company evaluate a wide set of options in its updated Strategist modeling?

No. For the most part, instead of modeling a wide set of resources, the Company chose to focus on different types of natural gas procurement. These portfolios are very similar to each other. Nine of the eleven portfolios shown include a new natural gas combined cycle generator. The updated modeling also shows that the Preferred-7F5F portfolio is one of the cost options evaluated.

Did Pace Global update its risk analysis from the 2016 IRP for this case?

Only in part. In my understanding, Pace Global did not re-run the Aurora model to develop new NPV estimates for each portfolio under each risk factor. Instead, it merely removed two risk factors (“net sales” and “remote generation risk”) from

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28 From the Strategist files provided through informal discovery during CAC’s review of Vectren’s 2016 IRP using the study period plan comparison report for each of these portfolios.

29 See pages 526 – 534 of Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1 for a description of the resources contained in each of these portfolios.
the final scorecard calculation, based on feedback from the IURC Director of Resource Planning.\textsuperscript{30}

**Q** After removing those risk factors, was the preferred portfolio from Vectren’s 2016 IRP still ranked the highest in Pace Global’s scorecard analysis?

**A** No. Portfolio L moved from highest to third highest ranking—as shown in \textbf{Figure 7}.

![Figure 7: Portfolio Scores for 2016 IRP Portfolios – Updated in 2017\textsuperscript{31}](image)

**Q** Did the Company reject portfolios in its 2017 update that were lower cost and lower risk than its preferred portfolio?

**A** Yes. Relative to Portfolio L (the preferred plan), Portfolio D included 400 MW of wind and the retirement of F.B. Culley Unit 3. Portfolio D was lower cost than Portfolio L and the only one that Pace Global gave a 10.0 score on “cost-risk trade-off.”\textsuperscript{32} Portfolio D’s overall score was also slightly higher than Portfolio L’s score in Pace Global’s 2017 updated analysis (shown above in \textbf{Figure 7}). Yet the Company did not choose this Portfolio D because: 1) the Company determined it

\textsuperscript{30} Cause No. 45052, Petitioner’s Exhibit No. 7, p.19, lines 13-18.

\textsuperscript{31} Cause No. 45052, Petitioner’s Exhibit No. 7, workpapers.

\textsuperscript{32} \textit{Id.}
the portfolio would include “a significant capacity deficit”; 2) the Company was uncertain of the future capacity credit for wind in MISO; 3) and the Company claimed that keeping F.B. Culley 3 operational would provide “additional flexibility to meet future growth.”

Q How did the Company define a “significant capacity deficit”?  
A Portfolio D included an average capacity purchase of 35 MW per year while Portfolio L included 23 MW of annual purchases. However, the Company does not explain why an incremental 12 MW is somehow unacceptable. (This increment represents less than one percent of the Company’s capacity.) Regardless, capacity risk was already included as a factor in the quantitative risk analysis. After already accounting for that risk, Portfolio D fared better than Portfolio L. The Company is essentially counting capacity risk twice by including the factor in the quantitative risk assessment then using that same factor to reject a better-performing portfolio (according to its own risk assessment methodology) on a qualitative basis.

Q Are uncertain wind capacity credits a reason not to pursue additional wind resources?  
A No. There is uncertainty with many elements of electric system modeling: fuel prices, capital costs, peak load, etc. The Company conducts its own analyses or relies on other entities to forecast these elements. Wind capacity credit is another element that is uncertain but can also be estimated—as is done by other MISO utilities.

Q Were “net sales” and “remote generation risk” removed from consideration in the 2017 updated Aurora score?  
A Yes, based on comments from the IURC Director’s report on Vectren’s 2016 IRP, the Company removed “net sales” and “remote generation risk” from consideration in the 2017 updated Aurora score. Yet, the Company’s decision to

33 Cause No. 45052, Petitioner’s Exhibit No. 5, p.16.  
34 Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1, p. 230, Figure 7.18.
pursue its preferred plan (“Portfolio L”) in the 2016 IRP relied, in part, on these factors.

Q According to the Company, how does F.B. Culley Unit 3 provide “additional flexibility”?  
A In its 2016 IRP, the Company discussed “balance and flexibility/diversity” metrics that included: concentration in one technology, number of technologies deployed, number of 24/7 baseload units, remote generation and net sales. The last two factors were later removed in the updated Aurora results. In the updated results, Portfolio D fared better than Portfolio L. Again, “balance” and “flexibility” factors were accounted for in these scores already. The Company opted to keep F.B. Culley Unit 3 operating based on factors that were already included in that score. Once again, the Company is leaning on a risk factor twice: once in the quantitative analysis and then applying it again in a qualitative manner.

Q On what basis did the Company choose to construct the new natural gas plant and continue to operate F.B. Culley Unit 3?  
A The decision to pursue a new natural gas resource in the first place was ostensibly supported by Strategist and Aurora modeling surrounding the IRP in 2016, updated Strategist modeling in 2017 and re-weighting of the 2016 risk analysis in Aurora in 2017. However, these modeling exercises did not properly justify the Company’s planned new natural gas plant. The Company also used PROMOD to evaluate different natural gas plant options—after issuing a resource-limited RFP. However, this modeling showed that a smaller natural gas plant would have been lower cost than what the Company is applying for in this case.

35 Id. p. 74.
Q  Is there evidence from the Company’s modeling that keeping F.B. Culley Unit 3 on-line is more expensive than taking it off-line?

A  Yes. The Strategist results from the 2017 IRP Update modeling included a portfolio where F.B. Culley Unit 3 remained on-line after 2024 and another portfolio where it was retired in that year. The portfolio where the unit remained on-line cost \textbf{2024} more than when the unit was retired.  

Q  Vectren Witness Carl Chapman describes Vectren’s preferred retirement and expansion plan as a “diversification strategy.” Does Vectren’s modeling validate that characterization?

A  No, not at all. Rather than a diversification strategy, Vectren’s plan is simply one that replaces a heavy reliance on coal with a heavy reliance on natural gas. As shown in Figure 8, the addition of the AB Brown CC and retirement of many of Vectren’s existing coal units would take its system from one supplied by coal over \textbf{2024} percent of the time to one supplied by natural gas roughly \textbf{2024} percent of the time (almost all from the single proposed plant). Solar energy would increase slightly from \textbf{2024} percent today to approximately \textbf{2024} percent and the proportion of energy supplied from wind would go \textbf{2024} from \textbf{2024} percent to \textbf{2024} percent. The heavy reliance on one plant for providing energy and capacity creates significant risk. For instance, if the plant were on either a forced or planned outage then most of Vectren’s energy would need to be purchased from the wholesale market.

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36 Company 2017 Updated Strategist files: Base-Cease Coal 2024-Keep FB Culley 3, Base-Cease Coal 2024.
This is not a diversification strategy at all, but a radical swing from overreliance on one fuel to overreliance on another.

Does the Company’s analysis justify its preferred plan?

No. In the multi-stage, convoluted modeling process it is important to not lose sight of the fact that none of the modeling exercises have shown the Company’s plan to be least-cost. The Company’s preferred plan was not the lowest cost plan in Strategist—in either the 2016 and 2017 modeling exercises or the PROMOD modeling. The preferred plan was also not the lowest risk in the latest Aurora results. While these modeling exercises were meant to justify the Company’s plan, the ultimate resource investment decisions were based on subjective, qualitative factors that had the effect of overriding the results of the modeling that the Company did.

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37 Based on the workpapers of Cause No. 45052, Petitioner’s Exhibit No. 6. I used the outputs of the PROMOD simulation of Vectren’s preferred plan since it yielded unit capacity factors that were more realistic than those contained in the Strategist modeling.
Do you agree with the assumptions and methodology employed by the Company?

To a large extent, no. I have previously discussed why I do not think that the Company’s analysis justifies its plan—even at face value. However, I also find many flaws and concerns about the Company’s assumptions and methodology which I discuss in the next section.

4. Even if interpreted correctly, the Company’s analysis could not be used as the basis for a resource decision

Could the Company’s analysis justify a least-cost, least-risk plan if interpreted correctly?

No. The Company’s analysis has many major flaws and inconsistencies which I will describe in this section, including:

- mischaracterization of market risk and introducing market risk exposure
- overestimation of load
- underestimation of demand response
- overestimation of renewable resource costs
- use of a biased and arbitrary risk scoring system
- failure to encourage other resource options in the request for proposals (RFP)

A. The Company’s Plan Involves Excessive Market Risk

Has the Company properly accounted for market risk in its analysis?

No. The Company appears to see market risk as only one-sided, concluding that having surplus capacity and generation offers only benefits to ratepayers. It stated that: “higher net sales provide a ‘cushion’ against higher than expected load, as well as redundancy to quickly adapt to unexpected change.” However, this view

38 Cause No. 45052, Petitioner’s Exhibit No. 5, Attachment MAR-1, p.553.
only holds true when market prices and/or load are high enough to justify it. Conversely, if market prices and/or load remain low, then the risk is that the Company’s system will be overbuilt and ratepayers will have paid for too much capacity. Under current market conditions, excess capacity would be sold at very low market prices whereas if the Company were slightly short on capacity, it could purchase additional capacity at those same low prices.

**Q** Is the Company planning to have significantly more capacity than required—even under its own peak load assumptions?

**A** Yes. The Company is required to maintain a planning reserve margin (which acts as a “cushion”) above its peak load. The Company can provide its own capacity, sign contracts with owners of other capacity, or purchase from the MISO capacity market to meet this requirement (or a combination of those options). However, the Company is opting to provide all of its own capacity—and then some. Figure 9 shows the Company’s capacity over and above what is required by MISO. Once the planned natural gas plant is in-place in 2024, the Company will have 22 percent more capacity than it needs—taking the Company’s requirements as-read. While this surplus gradually decreases over time, a sizeable surplus remains through 2036. Note that if peak load is lower than what the Company claims, this surplus will be even higher. (Later, I discuss inconsistencies in the Company’s load forecasts.)
Q Could the Company procure a smaller natural gas plant or portion of a gas plant than what it is planning?

A Yes. The Company is procuring a larger natural gas resource than it needs and its own modeling using PROMOD shows that a smaller plant would cost ratepayers less. Moreover, there is the risk that capital costs will be higher than what was modeled. Vectren has already supplied CAC with at least one capital cost projection for its CC, a data point that Vectren characterizes as merely provided "". That workbook, which was prepared in July 2018, estimated the capital cost of the 2x1 Fired CCGT that Vectren proposes to build at percent than what was assumed in its modeling.

Q Did modeling by Dr. Christopher Clack show that even under the Company’s assumptions, the proposed natural gas plant is likely too large?

A Yes. Dr. Clack’s analysis using the WIS:dom model showed that using Vectren’s assumptions an optimized, lower-cost portfolio would lead to the selection of a

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39 Cause No. 45052, Vectren Response to OUCC DR 2.5-R1 (included as Attachment TFC-8). Note: These figures were adjusted to account for the Company’s decision to continue operating Warwick Unit 4 until 2024.

40 Vectren Response to CAC DR Confidential 10.1-R1 (Attachment TFC-9-C).

41 Personal communication with Matthew Lind, August 7, 2018.
much smaller natural gas unit. This modeling did not account for lower renewable energy costs I will discuss later.

Q  **Is it likely that the Company’s plan will lead to excessive market risk for ratepayers?**

A  Yes. Throughout its petition, the Company focuses on the *possibility* of high load and high market prices in order to justify its preferred plan. By the Company’s logic, building a new large resource is justified as a hedge against these events. However, excess capacity can cost ratepayers more when market prices are not sufficiently high if the Company overbuilds. Relying on selling excess capacity only makes sense if capacity prices are sufficiently high—contrary to recent trends in MISO. The Company plans to have substantially more capacity than it believes it will need—or as it claims a “healthy capacity surplus.”42 It claims that this provides a “cushion” to protect against the possibility of higher load. However, if peak load is not as high as the Company expects, then its system will be overbuilt even further. (Notably, the Company has refused thus far to provide us with the information necessary to verify and analyze the specific load additions the Company contemplates.)

Q  **Does the Company overestimate future capacity prices in MISO?**

A  Yes. The MISO capacity price forecasts used by the Company routinely assume that the price of capacity in MISO will [ ]—see Figure 10. In the past five years, the price of capacity in MISO Zone 6 has averaged around $7.30 per kw-year, or [ ] than what the Company assumes in all three of its forecasts.43 The Company predicts that the price will average [ ] per kw-year

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42 Cause No. 45052, Petitioner’s Exhibit No. 1, p. 10, lines 5.
43 MISO 2018/2019 Planning Resource Auction Results, p.8. Available at: https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf. MISO 2013-2014 Plan Year Planning Resource Auction Results. Available at: https://cdn.misoenergy.org/20130415%20SAWG%20Item%2002%2013-14%20PRA%20Results150842.pdf. Note that MISO reports auction results in terms of $/MW-day. I translated these to $/kW-year to match the Company’s units (Price per kW-year = Price per MW-day / 1000 * 365).
from 2019 through 2036—about the historical average. This opens up the Company’s plan to excessive capacity market risk that will be borne by ratepayers.

Figure 10: Actual and Predicted Capacity Prices ($/kW-year) - CONFIDENTIAL

Q Has the Company overestimated capacity prices in the past?

A The MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. For instance, the MISO capacity price in Zone 6 (the zone in which Vectren is located) in 2018 was $2.36 per kw-year. In January 2016, the Company assumed that the 2018 price would be per kW-year (the actual price). This outlook was modulated slightly in the 2016 IRP where the Company assumed a 2018 price of $ per kW-year (the

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44 Vectren Response to CAC DR 1.28, Confidential Attachment CAC DR 1.28-R1 (included as Attachment TFC-10-C).
45 Vectren forecasts: –Attachment TFC-10-C.
MISO 2013-2014 Plan Year Planning Resource Auction Results. Available at: https://cdn.misoenergy.org/20130415%20SAWG%20Item%2002%202013-14%20PRA%20Results150842.pdf
Note that MISO reports auction results in terms of $/MW-day. I translated these to $/kW-year to match the Company’s units (Price per kW-year = Price per MW-day / 1000 * 365). They are also presented in terms of calendar year instead of MISO delivery year (e.g. 2017/2018).
actual price). Each of the forecasts the Company provided show a similar pattern of [blank] in capacity price that [blank] in the long-term. There is no reason to believe that this would occur. This trajectory has yet to occur in any wholesale capacity market in the U.S., let alone the MISO capacity market, and is highly unlikely to occur in the near or long-term future.

6  Q Why is it important that the Company has predicted [blank] capacity prices?

7  A This assumption is critical because it makes the economics of building a new resource more attractive. The Company is assuming in its planning that capacity will be [blank] in MISO and capacity prices will therefore [blank]. This biases the modeling towards portfolios that oversupply the Company’s capacity need in order to avoid these [blank] capacity charges. But in the far likelier event that there is sufficient or excess capacity and MISO capacity prices remain low, purchasing some amount of capacity is more attractive than building too much capacity.

16  Q Does the Company’s modeling of the preferred plan rely on significant energy market sales revenue?

17  A Yes. As shown in Figure 11, off-system sales revenue represents a significant reduction to the NPV of the preferred plan as well as the other portfolios that include a large CC addition.
Does the Company expect to generate more energy than it has in the past?

Yes. Similar to its stance on capacity, the Company’s case relies on the assumption that it will be able to bring in additional revenue by selling excess generation outside of its territory. In fact, the Company’s modeling predicts that Vectren’s system will generate much more electricity than it has in the past—even before the new natural gas plant would be in place. Figure 12 shows the actual generation from Vectren’s fleet compared to the expected generation from the Company’s modeling. On average, the fleet produced 4,890 GWh per year from 2013 through 2017.47 In the Company’s modeling, the same fleet is expected to produce GWh in the first five years modeled (2017 through 2021).48 This represents an astonishing percent increase in annual generation from the

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46 Company’s 2017 Updated Strategist files.
47 SNL data for historical generation.
48 Company’s 2017 Updated Strategist files: Preferred-75F5-GAF UNIT - CONFIDENTIAL, Preferred-75F5-GAF TRANSACTION - CONFIDENTIAL.
Company’s existing fleet before any new generation is added to its system. In 2017, the Company’s Strategist modeling projected that its fleet would generate 4 percent more electricity than what it actually produced in that year. The Company’s modeling missed the mark completely, even when simulating the near term.

**Figure 12: Actual and Predicted Vectren System Generation, (GWh)**

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**Q** What effect does the modeling of significantly more generation than the Company has historically produced have on its modeling results?

**A** The effect would be to bias the modeling towards portfolios that oversupply Vectren’s system. One or more factors is causing Strategist to view excess generation as economic and therefore a credit against the Net Present Value of system cost. As shown in **Figure 11**, revenue from off-system sales is quite significant in comparison to total NPV for many of Vectren’s updated Strategist runs. Under Vectren’s proposal, ratepayers would bear much of the risk that these sales will not materialize.

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49 *Id.* SNL data for historical generation.
Q Are off-system sales problematic for ratepayers?
A There is nothing inherently wrong with having off-system sales. It is common for utilities to sell and purchase from available markets when economic to do so. However, when conducting modeling for resource selection, it is essential to realistically represent the utility’s system—including purchases and sales. It should also account for the risk inherent in planning to sell large amounts of excess energy. Vectren fails in that respect and creates a very risky situation by vastly overstating its potential for off-system sales and using this flawed analysis to justify the investment of hundreds of millions of dollars of ratepayer funds.

Q Is purchasing energy problematic for ratepayers?
A Not necessarily. Purchasing energy (or capacity) can cost less than if the energy (or capacity) were provided from a self-supply option. The Company could also engage in bilateral contracts where prices were known for the contract term. The latter could provide a hedge against market risks. The Company could also, as it has done in the past, purchase limited amounts of energy out of the MISO market so that ratepayer exposure to market price fluctuations is small. To be clear, I am not suggesting that Vectren retire all the units of its plants and rely completely on market capacity and energy. Rather, my point is that moving to a position of significant oversupply creates substantial market risk for ratepayers and is predicated on unrealistic and highly speculative modeling.

Q Has the Company been a net importer or exporter of energy in recent years?
A It has mostly been a net importer. Figure 13 below shows the balance of energy sales and purchases from the Company in the past ten years. In eight of the last ten years, the Company bought more energy than it sold.
Does the Company attempt to justify its plan by becoming a net exporter of energy?

Yes. The Company’s modeling of its preferred plan shows that it expects not only to be self-sufficient but also to sell a significant amount off-system—despite its recent history. Figure 14 shows the actual net sales (also shown in Figure 13) with the Company’s prediction of net sales in its modeling. The Company’s modeling shows an unrealistic future where its system is generating much more than is needed (see Figure 12) in order to sell the energy elsewhere. Even in 2017, the Company predicted that it would be a net seller of GWh when it actually was a net purchaser of 30 GWh in that year. Thus, if modeled more realistically, the Company’s plan should appear significantly more expensive as ratepayers are not benefitting from overly optimistic off-system sales assumed by the Company.

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50 Vectren Response to CAC DR 8.7, Attachment CAC DR 8.7-R1 (included as Attachment TFC-11).
Why are the modeling results for net sales important?

The costs of portfolios, in terms of net present value (NPV), are defrayed by off-system sales revenue less the portion of that revenue that is “shared” with shareholders. Net energy sales and the revenue from these sales flow to ratepayers as a decrease on their bills. However, there is no guarantee that these sales will actually materialize nor that they will cover the costs of building this additional capacity, the risks of which would fall on ratepayers under Vectren’s proposal.

B. LOAD FORECAST ASSUMPTIONS ARE INCONSISTENT

What load forecast information did you review in preparing this testimony?

I reviewed the 2016 IRP forecast prepared by Itron and the Organization of MISO States (OMS) surveys supplied to MISO provided in discovery to CAC, and two load forecasts that Vectren supplied to MISO.

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51 Id. Company’s Strategist files: Preferred-7F5F-GAF SYSTEM - CONFIDENTIAL.
52 MISO survey data from Vectren Confidential Attachments CAC DR 2.29-R1 and CAC DR 2.29-R2 (Attachments TFC-12-C and TFC-13-C).
53 Vectren Confidential Attachment CAC DR 1.5-R1 (Attachment TFC-14-C).
Q When were the load forecasts conducted?
A The Itron forecast was included in Vectren’s 2016 IRP which was filed on November 1, 2016. It appears that the forecasts submitted to MISO were developed in 2017 and 2018, respectively.

Q Which forecast did Vectren use for its analysis?
A Vectren reported that the Itron forecast used for its 2016 IRP was the same forecast utilized for its 2017 updated Strategist modeling for this cause.\(^{54}\)

Q Were there differences between the three energy forecasts, all supplied by Vectren?
A Yes, each forecast is different. Please see Figure 15 for an illustration of the Itron, PROMOD, and 2017 and 2018 MISO forecasts. As can be seen in Figure 15, the Itron forecast, i.e., what Vectren used in the Strategist modeling, projects the highest amount of energy needs for Vectren across the three different forecasts, with the later MISO forecasts projecting slightly less of an energy need.

Figure 15: Comparison of Energy Forecasts (MWh) \(^{55}\) - CONFIDENTIAL

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\(^{54}\) Vectren Response to CAC-VW Data Request 8.2 (Attachment TFC-15).

\(^{55}\) Itron forecast from the 2016 IRP; Promod forecast from CONFIDENTIAL 2x1 F-Class Unfired (GE7F 05); MISO forecasts from worksheets “Winter 2017 MISO” and “Winter 2018 MISO” within CAC DR 1.5-R1 CONFIDENTIAL.
Figure 16 below highlights the peak demand (MW) forecasts for Vectren. Out of the three forecasts, the Itron forecast is the only one that projects an increase in peak demand for each year between 2018 and 2027. By 2027, the Itron forecast projects a peak demand of [___] MW, which is higher than the [___] MW in 2018 MISO forecast.

![Figure 16: Comparison of Peak Demand (MW) Forecasts](image)

In the 2020’s, the Itron forecast exceeds the MISO forecasts by [___] to [___] MW, a difference of [___] MW.

Q: Do you know why there are differences between the Itron forecast and the more recent MISO forecasts?

A: I do not. The MISO forecasts were provided to CAC without any documentation describing their development. Itron’s forecast assumed that Vectren would serve an unspecified level of new industrial load:

New customers are specifically identified and forecasted based on expected load. An overall growth rate of approximately 1% is then

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*Note that the MISO forecasts were adjusted to account for DSM savings. DSM savings were adjusted by 6.3% and then added back in to get the total energy. The 2017 and 2018 MISO forecasts reflect the exclusion of future DSM savings.

56 MISO survey data from Vectren Confidential Attachments CAC DR 2.29-R1 and CAC DR 2.29-R2 (Attachments TFC-12-C and TFC-13-C).
applied to the baseline period to capture growth that has not been specifically identified by customer.\(^5\)

This means that Vectren is assuming not one, but two “cushions” for additional industrial load growth, one in its load forecast and another by building capacity well in excess of its projected needs. I would also note that as of the date of this testimony, Vectren has not supplied CAC with the data demonstrating when these specific new customers would come online, what their firm vs. non-firm requirements are, nor the likelihood of their coming online.\(^8\)

**C. THE COMPANY UNDERESTIMATED DEMAND RESPONSE POTENTIAL**

**Q** What amount of demand response did the Company include in its Strategist analysis?

**A** Vectren included \( \Box \) MW of existing demand response.\(^5\) The Company considered only a small amount of additional demand response, beyond its existing demand response and in only some of its updated Strategist runs – \( \Box \) additional in each year between 2020 and 2024.\(^6\)

**Q** How does the Company’s level of demand response compare to other utilities?

The Company’s demand response accounted for just \( \Box \) of its peak load as reported in 2016.\(^6\) This is the \( \Box \) lowest of investor-owned utilities in Indiana, based on the percentage of peak load (see Figure 17 below).

\(^{57}\) Attachment 4.1 of Vectren’s 2016 IRP at page 12.

\(^{58}\) Vectren Response to CAC Data Request 8.1 (Supplemental) (Attachment TFC-16).

\(^{59}\) See Cause No. 45052, Petitioner’s Exhibit 6, Strategist workpapers.

\(^{60}\) Id.

\(^{61}\) EIA Form 861. Available at: [https://www.eia.gov/electricity/data/eia861/](https://www.eia.gov/electricity/data/eia861/).
Q How much additional demand response could Vectren deploy on its system?

A A report prepared for Indiana Advanced Energy Economy (AEE) by Demand Side Analytics in February 2018 provided information on demand response potential for the state of Indiana. The authors of the report concluded that:

While Duke, NIPSCO, and I&M have well developed portfolios of non-residential DR resources, Vectren and IPL show limited contribution to resource adequacy from C&I [commercial and industrial] demand response.

The report indicated that there was further potential for the Company:

Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power. The remaining non-residential potential is largely concentrated in Vectren and Indianapolis Power and Light service territories.

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62 Peak load data from EIA Form 861.
64 Id. p. 10.
65 Id. p. 31.
AEE’s medium case industrial demand response potential in 2018 includes 1,379 MW of day-ahead demand response and 743 MW of day-of demand response. This would leave an additional [ ] MW of demand response untapped with the majority of it available in IPL and Vectren’s service territories.

**Q** Is there other evidence that industrial demand response may be available in significant quantities on Vectren’s system?

**A** Yes. Prior to 2017, Vectren’s sales to industrial customers were the second highest percentage of any of the investor owned utilities (IOUs) in Indiana. Figure 18 below shows the percentage of industrial customer sales for each IOU in 2015 or 2016. (These years were chosen to match Figure 17 data, above.) NIPSCO has the highest share of industrial sales (55 percent) and highest percentage of demand response (16 percent), as a share of peak load in Indiana.

![Figure 18: Industrial Sales as a Percentage of Total Retail Sales](image)

**Q** What cost was assumed for this new demand response?

**A** It appears that the cost varied from $[ ] per kw-yr in 2020 and then levels out at a low of $[ ] per kw-yr in 2025 (all in real 2017 dollars). The cost declines

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66 Id. p. 13.
67 Sales data from EIA Form 861 for 2016.
68 See, for example, provided in Cause No. 45052, Petitioner’s Exhibit 6, Base-Cease Coal 2024-SCGT-LFA Input Summary report workpaper of Matthew Lind.
over time because a one-time expense incurred by new participants goes away when the [ ] MW is fully subscribed.

Q  What are Vectren’s current payment credits available under its demand response tariffs?
A  Vectren’s Interruptible Contract Rider provides a capacity credit ($/kVa) to customers that qualify for the Rider in the amount of 90 percent of Vectren’s Rate CSP. Under Vectren’s Rate CSP, the capacity payment is set at $3.88 per kW-month or $46.56 per kw-yr. Vectren’s Interruptible Option Rider provides an interrupted capacity credit of 80 percent of the $3.88 per kW-month capacity payment in addition to an interrupted energy credit in the amount of the fuel cost adjustment for the customer’s applicable rate schedule.

Q  Have you reviewed other demand response incentives in the region?
A  Yes. Robert Stephens, a consultant for Brubaker and Associates, whose firm frequently provides expert witness testimony for industrial customers in Indiana, submitted testimony before the Minnesota Public Utilities Commission describing the different credits for demand response participation under NIPSCO’s Rider 775. Mr. Stephens discussed different service options with varying interruption and curtailment requirements for large customers. His “Option E” provided significant opportunity for curtailment and load reduction while compensating participants at levels greater than those currently offered by Vectren.

Option E allowed for up to 400 interrupted hours at an incentive payment of $9.50 per kw-month. This payment is significantly above the ongoing incentive payment assumed by Vectren and the number of curtailment hours is well below the [ ] hours assumed by Vectren in its modeling. As described above, the

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69 Please see Rate CSP – Cogeneration and small power production on Sheet No. 79 from https://www.vectren.com/assets/downloads/rates/in-south-electric-tariff.pdf
Advanced Energy Economics’ Indiana demand response potential report concluded that approximately □ MW of additional industrial demand response is available in 2018.

Q Did Dr. Clack model more demand response potential for Vectren?
A Yes. I asked Dr. Clack to assume that the total level of industrial DR ought not to exceed that achieved by Duke Energy Indiana or 11 percent of its system peak in 2018. While Vectren has a higher proportion of industrial sales than Duke does, this assumption was made in order to be conservative. That means that an additional □ MW of demand response was made available to Vectren in the WIS:dom runs that optimized DR resource selection. The incentive payment for this resource was assumed to be $9.50 per kw-month and participants could be interrupted for up to 400 hours per year.

Q Should the Company have considered more demand response in its planning?
A Yes. There is clearly room for growth for the Company. Pursuing cost-effective demand response would decrease the level of generating capacity needed and could result in savings to ratepayers. As noted above, the Company considered only a small amount of additional demand response in only some of its updated Strategist runs – □ additional in each year between 2020 and 2024.71 This would raise Vectren’s total demand response to just □ percent of peak load, meaning Vectren would still lag behind most of the other Indiana IOUs.

D. THE COMPANY OVERESTIMATED MOST RENEWABLE ENERGY COSTS

Q What is your opinion of Vectren’s forecast for the capital and fixed O&M costs of future wind resources?
A The capital costs are higher than I would recommend while the fixed O&M are actually lower. Vectren assumed the capital cost of a 200 MW wind resource to

71 See Cause No. 45052, Petitioner’s Exhibit 6, Strategist workpapers.
be [REDACTED] per kW with a fixed O&M cost of [REDACTED] per kW-year throughout the entire planning period.\textsuperscript{72} It is slightly higher in capital cost, but lower in fixed O&M than the values I would recommend for this type of planning analysis.

For this type of planning analysis where the utility lacks the type of project specific information that one would receive through a recent all-source Request for Proposals (RFP), I would recommend the use of the National Renewable Energy Laboratory’s Annual Technology Baseline (ATB) Techno-resource group\textsuperscript{6.73} Figure 19 and Figure 20 show a comparison of the two forecasts.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure19.png}
\caption{Wind Capital Cost Comparison\textsuperscript{74}}
\end{figure}

\textsuperscript{72} Vectren Response to CAC DR 5.2 and 5.3, Confidential Attachment CAC DR 5.2-5.3-R1 (included as Attachment TFC-17C). Costs are converted to 2015 dollars.

\textsuperscript{73} National Renewable Energy Laboratory’s Annual Technology Baseline. Available at: https://atb.nrel.gov/electricity/2017/index.html?t=1w.

\textsuperscript{74} Attachment TFC-17C. Costs are reported in 2015 dollars.
Fig. 20: Wind Fixed O&M Cost Comparison

Q: What is the basis for the ATB wind cost forecast?

A: This forecast was derived from a survey of 163 of “the world’s foremost wind experts.” According to the authors, the study “may be the largest single elicitation ever performed on an energy technology in terms of expert participation.” NREL applies the results of this expert survey to estimate the future levelized cost of energy in various locations. It has developed detailed estimates of wind speeds across the U.S. Using this data, the ATB developed ten “Techno-resource Groups” to reflect the varying wind resource at different locations. It then developed individual price forecasts for each of the groups for each year through 2050.

Q: Why do you recommend Techno-resource Group 6 as the point of comparison?

A: The techno-resource groups are classified according to wind resource potential, with Zone 1 having the highest wind speeds and Zone 10 having the lowest wind speeds. For their modeling, Vectren used a capacity factor of 30% for wind.

76 Id.
77 Attachment TFC-17C. These costs are converted to real 2015 dollars.
The weighted average capacity factor for Techno-resource Group 6 is 36.4%, which is a more capacity factor than the one used by Vectren.

**Q** Is the ATB currently being used for planning purposes by other Indiana related entities?

**A** Yes. MISO began using the ATB price forecasts in its MISO Transmission Expansion Planning (MTEP) reports starting in 2017 for both solar and wind.\(^7\)\(^8\) It’s my understanding the Duke Energy Indiana will also use these forecasts as the basis for its upcoming IRP filing.\(^9\)

**Q** What is your opinion of Vectren’s forecast for the capital and fixed O&M costs of future solar resources?

Vectren’s costs for both are too high. The Company assumed the capital cost for a 50 MW solar resource to be per kW and the fixed O&M costs to be per kW-year throughout the planning period.\(^8\)\(^0\) However, installed solar project costs have declined dramatically over the past decade and utility scale solar costs will likely continue to decline throughout the planning period. Vectren’s assumption that solar costs (in real terms) runs contrary to the experience of the last decade and the consensus of solar market experts. Specifically, I recommend using the ATB midpoint projection for utility-scale PV with a 20% capacity factor. Figure 2\(^1\)\(^2\) and Figure 2\(^2\)\(^2\) show that ATB forecasts much lower capital and fixed O&M costs (respectively) for solar photovoltaic (PV).

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\(^0\) Attachment TFC-17C. These costs are converted to real 2015 dollars. National Renewable Energy Laboratory’s Annual Technology Baseline. Available at: [https://atb.nrel.gov/electricity/2017/index.html?t=1w](https://atb.nrel.gov/electricity/2017/index.html?t=1w)
What is the basis for the ATB solar PV cost forecast?

The ATB’s solar cost projections are based on “14 system price projections from 8 separate institutions with short-term projections made in the past six months and

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81 Id.
82 Id.
long-term projections made in the last three years.” According to this source, the institutions include both public (e.g. the U.S. Energy Information Administration and the International Energy Agency) and private research firms (e.g. Bloomberg New Energy Finance and GTM Research). Using these price projections, the Annual Technology Baseline projects utility scale solar costs will continue to decline throughout the planning period.

Q Why is Utility PV with a 20% capacity factor the most appropriate point of comparison for Vectren?
A The ATB provides cost forecasts for three different levels of solar resource quality: projects with a capacity factor of 14%, 20%, or 28%. The middle capacity factor is in alignment with the capacity factor used by Vectren in their modeling, which was.

Q What are the implications of Vectren’s renewable cost assumptions?
A The Company has mostly overestimated renewable costs. It has opted to be too conservative in light of projected cost declines from other reputable sources—especially for solar PV. The Company’s assumptions bias the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

E. THE RISK ASSESSMENT WAS HIGHLY FLAWED

Q Was the risk assessment done by Pace Global in 2016 and 2017 a reasonable method to determine a least-cost, least-risk plan?
A No. I have discussed the risk assessment previously but mostly with regards to how the results were interpreted to support the Company’s preferred plan. I also take issue with several of the risk metrics and their weighting.

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Please describe your concerns with the risk metrics.

First, I am concerned with some of the risk metrics used in the assessment. The “capacity purchase” metric follows the trend of the Company being only concerned with the risk from having to make market purchases, rather than carrying excess capacity. This metric presumes that purchasing capacity is inherently more risky than selling. This is not the case if one expects capacity to remain inexpensive. The Company did not assume that owning excess capacity was a risk—though it should have. Moreover, the scores imposed by Pace Global draw arbitrary lines (more than 31 MW capacity purchases gets a red light; less than 20 MW gets a green light). This metric should not be used unless the risks of excess capacity are also taken into account. For a start, the Company should consider a lower capacity price trajectory, one that better reflects the oversupplied MISO market. The same issues arise with the “market purchases” metric: purchases of energy out of the MISO market are assumed to be a negative, but sales are a positive.

Second, I agree with the Company’s removal of the “remote generation” and “net sales” metrics per the recommendations in the Director’s 2016 IRP Report. As I mentioned, however, Pace Global did not re-run the risk analysis; rather, it re-weighted the results from the 2016 IRP modeling and removed these two metrics, which does not fully address the Director’s concern. At the very least, the risk analysis should rely on the most updated modeling runs done by the Company.

Please describe your concerns with the weighting of risk metrics.

Some portfolio scores are very close together (see Figure 7) thus, apart from the metrics themselves, the weighting of them is a large determinant of the score. The NPV costs of portfolios are weighted with the same importance as the other main categories of “risk,” “cost-risk trade-off,” “balance/flexibility”, “environment,” and “economic impact” (see Table 1 below)—each contributing 17 percent to the

84 Cause No. 45052, Petitioner’s Exhibit 5, Attachment MAR-1, p. 545.
final score. Within the main categories of risk and balance/flexibility, each subcategory is weighted equally—25 percent for the four subcategories.

I am not sure why the main categories are given the exact same level of importance. For instance, why is portfolio cost just as important as balance/flexibility? Why is remote generation risk just as important as the standard deviation above the lowest cost? The risk scores that the Company relies upon are very sensitive to these weights, which is worrisome. If the Company must include weights, it should justify these assumptions. The current weights appear to be arbitrary and do not produce robust results, yet they are ostensibly relied upon for major investment decisions funded by ratepayers.

Table 1: Risk Metrics and Scoring Weights

<table>
<thead>
<tr>
<th>Risk Factor</th>
<th>Weighting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio NPV</td>
<td>17%</td>
</tr>
<tr>
<td>Risk</td>
<td>17%</td>
</tr>
<tr>
<td>STD Above Lowest</td>
<td>25%</td>
</tr>
<tr>
<td>Capacity Purchases</td>
<td>25%</td>
</tr>
<tr>
<td>20 Year Average Market Purchases</td>
<td>25%</td>
</tr>
<tr>
<td>Remote Gen Risk</td>
<td>25%</td>
</tr>
<tr>
<td>Cost-Risk Trade-Off</td>
<td>17%</td>
</tr>
<tr>
<td>Balance/ Flexibility</td>
<td>17%</td>
</tr>
<tr>
<td>Largest 24/7 Power Source</td>
<td>25%</td>
</tr>
<tr>
<td>% Reliance Largest Tech</td>
<td>25%</td>
</tr>
<tr>
<td># of Technologies</td>
<td>25%</td>
</tr>
<tr>
<td>Net Sales</td>
<td>25%</td>
</tr>
<tr>
<td>Environment</td>
<td>17%</td>
</tr>
<tr>
<td>Local Econ Impact</td>
<td>17%</td>
</tr>
</tbody>
</table>

F. THE COMPANY DID NOT ADEQUATELY EVALUATE FINAL RESOURCE SELECTION

Q Were you able to fully vet the Company’s assumptions used in comparing natural gas resources?

A No. I asked the Company for clarification on how the costs of a new pipeline (serving the Company’s self-build proposal) were incorporated into the analysis. We asked for how these costs were developed for modeling purposes and the Company simply supplied numbers that were used in modeling without showing
how they were derived. I could not verify whether or not the capital costs of the new pipeline used in modeling matched the capital cost provided elsewhere in the filing.

Q Is there potential for cross-subsidization between Vectren’s gas and electric customers for the new pipeline?

A Yes. The Company has indicated that there will be a “contractual arrangement” between the gas and electric utilities for the pipeline. However, to my knowledge, there is no more specificity than that. This raises the concern that gas customers would be subsidizing electric customers as the pipeline would be used primarily to serve the proposed natural gas generator.

Q Even if the preferred plan were least-cost, least-risk—did the Company facilitate a competitive bidding process to choose a resource?

A No. First, the Company’s RFP is not explicitly limited to natural gas resources but is tailored towards natural gas bids by the criteria listed, despite the Company failing to adequately justify that this type of resource was required. Indeed, the Company only received bids for natural gas resources in response to its RFP. This limited the possibility of lower-cost, lower-risk bids from other resources.

Second, the Company’s solicitation for natural gas states a bias towards ownership that would discourage other types of bids. The Company says upfront that it “has a preference for asset purchase proposals… or a new facility which is under construction or will be operational…” This would strongly discourage bidders from offering power purchase agreements (PPAs)—even though it might be a lower cost option for ratepayers. Even if one were to bid a PPA, the Company would not consider one with less than a 20-year term. It is unclear why a 10 or 15-year PPA would not be viable. Short-term PPA’s provide

85 Vectren Attachments to CAC Data Request 10.1-R1 CONFIDENTIAL (Attachment TFC-9-C) and CAC Data Request 5.15a (Supplemental) (Attachment TFC-18).
86 Cause No. 45052, Petitioner’s Exhibit 12, Attachment SAH-2 (Confidential).
87 Vectren Response to IG Data Request 4.7 (Attachment TFC-19).
88 Cause No. 45052, Petitioner’s Exhibit 6, Attachment MEL-1, p. 34.
89 Id.
optionality, contrary to building a large resource that will likely be operational for
decades and foreclose future resource options.

Third, the Company stipulates that the resource must be located in MISO Zone
6. This would severely limit the location of the resource to within parts of
Indiana and Kentucky. A resource in Illinois (for example) would be excluded
from consideration even though it might be the lowest cost and close to where the
load is needed. Resources do not necessarily need to be located within a specific
MISO zone to provide capacity and energy to that zone.

Finally, the size of capacity was limited to between 600 and 800 MW. Instead, the
Company could have considered smaller resources or combinations of small
resources less than 600 MW. This would lower the market risk exposure for
ratepayers, which I have discussed previously, as well as permit a combination of
bids to make up a least cost alternative. This could have also provided future
optionality and resource diversity. Instead, the RFP merely reinforced the
Company’s selection, or as CEO Chapman says: “The RFP results validate our
own study process and provide assurance of the reasonableness of the proposed
project.”

Q Have other Indiana utilities issued solicitations that facilitated more
competitive bidding with a broader category of eligible respondents?
A Yes. Recently, Northern Indiana Public Service Company (NIPSCO) issued an
RFP that included:

- Consideration of all technologies
- Sought to fulfill a total need of 600 MW but allowed for “smaller
  resources to offer their solution as a piece of the total need”
- Did not offer a preference for ownership versus a PPA

90 Id.
91 Cause No. 45052, Petitioner’s Exhibit 1, page 11, lines 3-4.
Specified that the resource should be deliverable to MISO Zone 6 but does not need to be located in Zone 6. As a result of having a more open, competitive RFP, the Company received 90 bids for resources in five states including average prices of $26.97/MWh for wind bids and $35.67/MWh for solar bids.

5. RECOMMENDATIONS

Q What are your recommendations?

A I recommend that the Company’s petition be denied. The Company has not provided sufficient justification or analysis for its choice to build a new natural gas plant, especially one of this size. Its modeling contained many flaws and even that Company flawed exercise did not show that the preferred plan was low cost or low risk. At the very least, the Commission should require the Company to conduct a new, more reasonable and up-to-date analysis prior to making any final decision to grant or deny the Company’s petition.

Should the petition be granted, given the excessive market risk of the Company’s plan, the Commission should adopt protections for Vectren ratepayers as a condition on any approval. The Company is asking for ratepayers to fund a speculative, risky investment venture in place of other lower cost, lower risk alternatives. The Company should be held accountable if this investment does not pay off.

Conditional approval should include: 1) limiting capital costs charged to ratepayers for the natural gas plant to those presented in this filing; 2) applying credits to ratepayers for off-system sales revenue that were projected in this filing but do not materialize; 3) exempting ratepayers from environmental compliance costs for F.B. Culley Unit 3 over and above what is included in this filing.

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93 Id., slide 19.
Q: Does this conclude your testimony?
A: Yes. However, I reserve my right to supplement this testimony should new information become available.
ATTACHMENT TFC-1
Tyler Comings, Senior Researcher, Applied Economics Clinic
44 Teele Avenue, Somerville MA 02144  tyler.comings@aeclinic.org  617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic. Somerville, MA. Senior Researcher, June 2017 – Present.
Provides technical expertise on electric utility regulation, energy markets, and energy policy.
Clients are primarily public service organizations working on topics related to the environment,
consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017,
Provided expert testimony and reports on energy system planning, coal plant economics and
economic impacts. Performed benefit-cost analyses and research on energy and environmental
issues.

Organized studies analyzing behavior of consumers regarding finances, working with top
researchers in behavioral economics. Managed studies of mortgage default mitigation and case
studies of financial innovations in developing countries.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for
transportation and renewable energy projects, including support for Federal stimulus applications.
developed a unique web-tool for the National Academy of Sciences on linkages between
economic development and transportation.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable.
Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.
Designed statistical programs using SAS based on data from health-related surveys.
Extrapolated trends in health awareness and developed benchmarks for performance of clinics
for a statewide assessment.

EDUCATION

Tufts University, Medford, MA
Master of Arts in Economics, 2007
Boston University, Boston, MA
Bachelor of Arts in Mathematics and Economics, 2002. Cum Laude, Dean's Scholar.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA), Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Research Fellow, 2017 – present

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS


**Testimony and Expert Comments**

Page 6 of 8


ATTACHMENT TFC-2
10. Please confirm that the “Preferred-7F5U-Solar” Strategist modeling case is in fact the Company’s preferred portfolio in this docket.

**Response:**

No, the preferred portfolio in this docket would correspond to Strategist modeling files labeled “Preferred-7F5F”.
ATTACHMENT TFC-3
Report on Vectren 2016 IRP
Submitted to the IURC on April 17, 2017
Updated July 26, 2017 (Clean)

Authors:
Anna Sommer, Sommer Energy, LLC
Elizabeth A. Stanton, PhD, Applied Economics Clinic
on behalf of CAC, Earthjustice, Indiana Distributed Energy Alliance,
Sierra Club, and Valley Watch
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Overview

The following comments on the 2016 Integrated Resource Plan submitted by Vectren Energy Delivery of Indiana (“Vectren” or the “Company”) were prepared by Anna Sommer with Sommer Energy, LLC, and Elizabeth A. Stanton, PhD, with Applied Economics Clinic. These comments were prepared for Citizens Action Coalition of Indiana (“CAC”), Earthjustice, Indiana Distributed Energy Alliance (“IndianaDG”), Sierra Club, and Valley Watch (collectively, “Commenters”) pursuant to the Indiana Utility Regulatory Commission’s (“IURC” or “Commission”) draft Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.1

Our review of Vectren’s 2016 Integrated Resource Plan (IRP) is organized in response to IURC guidance on IRP preparation in the IURC’s IRP Rule (170 IAC 4-7-4, 4-7-8). Table 1, on the following page, summarizes our findings for each of the eighteen (18) Indiana IRP requirements.

More generally, our review raised the following main categories of concerns with the Vectren 2016 IRP and how it aligns with the IRP Rule:

- **Failure to communicate core concepts to nontechnical audiences (170 IAC 4-7-4(a)):** Despite the non-technical executive summary submitted with the IRP and overall careful explanations of much of its methodology, Vectren’s 2016 IRP obscures critical basic information, includes critical errors and inconsistencies. In addition, some materials necessary for a thorough review were not made available to stakeholders. See Section I of our report below.
- **Incomplete documentation of inputs, methods, and definitions (170 IAC 4-7-4(b)(1)):** Key sections of Vectren’s IRP are not transparent to stakeholders, including the scorecard methodology on which the utility bases its selection of its preferred portfolio. See Section II below.
- **Numerous modeling errors (170 IAC 4-7-4(b)(9)):** Vectren’s modeling errors include its failure to actually optimize its resource portfolios, overemphasis of long-term costs over near-term costs, and excess capacity acquisition. See Section IV below.
- **Biases against coal retirement (170 IAC 4-7-8(b)(3),(b)(4)):** Vectren’s retirement analysis is biases towards later retirement of uneconomic units. See Section IX below.
- **Biases against renewable resources (170 IAC 4-7-8(b)(3),(b)(4)):** Vectren’s modeling includes several assumptions that bias resource selection against renewable generation. See Section IX below.
- **Demand-side resources not evaluated on consistent and comparable terms with supply-side resources (170 IAC 4-7-8(b)(3),(b)(4)):** Vectren’s modeling includes a faulty projection of energy efficiency costs that bias resource selection against energy efficiency. Demand-side resources are not evaluated on a consistent and comparable basis with supply-side resources. See Section IX below.

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1 All references to the Commission’s IRP Rule, 170 IAC 4-7, refer to the revised draft of the Proposed IRP Rule, which the Commission circulated on October 4, 2012 in the IRP rulemaking, RM# 11-07. As explained in the Electricity Director’s Final Report on the 2015 IRPs, since 2012 the Commission, utilities, and other stakeholders have followed the requirements of the draft rule (which was negotiated collaboratively, and includes improvements on the prior IRP rule) as if it were in effect. See Electricity Director’s Final Report: 2015-16 Integrated Resource Plans, at p. 1 (Aug. 30, 2016) (hereinafter “2015 Final Report”), available at: http://www.in.gov/iurc/files/Consolidated%20IRP%20Report%20for%20DEI%20M%20MPA%20and%20WVPA%20-%20Final%208-30-16.pdf.
• **Flawed scorecard methodology for choosing the preferred portfolio (170 IAC 4-7-8(b)(7)(B),(C)):** Vectren’s scorecard assessment methodology includes errors in its execution and modeling choices that bias its results. See Section XIV below.

• **Inflated energy forecast (170 IAC 4-7-5)):** Vectren’s energy forecast is predicated on a significant and subjective assumption about growth in industrial sales as well as overly aggressive near-term growth in key drivers of the commercial sales forecast. See Section XIX below.

Vectren did not make all of its background materials and modeling files available together with its 2016 IRP submission, and despite several rounds of discovery requests made over the course of 4.5 months for these documents, we still do not have a complete set at the time of our writing of this report. For these reasons, we respectfully reserve the right to continue reviewing materials as we receive them and to add new information to our response to the Director’s Draft Report.
<table>
<thead>
<tr>
<th>Requirement</th>
<th>Findings</th>
<th>Citation</th>
</tr>
</thead>
<tbody>
<tr>
<td>I The IRP must communicate core IRP concepts and results to non-technical audiences</td>
<td>Not Met</td>
<td>170 IAC 4-7-4(a)</td>
</tr>
<tr>
<td>II IRP documentation must include inputs, methods, and definitions</td>
<td>Not Met</td>
<td>170 IAC 4-7-4(b)(1)</td>
</tr>
<tr>
<td>III The IRP must include a discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting</td>
<td>Not Reviewed</td>
<td>170 IAC 4-7-4(b)(5)</td>
</tr>
<tr>
<td>IV The IRP must include a description of the generation expansion criteria, including a full explanation of the basis for the criteria selected</td>
<td>Not Met</td>
<td>170 IAC 4-7-4(b)(9)</td>
</tr>
<tr>
<td>V The IRP must include an explanation of the contemporary methods utilized in its development, including model structure and reasoning, and the utility’s efforts to develop and improve its methodology</td>
<td>Not Met</td>
<td>170 IAC 4-7-4(b)(11)</td>
</tr>
<tr>
<td>VI The IRP must include an explanation, with supporting documentation, of an avoided cost calculation for each year in the forecasted period</td>
<td>Not Met</td>
<td>170 IAC 4-7-4(b)(12)</td>
</tr>
<tr>
<td>VII Preferred resource portfolio must be selected from among the candidate resource portfolios developed</td>
<td>Met</td>
<td>170 IAC 4-7-8(a),(b)</td>
</tr>
<tr>
<td>VIII Preferred resource portfolio must be described, including key variables, standards of reliability, and other assumptions</td>
<td>Met</td>
<td>170 IAC 4-7-8(b)(1),(2)</td>
</tr>
<tr>
<td>IX Supply-side and demand-side resource alternatives must be evaluated on a consistent and comparable basis in the selection of the preferred resource portfolio</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(3)</td>
</tr>
<tr>
<td>X Preferred resource portfolio must utilize, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(4)</td>
</tr>
<tr>
<td>XI Targeted DSM programs must be evaluated, including impacts on the utility’s transmission and distribution system</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(5)</td>
</tr>
<tr>
<td>XII Financial impact to the utility of acquiring the future resources identified in the preferred resource portfolio must be assessed</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(6)</td>
</tr>
<tr>
<td>XIII Preferred resource portfolio must balance cost minimization with cost-effective risk and uncertainty reduction</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(7)</td>
</tr>
<tr>
<td>XIV Where possible, assumed risks and uncertainties must be quantified</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(7)(B)</td>
</tr>
<tr>
<td>XV Candidate resource portfolios performance across a wide range of potential futures must be analyzed</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(7)(C)</td>
</tr>
<tr>
<td>XVI Candidate resource portfolios must be ranked by present value of revenue requirement and by risk metric</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(7)(D)</td>
</tr>
<tr>
<td>XVII An assessment of robustness must factor in to the selection of the preferred resource portfolio</td>
<td>Not Met</td>
<td>170 IAC 4-7-8(b)(7)(E)</td>
</tr>
<tr>
<td>XVIII The preferred resource portfolio must incorporate a workable strategy for reacting to unexpected changes in circumstances quickly and appropriately</td>
<td>Met</td>
<td>170 IAC 4-7-8(b)(8)</td>
</tr>
<tr>
<td>XIX The IRP must include an analysis of historical and forecasted levels of peak demand and energy usage.</td>
<td>Not Met</td>
<td>170 IAC 4-7-5</td>
</tr>
</tbody>
</table>

Source: 170 IAC 4-7-8 amended 10-4-12
Analysis

I. Does the IRP communicate core IRP concepts and results to nontechnical audiences?

No. However,Vectren’s communication of core IRP concepts and results to nontechnical audiences is far more successful than that found in other recent Indiana utility IRP submissions. We appreciate Vectren’s clear prose, non-technical executive summary, and efforts to explain complex concepts to a technical audience.

While Vectren’s style of presentation deserves praise, we found that the absence of tables and figures comparing resource retirements, additions, and other inputs across portfolios greatly hindered our ability to understand and analyze Vectren’s 2016 IRP findings.

To best communicate core IRP concepts and results to nontechnical audiences, we recommend a clear presentation comparing both inputs and outputs across candidate portfolios. Vectren’s 2016 IRP provides a helpful Executive Summary, and many charts comparing portfolio outputs, but its presentation would be improved by the addition of tables or figures comparing portfolio inputs.
II. Does IRP documentation include inputs, methods, and definitions?

No. Vectren’s 2016 IRP documentation does not clearly present inputs, methods, and definitions.

II-A. Complete documentation of inputs and outputs

The term “inputs” should not mistakenly be interpreted to be limited to cost and electric consumption projections such as coal and natural gas price forecasts, the load forecast, combined cycle, solar, and wind costs. The full set of inputs to an IRP is significantly more complex than this and includes a very large number and variety of input assumptions made by the modeler, for example:

- 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
- The reserve margin requirement
- The order in which resources must be dispatched
- Forced outage rates
- Heat rate profile
- Fuel delivery charges by unit
- Emissions rates
- Schedule of maintenance outages

Because there are so many inputs to an IRP, the only plausible way to completely document them is to provide the modeling input files in a format that is easily machine readable (for example, in an Excel spreadsheet) without requiring public interest groups and other intervenors to pay tens of thousands of dollars to license the model.

For future resource plans, it would be extremely helpful to a meaningful and cooperative public process to set the expectation that all modeling files be delivered concurrently with the final IRP report. We would be happy to work with each individual utility to help its staff understand how to best comply with this request given its particular modeling protocols.

These comments extend not just to the Strategist files that we did receive on a timely basis in response to informal discovery, but also to the Aurora stochastic modeling files that supported many of Vectren’s scorecard metrics.

We first made the request for the spreadsheet underlying the scorecard in CAC Data Request 1.20 on February 9, 2017. On February 20, 2017, Vectren responded referring CAC to the Risk Analysis secton of the November 29, 2016 stakeholder slide deck. On March 6, CAC again asked for the spreadsheets and underlying data for the scorecard. On March 13, Vectren responded that “[T]he premise of this question is flawed in that you assume a spreadsheet was used to develop the figure, but that assumption is not true. Furthermore, we have previously provided to the CAC all of the underlying data that went into creating the figure.” On March 24, CAC again followed up asking Vectren to identify where exactly the scorecard data was in the information already provided to CAC because we could not find it. On March 27, Vectren followed saying, among other things, that Pace Global used the Aurora model to generate most risk analysis metrics, including NPVs. On March 28, CAC again requested Vectren to specify
exactly where in the Aurora files the data was contained because we did not see key information like the NPVs. It was not until April 13, the day our comments were due (until a four-day extension was granted later that day) that Vectren responded saying, “Pace provided all Aurora model outputs (which Vectren sent to CAC), which were used as an input for most risk measures. Pace’s post process files are work products, not formatted for audiences beyond Pace modelers. For Pace to reproduce the information in a way that is easily understandable is time consuming, as it requires Pace to perform extra work. The files will be available tomorrow and will be provided to you, then, but will not be available until then.”

On April 14, 2017, Vectren supplied a spreadsheet with nothing more than hard coded data, most, if not all of which, was not given to us in the original transmittal of the Aurora modeling files. This lack of an adequate response makes a complete review of the stochastic modeling impossible.

It is also worth noting that while this section of the Indiana IRP requirements is specific to “inputs, methods, and definitions”, input files must be accompanied by output files for useful third-party review.

II-B. Lack of comparisons across portfolios

Vectren does not provide a complete comparison of its portfolios’ resource retirements, additions, and other inputs in a way that facilitates comparison across portfolios. A series of tables or figures presenting these comparisons would make review of Vectren’s IRP modeling more effective. Vectren 2016 IRP Attachment 7.1 does not include all retirements and additions, and is only referred to once, on page 203 of the IRP. For our own use, we assembled Table 2 (below), which is best viewed electronically where it is possible to zoom in on the image. Making these comparisons more accessible to stakeholders would likely require multiple tables or figures along with a discussion of why choices to retire or add resources were made, and some indication of which resource changes are fixed (set by the modeler) as compared to optimized (chosen by the model based on the constraints set by the modeler).
Table 2. Vectren 2016 IRP comparison of portfolio retirements and additions

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy Efficiency</strong></td>
<td>1.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>1.0%</td>
<td>1.0%</td>
<td>1.0%</td>
<td>1.0%</td>
<td>1.0%</td>
<td>1.0%</td>
</tr>
<tr>
<td><strong>Demand Response</strong></td>
<td>12 MW</td>
<td>12 MW</td>
<td>8 MW</td>
<td>8 MW</td>
<td>12 MW</td>
<td>8 MW</td>
<td>8 MW</td>
<td>8 MW</td>
<td>8 MW</td>
<td>8 MW</td>
</tr>
<tr>
<td><strong>Solar</strong></td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
<td>4 MW</td>
</tr>
<tr>
<td><strong>Wind</strong></td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
<td>400 MW</td>
</tr>
<tr>
<td><strong>Battery</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>SCGT (220 MW Additions)</strong></td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
<td>10 MW</td>
</tr>
<tr>
<td><strong>CCGT (Additions)</strong></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Combined Heat and Power (38 MW)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Market Capacity Purchases</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
II-C. Lack of transparency regarding modeling assumptions

Complete documentation of an IRP requires that all inputs, outputs, methods, assumptions, and definitions be made available to stakeholders clearly, transparently, and, for data files, in machine readable form. It also requires that key assumptions that influence modeling outcomes are documented in the IRP and that modeling inputs are consistent with how they are described in the IRP.

In addition, we find that Vectren’s scorecard methodology is not at all transparent. Its methodology is not fully explained and not all data used in its preparation were made available for stakeholder review. Our critique of Vectren’s scorecard methodology is presented in Section XIV-B.

II-D. Errors and inconsistencies in Vectren’s 2016 IRP

The Vectren 2016 IRP contained errors and inconsistencies in five main areas:

1. Opaque and inaccurate scorecard assessment (discussed in Section XIV)
2. Flawed projection of energy efficiency costs (discussed in Section IX-B)
3. Inaccurate energy forecast (discussed in Section XIX)
4. Improper restrictions on resource selection (discussed in Section IV)
5. Incorrect use of a pre-tax discount rate (discussed in Section V)

II-E. Recommendations for complete documentation of inputs, methods, and definitions

To assure complete documentation of an IRP, we endorse the recommendations made by CAC, Indiana Distributed Generation Alliance, the Indiana State Conference of the National Association for the Advancement of Colored People (NAACP), Sierra Club, and Valley Watch in IURC Rulemaking #15-06 to include a “technical appendix” as part of the IRP submission. The following is a partial list of key items for inclusion in an IRP technical appendix:

- The input and output files from all models in a readable electronic format
  - System Optimizer, Planning and Risk, Capacity Expansion: Input and output files should be presented in spreadsheet format.
  - Strategist: Input and output files should be in text format at a minimum. Strategist has the capability to export data into a spreadsheet, which is extremely helpful for review purposes.
  - With any of these models, if stakeholders or Commission staff wish to create their own modeling runs, the executable files also should be made available, but this type of exercise would require licensing fees for the model and is therefore usually beyond the resources available to an intervenor/stakeholder group.

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2 Public Comments received by the IURC in IURC RM #15-06 are available here: http://www.in.gov/iurc/2844.htm.
Other models: For most other models, spreadsheet-based input and output files will be the most useful. We would be happy to consult with any Indiana utility on the appropriate format to use for a given model.

- **A user guide for each model used**: Indiana utilities use many different models including Strategist, System Optimizer, Planning and Risk, MIDAS, Capacity Expansion model, and Plexos, so having a user guide on hand is essential to a public process so that stakeholders and Commission staff can have an understanding as to how a model works and how to interpret its input and output files.

- **Any files used to “post-process” IRP results in readable electronic format with formulae intact**: For example, at least two Indiana utilities, NIPSCO and Duke, take the results of their modeling and modify the present value of revenue requirements (PVRR) in a spreadsheet.

In addition, we recommend:

- **Earlier submission of key information even prior to the IRP’s release**: Early release of detailed descriptions and modeling files during the stakeholder process would make possible public review and comment that could aid the utility in identifying errors before the IRP is submitted to the Commission.
III. Does the IRP include a discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting?

We did not review this aspect of Vectren’s 2016 IRP.
IV. Does the IRP include a description of the generation expansion criteria, including a full explanation of the basis for the criteria selected?

No. The description of generation expansion criteria in Vectren’s 2016 IRP is incomplete and/or incorrect. Vectren’s portfolios are not optimized. Instead, they are constrained by multiple resource limitations set by scenario. Vectren also fails to mention that differences in the 20-year net present value costs among the three portfolios to which Vectren assigned the best overall scores (Portfolios L, K, and M) and the two stakeholder inspired (Portfolios I and J) is largely due to differences in the portfolios in the post 2023 time period. In addition, Vectren is modeling those late capacity additions such that reserves greatly exceed reserve margin requirements—which in turn tends to inflate longer-run costs in Stakeholder Portfolios I and J, as described in Section IV-C.

The bottom line is that there is nothing more than very shaky ground underlying Vectren’s premise that its Preferred Portfolio L is less costly than either of the Stakeholder Portfolios I and J and, notably, Vectren itself finds that Portfolios I and J are less risky than its preferred portfolio (see Section XIV). Vectren’s selection of Portfolio L as the preferred portfolio is also undermined by errors in Vectren’s load forecast (see Section XIX) as well as errors in calculating renewable costs (see Section IX-A) and energy efficiency costs (see Section XIV.B).

IV-A. Optimized portfolios are not really optimized nor even logical.

Vectren’s 2016 IRP modeling constructs a Base Case plus six scenarios for Strategist modeling:

- High Regulatory
- Low Regulatory
- High Technology
- High Economy
- Low Economy, and
- Base Case plus a Large Load Addition.

Vectren claims that the purpose of these scenarios is “to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions.” (Vectren 2016 IRP, p. 182)

Vectren devotes several pages to describing what it claims are the key characteristics of the first five scenarios in the short, medium, and long terms. Strangely, Vectren entirely fails to mention that a different set of technologies is available for selection in each of the scenarios. That is, Strategist is either prevented from selecting certain technologies entirely, or the first year those technologies are available to select is considerably delayed, depending on the scenario in question. This non-standard use of “scenarios” to restrict available resources is both troubling methodologically and not at all transparent to stakeholders. Scenarios classically—and in accordance with Vectren’s own definition above—provide a range of potential values for uncertain future conditions. Scenarios set up the circumstances under which resource portfolios are tested; they do not themselves call the shots as to what resources will or will not be available.
Vectren states that because of the limitations on Strategist, an “iterative” process was followed where the “model was run with several alternatives. Viable options were kept for the next model run, uneconomic options were screened out, and new options were added in for evaluation.” (Vectren 2016 IRP, p. 80) The criteria by which Vectren determined the “viable options” is completely opaque and many of the choices do not make sense not only because of the scenario characteristics but because Vectren is manipulating not just the resource available to the model but the first year in which those resources are available as described below.

IV-A-1. Resource availability

Table 3 provides a report of Vectren’s assumptions limiting the selection of energy efficiency and renewable energy resources by scenario. Designating a resource as having a “First Year Available” in 2099 means that resource is unavailable for the entire planning period, which spans from 2017-2036.

Table 3. Selected renewable and energy efficiency “First Year Available” by scenario

<table>
<thead>
<tr>
<th>Resource</th>
<th>Base</th>
<th>High Regulatory</th>
<th>Low Regulatory</th>
<th>High Technology</th>
<th>High Economy</th>
<th>Low Economy</th>
<th>Base + Large Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW Wind</td>
<td>2099</td>
<td>2030</td>
<td>2099</td>
<td>2099</td>
<td>2024</td>
<td>2099</td>
<td>2025</td>
</tr>
<tr>
<td>50 MW Solar</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2036</td>
<td>2024</td>
</tr>
<tr>
<td>50 MW Wind</td>
<td>2019</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2025</td>
</tr>
<tr>
<td>9 MW Solar</td>
<td>2019</td>
<td>2099</td>
<td>2099</td>
<td>2030</td>
<td>2024</td>
<td>2035</td>
<td>2025</td>
</tr>
<tr>
<td>4 MW DR added every 5 years</td>
<td>2020</td>
<td>2099</td>
<td>2020</td>
<td>2099</td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
</tr>
<tr>
<td>EE Block 1</td>
<td>2018</td>
<td>2018</td>
<td>2018</td>
<td>2099</td>
<td>2018</td>
<td>2099</td>
<td>2018</td>
</tr>
</tbody>
</table>

Data source: Strategist file PRV Input Summary report for each scenario

Note: “2099” indicates that this resource is never available for selection during the 20-year modeling period.

- **Base Case:** It is not clear to us how Vectren’s “Base Case” represents a “Base” set of conditions since the model cannot choose resources that are clearly available today including 200 MW wind and 50 MW solar.

- **High Regulatory:** Vectren states that its High Regulatory scenario is characterized in part by:
  - More renewable adoption pushed through via mandates;

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3 The energy efficiency options are chained in Strategist such that EE Block 1 must be selected before EE Block 2, etc. As such it is reasonable to assume that any first year available restriction on EE Block 1 has the effect of also limiting the remaining blocks.
• Additional regulations on carbon on the horizon after 2030 [apart from the Clean Power Plan] that are higher than in the base case;

• Greater adoption of distributed generation in the form of solar and combined heat and power; [and]

• Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices, and result in an additional push and economic case for renewable energy. (Vectren 2016 IRP, p.183)

And yet no renewable energy mandate appears to be modeled in this High Regulatory scenario in Strategist. Moreover, all of these factors “pushing” the adoption of renewable energy can have no effect because the 200 MW wind resource is the only renewable resource available in the High Regulatory scenario and even then it is only available to choose starting in 2030. It makes absolutely no sense to severely limit the model to only one renewable technology in a “High Regulatory” scenario, which has high fossil fuel prices and stringent regulations favoring renewables.

• High Technology: Likewise, Vectren’s High Technology scenario, which supposedly reflects, in part, “significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth” uses exactly the same load forecast as the Base Case scenario (see the discussion of this below) while preventing the model from selecting any energy efficiency.

• Base Case plus a Large Load Addition: Vectren claims that its Base plus Large Load Addition scenario “add[s] 100 MWs of load beginning in 2024 to the base forecast. All else is equal to the base scenario” (Vectren 2016 IRP, p. 193). This is clearly not the case. As shown in Table 3, only the resource choices of 4 MW of demand response added each year for 5 years, and energy efficiency block 1 are first available in the same years as in the Base Case; yet all other resources in Table 3 have different first years available.

IV-A-2. Peak load and energy requirement assumptions

Despite differing limits on the adoption of energy efficiency and demand response, all of Vectren’s scenarios use exactly the same peak load forecast, with the exception of the Base plus Large Load Addition scenario, as shown in Figure 1.

Vectren’s scenarios do differ in their reconstituted energy forecasts (before energy efficiency), as shown in Figure 2.

Unfortunately, these differences raise additional questions regarding Vectren’s peak load forecasts. Why is there no correlation between Vectren’s peak load and energy requirements forecasts? It simply does not make sense that the two would not be related.
Figure 1. Vectren 2016 IRP peak load forecast by scenario—CONFIDENTIAL

Data source: Strategist Loads and Resources Detail Report for each scenario.

Figure 2. Vectren 2016 IRP energy requirement forecast by scenario—CONFIDENTIAL

Data source: Strategist LFA Input Summary report for each scenario.
As an example of this lack of relationship, note in Figure 1 and Figure 2 that the energy requirements of the Low Regulatory scenario dramatically increase above those of the Base Case scenario, yet the peak load remains the same. Conversely, the energy requirements of the Low Economy scenario fall for the first six years of the planning period before growing again, but peak load remains unchanged from the Base Case scenario. Indeed, not only are the rates of growth in peak load and energy requirements seemingly unrelated to each other, but in some instances such as the Low Economy scenario, these rates of growth have opposite signs (i.e., positive or negative). Again, this result is nonsensical and totally undermines Vectren’s portfolio results.

While Vectren might claim that “each of these scenarios has an internally consistent narrative” (Vectren 2016 IRP, p. 194), that narrative does not seem to translate into logical inputs in its scenarios. These scenarios cannot even be claimed to be “plausible” as Vectren asserts on page 194 of its IRP, because the peak load forecast is a key input into any resource plan scenario, and the fact that it does not change when the energy forecast changes renders these scenarios unusable. In addition, we have concerns about the validity of the base case energy forecast as described in Section XIX.

Our discussion in this section includes just a sample of the ways in which Vectren’s descriptions of scenarios are not consistent with its scenario assumptions. A full comparison of scenarios, along with extraction of this information from the Strategist files, would be very time consuming and was beyond the scope of this analysis at this time.

One way that Vectren could make its scenarios more transparent in the future is by linking its scenario descriptions to specific inputs. For example, if the High Regulatory scenario is characterized by “more renewable energy adoption pushed through via mandates”, then Vectren should specify what modification from the Base Case was made to represent this characteristic. Doing this would increase the transparency of Vectren’s IRP process since most of its scenario narratives do not lend themselves to clear, unambiguous interpretation. If no input was modified, then there would be no need to describe that aspect of a scenario in the IRP report.

IV-B. Stakeholder portfolios and Vectren’s preferred portfolio have very similar near-term costs.

Vectren selects its preferred portfolio using the scorecard assessment methodology critiqued in Section XIV below. Portfolios I and J—the Stakeholder portfolios—receive by far the worst scores for net present value (NPV) according to Vectren’s analysis, as shown by Vectren’s Figure 7.17, reproduced below as Figure 3. Indeed, these portfolios are the only ones that appear to have costs that differ significantly from the remaining 13 portfolios.
The data shown in Vectren’s Figure 7.17 are taken from Vectren’s Aurora stochastic modeling. As described in Section II-A, CAC has asked Vectren, on multiple occasions, to identify where the data underlying Figure 7.17 are located, but Vectren has not done so. Without this information, it is impossible for us to verify the accuracy of Figure 3. Because the equivalent cost data from Strategist is transparent and readily available, we constructed a similar graph with a subset of portfolios of particular interest, Portfolios I, J, K, L, and M (see Figure 4). We chose to present Portfolios I and J (the so-called Stakeholder Portfolios) and Portfolios K, L, and M which receive the highest overall scores in Vectren’s scorecard analysis in Figure 4. As a reminder, Vectren selects Portfolio L as its preferred portfolio.
While Figure 3 presents the portfolios’ 20-year NPV, Figure 4 shows the total cumulative present value of each selected portfolio in each year over a 20-year period. The 2036 value for each of these portfolios shows a similar trend to Figure 3 (above) – Portfolios I and J are substantially more expensive than Portfolios K, L and M.

What Figure 4 makes obvious, though, is that the 20-year NPV values obscure the fact that cost differences between the portfolios only arise starting in 2024; prior to that, the portfolios are very similar in cost. This is significant because one of the biggest differences between Portfolios I and J and Portfolios K, L and M in the initial seven years of each plan is the level of energy efficiency being implemented.

Even under Vectren’s flawed projection of energy efficiency costs, there appears to be very little difference in cost between adopting a 2 percent energy savings goal (as in Portfolios I and J) and adopting a 1 percent energy savings goal (Portfolios K, L and M) for the period 2018 – 2022.

Data source: Strategist PRV System Cost report for each scenario.

4 See Section IX-B-2 and Attachment A for a discussion of the problems underlying the analysis supporting Vectren’s cost projections.
The presence of a significant cost difference only later in the planning period is also important because:

1. It emphasizes how similar these portfolios are in the first seven years of the planning period. This means that Vectren’s modeling provides the utility and the stakeholders with very little information about different and plausible near term resource choices because those resource choices are simply not analyzed; and

2. It undermines Vectren’s choice to rely on the 20-year NPV as a good indicator of which portfolio is lower cost. That is not to say that a shorter planning period ought to have been used, rather it’s important to give much less weight to near-term decisions driven by the 20-year NPV results when the differences in cost between portfolios is largely due to resource choices made later in the planning period. This is partly because those later resource choices have little effect on the choice to implement higher amounts of energy efficiency or not, but also because the later into the planning period, the more costs become speculative and less certain. The post-2023 resource choices embodied in these portfolios are likely to change with changing load forecasts, changing capital costs, and changing decisions about unit retirements.

IV-C. Too much capacity is added in key Vectren portfolios

Vectren’s assessment of comparative portfolio costs is based on 20-year NPV, which appears (as is discussed in Section IV-B) to be driven by costs in the 2024 to 2036 period. Even if it were reasonable to allow the post-2023 years to drive the NPV results, Vectren’s portfolios suffer from an additional serious flaw: high levels of excess capacity. As presented in Figure 5, post-2023 reserves often greatly exceed MISO reserve margin requirements.
Figure 5. Reserves and reserve margin requirement for selected portfolios—CONFIDENTIAL

*Data source: Strategist GAF Loads and Resources Detail reports for each scenario*

Vectren’s reserve margin requirement, accounting for its coincidence with the MISO peak, is percent. Portfolios I, J, K, and L inexplicably include much higher levels of capacity than what is necessary to meet reserve requirements. This almost certainly drives costs higher than is necessary in each of these portfolios. One cannot, however, necessarily conclude that this impact is greater for Portfolios L and K simply because they have higher reserve margin levels. This is because to the extent there is a difference in cost per MW of accredited capacity added (the nameplate of all resources is adjusted for forced outages and/or ability to serve load at peak), the costs may be, for example, more for Portfolio I than Portfolio L. It is important to note that at least in the case of Portfolios I and J, this excess capacity is entirely the result of Vectren’s modeling specifications because every resource choice was determined by the modelers in those runs.

**IV-D. Recommendations for describing generation expansion criteria**

For a complete and accurate description of generation expansion criteria in an IRP, we recommend that detailed data be provided at the time of IRP submission that is sufficient for a public process and third-party review. This information should include: the type, quantity, and size of capacity available to the model in each year, as well as any limitations on resource choices.

In addition, utilities should carefully review all narrative descriptions of scenario assumptions and modeling methodologies to ensure that this text is accurate, clear enough to be easily interpreted by a nontechnical audience, and internally consistent across all sections of the IRP.
V. Does the IRP include an explanation of the methods utilized in its development?

No. While Vectren’s thorough explanation of most of the methods used in the development of its 2016 IRP is a helpful tool for stakeholders and third-party reviewers, Vectren does not explain certain key elements of its IRP. Specifically, it does not explain how it chose the retirement dates for its coal units, all of which seem to uneconomical to operate under Vectren’s own assumptions as described in Section IX. Vectren does not explain how, if at all, the so-called “optimized” portfolios relate to the Balanced Energy and Stakeholder portfolios in which some or all resources were specified by Vectren. And it does not justify its use of a pre-tax rather than post-tax discount rate, which leads to errors in its NPV values and a likely bias against the portfolios with the most renewable additions.

V-A. Does the IRP include an explanation of the model structure and reasoning?

No. As described above, key elements of Vectren’s 2016 IRP model structure and reasoning are missing.

V-B. Does the IRP include an adequate explanation of its use of a weighted average cost of capital?

No. Vectren’s 2016 IRP uses a pre-tax 10.09 percent discount rate to do two important functions in its modeling: (1) create a levelized annual fixed cost for each new resource available in Strategist (see response to CAC 1.29-Confidential (Exhibit 1-C)) and (2) discount the cost streams in Strategist to arrive at a net present value (NPV). It is likely thatVectren also uses a pre-tax discount rate to calculate NPV in Aurora, its stochastic risk model. The NPVs from Aurora are included in two of Vectren’s scorecard metrics: Portfolio NPV (where 20-year NPV is the only component measure) and Portfolio Cost/Risk Trade-Off (where the metric is scored based on an underspecified relationship between NPV and the standard deviation of costs, see Section XIV).

Given the importance of cost in Vectren’s selection of a preferred portfolio, it is worth considering whether the utility’s unusual selection of a pre-tax discount rate is proper or not. A 2009 article in the Journal of Applied Research in Accounting and Finance (Lonergan, “Pre and Post Tax Discount Rates and Cash Flows – A Technical Note”, Volume 4, Issue 1)\(^5\) asserts that,

> When discounting pre tax cash flows it is often assumed that discounting pre tax cash flows at pre tax discount rates will give the same answer as if after tax cash flows and

\(^5\) See [http://hdl.handle.net/1959.14/98570](http://hdl.handle.net/1959.14/98570).
after tax discount rates were used. However, this is not the case and material errors can arise, unless both the cash flows and the discount rate are after-tax.

Lonergan concludes that, “There are only a few special cases where [using pre-tax cash flows and discount rates] may give the same answer as discounting after tax cash flows at after tax discount rate[s], for instance the case of cash flows in perpetuity with no growth…Consequently, it is important that after tax cash flows and after tax discount rates are applied in DCF [discount cash flow] valuations.”

It is highly unlikely that one would encounter a case where there is no growth in spending and therefore no growth in “cash flow” in an IRP. As such, using a pre-tax discount rate would seem to give the incorrect NPV answer here.

To further illustrate this point, we reworked one example from Vectren’s IRP, which applies the 10.09 percent pre-tax discount rate to a pre-tax “cash flow” to demonstrate that one does not get the same answer as when discounting post-tax cash flows using a post-tax rate.

Our point of comparison was Vectren’s 50 MW wind resource modeled. According to Vectren, the levelized annual cost of that resource over a 25 year period without consideration of the production tax credit is each year (CAC 1.29-Confidential (Exhibit 1-C)). Based on an April 11, 2017 email from Vectren staff (Exhibit 2), the utility’s calculations do not assume accelerated depreciation and the discount rate is grossed up for federal income tax at an assumed rate of 35 percent and the state income tax is assumed to be 4.9 percent. We applied these tax rates to the common equity portion of the return on the investment rather than grossing up the discount rate and arrived at a 25-year levelized value of , which is approximately 4 percent less than what Vectren calculated.

Even if you assume this problem equally affects all resources, overestimating capital costs due to this incorrect pre-tax treatment seems likely to have the biggest impact on Stakeholder Portfolios I and J because they have significantly more capital spending than Portfolios K, L, and M as shown in Figure 6.
Figure 6. Annual nominal capital investment by portfolio—CONFIDENTIAL

Data source: Strategist PRV System Cost reports for each scenario

Portfolio I contains more than twice as much capital spending in the period 2024 – 2036 while Portfolio J has about three times the capital investment compared to Portfolios K, L, and M. Put another way, even if one assumes that the annual costs of each resource embedded in these cost streams is overestimated by 4 percent, the absolute impact of that 4 percent is more than twice as significant for Portfolio I as it is for Portfolios K, L, and M, and more than three times as large for Portfolio J. And in turn, the capital costs are about 60 - 80 percent of the total cost post-2023 for Portfolios I and J.

V-C. Recommendations for explaining methods used in IRP development

For a complete and accurate explanation of the methods used in the development of an IRP, we recommend that Vectren address the issues regarding methodology, data quality, and clarity of presentation identified in this report. We also recommend that Vectren reexamine and replace its discounting methodology and/or demonstrate that it provides the same results as a post-tax methodology.
VI. **Does the IRP include an explanation, with supporting documentation, of an avoided cost calculation for each year in the forecasted period?**

No. While the Vectren IRP provides a very brief description of its avoided cost methodology on page 260, its methodology is not appropriate for use in an IRP. Vectren bases its avoided costs on marginal costs:

> The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO2 starting in 2024, estimated capital, variable operation and maintenance, and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses. (Vectren 2016 IRP, p.260)

Avoided costs based on marginal costs are not appropriate for DSM screening because the impact of energy efficiency is not “marginal”, particularly when programs are implemented over many years. In addition, marginal cost is not used to justify a utility’s investment of capital in a supply-side resource in, for example, a Certificate of Public Convenience and Necessity proceeding; that is, utilities do not typically invest capital only up to the “marginal cost”. So to apply this convention to energy efficiency creates unequal treatment of supply and demand side resources.

By limiting its avoided cost calculations to the marginal cost, Vectren may unnecessarily limit the energy efficiency chosen in its DSM plans.
VII. Was the preferred resource portfolio selected from among the candidate resource portfolios developed?

Yes. The preferred resource portfolio was selected from among the candidate resource portfolios developed.
VIII. Is the preferred resource portfolio described?

Yes. Vectren provides a description of the inputs and outcomes associated with its preferred resource portfolio.
IX. Are supply-side and demand-side resource alternatives evaluated on a consistent and comparable basis?

No. Supply-side and demand-side resource alternatives are not evaluated on a consistent and comparable basis in Vectren’s 2016 IRP. Vectren’s IRP modeling assumptions and methodology distort the costs of supply-side resources (Section I-C) and also create a bias against renewables. In addition, demand-side resources are subjected to inaccurate and biased projections of future costs (Section IX-B-2).

IX-A. Is each supply-side resource alternative evaluated on a consistent and comparable basis with other supply-side resources?

No. There are multiple biases against renewables, energy efficiency, and coal plant retirements as detailed below.

IX-A-1. Retirement analysis is biased towards later retirement of uneconomic units

Vectren assumes that Warrick Unit 4 retires in 2020 in all cases. As Vectren states in a footnote to its IRP at page 163, “There is still uncertainty with respect to the ALCOA-Warrick generation facility following the retirement of ALCOA’s aluminum smelter. A conservative planning approach was taken in this analysis and all four Warrick generating units were modeled as retired with Vectren serving the remaining ALCOA load.” Given that this is an “uncertainty” it would have made far more sense to model scenarios with and without Warrick rather than simply assuming that it is retired. In addition, there may be concerns about what it means to assume that Vectren continues to serve the “remaining ALCOA load”, the implication of which is never specified.

The retirement of Warrick Unit 4 takes Vectren’s system down from a position of significant excess capacity to one with a slight deficit in capacity. The continued operation of Warrick Unit 4 is likely to be preferable if only because Warrick Unit 4 is more efficient than Culley Unit 2 and the ABB Brown units. However, it is also worth noting that the operation of all the Culley and ABB Brown units is anticipated to be uneconomic even under Vectren’s optimistic assumptions. Specifically, according to Vectren’s modeling under Base Case scenario conditions, the Culley and ABB Brown units would lose millions of dollars each year starting in 2017, as shown in Figure 7.
In 2017 alone, the total amount of losses from these four units is projected to be $\text{[redacted]}$ million.

It is also important to note that Vectren is predicting these losses based on projected capacity factors that far exceed the historic performance of these units as shown in Figure 8.

Figure 7. Vectren 2016 IRP Culley and Brown unit projected net profits—CONFIDENTIAL

Data source: Strategist modeling file labeled “Base-Business as Usual (Continue Coal)-A GAF Unit Report”

Figure 8. Historic capacity factors compared to projected capacity factors used in Vectren modeling—CONFIDENTIAL

Data source: Strategist modeling file Base-Business as Usual (Continue Coal)-A GAF Unit Report and SNL Financial
While Vectren also projects that Warrick Unit 4 will lose money, it anticipates Warrick’s losses will be smaller than those of the Brown units or Culley Unit 3.

Despite the Culley and Brown units’ expected losses, Vectren appears to have not considered the retirement of these more expensive units in place of Warrick Unit 4, in advance of the year 2021. Nor has Vectren included a discussion of the reasonableness of the factors that led to its very high projections of coal unit generation. While Vectren did explore the retirement of the Culley and Brown units in 2021, it is not clear if earlier retirement of those units was rejected on its own merits or because of the modelers’ restrictions on the resources that could be added to replace those units and Vectren’s projected high costs of the alternatives (see our critiques in Sections, IV, V and IX-A-2). Vectren fails to discuss these choices or the retirement of its more inefficient, more expensive units in its IRP.

**IX-A-2. Biases against renewables**

The earliest that wind appears to be available for commercial operation in Vectren’s Strategist modeling is [ ] in the scenarios we reviewed. The assumed capital cost in that year is $[ ] per kW (nominal) or about $[ ] per kW (in real 2015$). While Vectren’s trajectory of wind costs includes a slight decline in real pricing, we do not think it is in line with current expectations regarding future wind costs. There have been significant declines in wind pricing since 2010, as shown in Figure 9.

![Figure 9. Historical wind installed project cost (2015 $/kW)](https://emp.lbl.gov/publications/2015-wind-technologies-market-report)


There have likely been further price declines since the 2015 data for LBL’s report was collected. For example, UBS Securities reports that current equipment pricing for wind is in the $900 per kW range with an all-in cost of $1,300 per kW, with some companies expecting that the
continued decline in pricing will at least make up for the roll-off of the production tax credit (PTC).  

Deflationary trends in solar also make it difficult to predict what solar will cost in the future. One estimate from UBS Securities predicts that solar is poised to cost in the range of $800 to $900 per kW with total levelized costs in the $30 per MWh range across much of the U.S. Conversely, Vectren’s 2017 estimated cost for a utility scale 50 MW solar plant is $ per kW (CAC 1.29-Confidential (Exhibit 1-C)) or $ per MWh. Vectren’s estimate is much higher than the UBS forecast in part because of assumptions like the need for significant owner and contractor contingency as well as a large amount of AFUDC (CAC 2.3-A Confidential (Exhibit 3-C)). While there is certainly evidence to assume that solar costs will continue to decline significantly, there is also reason to assume a lower solar cost than $ per MWh today. The National Renewable Energy Laboratory (NREL) benchmarks the cost of solar around the country. According to its analysis, New Jersey, which has a roughly comparable solar resource to Indiana, was estimated to have a nominal levelized cost of solar energy of $99 per MWh in the first quarter of 2016, far lower than Vectren’s current estimate.

These overestimates of renewable costs not only bias the IRP against the stakeholder portfolios, they also bias the selection of renewables in other portfolios, to the extent that their selection is permitted by Vectren’s modelers. Either way, Vectren’s assumptions likely led to a suboptimal amount of renewable energy being selected.

IX-A-3. Inconsistent screening of resources

Vectren’s decisions regarding what resources to screen for inclusion in modelling and what resources to model appear to be largely ad hoc. Table 4 presents resources listed, screened for inclusion in modeling, and modeled in Vectren 2016 IRP. The utility’s rationale for these choices is not explained in the IRP: Why are resources screened that are not described in Section 5.2? Given the busbar analysis performed by Vectren, how then were resources chosen for inclusion in modeling? Additional information on these decisions would facilitate stakeholders’ ability to review the IRP.

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7 See also page 10 of https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf for an additional estimate of how much wind (and solar) costs have declined in recent years.
8 Ibid.
9 See http://www.nrel.gov/docs/fy16osti/66532.pdf
Table 4. Resources listed, screened, and approved for modeling for Vectren 2016 IRP

<table>
<thead>
<tr>
<th>Section 5.2 Listed</th>
<th>Section 5.5 Screened</th>
<th>Section 5.5 Approved</th>
</tr>
</thead>
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<tr>
<td>TOTAL</td>
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<td>34</td>
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<tr>
<td>Coal</td>
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<td>3</td>
</tr>
<tr>
<td>500 MW Supercritical Pulverized</td>
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<td>yes</td>
</tr>
<tr>
<td>750 MW Supercritical Pulverized</td>
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<td>yes</td>
</tr>
<tr>
<td>525 MW IGCC 2x1</td>
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<td>yes</td>
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<tr>
<td>SCGT</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>40 MW 1xLM6000</td>
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<td>yes</td>
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<tr>
<td>100 MW 1xLMS100</td>
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<td>yes</td>
</tr>
<tr>
<td>90 MW 1xE-Class</td>
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<td>yes</td>
</tr>
<tr>
<td>220 MW 1xF-Class</td>
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<tr>
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<tr>
<td>170 MW</td>
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<tr>
<td>240 MW (ABB)</td>
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<td>yes</td>
</tr>
<tr>
<td>343 MW 2x1 7FA.05 (ABB)</td>
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</tr>
<tr>
<td>440 MW 1x1 7FA.05</td>
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<tr>
<td>580 MW 2x1 7FA.04 (ABB)</td>
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<td>750 MW 2x1 7FA.04</td>
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<td>690 2x1 7FA.05 (ABB)</td>
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<td>no</td>
</tr>
<tr>
<td>890 2x1 7FA.05 (ABB)</td>
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</tr>
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<td>1,340 MW 3x1 7FA.05 (ABB)</td>
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<td>CHP</td>
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<td>5</td>
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<td>1 MW Microturbine</td>
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</tr>
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<td>10 MW Combustion Turbine Generator</td>
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<td>14-15 MW Combustion Turbine Generator</td>
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<td>Wind</td>
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<td>50 MW Wind (Indiana)</td>
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<td>200 MW Wind (Indiana)</td>
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<td>yes</td>
</tr>
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<td>Solar</td>
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<td>5</td>
</tr>
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<td>3 MW Solar PV</td>
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<td>yes</td>
</tr>
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<td>4 MW Solar PV</td>
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<td>100 MW Solar PV</td>
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<tr>
<td>Hydro</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>50 MW Lowhead Hydroelectric</td>
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<td>no</td>
</tr>
<tr>
<td>WTE</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>50 MW Wood Stoker Fired</td>
<td>yes</td>
<td>no</td>
</tr>
<tr>
<td>5 MW Landfill Gas IC Engine</td>
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<td>yes</td>
</tr>
<tr>
<td>Storage</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>10 MW / 40 MWh Lithium Ion</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>1 MW / 1 MWh Lithium Ion</td>
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<td>yes</td>
</tr>
<tr>
<td>100 kW / 250 kWh Commercial</td>
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<td>yes</td>
</tr>
<tr>
<td>2 kW / 7 kWh Residential</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Compressed Air Energy Storage</td>
<td>yes</td>
<td>yes</td>
</tr>
</tbody>
</table>

Data source: Vectren 2016 IRP, Section 5.2 and 5.7
IX-B. Are supply-side resource alternatives evaluated on a consistent and comparable basis with demand-side resources?

No. Demand-side resources are not treated on a consistent and comparable basis with supply-side resources. Specifically, energy efficiency costs are inflated based on a flawed statistical model supposedly linking energy efficiency costs and market penetration. These flaws are described in the subsection IX-B-2 and Attachment A.

IX-B-1. Vectren avoided certain critical mistakes in its analysis of DSM

We commend Vectren for certain aspects of its treatment of DSM that are superior to IPL and NIPSCO’s approaches. Specifically, we appreciate that Vectren’s energy efficiency cost analysis, while flawed, 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 energy efficiency than supply-side measures. We say this with the caveat that the IRP’s Section 5.2.3.7 Cost Benefit Analysis appears to apply to the DSM planning process rather than the IRP itself.

IX-B-2. Improper inflation of efficiency costs due to market saturation

Vectren’s 2016 IRP uses a projection of future energy efficiency program costs based on Richard Stevie’s 2015 working paper. In a separate paper, attached to this report as Attachment A, we critique Stevie’s econometric results and their application to efficiency cost projections. To demonstrate the errors and inconsistencies in Stevie’s methodology and conclusions, we replicated his results using the same data.

Stevie’s study asserts that no other study has illuminated the relationship between energy efficiency program costs and market penetration, and purports to itself demonstrate that market saturation causes higher efficiency program costs. We find that Stevie’s study provides no usable evidence of a market saturation-program cost relationship and ipso facto no such relationship has as yet been demonstrated. Stevie’s analysis suggests, erroneously, that there exists evidence of efficiency market saturation significantly driving up programs costs. We find, in contrast, that the evidence presented is insufficient and inaccurate. We are aware of no reliable evidence for higher energy efficiency market penetration leading to higher efficiency costs. Inclusion of a baseless inflation of efficiency program costs in the name of market saturation results in higher energy efficiency costs than would otherwise be expected. When applied to Vectren’s energy efficiency program cost projections, it can be expected that less efficiency than is optimal will be selected.

IX-C. Recommendations for a consistent and comparable resource evaluation

Vectren’s approach to evaluating energy efficiency in its IRP, setting aside its cost assumptions which have serious implications, is superior to IPL and NIPSCO’s approaches. However, the usefulness of its modeling for purposes of DSM plan formation can be enhanced. As we did in our recommendation on this topic in our comments on the NIPSCO and IPL IRPs, we also recommend that Vectren move to an avoided cost proxy for DSM. Under this approach, the appropriate level of savings is calculated in the DSM plan proceeding, but relies on avoided costs developed from the IRP, not on cost assumptions in the IRP modeling that may or may not be correct. Vectren is closer to this methodology than the other utilities, in that it modeled energy efficiency as 0.25 percent blocks of savings. However, to determine an avoided cost proxy, it is necessary to have 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.

This analysis must also be predicated on appropriate (and even-handed) selection of supply-side resources. The types of restrictions on renewable resources in the “optimized” portfolios are certainly not appropriate or even-handed and will not give a useful answer about the value of each load decrement.
X. Does the preferred resource portfolio utilize all economical resource alternatives as sources of new supply?

No. The preferred resource portfolio does not utilize all economical resource alternatives as sources of new supply.

X-A. Overall issues with Vectren’s method of selection of economical resources

Vectren fails to provide the reasonable modeling of future conditions that would be necessary to utilize all economical resource alternatives including biases against the addition of renewables resources and demand-side measures.

X-B. Does the preferred resource portfolio utilize all economical load management, demand-side management, and energy efficiency improvements?

No. Vectren’s 2016 IRP does not appear to utilize all economical demand-side management and load management as discussed in Section IX-B.

X-C. Does the preferred resource portfolio utilize all economical technology relying on renewable resources?

No. Vectren’s 2016 IRP does not appear to utilize all economical technology relying on renewable resources as discussed in Section IX-A.

X-D. Does the preferred resource portfolio utilize all economical cogeneration?

We did not assess Vectren’s use of cogeneration.

X-E. Does the preferred resource portfolio utilize all economical distributed generation?

We did not review this aspect of Vectren’s modeling.

X-F. Does the preferred resource portfolio utilize all economical energy storage?

We did not assess Vectren’s use of energy storage.

X-G. Does the preferred resource portfolio utilize all economical transmission?

We did not review this aspect of Vectren’s IRP modeling.
X-H. Recommendations for utilizing all economical resource alternatives

For a complete, and even handed, utilization of all economical resource alternatives, we recommend that Vectren use a technology neutral approach to resource inclusion in modeling and take care to evaluate all resources on a consistent and comparable basis (see Section IX for a discussion of consistent and comparable resource evaluation).
XI. Are targeted DSM programs evaluated, including their impacts on the utility’s transmission and distribution system?

No. Vectren does not evaluate DSM targeted at transmission and distribution system issues.
XII. Are the financial impacts to the utility of acquiring the future resources identified in the preferred resource portfolio assessed?

No. Vectren does not discuss any analysis of the financial impacts of acquiring the future resources identified in the preferred resource portfolio.
**XIII. Does the preferred resource portfolio balance cost minimization with cost-effective risk and uncertainty reduction?**

No. Vectren includes both cost minimization and risk and uncertainty reduction in its scorecard assessment. However, the insurmountable flaws in Vectren’s scorecard method render its results meaningless, as discussed in detail in Section XIV-B.
XIV. Are risks and uncertainties quantified, including, but not limited to: regulatory compliance, public policy, fuel prices, construction costs, resource performance, load requirements, wholesale electricity and transmission prices, RTO requirements, and technological progress?

No. Vectren’s 2016 IRP analysis of risks and uncertainties, while quantitative, does not include many of the risk categories listed in IURC guidance and contains other errors and limitations.

Overall, we question the usefulness of black box, qualitative “scorecard” approaches to IRP portfolio selection. These methods are largely opaque to the IRP audience and cannot be subjected to the kind of rigorous third-party analysis that protects the public interest in an IRP process. Furthermore, because of their black box and qualitative characteristics, such analyses can be made to produce a very wide range of policy results (here, IRP preferred resource portfolios) based on small modeling choices that are not always expressed to stakeholders as explicit IRP goals.

Vectren’s 2016 IRP uses just such a black box scorecard methodology, which appears to contain multiple errors in its execution, including insufficient iterations of its model to appropriately represent uncertain future conditions, and choices of scorecard ranking rules that have the effect of biasing results against particular portfolios.

XIV-A. Not enough iterations

Each of Vectren’s 15 portfolios was tested “under 200 iterations representing different, but cohesive and plausible market condition scenarios” (Vectren 2016 IRP, p.84). Vectren’s portfolio results are the average of these 200 iterations or model runs. The variables that were chosen by Vectren to model stochastically include:

1. Load
2. Natural gas price
3. Coal price
4. Carbon compliance costs
5. Capital costs
6. Cross-commodity correlation for gas, coal and carbon prices

As explained below, with six independent variables it is not at all clear how a full range of possible combinations of variables could be represented in just 200 iterations.

Vectren has chosen to use a style of sensitivity analysis referred to as Monte Carlo analysis. In brief, Monte Carlo analysis tests out the potential range of NPVRR, emissions and other modeling results using (1) the range of values deemed possible for each uncertain variable, and (2) multiple intersecting uncertainties (this means that more than one variable’s value is changing in each modeling run). The more uncertain variables being examined, the more modeling runs (each with a new set of values for the uncertain variables) are needed to get a

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11 Vectren 2016 IRP pp. 221-223
good sample of the entire range of potential modeling results. Monte Carlo analyses of two or three uncertain variables often involve tens of thousands of modeling runs.

Monte Carlo analysis is a well-accepted methodology used in sensitivity analysis—although, perhaps not one that it is particularly transparent to a nontechnical audience. The problems with Vectren’s choice of this methodology result from the number of uncertain variables that they are simultaneously sampling. Vectren appears to be testing the sensitivity of modeling results to six uncertain variables simultaneously. Vectren reports that it uses just 200 modeling runs to provide a complete sensitivity analysis. In our opinion, this number of runs cannot be sufficient to provide a good sample of potential modeling results.

Here’s how the math works under a typical Monte Carlo analysis, assuming that each uncertain variable’s range of possible values is divided into 10 parts (in principle, such a grid could be divided into many more parts, compounding the problem presented here):

- Two uncertain variables: Two dimensions, each with 10 segments, results in 10x10 or 100 samples (sets of variable value combinations)
- Three uncertain variables: Three dimensions, each with 10 segments, results in 10x10x10 or 1,000 samples
- Four uncertain variables: Four dimensions, each with 10 segments, results in 10x10x10x10 or 10,000 samples
- Five uncertain variables: Five dimensions, each with 10 segments, results in 10x10x10x10x10 or 100,000 samples
- Six uncertain variables: Six dimensions, each with 10 segments, results in 10x10x10x10x10x10 or 1,000,000 samples

In contrast, Vectren conducts just 200 modeling runs for six uncertain variables. For this number of independent variables, a grid divided into 10 parts would require 1 million modeling runs for good sampling. (For context, a grid divided into 3 parts, requires 729 runs, while a grid divided into 100 parts requires 1 trillion runs.) As a result, Monte Carlo analysis typically includes far fewer than six uncertain variables and/or far more than 200 runs.

XIV-B. Scorecard weighting is inconsistent and/or inaccurate

Vectren’s 2016 IRP scorecard methodology for selection of the preferred portfolio ranks each of its 15 resource portfolios by a score on six categories of metrics and then purports to average these metrics to result in a final ranking (see Figure 10). Vectren explains that its consultant, Pace Global:

> [C]onducted a risk analysis of 15 portfolios. The analysis subjects each portfolio to 200 iterations (future market and regulatory outcomes). Then portfolios were ranked by each group of key criteria and associated metrics. The best performers in each metric were given a green color and the worst were given a red color; yellow was also shown as caution within a given metric. (Vectren 2016 IRP, p.224)
To better understand this methodology, we replicated Vectren’s scorecard metric and weighting system (see Figure 11 for a direct reproduction of Vectren’s six main metrics and overall metric using our formatting, here presented in a neutral order). Figure 11 shows Vectren’s red, yellow, and red scores with black text and its red-yellow and green-yellow scores with yellow text. The numbers shown are ranks, 1-5, for these colors: red (worst) = 1; red-yellow = 2; yellow (caution) = 3; green-yellow = 4; and green (best) = 5.

Figure 11. Reproduction of Vectren 2016 IRP Portfolio Balanced Scorecard (ranked from 1=worst to 5=best)

<table>
<thead>
<tr>
<th>Portfolios</th>
<th>Portfolio NPV</th>
<th>Risk</th>
<th>Cost Risk Trade-off</th>
<th>Balance/Flexibility</th>
<th>Environment</th>
<th>Local Econ Impact</th>
<th>Overall: As Reported</th>
</tr>
</thead>
<tbody>
<tr>
<td>A - Existing Portfolio</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>5</td>
<td>1</td>
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<tr>
<td>B - Heavy Gas</td>
<td>5</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>4</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>C - Gas &amp; Solar</td>
<td>5</td>
<td>3</td>
<td>1</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>D - Gas &amp; Wind</td>
<td>5</td>
<td>2</td>
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<td>2</td>
<td>4</td>
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<td>4</td>
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<td>E - Heavy Gas</td>
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<td>F - Gas &amp; Wind</td>
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<td>3</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>I - Stakeholder w/ Renewables</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>4</td>
<td>4</td>
<td>5</td>
<td>1</td>
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<tr>
<td>J - Stakeholder w/ Renewables</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>4</td>
<td>5</td>
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<tr>
<td>K - Diversified w/ Coal</td>
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<tr>
<td>L - Diversified w/ Coal</td>
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<tr>
<td>M - Diversified w/ Coal</td>
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<tr>
<td>N - Gas &amp; Solar</td>
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<tr>
<td>O - Gas &amp; Solar</td>
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</tbody>
</table>

While Figure 11 directly reproduces Vectren’s metric results, Figure 12 instead replicates these results using the exact numeric ranks by color for the 13 sub-metrics presented in Vectren’s 2016 IRP. It is assumed, because Vectren did not specify otherwise, that all metrics are given
equal weight, both among the sub-metrics (not shown in Figures 2 or 3) that combine to these six main metrics and also among the six main metrics in order to determine an overall metric.

**Figure 12. Replication of Vectren 2016 IRP Portfolio Balanced Scorecard (ranked from 1=worst to 5=best)**

<table>
<thead>
<tr>
<th>Portfolios</th>
<th>Portfolio NPV</th>
<th>Risk</th>
<th>Cost Risk</th>
<th>Trade-Off</th>
<th>Balance/ Flexibility</th>
<th>Environment</th>
<th>Local Econ Impact</th>
<th>Overall: Calculated</th>
</tr>
</thead>
<tbody>
<tr>
<td>A - Existing Portfolio</td>
<td>3</td>
<td>2</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>5</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>B - Heavy Gas</td>
<td>5</td>
<td>2</td>
<td>3</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>3</td>
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<tr>
<td>C - Gas &amp; Solar</td>
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<tr>
<td>D - Gas &amp; Wind</td>
<td>5</td>
<td>3</td>
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<td>3</td>
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<td>3</td>
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<tr>
<td>E - Heavy Gas</td>
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<tr>
<td>F - Gas &amp; Wind</td>
<td>5</td>
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<td>G - Gas &amp; Solar</td>
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<td>H - Heavy Gas</td>
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<tr>
<td>I - Stakeholder w/ Renewables</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>5</td>
<td>4</td>
<td>5</td>
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<tr>
<td>J - Stakeholder w/ Renewables</td>
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<tr>
<td>K - Diversified w/ Coal</td>
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<tr>
<td>L - Diversified w/ Coal</td>
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<td>M - Diversified w/ Coal</td>
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<td>N - Gas &amp; Solar</td>
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<td>O - Gas &amp; Solar</td>
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A comparison of Figure 12 to Figure 11 raises several questions:

- If these metrics were not equally weighted (as appears to be the case judging from the discrepancies between Figure 11 and Figure 12), on what basis were they weighted and why?
- Why has Vectren chosen to rerank the overall metric results in a manner which certainly accentuates and perhaps overemphasizes the differences between them?

When weighted equally, Vectren’s top ranked Portfolios K, L and M share their “best”/“caution” score with Portfolios D and F, while the remaining 8 Portfolios share the “caution” score.

In addition to these concerns, our detailed review of Vectren’s specific sub-metrics drew our attention to the possibility of other equally reasonable interpretations of these measures and their rankings. Figure 13 presents a revised version of Vectren’s scorecard using these changes (which are described in detail in the sections that follow).
Figure 13. Revisions to Vectren 2016 IRP Portfolio Balanced Scorecard (ranked from 1=worst to 5=best)

<table>
<thead>
<tr>
<th>Portfolios</th>
<th>Portfolio NPV</th>
<th>Risk</th>
<th>Cost Risk Trade-Off</th>
<th>Balance/Flexibility</th>
<th>Environment</th>
<th>Local Econ Impact</th>
<th>Overall: Calculated</th>
</tr>
</thead>
<tbody>
<tr>
<td>A - Existing Portfolio</td>
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<td>1</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>5</td>
<td>2</td>
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<tr>
<td>B - Heavy Gas</td>
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<tr>
<td>C - Gas &amp; Solar</td>
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<tr>
<td>D - Gas &amp; Wind</td>
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<td>E - Heavy Gas</td>
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<td>F - Gas &amp; Wind</td>
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<td>G - Gas &amp; Solar</td>
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<td>H - Heavy Gas</td>
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<tr>
<td>I - Stakeholder w/ Renewables</td>
<td>1</td>
<td>4</td>
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<tr>
<td>J - Stakeholder w/ Renewables</td>
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<td>5</td>
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<tr>
<td>K - Diversified w/ Coal</td>
<td>5</td>
<td>4</td>
<td>5</td>
<td>4</td>
<td>2</td>
<td>5</td>
<td>5</td>
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<tr>
<td>L - Diversified w/ Coal</td>
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<td>3</td>
<td>4</td>
<td>2</td>
<td>5</td>
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<tr>
<td>M - Diversified w/ Coal</td>
<td>5</td>
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<td>N - Gas &amp; Solar</td>
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<tr>
<td>O - Gas &amp; Solar</td>
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</tr>
</tbody>
</table>

The changes presented in the next subsections are at least as reasonable—and, we would argue, more reasonable—than the assumptions chosen by Vectren. The result of these small adjustments to the scorecard ranking system is the very different ranking of portfolios as presented in Figure 13. To be clear, we did not adjust the underlying data or measures. Instead, we made changes to Vectren’s methods of ranking and combining these measures.

Figure 14 compares Vectren’s overall portfolio scores with our revisions (based solely on changes to the method of ranking). In our revised scorecard, no portfolio receives the top green score (5) and the “best”/”caution” (4) score is shared by nine portfolios, including those scored “best” by Vectren (Portfolios K, L, and M) and one of the stakeholder portfolios (I).

Figure 14. Revisions to Original Vectren 2016 IRP Scorecard Comparison (ranked from 1=worst to 5=best)

<table>
<thead>
<tr>
<th>Portfolios</th>
<th>Overall: As Reported</th>
<th>Overall: Calculated</th>
</tr>
</thead>
<tbody>
<tr>
<td>A - Existing Portfolio</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>B - Heavy Gas</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>C - Gas &amp; Solar</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>D - Gas &amp; Wind</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>E - Heavy Gas</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>F - Gas &amp; Wind</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>G - Gas &amp; Solar</td>
<td>2</td>
<td>3</td>
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<tr>
<td>H - Heavy Gas</td>
<td>2</td>
<td>3</td>
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<tr>
<td>I - Stakeholder w/ Renewables</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>J - Stakeholder w/ Renewables</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>K - Diversified w/ Coal</td>
<td>5</td>
<td>4</td>
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<tr>
<td>L - Diversified w/ Coal</td>
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<tr>
<td>M - Diversified w/ Coal</td>
<td>5</td>
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<tr>
<td>N - Gas &amp; Solar</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>O - Gas &amp; Solar</td>
<td>3</td>
<td>4</td>
</tr>
</tbody>
</table>

Note: The “Overall: As Reported” values are Vectren’s overall portfolio scores shown in Figure 10 and Figure 11. The “Overall: Calculated” values are recalculated with our changes to ranking methods only, shown in Figure 13.

We present this revised treatment of Vectren’s scorecard system not to argue for the choice of any particular scenario as “preferred” but instead to draw attention to the problems inherent in
any black box scorecard assessment. Small, reasonable changes in ranking assumptions result in big changes in assigned scores. Vectren’s method of choosing its preferred portfolio is not robust to small changes in metric assumptions nor is it the only possible interpretation of the data upon which Vectren relies.

XIV-B-1. “Customer Rates”

We question Vectren’s characterization of differences across its Portfolios’ net present value of revenue requirements (NPVRR) as differences in “customer rates”. On page 225 of the IRP, Vectren clarifies that NPVRR “facilitate[s] lower customer rates”. We feel that it would be more transparent to consistently refer to this metric as “Portfolio NPV”.

We made no adjustments to Vectren’s Portfolio NPV metric in our revised scorecard shown in Figure 13. We do, however, question the modeling assumptions that led to these NPVRR results as we discuss in Sections IV, V, and IX.

XIV-B-2. Risks

Vectren’s Risk metric is composed of four component metrics: (1) standard deviation above the portfolio with the lowest cost; (2) 20-year average capacity purchases; (3) 20-year average market purchases; and (4) remote generation risk.

20-year average capacity purchases

This component takes the 20-year average of capacity purchases and assigns a green score if a portfolio purchases an average of 20 MW or less. However, a portfolio with significant capacity purchases is not inherently risky as much as poorly planned. If the resource plan that results from a modeling run includes significant capacity purchases for several years, that is an indication that more self-build, contracted, or demand-side resources need to be added to the portfolio even if that might be more expensive over the long-term. This approach is rational because the resources in any given scenario should be indicative of action a reasonable utility would actually take. Nor is the 20-year average of capacity purchases indicative of any real long-term risk that a utility cannot mitigate since even if load grew suddenly and unexpectedly in the real world, a utility can react by building or purchasing through contract the additional capacity it needs, rather than relying on the MISO capacity auction (called the Planning Resource Auction (PRA)).

Indeed, Vectren’s focus on what it considers to be the volatility (see for example, Vectren 2016 IRP, p. 71) of MISO PRA prices as a justification for including this risk sub-metric is confusing because even MISO describes the PRA as

>a voluntary annual capacity auction [that] allows Market Participants to achieve resource adequacy more economically and its enhanced market-based design allows for greater transparency. The location-specific approach used in the PRA provides efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This methodology creates a variety of options for Load Serving Entities (“LSEs”) to obtain the resources required to meet
their Planning Reserve Margin Requirement, including Fixed Resource Adequacy Plans, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases.12

MISO itself notes the many ways in which a utility can meet its resource adequacy requirements without exposure to the “volatility” of the PRA: by submitting a Fixed Resource Adequacy Plan, by entering into a bilateral transaction, by self-scheduling, or by making capacity deficiency payments. And of course, in the 20 years contemplated by Vectren, by constructing a new unit or acquiring more demand-side resources.

In fact, having an excess of capacity is much more concerning since it is likely to be difficult to extract the utility from that risk without prematurely retiring assets. Simply changing this sub-metric to the 20-year average of excess capacity would make it more indicative of risk to the utility. A better solution is to eliminate it entirely since planning to have 20-year long excesses of significant capacity is also likely an indication of a poorly planned modeling run.

20-year average market purchases

Market purchases of less than 800 GWh per year are awarded a green (best) score, and we believe this component is a good one. Relying on the MISO market for large quantities of energy is a risky long-term strategy. And 800 GWh, which equates to about 15 percent of Vectren’s needs, is a reasonable rule of thumb cap on purchases.

Vectren contradicts itself, however, when it rewards portfolios for selling as much energy as possible in its Balance and Flexibility metric (see below).

Remote generation risk

Vectren does not adequately justify its assumption that “remote” generators are more risky than other generators. The locational marginal prices calculated at any given generator node are likely to include a congestion component, so it is not clear why generators that are “remote” to Vectren would necessarily experience higher congestion costs than any other generator. Nor is it even clear which generators Vectren considers “remote”. It simply provides the following explanations for its remote generation metric:

Portfolios that have stations far removed from its load centers are more subject to transmission congestion, transmission failures, or price spikes than local generation. (p.72)

Portfolios with generation assets located away from Vectren’s service territory are exposed to greater risk of transmission congestion and outages. (p.227)

The fourth metric is the risk of remote sources, which subjects capacity to greater levels of transmission and site related risks, simply by being remote to its service territory. (p.241)

In addition, on Vectren 2016 IRP p.69 in its explanation of the objectives of its metrics, Vectren lists only three component metrics to its risk metric, and instead includes “new remote resources in generation mix” under its Balance and Flexibility metric.

12 See https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/RAContruct.aspx
Risk metric revisions

In our revised scorecard shown in Figure 13, we adjusted Vectren’s Risk metric by removing the underexplained remote generation metric. The result is better Risk metric scores for the portfolios with the most wind energy.

IV-B-3. Cost-Risk Trade-Off

Vectren’s Cost-Risk Trade-Off metric combines data points that have already been incorporated in the scorecard: the NPVRR of the portfolio and the standard deviation of the NPV (a component measure under the Risk metric). By including both of these metrics a second time in the Cost-Risk Tradeoff, their impact is double counted, increasing the weight given to the standard deviation and NPV outcomes.

Furthermore, Vectren’s method of assigning scores to its Cost-Risk Trade-Off metric is entirely arbitrary. On page 229 of the IRP, a scatterplot of portfolio standard deviations versus portfolio NPVRR is presented. Vectren’s qualitative assignment of scores in this metric appears to be made on the basis of visual inspection of this graph and a sketched “Efficient Frontier (for illustration Purpose Only)” curve (see Figure 15).

Figure 15. Vectren 2016 IRP, Figure 7.19—Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Tradeoff

Cost-Risk Trade-Off metric revisions

Vectren’s illustrative, so-called “Efficient Frontier” (shown in Figure 6 above) is given without explanation or justification and appears to lead to a scoring system that is to the disadvantage of the two stakeholder portfolios, I and J. In order to illustrate the problems with Vectren’s method of assigning scores to a metric, Figure 7, below, reproduces Vectren’s data in Figure 6, but with a different rule of thumb for determining which portfolios receive which scores. Our equally illustrative “efficient frontiers”, drawn in Figure 16, both pass through the portfolio with
the lowest cost (Portfolio B) and the portfolio with the lowest standard deviation (Portfolio I). We have adjusted Vectren’s Cost-Risk Trade-Off scores based on each portfolio’s position with respect to these two frontiers.

Figure 16. Replication of Vectren 2016 IRP, Figure 7.19—Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Trade-off

**XIV-B-4. Balance and Flexibility**

Vectren’s Balance and Flexibility metric is composed of four component metrics: (1) number of baseload units in 2036; (2) reliance on the technology with the greatest share of generation; (3) number of technologies; and (4) net sales.

*Number of baseload units in 2036*

Vectren characterizes the largest number of baseload units in 2036 as a benefit because it is a “hedge against outages” (Vectren November 29, 2016 Stakeholder Presentation, slide 60). We would instead say that having multiple units of any kind is a meaningful hedge against outages. Further, to view power plants as neatly falling into baseload, intermediate, or peaking is outdated thinking that does not square with current-day realities. What matters is that generation and consumption largely align and that alignment can be tweaked on both the supply and demand side.

More specifically, the problem with this sub-metric is that the term “baseload” is losing its meaning as applied to coal-fired power plants. Does F.B. Culley Unit 2’s 20 percent capacity factor in 2016 indicate that it should be viewed as an intermediate or perhaps even a peaking
resource instead of baseload? Does this suggest that F.B. Culley Unit 3, which had a 41 percent capacity factor in 2016, is an “intermediate” unit? This portion of the Balance and Flexibility metric would more meaningfully capture outage risk if what was being measured was the number of individual units being relied upon for, say, 10 percent or more of total customer consumption with the green color going to those portfolios that relied on the highest number of unique generators.

**Reliance on the technology with the greatest share of generation**

This sub-metric is a poor approximation for resource diversity and seems to be partially justified by risk that is already accounted for in other metrics. In addition, the metric looks only at a single year, far in the future in 2036, which is akin to saying that 2036 is really the only year in which this sub-metric matters.

The single largest concern about relying on any one technology is likely to be fuel related. Indeed, Vectren partially justifies this sub-metric by saying “If Vectren relies heavily on the economic performance of any one technology, such as natural gas or coal, higher than anticipated fuel costs for one technology could expose customers to higher prices than a more balanced portfolio” (Vectren 2016 IRP, p.72). Fuel related costs do not apply to wind and solar, of course, even so portfolios with just these supply-side resources would be ranked worse than those with wind, solar, gas, and coal. In addition, fuel risk is captured in the standard deviation results that are already part of the scorecard. All of these factors suggest that this sub-metric should be eliminated from Vectren’s scorecard.

**Number of technologies**

Vectren’s inclusion of the number of technologies is somewhat duplicative of its reliance on the sub-metric based on the technology with the greatest share of generation and indeed the justification for the two are lumped together in Section 2.2.4.1 of Vectren’s IRP. Furthermore, the number of technologies is also largely meaningless as a measure of risk since there are many more direct and accurate ways to capture risk by technology category, such as by weighing fuel risk. Simply focusing on the absolute “number of technologies” is, objectively, an inadequate measure of fuel risk if only because some of the technologies counted consume no fuel whatsoever.

**Net sales**

Vectren awards worse scores for high energy purchases in its Risk metric but better scores for high energy sales in its Balance and Flexibility metric. The net sales component metric rewards portfolios for selling as much energy as possible, assigning the green (best) color to those portfolios with total net sales of more than 10 percent over the 20-year period, while purchases over roughly 15 percent are penalized. This contradiction is inexplicable. To the extent that Vectren deems it “risky” to rely on the market to purchase power, it must be equally risky to plan on selling power to the market. There is no mechanism that will always make a kWh sold riskless or even beneficial for the seller but risky for the buyer.

Vectren claims that high net sales allow “the flexibility to adapt to unexpected breakthroughs in technology” (Vectren 2016 IRP, p. 230). Many technology breakthroughs, however, make it more risky to sell power. For example, the dramatic declines in the cost of wind and solar
coupled with the low cost of gas due to the growth of fracking technology have depressed wholesale market prices, making excess power a liability more than a benefit to customers.

**Balance and Flexibility metric revisions**

We adjusted Vectren’s Balance and Flexibility metric in our revised scorecard shown in Figure 13 by removing the “largest number of baseload units” metric. The result is better Balance and Flexibility metric scores for the portfolios with the highest net sales including the stakeholder portfolios I and J.

**XIV-B-5. Environmental**

Vectren’s Environmental Metric is composed of two component metrics: (1) reduction in CO₂ emissions; and (2) reduction in NOₓ and SO₂ emissions. The Environmental metric assigns equal weight to a reduction in CO₂ emissions consistent with what it describes as the goals of the Clean Power Plan and an 80 percent reduction in NOₓ and SO₂ from 2012-2015. The IRP provides no explanation for why Vectren weighted these two submetrics equally.¹³ Do both cost the same to achieve? Do both arise from finalized or near finalized rules? Do both reduce health or other societal impacts equally? Nor does the IRP explain why Vectren disregarded other environmental risks, such as water and solid waste pollution. One might, for example, also consider the risk associated with effluents and coal combustion residuals if their costs are to some degree avoidable by making different resource choices. These costs are very real since the EPA has promulgated rules addressing those waste streams.

Instead, Vectren states that, “Since EPA clean air standards, both national ambient air quality standards and public health-based risk standards for hazardous air pollutants already take public health into account, there is no basis for trying to further account for health impacts from the preferred portfolio.”(p.93) This amounts to an assertion by Vectren that EPA rules are immediate, comprehensive, inviolable, and well enforced and that public health impacts arise only from air pollutants. We strongly disagree with the concept that any health or environmental impact for which EPA regulation exists need not be considered in the choice of a preferred portfolio.

**CO₂ emission reductions**

Vectren awards the same “caution” or yellow score to all portfolios with emission CO₂ reductions from 2012 levels ranging from 67 percent to 35 percent. We think that a more reasonable designation of scores would be green (best) to reductions above 75 percent, yellow to reductions between 50 and 75 percent, and red to reductions below 50 percent.

**NOₓ/SO₂ emission reductions**

Vectren appears to average each portfolio’s NOₓ and SO₂ reductions to arrive at a single score. It then assigns a green score to all but the existing portfolio, which receives a red score. We think that a more reasonable designation of scores would be green (best) to reductions above

¹³ See November 29th stakeholder meeting presentation at slide 65.
90 percent, yellow to reductions between 50 and 90 percent, and red to reductions below 50 percent.

Environmental metric revisions

We adjusted Vectren’s Environmental metric in our revised scorecard shown in Figure 13 using the alternative scoring criteria presented above. As a result of our revisions, the portfolios with the highest air emissions receive the worst “environmental metric” scores.

XIV-B-6. Local Economic Impact

Vectren’s Local Economic Impact metric is based on the results of a 2016 study by Alhenawi and Bayar. The actual application of Alhenawi and Bayar’s findings to the Local Economic Impact metric was not made available to stakeholders. In its response to informal discovery request CAC 2.2, Vectren states that, “Vectren did not do an analysis of jobs and tax base impacts for wind generation and demand side measures.” Both wind additions and demand-side measure can have substantial positive job impacts. As one example, a 2015 study of demand-side management programs in Indiana found:

The estimate covers the portfolio as implemented by GoodCents over the three-year program cycle, consisting of program years 2012–2014. …The results of this analysis indicates that Energizing Indiana initiatives produced approximately 18,679 jobs as a result of implementing the three-year program cycle. This estimate removes 438 jobs that are associated with the direct hires as reported by GoodCents to avoid double counting. (p.161)\textsuperscript{14}

We disagree with Vectren’s partial and biased methodology of selectively valuing jobs and other economic impacts from some resources but not others. Nonetheless, we have made no adjustments to this measure in our replication of Vectren’s scorecard.

XIV-C. Recommendations for quantifying risks and uncertainties

For complete quantification of risks and uncertainties, we recommend against the use of black box, qualitative scorecards for IRP portfolio section and instead recommend clearly presented quantitative results (and not the subjective rankings) for various key findings presented side-by-side for all portfolios and scenario combinations. This grid of results could be color coded to indicate obvious gradations in value without disguising the underlying information. Utilities should reference this grid in their presentation of a clear, detailed justification for their choice of a preferred portfolio from among the candidates. This, too, is a qualitative and subjective approach, but it is far more transparent to stakeholders and requires utilities to carefully justify their subjective choices.

\textsuperscript{14} IURC Cause No. 42963-S1, Demand Side Management Coordination Committee’s Response to June 4, 2015 Docket Entry, June 9, 2015.
XV. Is the performance of candidate resource portfolios analyzed across a wide range of potential futures?

No. The Vectren 2016 IRP introduces a wide range of candidate resource portfolios but its method for testing its portfolios against this range is not sufficient as discussed in Section XIV-A.
XVI. Are candidate resource portfolios ranked by present value of revenue requirement and by risk metric?

No. Vectren’s 2016 IRP candidate resource portfolios are only partially ranked by the PVRR values that the IURC requires, and the utility’s approach to ranking by risk metric uses a methodology that is deeply flawed and almost entirely opaque to stakeholders.

XVI-A. Are candidate resource portfolios ranked by their present value of revenue requirement in total dollars and dollars per kilowatt-hour delivered with discount rate specified?

No. Vectren's candidate resource portfolios are ranked only by their present value of revenue requirement in total dollars and not by dollars per kilowatt-hour.

XVI-B. Are candidate resource portfolios ranked by risk metric?

Vectren includes both a Risk and a Cost-Risk Trade-Off metric in its scorecard assessment. Our concerns with Vectren’s scorecard method are discussed in detail in Section XIV.

XVI-C. Recommendations for appropriate ranking PVRR and risk metric

For a complete and appropriate ranking by PVRR and risk metric, we recommend a transparent IRP process in which all modeling files and descriptions, as well as all background analyses, are made available to stakeholders. We recommend against the use of black box, qualitative scorecards for IRP preferred portfolio selection as used in Vectren’s 2016 IRP.
XVII. Does an assessment of robustness factor into the selection of the preferred portfolio?

No. Vectren mentions the robustness of future economic conditions, DSM resource selections, load growth, the MISO’s regional Transmission Expansion Plan for development of transmission infrastructure, and its own approach to risk modeling. Vectren’s 2016 IRP does not, however, factor an assessment of robustness into the selection of its preferred portfolio.

We recommend that IRPs include an explicit, detailed account of how robustness was factored into the selection of the preferred resource portfolio from among the candidate portfolios.
XVIII. Does the preferred resource portfolio incorporate a workable strategy for reacting to unexpected changes in circumstances quickly and appropriately?

Yes. Vectren includes an assessment of flexibility among its metrics used to determine the preferred portfolio. The component measures of reliance on the technology with the greatest share of generation and (although perhaps duplicative) number of technologies are at least a partial indicator of the preferred resource portfolios ability to react to unexpected changes in circumstances.
XIX. Did the utility prepare an analysis of historical and forecasted levels of peak demand and energy usage?

No. Vectren’s analysis of historical and forecasted levels of peak demand and energy usage is inaccurate. Vectren hired Itron to prepare a peak and energy load forecast on its behalf, but provided key pieces of the energy forecast itself. In addition, some of the data Itron relied upon for its forecast appears to be unrealistic and biases the commercial and industrial growth rates.

XIX-A. Flaws and/or concerns with the load and energy forecasting methodologies

Economic data on household income, number of new households, nonmanufacturing output, nonmanufacturing employment, and population are among the key economic drivers of Vectren’s load forecast (Attachment 4.1, p. 30). In addition, the residential and commercial sales models are specified by heating, cooling and “other” requirements.

The source for the economic data is cited as Moody’s Economy.com December 2016 economic forecast for the Evansville Metropolitan Statistical Area (MSA) (Attachment 4.1, p. 30). We cannot see how this is possible, however, since Itron’s report, Attachment 4.1, is dated August 4, 2016.

Setting aside that issue and assuming that the economic forecast described in Itron’s report is indeed the data with which the sales forecast was developed, there are still concerns regarding the Moody’s dataset. Concerns have been raised in other jurisdictions regarding Moody’s practice of forecasting strong near term growth in key variables, indeed growth that is much stronger than recent historic performance. ERCOT, Texas’s wholesale market operator, found that Moody’s overestimation of a key driver in its forecast, non-farm employment, led to overly optimistic load growth. It seems likely the same problem is occurring here.

Itron describes the Moody’s dataset (Attachment 4.1, pp. 30-31) as follows:

The primary economic drivers in the residential model are household income and the number of new households. Household formation is stable and increasing consistently though [sic] the forecast period with a CAGR of 0.4%, this is slightly stronger than population growth of 0.2%. Household income growth is forecasted to be stronger in the first 3 years of the forecast period, with a CAGR of over 2.5%, after which point growth declines to a long-term rate of 1.6%.

Commercial sales are driven by nonmanufacturing output, nonmanufacturing employment, and population. Moody’s is forecasting strong near-term growth in non-manufacturing output, with a CAGR of 3.6% for the first three years of the forecast period, after which point growth declines to a long-term rate of 2.0%. Non-

manufacturing employment follows [sic] a similar path with strong near-term growth of 2.6% and long-term growth of 0.8%. Population is forecasted to increase at 0.2% annually through the forecast period.

Industrial sales are driven by manufacturing output, and manufacturing employment. Manufacturing output is not projected to grow as rapidly as non-manufacturing output [sic], with a long-term CAGR of 1.8%. Manufacturing employment is the only economic indicator which is declining, with a long-term CAGR of -0.4%.

In response to CAC 1.1a, Vectren provided both the annual projected values for these drivers as well as historic values going back to 2010. It appears to us that the projections begin with the year 2015. Some drivers, like population, with a CAGR of 0.2 percent, and perhaps even household income, are consistent with the 5-year historic data provided to us. However, others, specifically non-manufacturing output and manufacturing output, clearly have predicted growth rates that are radically different than recent historic values as shown in Figure 17 and Figure 18.

**Figure 17. Non-manufacturing output historic and projected values by Moody’s—CONFIDENTIAL**

![Graph showing non-manufacturing output historic and projected values]

_Data Source: CAC 1.1a – Confidential_

While non-manufacturing output was between 2010 and 2014, Moody’s is projecting in 2015 and beyond (the solid black line is the historic values and the dotted black line is the projected values).
Figure 18. Manufacturing output historic and projected values by Moody’s—CONFIDENTIAL

Data Source: CAC 1.1a – Confidential

Similarly, historic manufacturing output has been [redacted], while Moody’s projects an [redacted] in this driver, a CAGR of 1.8 percent.

The industrial forecast is not only biased by this aggressive rate of projected manufacturing output, but also by the fact that the first five years of the forecast are estimated entirely by Vectren, not Itron (Attachment 4.1, p.12), using a process that is completely distinct from Itron’s statistically adjusted end-use modeling. Itron describes the process as follows:

The first five years of the forecast is based on Vectren’s internal forecast. Industrial sales are forecasted using a historical baseline of 12 months ended December 2015. Vectren reviews baseline volumes at the customer level and is adjusted based on known customer activity such as closures and expansions. New customers are specifically identified and forecasted based on expected load. An overall growth rate of approximately 1% is then applied to the baseline period to capture growth that has not been specifically identified by customer. The forecast after that is based on a model-based forecasted growth rate; the forecasted growth rate is applied to the fifth year industrial sales forecast. (Attachment 4.1, p.12)

Not only are sales in the first five years based on just one year’s worth of historical sales data, but an additional one percent of growth is added under the assumption that there will be significant growth in industrial sales no matter what. With industrial sales making up 50 percent of total sales, this assumption is significant.

Given these very optimistic assumptions from Moody’s and by Vectren, it should not be surprising that the commercial and industrial sales projections are driving the overall projected growth in sales (Figure 19).
While residential use grows very slowly, the majority of growth in sales is in the industrial and commercial sectors after accounting for the expected loss of an industrial customer in 2017.

The historic sales do include energy efficiency impacts to the extent those programs existed at the time, but it is our understanding that Vectren achieved very few energy savings prior to implementation of the IURC’s Phase II Order in 2009, so utility-sponsored energy efficiency cannot explain the mostly stagnant load growth prior to that time.

All of this leads to the conclusion that Vectren is likely overestimating projected growth in energy sales.

**XIX-B. Recommendations on preparing an analysis of historical and forecasted levels of peak demand and energy usage**

To prepare a complete and accurate analysis of historical and forecasted levels of peak demand and energy usage, we recommend the use of an economic dataset that does not include unrealistic near-term rates of growth in key drivers. We also recommend that if a statistically
adjusted end-use model does not explain industrial load growth well, then industrial load growth projections should be linked to known factors that can be documented for stakeholder review rather than black box and entirely subjective assumptions about growth in energy consumption.
ATTACHMENT A

No Evidence for Energy Efficiency Market Saturation Leading to Higher Costs

Public Version

Elizabeth A. Stanton, PhD, Applied Economics Clinic
Anna Sommer, Sommer Energy, LLC

April 17, 2017
(Updated July 26, 2017)
(Corrected August 7, 2017)
No Evidence for Energy Efficiency Market Saturation Leading to Higher Costs

Elizabeth A. Stanton, PhD, Applied Economics Clinic

Anna Sommer, Sommer Energy, LLC

April 17, 2017 (Updated July 26, 2017) (Corrected August 7, 2017)

Abstract

A 2015 working paper by Richard Stevie asserts that no other study has illuminated the relationship between energy efficiency program costs and market penetration, and purports to itself demonstrate that market saturation causes higher efficiency program costs. We find that Stevie’s study provides no usable evidence of a market saturation-program cost relationship and ipso facto no such relationship has as yet been demonstrated. The results of Stevie’s working paper have impacted resource decisions proposed by electric utilities in at least three states (Indiana, North Carolina, and South Carolina). Stevie’s analysis erroneously suggests that there exists evidence of efficiency market saturation significantly driving up programs costs. We find, in contrast, that the evidence presented is insufficient and inaccurate. We are aware of no reliable evidence for higher energy efficiency market penetration leading to higher efficiency costs. Inclusion of a baseless inflation of efficiency program costs in the name of market saturation results in higher energy efficiency costs than would otherwise be expected. Implementing Stevie’s suggestions would lead utilities to select less energy efficiency than is optimal.

1. Background

Projected energy efficiency cost and savings levels are an important input to electric utilities’ modeling of future resource additions and retirements. These projections are used in Integrated Resource Plans and other, similar filings submitted to state utility commissions for their approval. Some contend that the future cost of saved energy is influenced both by historical costs and by patterns in the relationship between the cost of saved energy and other factors, including: The amount of new efficiency savings in a given year, and the cumulative amount of savings that has built up over time (after adjusting for efficiency measures that have “sunset” at the end of their measure life).

In many jurisdictions around the United States, projected energy efficiency costs are used to determine utilities’ efficient or otherwise optimal investment in energy efficiency and other resources in the next few years. An expectation of high costs, rising costs, or both can reduce investments in energy efficiency. Studies that overestimate the future cost of efficiency programs—and thereby result in lower levels of planned efficiency—deprive electric customers of low (and often least) cost efficiency measures while simultaneously pushing states towards an electric resource mix with higher costs and higher emissions of greenhouse gases and other pollutants.
Richard Stevie’s 2015 analysis of these relationships has been used by utilities in Indiana, North Carolina, and South Carolina to justify a future cost of saved energy that rises with higher energy efficiency market penetration (that is, the higher the cumulative efficiency savings, the higher the efficiency cost). The rationale for this purported relationship—as discussed in Stevie’s paper—is market saturation and diminishing returns:

\[ \text{As market penetration increases, energy efficiency implementation costs are expected to rise at higher levels of penetration of the market. The degree of impacts on program costs, from these factors, is a question to be empirically analyzed.} \]  

(p.9)

Stevie provides a review of some of the existing literature exploring the relationship between efficiency costs and savings levels and finds it wanting:

\[ \text{In summary, this review of past studies on the costs of energy efficiency reveals that a significant void exists in our understanding of how the implementation costs of energy efficiency are affected by the level of market penetration.} \]  

(p.7)

Having noted this gap, Stevie performs regression analysis using data voluntarily reported by utilities to the U.S. Energy Information Administration (EIA) and concludes somewhat heroically that:

\[ \text{From the review of other studies, it is apparent that little to no evidence exists on the relationship between program costs, program size, and market penetration. But now, the research conducted in this study provides an initial insight into this relationship...It should be obvious that further research in this area is warranted. As mentioned, this study is the first to investigate how costs can rise with increases in program size and market penetration. The findings point to the existence of cost efficiencies with respect to program size, but rising costs as market penetration increases.} \]  

(p.21)

Stevie’s regression analysis—and the conclusions drawn from it that have been used to inflate the cost of saved energy—are the subject of this review. We found that Stevie’s analysis:

- Is based on highly questionable data sources (Section 2),
- 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 (Section 3), and
- Is applied incorrectly and incompletely in the utility filings for which we were able to review workpapers (Section 4).

The result of these errors and omissions is higher energy efficiency costs than would otherwise be expected in utility planning and, consequently, less efficiency chosen in optimal resource planning.

2. Data Sources

In regression analysis, variations in the value of one data point or “variable” (here, program costs) are explained through patterns in the values of other related variables. Stevie bases his analysis on the presumption that energy efficiency program costs can be explained using the values of several other variables, which he aggregates to the state level.

The dependent or explained variable in Stevie’s regressions is:

- **Program Cost**: “the level of direct program spending (dollars) on energy efficiency programs only. Indirect costs are not included.” (p.10); “For the purposes of this study, only the direct program costs including incentive payments to participants will be considered in the analysis.” (p.15); Stevie reports that his data for direct spending on energy efficiency program are taken from EIA Form 861 (p.13).

Stevie’s explanatory variables are:

- **Program Size**: “the current year achievement of energy impacts as a percent of current year retail kWh sales” (Stevie (2015), p.11); Stevie reports that his data for incremental energy efficiency (or current year annualized impacts) are taken from EIA Form 861 (p.13).
- **Market Penetration**: “the cumulative achievement of energy efficiency sales as a percent of retail kWh sales” (p.11); Stevie reports that his data for cumulative energy efficiency (called “annual” in the EIA data set) are taken from EIA Form 861 (p.13).
- **Electric Rate**: “the cost of power ($/kWh) to customers in an area” (p.11); Stevie reports that his data source for total revenue and total retail sales are taken from EIA Form 861.
- **“Unemployment Rate”** (p.12): Stevie gives no data source for his unemployment rate measure, instead noting that, “Data on national inflation and unemployment may be found from numerous sources” (p.14), and mentions but does not directly cite a secondary data source for these measures, “See the website Freelunch.com sponsored by Moody’s Analytics for general macroeconomic data including inflation and unemployment.” (p.14, fn.21).

While Stevie relies exclusively on EIA Form 861 for his data on energy efficiency spending, Stevie himself notes that EIA Form 861 data have limitations that impede their ability to correctly characterize the relationship between energy efficiency savings and the cost of saved energy. While Stevie’s list of concerns is not comprehensive, it provides an overview of this data set’s flaws, including: (1) a lack of data on the life of efficiency measures; (2) various known reporting errors (incorrect or mislabeled responses, inconsistent treatment of free riders, inconsistent classification of costs); and (3) changes in reporting requirements and instructions over time (p.14).

With respect to using these data to understand the effect of efficiency market penetration on costs, the most important issue is EIA Form 861’s lack of information on the life of efficiency measures. Without this data point there is no way to measure the cost of saved energy, because this year’s efficiency savings are not the only savings that will arise from this year’s efficiency costs. The best and most commonly used measure for any energy resource cost is a “levelized” cost, which divides a resource’s total fixed and variable costs by the total amount of
energy that it will provide (or save) over its lifetime. EIA Form 861’s cost and savings data are simply not sufficient to provide a measure of the levelized cost of saved energy.

Stevie acknowledges these data limitations. His stated solution is to limit his data set to the most recent three years of data available at the time of his study—a remedy that in no way addresses the problem of the mismatch between the cost and savings data available in EIA Form 861:

For this reason, the analysis conducted here looks at total annual spending relative to the first year impacts. Trying to compute a levelized cost requires knowledge that is just not available. While one might intuit an expected measure life for a portfolio, it is only a guess and could lead to misleading conclusions. In reviewing the EIA data, it is apparent that the reporting is not consistent. For example, kWh could be reported instead of MWh or dollars instead of thousands of dollars as specified in the instructions to the form. For this reason, the study will focus on the last three years of data for the years 2010 through 2012. Use of the most recent data should provide the best quality of data from the data base. (p.14)

In addition, while EIA’s Form 861 data are voluntarily reported by utilities—and are, therefore, available disaggregated by utility—Stevie makes the choice to aggregate these data:

Finally, to facilitate the research, costs and impact data is [sic] aggregated to a state level. This provides a useful data set for the 50 states plus the District of Columbia. (p.15)

Stevie’s choices to limit his data to three years and aggregate the data to the state level results in a very small dataset for his regression. While Stevie does not follow the convention of reporting the size of his data sets in his working paper, it would appear that his “Model 1” has 153 data points and his “Model 2”—which he further limits to just data for the year 2012—has 49 data points.² If this analysis were performed at the utility level, using these same data, its data points would number in the thousands. The small data set used by Stevie limits the reliability of his regression findings and call into question the confidence that can be placed in patterns observed in Stevie’s study.

Our replication of Stevie’s analysis uses his data and methodology to the greatest extent possible given his omission of some key details regarding variable specification and data sources:

- Program Cost: (dollars) EIA Form 861³ 2010-2012 aggregated to 50 states plus the District of Columbia:

₂ Stevie notes in Fn.23 that, “Data for Delaware and Louisiana were deleted since the EIA data indicates [sic] essentially zero cumulative impacts for the year 2012.”(p.16)
³ EIA Form 861 data consists of multiple spreadsheets. For the years 2010 and 2011, “program cost”, “program size”, and “market penetration” data are taken from Form 3 and from the “dsm_2012” spreadsheet for 2012. While “electric rate” data are calculated from Form 2 for the years 2010 and 2011 and from the “retail_sales_2012” spreadsheet for 2012.
**DIRECTCOSTEEF + INCENTIVEEF**

- **Program Size**: (%) EIA Form 861 2010-2012 aggregated to 50 states plus the District of Columbia divided by EIA Form 861 2010-2012 aggregated to 50 states plus the District of Columbia states:

  \[
  ENERGYEFFINCTOT / Total Sales
  \]

- **Market Penetration**: (%) EIA Form 861 2010-2012 aggregated to 50 states plus the District of Columbia states divided by EIA Form 861 2010-2012 aggregated to 50 states plus the District of Columbia states:

  \[
  ENERGYEFFANNTOT / Total Sales
  \]

- **Electric Rate**: ($/kWh) EIA Form 861 aggregated to 50 states plus the District of Columbia states divided by EIA Form 861 2010-2012 aggregated to 50 states plus the District of Columbia states:

  \[
  \text{Total Revenue} / \text{Total Sales}
  \]

- **Unemployment Rate**: (%) U.S. Bureau of Labor Statistics (LNS14000000) Unemployment Rate, U.S. annual average

Using the data gathered from public sources to replicate Stevie’s analysis, Figure 1 depicts the relationship between energy efficiency program costs and market penetration that Stevie recommends be used in forecasting future utility efficiency costs, claiming that: “It provides guidance on the expectation that as the market penetration of energy efficiency increases, the unit cost increases.”(p.21)
Figure 1 provides a snapshot of several critical weaknesses in both Stevie’s analysis and the data on which it was based:

- **The positive correlation between direct costs and market penetration (cumulative savings) is weak and appears to be driven by a few outliers.** Figure 1 above shows a dense cloud of data points with a few outliers, and not an obvious trend in which higher costs are associated with greater levels of market saturation. (Note that the data points do not congregate around the trendline but rather are found well above and below these lines.)

- **Larger programs have larger costs, and smaller programs have smaller costs.** Stevie’s analysis offers little insight into the relationship between market penetration and the cost of saved energy. Stevie’s puzzling choice of program costs in dollars as the dependent variable and percentage savings as the explanatory variable results in a regression analysis that points only to the obvious relationship between program size and program costs while failing to ask pertinent questions about how any one utility’s repeated investments in efficiency over many years may impact its program costs.

- **A few years of state-level data cannot reveal an actionable expectation regarding efficiency program costs.** Stevie purports to identify a pattern among states over three years that can be applied to long-term projections of efficiency costs for individual utilities. Not only does Stevie’s methodology suffer from well-known reliability issues...
arising from very small datasets, it also fails to track individual utilities over time, because his data are aggregated to the state level, and three years of data do not provide a pattern that can be applied to decades of projections. One year of data (as used in Stevie’s Model 2) has no information whatsoever about the pattern of changes over time.

3. Regression Analysis

We attempted to replicate Stevie’s regression analysis results using the data described in the previous section and the two regression equations reported in his working paper:

\[
\text{Model 1: ProgCost}_{it} = \text{Intercept} + \beta_1 \cdot \text{ProgSize}_{it} + \beta_2 \cdot \text{MarketPen}_{it} + \beta_3 \cdot \text{ElecRate}_{it} + \beta_4 \cdot \text{Unemploy}_{it} + \varepsilon_{it}
\]

\[
\text{Model 2: ProgCost}_i = \text{Intercept} + \beta_1 \cdot \text{ProgSize}_i + \beta_2 \cdot \text{MarketPen}_i + \beta_3 \cdot \text{ElecRate}_i + \varepsilon_i
\]

This exercise was successful for Stevie’s Model 2 (2012-only) and achieved results that were similar but not identical to Stevie’s Model 1 (2010-2012), as shown in Table 1. (“Original” is Stevie’s reported regression results. “Replication” is our attempt to match his results using his data; “Replic_State” and “Replic_Year” are two different versions of our replication attempts, differentiated by the type of dummy variable.4 “Public Data” is the corrected version of the EIA Form 861 data cited by Stevie. “Clean Data” is a subset of these Public Data, as discussed below.)

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4 Stevie appears to have assigned “dummy variables” to differentiate results by state. We attempted regression replications that differentiate results by state and, separately, by data year.
The coefficients (“coeff.”) in Table 1 are Stevie’s main regression result and can be interpreted as for every 1 percent change in Variable X expect a $\beta$ percent change in Stevie dependent variable, energy efficiency program costs. For example, using the “Original” results from Stevie’s Model 1 would suggest that every 1 percent change in cumulative efficiency savings was associated with a 0.28 percent change in program costs.

After careful review, we believe that three key factors interfere with replication and interpretation of Stevie’s results: unexplained changes by Stevie to EIA Form 861 data; data quality issues in EIA 861 data not properly addressed by Stevie; and Stevie’s specification of the dependent variable.

### 3-a. Unexplained changes by Stevie to EIA Form 861 data

Our review of Stevie’s regression analysis workpapers revealed widespread, large-scale inconsistencies between EIA Form 861 source data and the actual data on which Stevie based his regressions. These inconsistencies take two forms:

1. Stevie’s working paper mentions only one adjustment made to EIA data (the removal of two states in the 2012-only regression). We can offer no possible explanation for a large share of Stevie’s data entries being different from those calculated directly from EIA data as state weighted averages (see Table 2). Still more puzzling is the finding that some of Stevie’s data are exactly identical to EIA data—meaning that whatever factor is causing

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5 We were provided access to Stevie’s workpapers, including his underlying data and regression results, on April 12, 2016, through the IRP stakeholder process.
this inconsistency is only present in some of Stevie’s data extraction. It should also be noted that these data errors were not small in scale: the average error for program costs was 32 percent; current year savings, 34 percent; cumulative savings, 31 percent; and total sales, 31 percent.

Table 2. Share of erroneous data entries

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Costs ($)</td>
<td>65%</td>
<td>27%</td>
<td>4%</td>
</tr>
<tr>
<td>Current Year Savings (kWh)</td>
<td>67%</td>
<td>27%</td>
<td>8%</td>
</tr>
<tr>
<td>Cumulative Savings (kWh)</td>
<td>65%</td>
<td>24%</td>
<td>6%</td>
</tr>
<tr>
<td>Total Revenue ($)</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Total Sales (kWh)</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
</tr>
</tbody>
</table>

2. Stevie has, without explanation, replaced zero current-year and cumulative savings, and zero program costs with the value 0.00001. This type of change makes it possible to use these data in regression analysis and can be a necessary tactic in logarithmic regressions (since the logarithm of zero is undefined). In this instance, however, data entries with zero savings do not offer information to an analysis of energy efficiency programs and should be removed, as Stevie himself does with such entries in his 2012-only analysis.

Given these serious issues, we reran Stevie’s regressions using the correct public data (“Public Data” in Table 1 above) and found that this correction resulted in changes to both coefficient values and the level of their significance. As shown in Table 1, using corrected data, the overall significance of the regression (Adjusted R²) falls from 76 percent to 20 percent—a substantial decrease suggesting little value to these regression results as whole. The impact of significance on each variable differs, some increasing and some decreasing. These low statistical significance of the regression as a whole suggests that the findings used by Stevie in various utility dockets represented relationships between the data that cannot be distinguished from happenstance.

3-b. Data quality issues in EIA 861 data not properly addressed by Stevie

Stevie’s working paper reports only two data points removed from Model 2 (“since the EIA data indicates [sic] essentially zero cumulative impacts for the year 2012”(p.16)). From this we can infer that all 153 data entries are included in Stevie’s 2010-2012 regression and 49 in his 2012-only regression.⁶

Our review of the 2010-2012 data showed that 25 entries include zero values for current-year savings, incremental savings, or both. State-years without energy efficiency savings cannot offer useful information to the analysis and should be removed. In addition, our review found another 23 data entries with obvious data quality issues: some with $1 entries in program costs or other obvious errors, and some states where there were unambiguous inconsistencies

⁶ Stevie’s workpapers show that out of 153 possible data entries in this analysis, he used 153 in his Model 1 regression and 49 in his 2012-only Model 2 regression.
between reported incremental and cumulative savings (for example, 2011-2012 incremental savings that, when added to 2010 cumulative savings, resulted in a value far greater than the reported 2012 cumulative savings\(^7\)).

These apparently erroneous data comprised the majority of data outliers shown in Figure 1 (above); the remaining high program cost outliers are three-years of program data for California. We reran our “Public Data” regression with this smaller, corrected data set (called “Clean Data”) to examine its sensitivity to changes in the underlying data. In the “Clean Data” regression, coefficient values were dramatically different from those in the “Public Data” regression (see Table 1 above) but the statistical significance of the regression and variables remained very low and/or fell.

3-c. Stevie’s specification of the dependent variable

Program costs in dollars are impacted by the scale of savings, not because of market saturation but—more fundamentally—as a result of the size of the state or utility itself. Program costs on a per kWh basis, however, are far more likely to show meaningful impacts of current year program size and cumulative savings. Using the improved (but very small) dataset described above (“Clean Data”), we examined the sensitivity of Stevie’s results to his unusual choice of dependent variable by comparing (1) the correlation of program costs in dollars to market penetration to (2) the correlation of program costs per kWh to market penetration (see Table 3, which presents the degree of correlation between variables in percentages).

Table 3. Correlation matrix using EIA Form 861 data with obvious errors removed

<table>
<thead>
<tr>
<th></th>
<th>ProgCost$</th>
<th>ProgCost$/kWh</th>
<th>ProgramSize</th>
<th>MarketPen</th>
<th>ElectricRate</th>
<th>UnemploymentRate</th>
</tr>
</thead>
<tbody>
<tr>
<td>ProgCost$</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ProgCost$/kWh</td>
<td>60%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ProgramSize</td>
<td>91%</td>
<td>51%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MarketPen</td>
<td>94%</td>
<td>57%</td>
<td>90%</td>
<td>100%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ElectricRate</td>
<td>32%</td>
<td>18%</td>
<td>18%</td>
<td>31%</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>UnemploymentRate</td>
<td>27%</td>
<td>22%</td>
<td>28%</td>
<td>26%</td>
<td>24%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Both program size and market penetration are less correlated with program costs in $ per kWh than they are with program costs in dollars. Any conclusions that might be drawn from that finding should, however, be considered in light of the following caveats: (1) these regression models have too small of a sample size and therefore may not be statistically significant (i.e., discernable from happenstance), and (2) Stevie’s choice to limit his regressions to model just a few years of data makes it impossible to discern data patterns that can have any application to long-term changes in efficiency costs.

Overall, our review of Stevie’s regression analysis calls into question the quality of his data, the significance of his results, and whether or not any results produced using this methodology can be said to add meaningful insight to the projection of future efficiency costs.

\(^7\) We recognize that some utilities will have correctly adjusted for sunsetting measures in their cumulative savings, and for this reason we removed only gross differences between these reported and calculated values.
4. Application of Stevie’s Analysis in Utility Planning

We also had the opportunity to review Stevie’s workpapers in which the results of his regression analysis were applied to an electric utility’s 20-year projection of energy efficiency program costs. The coefficients resulting from a logarithmic regression can be interpreted as elasticities, that is, a 1 percentage point change in the value of an explanatory variable can be said to be associated with a $\beta$ percentage point change in the value of the dependent variable, where $\beta$ is the coefficient value for the explanatory variable.

In the utility’s projection of future efficiency program costs, the coefficients for Stevie’s market penetration variable are applied to program costs for a recent historical year such that each incremental 1.0 percent increase in savings has the effect of adding the cost equivalent of 0.6 percent savings (calculated as the average of Stevie’s Model 1 and Model 2 coefficients for market penetration: 0.278 and 0.897, respectively). Over the course of 20 years, the utility interprets this as resulting in a more than doubling of the program costs associated with a 1 percent incremental annual savings level: from 3 cents per kilowatt-hour in 2016 to 8 cents in 2036.

In summary, this utility application of regression findings to efficiency cost projections suffers from several errors in substance and logic, any one of which would, by itself, render the study’s use in resource decisions inappropriate:

- **Errors, omissions, and misspecifications of data:** Stevie’s data are taken—by his own admission—from a deeply flawed dataset, use an illogical combination of dependent and independent variables, are too few in number to provide meaningful results, and do not include the correct variables (or encompass sufficient years) to provide insight into changes to state’s or utility’s costs over time. In addition, our review of the data used in his regressions found serious unexplained errors and inconsistencies.

- **Weak significance and a lack of robustness in regression findings:** Stevie’s overall model significance and significance for his key variable, market penetration, appear to be sensitive to removal of problematic data entries and corrections to his misspecified functional form.

- **Purported impact of electric rates on program costs is excluded from the application of regression findings:** Stevie’s regression analysis also finds a significant impact of electric rates on program costs, but this effect is excluded from the utility’s projection of future efficiency costs. Our calculations suggest that including this effect on a forecasted growth of electric rates ranging from 0.7 percent per year$^8$ to 3.2 percent per year$^9$ results in a decrease in the incremental change in program costs of 4 to 20 percentage points in each year averaged across Stevie’s two models. Put into context, just this countervailing effect would reduce Stevie’s 0.60 percent increase in annual costs.

---

$^8$ Vectren 2016 IRP Attachment 4.1

incremental efficiency costs for each 1 percent increase in market saturation down to 0.40 to 0.56 percent.

- **Averaging a coefficient from a full dataset with the same coefficient from a truncated version of the data set**: Stevie’s explanation of the inclusion of Model 2 (which excludes all data entries from 2010 and 2011) is largely rhetorical: He—without substantiation—calls this method “traditional” and notes that it is “extremely useful” because it “provides a view into the long-run since the data contains multiple points along the continuum of experience” (p. 16). This approach is neither traditional nor particularly useful, and a regression of data from various states (each unique in program size, market penetration, and electric prices) in the same year in no way provides a view into the long-run and cannot be said to contain multiple points along a continuum of experience. Indeed, the extent to which those multiple data points from various states do predict future performance would be mere coincidence. Averaging the regression result of the 2012 truncation with the full dataset does have one clearly observable result: It increases the assumed addition to program costs from 0.28 percent to 0.60 percent from each 1 percent increase to market penetration.

5. **Findings and Conclusion**

Stevie asserts repeatedly in his working paper that no other study has illuminated the relationship between energy efficiency program costs and market penetration. If this is the case, then that status quo remains unchanged: Stevie’s study provides no usable evidence of such a relationship and *ipso facto* no such relationship has, as yet, been demonstrated.

This area of research is by no means purely scholarly or theoretical. To our knowledge the results of Stevie’s working paper have impacted the resource decisions proposed by electric utilities in no fewer than three states. Stevie’s analysis suggests, erroneously, that there exists evidence of energy efficiency market saturation driving up programs costs that is sufficient to justify a more than doubling of the direct cost per kWh over 20 years.

We find, in contrast, that the evidence presented in his working paper is insufficient and inaccurate. We are aware of no reliable evidence for higher energy efficiency market penetration leading to higher efficiency costs. Inclusion of a baseless inflation of efficiency program costs in the name of market saturation results in higher energy efficiency costs than would otherwise be expected in utility planning and, consequently less efficiency chosen in optimal resource planning.
EXHIBIT 1-Confidential

Vectren Attachment to CAC 1.29-Confidential
EXHIBIT 2

4/11/17 Email Exchange with Vectren
Jennifer Washburn

2016 Vectren IRP--follow-up on Vectren responses to CAC et al. Set 1

This EXTERNAL email may contain an attachment. Do not open attachments or click on links in emails unless you are certain the source AND content of the email are credible.

Good morning,

Could we please have an update?

Thanks,

Jennifer

On Tue, Apr 4, 2017 at 12:30 PM Jennifer Washburn wrote:

https://mail.google.com/mail/u/0?ui=2&ik=0660b71dca&view=pt&msg=15b5d85c4baaf5d7&q=mquinn%40vectren.com&qs=true&search=query&dsqt=1&siml=...
Good afternoon,

We were just checking to see if you by chance had a status update re where exactly the data is in the Aurora files, i.e. we don't see any NPV, standard deviation, emissions, etc., in the files that have been provided to us. Thanks!

Sincerely,

Jennifer

On Tue, Mar 28, 2017 at 11:57 AM, Jennifer Washburn <jwashburn@citact.org> wrote:

Thanks, Michelle. We appreciate it. However, we still don't see our question addressed re: exactly where the data is in the Aurora files, i.e., we don't see any NPV, standard deviation, emissions, etc., in the files that have been provided to us. Could you please tell us where exactly we can find this information? Thanks in advance.

Sincerely,

Jennifer

On Mon, Mar 27, 2017 at 5:23 PM Quinn, Michelle D. <mquinn@vectren.com> wrote:

Jennifer,

Please be advised that Figure 2.6 was derived from the risk analysis presented at Vectren’s final stakeholder meeting, which was held on November 29, 2016. You may access this presentation from Attachment 3.1 Stakeholder Materials or by clicking the following link https://www.vectren.com/assets/cms/pdfs/irp/Third%20IRP%20Stakeholder%20Meeting%20Presentation.pdf. Column 1, labeled Portfolio NPV, can be found on slides 46-47. Criteria for red, green, or yellow lights are generally provided for each metric. For example, as noted on these slides, NPVs within 5% of the lowest cost portfolio were given a green light. Portfolios between 5 and 10% were given a yellow light, and portfolios over 10% were given a red light. Information used to create column 2, labeled Risk, can be found on slides 50-53. When several metrics were included in a risk category we included a summary slide. For example, slide 53 shows the summary slide used to build up the risk column in Figure 2.6. Each category follows this same approach. Cost Risk Trade-off can be found on slides 56-57. Balance/Flexibility can be found on slides 59-60. Environmental can be found on slides 63-65. Local Economic Impact can be found on 68. Overall corresponds with slide 70.

PACE used Aurora to generate most risk analysis metrics, including NPVs. Note that the Economic Impact was not generated by PACE in Aurora.

The breakpoints for the cost risk trade off were not provided because the answer lies on the efficient frontier, which is represented by the dotted line on slide 56. Portfolios closest to the line have a better cost risk trade off. Portfolio D was closest to the efficient frontier and was therefore given a green light. A cluster of portfolios have a slightly worse cost/risk tradeoff and were labeled with a green light. Finally, those furthest from the line were given a red light. For example, portfolios I and J are low risk, but the NPVs of these portfolios is very high, far from the efficient frontier.

https://mail.google.com/mail/u/0?ui=2&ik=0660b7f0ca&view=pt&rsn=sg=15b5d85c4baaf5d7&q=mquinn%40vectren.com&qs=true&search=query&dsqt=1&siml=… 2/7
If you have additional questions, please let me know. Thanks!

Michelle

From: Jennifer Washburn [mailto:jwashburn@citact.org]
Sent: Friday, March 24, 2017 11:35 AM
To: Quinn, Michelle D.
Cc: Krohn, Karol; jreed@oucc.in.gov; Borum, Bradley; Comeau, Jeremy; Pauley, Morgan; Anna Sommer; Liz Stanton; Stephenson, Jason; Rice, Matt; Thomas Cmar
Subject: Re: 2016 Vectren IRP--follow-up on Vectren responses to CAC et al. Set 1

Good afternoon,

Regarding CAC 1.20, if Figure 2.6 was not created with a spreadsheet, that’s fine, but could you please at least tell us where the data is? And if you’ve already provided it, could you please tell us exactly where it is because we’re having a difficult time finding it?

The NPV as it relates to Figure 2.6 isn’t clear either. Is it from the Strategist or Aurora files? If Strategist, which runs specifically? If Aurora, how did you get an NPV, because there doesn’t seem to be an NPV output from Aurora?

We have the same question for all the other metrics related to Figure 2.6 that probably came from the modeling runs: "flexibility measure", "environmental metric", etc.

Also, regarding CAC 1.20, the "break points" are not all on the Stakeholder slides from Nov. 29. The "cost/risk" tradeoff is missing. Could you please provide information about that?

As you know, we have our comments due in less than a week. If you could provide us this information as soon as possible, we would appreciate it.

Thanks, Jennifer

On Mon, Mar 13, 2017 at 10:18 AM, Quinn, Michelle D. <mquinn@vectren.com> wrote:

Jennifer, please see Vectren’s responses in blue below to the questions raised by the CAC in your March 6th email message. Thanks!

Michelle
Hi Michelle,

We had a few issues with the objections and responses to CAC et al.'s Set 1 from Vectren in the IRP Stakeholder Process, and are hopeful you can assist us. We've put them in order of priority with the hope that you can send us updates as you receive them.

1.11
CAC et al.'s Data Request 1.11 asked “Please provide an electronic copy of the Burns & McDonnell screening analysis discussed at the bottom of page 79 with all formulas and links intact.” Vectren objected stating:

 vectren objects to this Request on the grounds and to the extent that the Request seeks a document not presently in Vectren South's possession, custody or control. In addition, Vectren South objects to this Request on the separate and independent grounds that such Request seeks information which is the proprietary, competitively sensitive and trade secret information of a third party consultant who has not consented to the release of such information. The electronic screening analysis requested was developed by Burns & McDonnell over time and the release of the tool could result in economic harm to Burns & McDonnel, as the company has invested a significant amount of time and talent developing the tool for its internal business use.

Could you please provide some clarification as to what in this analysis is proprietary? Could you please redact the information that is being claimed as proprietary and provide that redacted document? Could we please sign a nondisclosure agreement with B&M to see the screening analysis?

Vectren's Response: The CAC requested an electronic copy of the B&M screening analysis with all formulas and links intact. Our objection is to providing the electronic spreadsheet with formulas and links intact. That electronic document itself is what is proprietary. B&M created that document and the document serves as a key component of its business model that B&M is not willing to provide to Vectren or anyone else. Vectren has provided you all of the inputs into the screening analysis model so that your experts can utilize the tools at their disposal to analyze the data. Vectren does not have the tool in its possession and B&M is not required to provide to you the proprietary tools of its trade.

1.2
CAC et al.'s Data Request 1.2(a) asked:

Refer to Confidential Attachment 1.2.

a. Please provide the documents that serve as the basis for the permitting and construction schedule assumption for each of battery storage, CAES, wind, and solar.

b. Please explain the relationship between these assumptions and the first year in which Strategist was able to pick these resources.

Vectren responded:

a. Please be advised that the schedule assumptions for the resources listed were developed by a third party consultant using expertise gained over time working with various electric utilities. As such, Vectren objects to this Request on the grounds and to the extent that the Request seeks documents not presently in its possession, custody or control. In addition, Vectren objects to this Request on the independent and separate grounds and to the extent that the documents requested are the proprietary, competitively sensitive and trade secret information of a third party vendor that has not consented to the release of such information.

b. The first year in which Strategist was able to pick any new generation resource was based on industry experience and reasonable expectations of the earliest calendar year in which a typical project could come online.

With regard to subpart (a), could you please provide some clarification as to what in these documents is proprietary? Could you please redact the information that is being claimed as proprietary and then provide the
redacted documents? Could we please sign a nondisclosure agreement with the third party consultant to see these documents?

Vectren’s Response: The premise of this question is flawed in that it assumes there is a single document or set of documents upon which the assumptions for permitting and construction schedules for the various resources (battery, wind and solar) are based. The issue is that there is no single document or set of documents upon which the assumptions are based. Instead, those assumptions were based upon the expertise of consultants with many years of experience assessing such matters through their work with other utilities on similar projects throughout the country. Neither Vectren nor its consultants have either a single written document or set of written documents in their possession that are responsive to this request. As a result of that fact, we objected to this request on the basis provided above.

1.20

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:

Response: 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.

We were requesting the spreadsheets and the underlying data in spreadsheet format used to develop that Figure. Could you please provide the spreadsheets and the data used to develop this in spreadsheet format?

Vectren’s Response: Again, the premise of this question is flawed in that you assume a spreadsheet was used to develop the figure, but that assumption is not true. Furthermore, we have previously provided to the CAC all of the underlying data that went into creating the figure.

Thank you in advance for your assistance,
Jennifer

--

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4/14/2017  Citizens Action Coalition Mail - 2016 Vectren IRP--follow-up on Vectren responses to CAC et al. Set 1

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Copy of VEDS Capital Structure with Capital Recovery Factor for 2016 IRP Modelin....xlsx
344K
EXHIBIT 3-Confidential

Vectren Attachment to CAC 2.3-A-Confidential
EXHIBIT 4

10/25/16 Email Exchange with Vectren
Michelle,

Thanks so much for your email. We appreciate you following up with us. We would like to please request for now:

- the PRV input and output summary reports
- the LFA input and output summary reports
- the GAF output summary reports

That should help us provide some clearer comments.

Sincerely,
Jennifer

On Tue, Oct 25, 2016 at 10:56 AM, Quinn, Michelle D. <mquinn@vectren.com> wrote:

Hi Jennifer,

I hope all is well. I just wanted to follow up with you on the discussion we had on October 14th regarding EE modeling. During the meeting, Anna Sommers expressed some concern about the 25 year horizon over which EE is modeled. She said that modeling EE over 25 years overly constrains EE and makes it difficult for the model to select any EE. But, when Matt asked whether modeling EE in 3 year increments is preferable, she seemed to me to say that she could not answer that question because she did not know what other inputs are included in the model. So, I write to ask you what inputs do you all need to know? We are trying to be responsive to your inquiries, but we need to understand what information about our inputs are relevant to EE modeling. If you could provide some additional details, I would certainly appreciate it. Thanks!

Michelle

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ATTACHMENT TFC-4
Public Response to the Director's Report on the Indiana 2016 IRPs
Submitted to the IURC on September 1, 2017

Authors:
Anna Sommer, Sommer Energy, LLC
Elizabeth A. Stanton, PhD, Applied Economics Clinic
on behalf of CAC, Earthjustice, Indiana Distributed Energy Alliance, Sierra Club, and Valley Watch
Public Response to Director’s Draft Report on the 2016 IRPs
September 1, 2017

We appreciate the Director’s Draft Report on the 2016 IRPs as well as the chance to respond before the final report is issued. Overall, we felt that the Director echoed many of the key issues identified in our comments on IPL, NIPSCO, and Vectren’s IRPs. There are certain areas in which we felt it may be helpful to provide more clarity to our comments and to add more information to the conversation. Those areas are:

1. Examples of ways in which other utilities presented IRP information in clear and concise manners.
2. Additional comments on issues with IPL’s stochastic analysis
3. Additional comments on Vectren’s energy efficiency cost projection.
4. Additional comments on Vectren’s Strategist modeling.
5. Recommendations to improve the stakeholder process.

Examples of Clean and Concise Presentation of Information

We enthusiastically second the Director’s recommendation that the utilities endeavor to present basic information in a more readable and accessible fashion. In addition to our original comments on this topic, we also offer some other thoughts on the matter here.

All of the utilities that were the subject of our comments met with TVA to discuss their 2015 IRPs and, as such, seem likely to have read that IRP. TVA’s method of presenting data in its IRP is, broadly speaking, better than that of IPL, Vectren, and NIPSCO. For example, TVA has the following graph in its IRP.

**Figure 4-6: Baseline Capacity, Summer Net Dependable MW**

*Figure 1. Example Graph Showing Resource Additions for a Modeling Scenario*
In our experience, other IRPs often have graphs of this kind, but among 2016 IRPs in Indiana only IPL offered something similar for its scenarios.

Likewise, offering the position of the utility relative to its expected peak requirements (and a similar graph for energy) before any resource additions is very helpful (see Figure 2 below, which is again from TVA’s 2015 IRP).

![Figure 2. Example Graph Showing the Difference Between Peak Needs and Existing Resources](image)

We should clarify, however, that these graphs are most useful when they are accompanied with tables showing the values in those graphs. Indeed, that criticism applies to many graphs in the Indiana utilities’ IRPs in which, oftentimes, information was presented only in graphical format without benefit of the specific values. And some information was even presented without the y-axis labeled – making those graphs not particularly useful.

There is also the need to sharpen the organization of information. For example, in the case of IPL, confidential information was not distinguished from public information in the confidential version of the IRP, making it necessary to compare two versions of the same document to determine what was public. Across all the IRPs, there was a tendency to include appendices without making reference to them in the body of the IRP itself, which begs the obvious question of why those appendices were included at all. Another way to improve data presentation would be to make sure confidential information is included in the body of the main IRP rather than relegating it to a confidential appendix.
Public Response to Director’s Draft Report on the 2016 IRPs
September 1, 2017

We are happy to review and comment on the utilities’ efforts to make information in their future IRPs more accessible and understandable before future filings are made.

IPL’s Stochastic Analysis

To perform stochastics on a resource plan, one needs to create a probability distribution for each variable tested. The probability distribution requires assumptions regarding its high value, low value, and shape. For this to be meaningful, one needs not only a set of data for each variable to characterize these parameters, but also a reasonable expectation that these data can be used to characterize future outcomes for that variable. In IPL’s case, the probability distributions for certain variables appear to bias outcomes against certain portfolios and in favor of others.

For example, using IPL’s indicative wind price presented in its first stakeholder presentation of $2,213 per kW\(^1\) (the actual price assumed by IPL is $\underline{2000} per kW\(^2\)), one can infer the high and low value assumed for IPL’s wind cost probability distribution. IPL assumes the low value multiplier to be 0.9, the high value multiplier to be 1.15, and the expected value multiplier to be 1.025. This means that for stochastic purposes, if the indicative price is applied, wind would be assumed to cost not $2,213 per kW, but $2,213 \times 1.025 = $2,268 per kW. And the lowest possible value is $1,991 per kW. These numbers are absurdly high. As the Department of Energy (DOE) found in its recent analysis, the average installed cost of wind turbines in 2016 was $1,590 per kW\(^3\) – less than three quarters of IPL’s public “expected” value.

Normally, stochastic distributions are constructed on the basis of historic information, though IPL gives no source for its wind or solar multipliers. Of course, the question for technologies like wind and solar is: how far back should one go to gather cost data that is still relevant to today? Because those technologies and their prices have changed so much, even data from five years may reflect different technologies, efficiencies, and cost than those likely to occur today. In future stakeholder processes, if IPL continues to rely so heavily on stochastic analysis instead of scenario testing, it is hard to see how IPL could address these kinds of concerns. Even if stakeholders had the opportunity to substitute their own probability distributions for those assumed by the utility, they would be spending their time developing meaningless probability distributions when a more straightforward and meaningful analysis would rerun the capacity expansion model, not the stochastic/production cost model, with the suggested, alternative

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\(^1\) See PDF page 115 of IPL 2016 IRP Volume 2.
\(^2\) See Table 6-3 of Confidential Attachment 2.2.
\(^3\) See https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf
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September 1, 2017

assumption(s) at issue. Using the example of IPL’s wind assumption again, if one
were to change the expected value of wind to a more reasonable $1,590 per kW, the
only impact would be to change the stochastic results for those portfolios that
contained some amount of wind. It would be even more important to see how the
expansion plan changed if the cost of wind were modified to this value. This is just
one example of how scenario testing in the capacity expansion model can be
preferable to stochastic modeling.

Even if the probability distributions are meaningful, we reiterate our concern that	
taking fifty draws, as IPL did, is not enough samples to produce a reliable result.
IPL’s response to our critique of their Latin Hypercube sampling technique appears
to willfully misunderstand and/or ignore our concerns. Pages 47-49 of our report
lay out these concerns in detail. IPL’s response fails to rebut or even address our
critiques on all points. Fifty samples, even when drawn through a Latin Hypercube
process, simply cannot adequately represent the variation in a multi-dimensional
problem space on the scale of IPL’s modeling exercise.

**Vectren’s Energy Efficiency Cost Projection**

We have learned since filing our comments on Vectren’s 2016 IRP that there are
additional issues with Vectren’s energy efficiency cost projection. Stevie’s regression
results from his analysis of the problematic EIA Form 861 data set were applied to
an estimated levelized cost of Vectren’s 2016 programs. This serves as the starting
point for the entirety of the cost projection. That starting point was calculated
incorrectly, however. The stated levelized cost of Vectren’s 2016 program in their
2016 IRP is $0.03322 per kWh. However, that number should be much lower. The
following are the generic equations used to develop this levelized cost:

\[
\text{Capital Recovery Factor (CRF)} = \frac{\text{Weighted Average Cost of Capital}(1 + \text{Weighted Average Cost of Capital})^{Portfolio \text{Weighted Measure Life}}}{(1 + \text{Weighted Average Cost of Capital})^{Portfolio \text{Weighted Measure Life}} - 1}
\]

\[
\text{Levelized Gross Cost per kWh} = \frac{\text{First year program cost} \times CRF}{\text{Annual kWh Savings}}
\]

The weighted average cost of capital was assumed to be Vectren’s pre-tax nominal
discount rate of 10.09%\(^5\). However, Stevie’s regression was intended to forecast
real, not nominal costs. That means that the Vectren’s real discount rate of 5.186%
should have been applied in order to arrive at the correct levelized cost.

\(^4\) See response to CAC DR 9-4 in Cause No. 44927 (Attachment 1).
\(^5\) See CAC response to Vectren DR 2-3 in Cause No. 44927 (Attachment 2) or CAC
Exhibit 2 Attachment AS-10_part 2, which was publicly filed in Cause No. 44927.
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This change alone reduces the starting cost of Vectren’s energy efficiency costs from $0.03322 per kWh to $0.02657 per kWh. In addition, Stevie’s cost projection model is limited to two categories of costs reported to EIA, direct costs and customer incentive payments. Excluded from his cost projections are all other costs of energy efficiency:

- administrative,
- marketing,
- monitoring & evaluation,
- performance incentive, and
- other non-program specific costs.

These other important costs were not excluded from Vectren’s calculation. Simply put, Vectren’s cost calculation is not made on the same basis as Stevie’s cost projection. Stevie’s projection is meant to apply to two categories of energy efficiency costs (direct costs and customer incentive payments), not to the full cost of energy efficiency.

Had Vectren limited the efficiency costs in this calculation to direct costs and customer incentives (in parallel to Stevie), the levelized cost would have been further reduced to $0.02393 per kWh, or 28 percent less than Stevie calculates as the starting value.

Even if Stevie had correctly specified his regression and used a reliable data source, the application of his results is fundamentally flawed. Several other serious errors and concerns with Stevie’s method of applying his cost escalation estimates to Vectren’s efficiency are discussed in IURC Cause No. 44927, CAC Exhibit 1, which is the Verified Direct Testimony of Dr. Stanton. These issues include:

1. the basis for his efficiency cost growth factors are artificially inflated;
2. he uses his regression results selectively, ignoring certain findings;
3. his 2017 efficiency costs are erroneously based on expected cumulative savings in 2036; and
4. he confuses the effects of changes over time with the effects of differing policy choices within a single year.

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6 See Attachment 3 for the 2016 Vectren DSM Electric Scorecard which shows the planned program costs and gross savings for both the C&I and residential sectors.
7 Based on Vectren’s 2016 DSM plan. If actual performance and cost had been used, the levelized cost would drop to $0.02298 per kWh.
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Stevie’s rebuttal in that docket addresses only some of these critiques and focuses on the language of the critique rather than its substance.

Again, the 2016 levelized cost serves as the starting point for the entirety of Vectren’s DSM cost projection, so this error is magnified throughout all the bundles and completely undermines the Strategist modeling evaluating those DSM bundles.

**Vectren’s Strategist Modeling**

In its reply to our comments, Vectren took issue with the following table:

<table>
<thead>
<tr>
<th>Resource</th>
<th>Base</th>
<th>High Reg</th>
<th>Low Reg</th>
<th>High Tech</th>
<th>High Econ</th>
<th>Low Econ</th>
<th>Base + Large Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW Wind</td>
<td>2099</td>
<td>2030</td>
<td>2099</td>
<td>2099</td>
<td>2024</td>
<td>2099</td>
<td>2025</td>
</tr>
<tr>
<td>50 MW Solar</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2036</td>
<td>2024</td>
</tr>
<tr>
<td>50 MW Wind</td>
<td>2019</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2099</td>
<td>2025</td>
</tr>
<tr>
<td>9 MW Solar</td>
<td>2019</td>
<td>2099</td>
<td>2099</td>
<td>2030</td>
<td>2024</td>
<td>2035</td>
<td>2025</td>
</tr>
<tr>
<td>4 MW DR added every 5 years</td>
<td>2020</td>
<td>2099</td>
<td>2020</td>
<td>2099</td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
</tr>
<tr>
<td>EE Block 1</td>
<td>2018</td>
<td>2018</td>
<td>2018</td>
<td>2099</td>
<td>2018</td>
<td>2099</td>
<td>2018</td>
</tr>
</tbody>
</table>

*Data source:* Strategist file PRV Input Summary report for each scenario.  
*Note:* “2099” indicates that this resource is never available for selection during the 20-year modeling period.

Vectren contended that each resource was available to be selected much earlier in the planning period within at least one of “8 model runs performed for each scenario.” We acknowledged in our comments that Vectren engaged in an iterative process of evaluating resources. However, we criticized Vectren for using a process that is entirely opaque and resulted in the nonsensical values shown in the table above. We stand by that criticism and offer some additional clarification given Vectren’s response to our comments. In its rebuttal testimony in Cause No. 44927, Vectren suggests consideration of the following, saying it should address concerns that it had improperly constrained resource choices: (1) a matrix of its Strategist runs, as well as (2) a flow chart (replicated below). We strongly disagree.
First, Vectren’s Process Flow Chart leaves out a fourth step, which is the construction of the final portfolio in each scenario. The third step shown in Figure 3 above (Vectren’s so-called “Portfolio Refinements”, a term that is literally never used in Vectren’s IRP) does not result in a final version of each scenario. Vectren’s flow chart does nothing to rectify our concern: the relationship between the eight modeling runs performed for each scenario and the final scenario run is completely undescribed.

In addition, each of the portfolio refinements is characterized in large part by requiring the model to include specific generation units—a modeling procedure that is at odds with any optimization process. Indeed, to call any of the scenarios run by Vectren “optimized” is, at best, disingenuous.

Finally, Vectren’s process flow chart sheds no light on the development of the “Balanced Energy” portfolios.
Vectren has also directed us to one of the slides from a stakeholder presentation. That slide says simply:

**Optimization Modeling Is an Iterative Process**

- Still too many options to model at one time
  - Model several options to determine what is selected
  - Keep selected options, rotate in new alternatives
  - Repeat process until all resources are considered

Not only is this explanation nonspecific, but it is contradicted by Vectren’s own modeling files.

Our interpretation of this language, based on its plain meaning, is that the final version of each scenario includes the option to select all the resources that were in all the other, non-final runs. A review of the Low Economy runs, as an example, does not bear this out. The final Low Economy run does not allow for the selection of energy efficiency, yet at least one of the non-final iterations of the Low Economy scenario requires adoption of the first four blocks of energy efficiency. Even if each resource was evaluated, selected options kept, and new alternatives rotated in as Vectren claims, it matters a great deal what the other assumptions were in each run when each alternative was considered.

For example, one of the non-final Low Economy runs is titled “Low Economy-Cease Coal 2024-Gas Conversion” meaning that the resource portfolio contains both the closure of certain Vectren coal units as well as their conversion to gas units. All of these resource choices are forced in with the end result that the reserve margin is well over what is required. It should be of no surprise, therefore, that no other resources including energy efficiency are chosen. Why should this run influence the
resources included in the final Low Economy run? And how, if at all, does it influence the included resources?

There is no satisfactory answer to these questions. And nothing Vectren has said about its IRP clarifies:

- (1) Why Vectren kept some resources but not others,
- (2) How and in what order each resource was evaluated, and
- (3) How one should interpret the results of any of these runs.

We find a clear explanation of the reasoning behind Vectren’s construction of its Strategist modeling completely lacking.

**Recommendations for Improving the Stakeholder Process**

In their responses to our comments, we noted that at least one utility was surprised to read our comments and would have expected that much of what we said would be addressed through the stakeholder process. As such, we thought it would be helpful to set expectations for stakeholder participation in the IRP process as well as make some recommendations to improve the stakeholder process.

*Review of submitted IRPs by stakeholders is a critical component of the integrated resource planning process:* We do not see future stakeholder processes resulting in a consensus IRP document. To reach such an outcome would require far more than just four meetings presenting public information. It would require extensive side-by-side work between stakeholders’ experts and utility staff/contractors running the IRP model and creating the inputs. It would require an ability to review all the modeling files as they are produced. It would also require an extensive back and forth process to create the narrative describing the modeling and forecasting efforts. And finally, it would require significant investment from outside sources because the level of funding needed to allow stakeholder groups to participate in the development of IRPs in that depth is not normally available. Because it seems highly unlikely that the stakeholder processes will move in this direction, it is unreasonable to expect that the stakeholder process will resolve all disagreements between stakeholders and utilities. It is also unreasonable to think the presentation of publicly available information in four different sessions can adequately substitute for

9. In addition, the utility runs these stakeholder sessions, controls the timing and amount of information that is shared with stakeholders, and controls the floor during the meeting, which also limits the ability of stakeholders (and their experts) to get complete information out of these meetings.

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the stakeholder process – often simply because they could not have been raised 
without the opportunity to review the final IRP and modeling files nor were there 
resources to engage us earlier in the process even if this information had been made 
available to us sooner.

*The stakeholder process plays a different role:* If the correct information is presented 
in the stakeholder process, it can alert all the parties to fundamental disagreements 
especially as to basic assumptions about modeling inputs. For example, even before 
the IRP was filed, a problem with the use of the PIRA forecasts in NIPSCO’s IRP had 
been identified. If the utilities are willing, an attempt at rectifying those 
disagreements by changing modeling assumptions could be made. To date, however, 
the utilities have often reacted defensively to questions raised about their modeling 
assumptions, and/or have claimed that they are unable to address any such 
questions during the current IRP process but could only consider doing so in future 
IRPs.

*The designation of “stakeholder portfolios” should be limited to stakeholders’ actual 
requests:* Another change that would improve the outcomes of stakeholder 
processes is to identify and model “stakeholder” portfolios only if the stakeholders 
can direct the modeler to make specific changes and can see all the modeling inputs 
and outputs before those runs are finalized. It is not possible to summarize all the 
key inputs to each run in a public presentation. As a result, each of the utilities 
constructed so called “Stakeholder” portfolios with assumptions that our clients did 
not endorse, but were not made apparent to us until we had reviewed the modeling 
files after the submission of the IRP. The whole process of constructing those 
portfolios and presenting them in the IRPs then becomes an exercise in wasted time 
and energy because they are portfolios that none of the parties believe to be realistic 
and yet the name “Stakeholder” portfolio implies our clients’ endorsement.

*The stakeholder process can add some additional value:* Our clients have expressed 
appreciation for the efforts NIPSCO put into communicating with stakeholders 
interested in participating. And while not all aspects of the process were desirable, 
NIPSCO is to be commended for going above and beyond in communicating with 
interested parties and scheduling one-on-one meetings to discuss issues and 
concerns.

In sum, we appreciate the opportunity to provide these additional comments and 
look forward to seeing the Director’s Final Report.
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (“Vectren South”), pursuant to 170 IAC 1-1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Responses to the Citizens Action Coalition’s (“CAC”) Ninth Set of Data Requests to Vectren South dated August 28, 2017 (“Requests”).

I. General Objections.

1. The responses provided to the Requests have been prepared pursuant to a reasonable and diligent investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable and diligent investigation and search, Vectren South objects on grounds that they include an undue burden and unreasonable expense.

2. Vectren South objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and which are not reasonably calculated to lead to the discovery of admissible evidence.
3. Vectren South objects to the Requests (including Instruction Nos. 1(a), 1(b) and 2(d)) to the extent they seek responses and information from individuals and entities who are not parties to this proceeding and to the extent they request the production of information and documents not presently in Vectren South’s possession, custody, or control.

4. Vectren South objects to the Requests to the extent the Requests seek information outside the scope of this proceeding, and as such, the Requests seek information not reasonably calculated to lead to the discovery of relevant or admissible evidence.

5. Vectren South objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed and which Vectren South objects to performing.

6. Vectren South objects to the Requests to the extent they are vague and ambiguous and provide no basis from which Vectren South can determine what information is sought.

7. Vectren South assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the instructions and/or Requests (including Instruction No. 2(f)) purport to impose any greater obligation.

8. Vectren South objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation, or other applicable privileges.

9. Vectren South objects to the Requests to the extent the seek information that is confidential, proprietary, competitively sensitive, and/or trade secret.

10. The responses constitute the corporate responses of Vectren South and contain information gathered from a variety of sources. Vectren South objects to the Requests (including Instruction Nos. 1(j), 1(k) and 2(g)) to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them.

11. Vectren South objects to the Requests to the extent the discovery sought is unreasonably cumulative or duplicative, or is obtainable from some other source that is more convenient, less burdensome, or less expensive.

12. Vectren South objects to the Requests to the extent the burden or expense of the proposed discovery outweighs its likely benefit, taking into account the needs of the case, the amount in controversy, the parties’ resources, the importance of
the issues at stake in litigation, and the importance of the proposed discovery in resolving the issues.

13. Vectren South objects to the Requests to the extent they solicit copies of voluminous documents.

14. Vectren South objects to the Requests (including Instruction No. 2(h)) to the extent they request identification of witnesses who will be prepared to testify concerning the matters contained in each response on the grounds that Vectren South is under no obligation to call witnesses to respond to questions about information provided in discovery.

Subject to and without waiver of the general and specific objections set forth herein, Vectren South responds to the Requests in the manner set forth below.

II. Data Request Responses.
Request No. 9-4: Refer to the response to CAC 2-1. Please confirm that the following generic equations were used to calculate the $0.03322 per kWh figure given at page 4 of Dr. Stevie’s rebuttal testimony. If it is not, please provide the generic equations used to calculate the $0.03322 per kWh figure.

\[
Capital\ Recovery\ Factor\ (CRF) = \frac{Weighted\ Average\ Cost\ of\ Capital(1+Weighted\ Average\ Cost\ of\ Capital)^{Portfolio\ Weighted\ Measure\ Life}}{(1+Weighted\ Average\ Cost\ of\ Capital)^{Portfolio\ Weighted\ Measure\ Life−1}}
\]

\[
Levelized\ Gross\ Cost\ per\ kWh = \frac{First\ year\ program\ savings \times CRF}{Annual\ kWh\ Savings}
\]

Response: Yes, the generic equations identified above are similar to the equations Vectren South used to calculate the $0.03322 per kWh figure at page 4 of Dr. Stevie’s rebuttal testimony.
ATTACHMENT 2
STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA )
GAS AND ELECTRIC COMPANY D/B/A )
VECTREN ENERGY DELIVERY OF INDIANA, )
INC. REQUESTING THE INDIANA UTILITY )
REGULATORY COMMISSION TO APPROVE )
CERTAIN DEMAND SIDE MANAGEMENT )
PROGRAMS AND GRANT COMPANY ) CAUSE NO. 44927
AUTHORITY TO RECOVER COSTS, )
INCLUDING PROGRAM COSTS, INCENTIVES )
AND LOST MARGINS, ASSOCIATED WITH )
THE DEMAND SIDE MANAGEMENT )
PROGRAMS VIA THE COMPANY’S DEMAND )
SIDE MANAGEMENT ADJUSTMENT )

CAC’S RESPONSES TO VECTREN SOUTH’S
SECOND SET OF DATA REQUESTS

Pursuant to 170 IAC 1-1.1-16 and the agreements regarding discovery reflected in the
Indiana Utility Regulatory Commission’s (“Commission”) Prehearing Conference and Docket
Entries in this cause, Citizens Action Coalition (“CAC”) submits the following responses to
Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana,
Inc.’s (“Vectren South” or “Petitioner”) second set of data requests.

GENERAL OBJECTIONS

A. CAC objects to Requests to the extent that they seek information that is not relevant to
the above referenced proceedings, Indiana Rule of Evidence 401.

B. CAC objects to Requests that are not “reasonably calculated to lead to the discovery of
admissible evidence,” Indiana Trial Rule 26(B)(1).

C. CAC objects to Requests that are overly broad, unduly burdensome, oppressive, and
calculated to take Joint Intervenors and their staff away from normal work activities, and require
them to expend significant resources to provide complete and accurate answers to Vectren South’s Request, which are only of marginal value to Vectren South. See Indiana Trial Rule 26 (B)(1).

D. CAC assumes, for the purpose of providing these objections and responses, that the Requests do not seek information that is privileged, protected by the work product doctrine, or otherwise exempt from disclosure. Joint Intervenors object to the Requests to the extent, if any, that they call for production of any such material.

E. CAC reserves all of its evidentiary objections or other objections to the introduction or use of any response at any hearing in this action.

F. CAC does not, by any response to any Request, waive any objections to that Request.

G. CAC does not admit to the validity of any legal or factual contention asserted or assumed in the text of any Request.

H. CAC reserves the right to assert additional objections as appropriate, and to amend or supplement these objections and responses as appropriate.

I. The foregoing general objections shall apply to each of the following Requests whether or not restated in the response to any particular response.
Request No. 2-1: Please provide in electronic, spreadsheet format with all formulas and links intact, all workbooks the CAC used to create the regression analyses described by CAC witness Stanton in CAC Exhibit 1. Please provide the data sets in Excel spreadsheet format, separately for each regression.

Response:

Please see the Excel sheet provided to Vectren with CAC’s Second Supplemental Response to Vectren Set 1.

Request No. 2-2: Please provide in electronic, spreadsheet format with all formulas and links intact, the regression results (actual model runs) discussed by witness Stanton in CAC Exhibit 1.

Response:

Please see the Excel sheet provided to Vectren with CAC’s Second Supplemental Response to Vectren Set 1.

Request No. 2-3: Please provide in electronic, spreadsheet format with all formulas and links intact, all workbooks the CAC used to calculate levelized costs, as discussed by witness Sommer in CAC Exhibit 2.

Response:

Please see the attached “44927--CAC Exhibit 2-Figure 4--CONFIDENTIAL Workpaper--7-28-17_5-Corrected,” which has been corrected in response to this request since our submission of workpapers to the parties on July 30, 2017, and will be provided to the Commission, under seal, once the Commission rules on the pending motion for confidential protection filed by Vectren. The corrections addressed the number of years of inflation included in the conversion of certain program costs from nominal to real dollars, but did not change anything presented in CAC Exhibit 2 or the approach that we took in our calculation of the levelized costs, as discussed by Witness Sommer in CAC Exhibit 2. Our approach was largely based on the spreadsheet Vectren provided in response to CAC Data Request 2-1, despite the fact that there are several aspects of Vectren’s analysis that did not make sense.
First, in order to levelize 2016 program costs, Vectren used its pre-tax nominal discount rate of 10.09%. This levelization is a key step in Dr. Stevie’s analysis because the resulting cost per kWh is the starting point for his DSM cost projections. However, as described in Vectren’s response to CAC Data Request 1-23, Dr. Stevie forecasts DSM costs in real dollars. So it is not clear why Vectren would have used a pre-tax nominal discount rate to develop the starting cost for a forecast in real dollars.

Second, as described in Vectren’s response to CAC Data Request 4-3, Dr. Stevie’s estimate of 2018-2020 proposed program levelized costs shown in Table RGS-1 are based on a different nominal discount rate, the post-tax nominal discount rate of 7.29%. In addition, the kWh impacts were levelized using the real discount rate of 5.186%, a step that was not employed in Dr. Stevie’s cost projections. So not only are the levelized costs in Table RGS-1 in nominal, not real, dollars, but they were developed using a different nominal discount rate than Dr. Stevie used in his DSM cost projections for the IRP, as well as a different levelization methodology.

When developing our levelized cost projection for CAC Exhibit 2, we decided to mimic Vectren’s approach in its response to CAC Data Request 2-1 while keeping the result as comparable as possible with Dr. Stevie’s real (not nominal) cost forecast for DSM. We converted Vectren’s program costs into real dollars using Vectren’s assumed inflation rate of 1.6%. Vectren levelizes program costs using a capital recovery factor (the ratio of a constant annuity to the present value of that annuity); therefore, we should have then calculated the present value of the program costs (in real dollars). However, since Vectren’s capital recovery factor is based on a pre-tax nominal discount rate, using the real discount rate would have resulted in the application of two different discount rates in the same levelization. Therefore, we simply ignored the present value step. Changing any one of these factors, i.e., levelizing using the real, not pre-tax nominal, discount rate or calculating the present value of 2018-2020 program costs would make the proposed program costs look even lower in comparison to Dr. Stevie’s DSM cost projections. Therefore our approach gave the most conservative, i.e., the highest result possible, for the 2018-2020 DSM plan.
ATTACHMENT 3
Cause No. 45052, JI Exhibit 2, Attachment TFC-4
Vectren December 2016 Electric DSM Scorecard
Portfolio period: January 2016 – December 2016

Measures/Projects Implemented

Residential Programs
Residential Lighting
Home Energy Assessments
Income Qualified Weatherization
Appliance Recycling
Energy Efficient Schools
Residential Prescriptive
Residential New Construction
Multi‐Family Direct Install
Residential Behavioral Savings
Conservation Voltage Reduction
Residential Smart Thermostat Program
Total Residential
Commercial & Industrial Programs
Small Business Direct Install
Commercial & Industrial Prescriptive
Commercial & Industrial New Construction
Commercial & Industrial Custom
Building Tune‐up
Conservation Voltage Reduction
Total C&I
Total Residential and C&I
Outreach
Evaluation
Total Outreach and Evaluation
Total Portfolio
Flex Funding
Appliance Recycling (Flex Funding 4/28/16)
Residential Prescriptive (Flex Funding 9/28/16)
C&I Custom (Flex Funding 9/28/16)
C&I Prescriptive (Flex Funding (9/28/16)
Market Potential Study (Flex Funding (10/11/16)
Food Bank (Flex Funding 9/28/16)
Total Flex Funding
Total Portfolio including Flex Funding

Gross kWh Savings

Net kWh Savings

Program Expenditures

Current
Month
(Dec)

Program
YTD

Planning
Goal

% to Goal

74,882
368
138
67
0
562
0
2,780
0

272,104
1,850
740
998
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ATTACHMENT TFC-5
DRAFT
DIRECTOR’S REPORT
for the
2016 Integrated Resource Plans
Dr. Bradley Borum
Director of Research, Policy, and Planning
on behalf of the
Indiana Utility Regulatory Commission
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

July 28, 2017
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EXECUTIVE SUMMARY

2016 INTEGRATED RESOURCE PLANS

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

Purpose of IRPs

By statute¹ 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 the 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 statute³, 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. Inherently, IRPs are forward looking so it is important for IRPs to consider a broad range of potential changes in environmental and other public policies.
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. Statutorily, it is the utility’s decision whether to modify their IRP or create a new IRP to support a case for a change in resources. Minor and significant changes will occur after submittal (or after the expensive and technically demanding modeling work has been completed). To avoid perpetual IRPs that are never completed as circumstances are always changing, modifying or preparing a new IRP to support a filing of a Certificate of Need case or other case may be appropriate. Such a decision is at the utility’s discretion under the law and the Commission will evaluate the reasonableness of the utility’s decision. 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 statute⁶ 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

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
19, 2016. Links to the IRPs, appendices, and other documents can be found at http://www.in.gov/iurec/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:

1. Indianapolis Power & Light Company (IPL)
   http://www.in.gov/iurec/files/pl%202016%20irp_without%20attachments.pdf
2. Hoosier Energy REC, Inc. (Hoosier Energy)
3. Northern Indiana Public Service Company (NIPSCO)
   http://www.in.gov/iurec/files/NIPSCO%202016%20IRP%20Without%20Appendices.pdf
4. Southern Indiana Gas & Electric Company (SIGECO or Vectren)
   http://www.in.gov/iurec/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

Links to these comments can be found at: http://www.in.gov/iurec/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 28, 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 may 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. Indiana law requires the Commission to consider the broad public interest when evaluating resource decisions and their consequences in CPCN processes or other proceedings. The Commission’s authority does not extend to pre-approval of a utility’s decision to retire resources. Nevertheless, the law requires the Commission to exercise its authority over the consequences of the utility’s resource decisions, including ensuring that older generating facilities are not closed prematurely.

- 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 8.41 in 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). 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

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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 (SO₂) and nitrogen oxide (NOₓ) 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.
### Table 1: Resource Portfolio Metrics

<table>
<thead>
<tr>
<th>Category</th>
<th>Metric</th>
<th>Unit</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cost</strong></td>
<td>Present Value Revenue Requirements (PVRR)</td>
<td>$MM</td>
<td>The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period</td>
</tr>
<tr>
<td></td>
<td>Incremental Rate Impact (over 5 years)</td>
<td>cents/kWh</td>
<td>The incremental impact to customer rates of adding new resources, shown in five year time blocks</td>
</tr>
<tr>
<td></td>
<td>Average Rate Impact (over 20 years)</td>
<td>cents/kWh</td>
<td>The average 20 year cost impact of adding new resources divided by total kWh sold</td>
</tr>
<tr>
<td><strong>Financial Risk</strong></td>
<td>Risk Exposure</td>
<td>$</td>
<td>The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)</td>
</tr>
<tr>
<td><strong>Environmental Stewardship</strong></td>
<td>Annual average CO₂ emissions</td>
<td>tons/year</td>
<td>The annual average tons of CO₂ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>Annual average SO₂ emissions</td>
<td>tons/year</td>
<td>The annual average tons of SO₂ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>Annual average NOₓ emissions</td>
<td>tons/year</td>
<td>The annual average tons of NOₓ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>CO₂ intensity</td>
<td>tons/MWh</td>
<td>Total tons of CO₂ during the study period per MWh of generation during the study period</td>
</tr>
<tr>
<td><strong>Resiliency</strong></td>
<td>Planning Reserves as a percent of load forecast</td>
<td>%</td>
<td>Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast</td>
</tr>
<tr>
<td></td>
<td>Distributed Energy Generation</td>
<td>%</td>
<td>Percent of IPL’s resources that is distributed generation, shown in five year time blocks</td>
</tr>
<tr>
<td></td>
<td>Market reliance energy</td>
<td>%</td>
<td>Percent of customer load met with market purchases</td>
</tr>
<tr>
<td></td>
<td>Market reliance capacity</td>
<td>MW</td>
<td>Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin</td>
</tr>
</tbody>
</table>

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 CO₂ 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 resiliency, 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 SO₂, NOₓ, and CO₂. 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.
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” 9is 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...
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 Sensitives 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: CO₂ 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). 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

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.\textsuperscript{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.\textsuperscript{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

\textsuperscript{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.

\textsuperscript{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 scorecard. 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/porfolios, 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.
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\(^\text{14}\) 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 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 CO2 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

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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 CO2 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. 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 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 CO₂ 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,

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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.
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 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. 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 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 SO₂ 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.
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)

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. 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

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19 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? 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

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20 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 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.21 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

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21 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 sensitivities. 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 snapshot 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 NIPCO, 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.
ATTACHMENT TFC-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

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.

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EXECUTIVE SUMMARY
2016 INTEGRATED RESOURCE PLANS
Indianapolis Power & Light, Northern Indiana Public Service Company, Vectren, and Hoosier Energy

Purpose of IRPs

By statute and rule, 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, 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. 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, 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 and rule, 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)  

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


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 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 8.41 in 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
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). 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

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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.
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

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<table>
<thead>
<tr>
<th>Category</th>
<th>Metric</th>
<th>Unit</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>Present Value Revenue Requirements (PVRR)</td>
<td>$MM</td>
<td>The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period</td>
</tr>
<tr>
<td></td>
<td>Incremental Rate Impact (over 5 years)</td>
<td>cents/kWh</td>
<td>The incremental impact to customer rates of adding new resources, shown in five year time blocks</td>
</tr>
<tr>
<td></td>
<td>Average Rate Impact (over 20 years)</td>
<td>cents/kWh</td>
<td>The average 20 year cost impact of adding new resources divided by total kWh sold</td>
</tr>
<tr>
<td>Financial Risk</td>
<td>Risk Exposure</td>
<td>$</td>
<td>The difference between the PVRR at the 95th percentile of probability and the PVRR at 50% percentile probability (expected value)</td>
</tr>
<tr>
<td>Environmental Stewardship</td>
<td>Annual average CO₂ emissions</td>
<td>tons/year</td>
<td>The annual average tons of CO₂ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>Annual average SO₂ emissions</td>
<td>tons/year</td>
<td>The annual average tons of SO₂ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>Annual average NOₓ emissions</td>
<td>tons/year</td>
<td>The annual average tons of NOₓ emitted over the study period</td>
</tr>
<tr>
<td></td>
<td>CO₂ intensity</td>
<td>tons/MWh</td>
<td>Total tons of CO₂ during the study period per MWh of generation during the study period</td>
</tr>
<tr>
<td>Resiliency</td>
<td>Planning Reserves as a percent of load forecast</td>
<td>%</td>
<td>Planning reserves are the MW of supply above peak forecast. This metric measures planning reserves as a percent of peak load forecast</td>
</tr>
<tr>
<td></td>
<td>Distributed Energy Generation</td>
<td>%</td>
<td>Percent of IPL’s resources that is distributed generation, shown in five year time blocks</td>
</tr>
<tr>
<td></td>
<td>Market reliance energy</td>
<td>%</td>
<td>Percent of customer load met with market purchases</td>
</tr>
<tr>
<td></td>
<td>Market reliance capacity</td>
<td>MW</td>
<td>Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin</td>
</tr>
</tbody>
</table>
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)

![Tornado Chart Example](image)

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 SO₂, NOx, and CO₂. 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 oversimplistic 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” is for production of oil, it would seem that the production of oil should be a variable in projecting future natural gas prices. 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 Sensitivity 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: CO₂ 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

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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. 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.

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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\(^\text{14}\) 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

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\(^\text{14}\) 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 snapshot 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\textsuperscript{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\textsubscript{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

\textsuperscript{15} November 16, 2016 \textbf{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. “\textit{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. “\textit{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 CO₂ 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. 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.

10 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 \(\text{CO}_2\) 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.”

\(^{17}\) 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

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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 SO₂ 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 events are so low that it would not have materially changed the risk analysis and the ultimate recommended portfolio.”

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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 Vectren’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), and participants in programs terminated since 1992 (those effects continue even though the programs have been discontinued) (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\textsuperscript{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.\textsuperscript{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.

\textsuperscript{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.

\textsuperscript{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

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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? 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

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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 prices have changed due to technological enhancements, the impact on overall supply is likely to be steady 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.

\(^{24}\) 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. 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.

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, 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.


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. 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. 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 TFC-7
Objective, Scope & Procedures

• This engagement was included in the 2016 audit plan approved by the Audit and Risk Management Committee of the Board of Directors.

• The objectives of this advisory engagement were to 1) ensure accurate, consistent data is used in the IRP process; 2) assess that the consultants used have reasonable control over their processes; and 3) develop a flowchart to explain the IRP process, including key inputs.

• The engagement focused on key drivers provided by Vectren personnel as of March 2016 and their accurate use in the modeling tools.

• This advisory service was conducted in accordance with the International Professional Practices Framework established by the Institute of Internal Auditors. This framework guides the performance of internal audit work.

• Corporate Audit inspected relevant documentation, inquired with key personnel, identified key risks related to the IRP process, assessed the internal control design mitigating such risks, performed detailed tests of underlying data, and considered the 2013 Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) – See Appendix A.

• The results of this engagement will only be communicated to 1) Wayne Games; 2) Robbie Sears; 3) Matt Rice; and 4) Scott Brown. Results will only be communicated to other parties upon the receipt of consent by the aforementioned individuals.
Key Risks Identified

• Use of accurate inputs in the modeling tools by outside consultants (Burns & McDonnell and PACE Global).
• Data is gathered and provided by appropriate Vectren personnel.
• Existence of clearly defined communication channels with outside consultants.
• Existence of clearly defined channels through which data is transferred between IRP process stakeholders to ensure consistency in transferring and receiving data.
• Appropriate commitment to a Quality Control/Quality Assurance (QC/QA) process by outside consultants.
Test Procedures

• Developed a flowchart of the process to ensure key inputs were understood.
• Validated key inputs provided by Vectren to outside consultants were accurately used in the model runs.
• Validated key inputs transferred between the outside consultants were accurately used in the model runs.
• Inquired with Vectren personnel relative to the submission of input data to outside consultants.
• Inquired with outside consultants’ personnel relative to the existence of, commitment to, and completeness of a QC/QA process.
• Reviewed the uniformity and consistency of input data provided to outside consultants.
• Reviewed evidence supporting the provision of input data by appropriate Vectren personnel.
Burns & McDonnell and PACE Global - Quality Control & Quality Assurance (QC/QA) Process

An appropriate commitment towards an effective QC/QA process was noted based on inquiries with personnel from Burns & McDonnell and PACE Global.

- **Multi-Step Internal Quality Review Process**
  - Preliminary review of project activities to define scope, responsibilities, timelines, and deliverables.
  - Intermediate reviews of model runs and results.
  - Final independent review of final deliverables/submittals by qualified personnel.
  - Assess the reasonableness of data provided by Vectren and/or other consultants.

- **Formation of Project Team**
  - Selecting members who demonstrate professionalism and possess the knowledge to support analysis, including modeling software knowledge.

- **Access Controls**
  - Access to modeling software and data is restricted to authorized individuals.
  - Periodic review of access rights.

- **Data Integrity Controls**
  - Data is stored on a secure server location.
  - Data “version control” exists.

- **Change Management Process**
  - Updates (i.e. version update) to the modeling software go through an established change management process.
  - As a best practice, the current version of the modeling software is not updated during the IRP process to keep modeling logic consistent throughout modeling runs.
Validation of Key Inputs - Base Case

• Validated a sample of key inputs provided by Vectren and used by outside consultants in the Base Case model runs.
  - Natural gas prices.
  - Coal prices.
  - Carbon (CO$_2$) prices.
  - Load forecast.
  - Net Energy and Net Demand savings.
  - Generating Units production costs.

• Validated a sample of Tech-Assessment inputs provided by Burns & McDonnell and used by PACE Global.
• Validated that outputs from the PACE Global model agreed to inputs used in the Burns & McDonnell model.

Validations resulted in no exceptions.
1. Vectren uses a "consensus" base case view by averaging forecasts from several sources, including recent forecasts from PACE Global, Ventyx, Wood Mac, PIRA, and EVA where available. This ensures that reliance on one forecast or forecaster does not occur.

2. Vectren and PACE Global worked together to develop a base case and five alternative scenarios (potential futures), to test which portfolios are optimal over a range of future market and regulatory conditions. Scenarios include a high and low regulatory case, a high and low economy case, and a high technology case.

3. Location Marginal Pricing (LMPs) are provided for the 20-year forecasted period, load data and coal, natural gas, CO₂, and capital cost data is also included.

4. Analyzes resource options for each scenario and provides for the lowest-cost plan to meet customer demand and the Planning Reserve Margin (PRM) required by MISC.

5. Provides for new power supply alternatives, including capital costs and C&V assumptions.

6. A diverse mix of portfolios, including the lowest-cost portfolio, are selected for risk analysis to determine which plan is the most resilient against future sensitivities (see next page).
IRP Process Flow MAP - Cont’d.

1. Each selected portfolio is subjected to additional risk sensitivities to identify which portfolio is the most resilient against future sensitivities.
2. “Preferred” portfolio is selected on the basis of flexibility, balance of strategic objectives, and reasonable cost to customers given future uncertainty.
Strengths Identified During Engagement

• Engagement of outside consultants to perform model runs who appear to have a proper QC/QA process in place to ensure inputs provided are correctly and appropriately used in the modeling software to generate reliable outcomes.
• Vectren data was generated and provided to outside consultants by competent employees with appropriate knowledge and institutional expertise.
• Existence of clearly defined communication channels between Vectren personnel and consultants’ team members to assist the transfer of data and sharing of expectations.
• Appropriate support by senior management during the IRP process in providing direction and reviewing outcomes.
Recommendations

- Additional structure and standard work instructions will be necessary, as people change roles and the relative criticality of the IRP process diminishes. A project structure with an assigned champion (project manager) can be considered as an option. This will facilitate more clearly defined ownership and responsibilities, ensure the continual engagement of team members, emphasize and facilitate communication, and keep schedules and deliverables on track.

- Corporate Audit can be engaged to perform this advisory service for future critical IRPs to provide an additional level of assurance that scenario outcomes are based on correct and accurate inputs. As an alternative, request that our consultants have their protocol process independently tested using a report, which indicates the robustness of their internal control structure. This report is commonly known as a SOC 2 (Service Organization Controls) report.
Appreciation & Acknowledgement

• Corporate Audit would like to express its appreciation to management and all employees who provided cooperation throughout this engagement.

• We would be pleased to provide you with any further assistance; please do not hesitate to contact us with any requests you may have.

• A detailed recommendation listing will be provided.

• An engagement survey will be sent to 1) Wayne Games; 2) Robbie Sears; 3) Matt Rice; and 4) Scott Brown. These surveys assist Corporate Audit in continuously improving our practices and procedures.

Patrick Edwards, Corporate Audit Vice President
Brian Hicks, Corporate Audit Director
Neophytos Neophytou, Senior Auditor
Natasha Scott, Staff Auditor
Appendix A: COSO Internal Control Framework (2013)

The 2013 COSO Framework includes five components of internal control and seventeen principles representing the fundamental concepts relating to each component.

This audit engagement focused on the below components and related principles.

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<th>COMPONENT</th>
<th>PRINCIPLE</th>
<th>EXAMINED</th>
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<tr>
<td>Control Environment</td>
<td>The organization demonstrates a commitment to integrity and ethical values.</td>
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<td>The Board of Directors demonstrates independence from management and exercises oversight of the development and performance of internal controls.</td>
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<td>Management establishes, with Board oversight, structures, reporting lines, and appropriate authorities and responsibilities in the pursuit of objectives.</td>
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<td>The organization demonstrates a commitment to attract, develop, and retain competent individuals in alignment with objectives.</td>
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<td>The organization holds individuals accountable for their internal control responsibilities in the pursuit of objectives.</td>
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<td>Risk Assessment</td>
<td>The organization specifies objectives with sufficient clarity to enable the identification and assessment of risks relating to objectives.</td>
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<td>The organization identifies risks to the achievement of its objectives across the entity and analyzes risks as a basis for determining how the risks should be managed.</td>
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<td>The organization considers the potential for fraud in assessing risks to the achievement of objectives.</td>
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<td>The organization identifies and assesses changes that could significantly impact the system of internal control.</td>
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<td>Control Activities</td>
<td>The organization selects and develops control activities that contribute to the mitigation of risks to the achievement of objectives to acceptable levels.</td>
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<td>The organization selects and develops general control activities over technology to support the achievement of objectives.</td>
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<td>The organization deploys control activities through policies that establish what is expected and procedures that put policies into action.</td>
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<td>Information and Communication</td>
<td>The organization obtains or generates and uses relevant, quality information to support the functioning of internal control.</td>
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<td>The organization internally communicates information, including objectives and responsibilities for internal control, necessary to support the functioning of internal control.</td>
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<td>The organization communicates with external parties regarding matters affecting the functioning of internal control.</td>
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<td>Monitoring Activities</td>
<td>The organization selects, develops, and performs ongoing and/or separate evaluations to ascertain whether the components of internal control are present and functioning.</td>
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<td>The organization evaluates and communicates internal control deficiencies in a timely manner to those parties responsible for taking corrective action, including senior management and the Board of Directors, as appropriate.</td>
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ATTACHMENT TFC-8
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<td>7 COINCIDENT PEAK DEMAND 98.23%</td>
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ATTACHMENT TFC-12C
ATTACHMENT TFC-14C
8.2 Please confirm that Vectren used the same load and sales forecast for its Strategist modeling in this docket that it used in its 2016 IRP? If not, provide any supporting documentation for the load forecast used in this docket.

Response:

Vectren South used the same load forecast in this analysis as in the 2016 IRP.
ATTACHMENT TFC-16
Data Request Supplemental Responses – Set 8

The following supplemental response is being provided subject to the general objections included with the original responses served on July 9, 2018.
CAC-VW 8.1 (Supplemental)

**Information Requested:**

Attachment 4.1 of Vectren’s 2016 IRP at page 14 states, “Load addition from specific customers contributes to relatively strong sales growth in the near-term.” With regards to this statement please answer the following:

a. What specific customers will Vectren add to its system through 2020?

b. What demand and energy sales does Vectren anticipate each of those customers needing? Provide any documents including contracts with those customers that support your answer.

**Information Provided**

**Objections:** Vectren South objects to the request on the grounds and to the extent the request seeks information that is proprietary, confidential and competitively sensitive business information. Vectren receives proprietary future load information from its large customers that it does not disclose given the competitively sensitive nature of the information. While Vectren does not disclose customer identities absent customer consent, Vectren has provided the load data below, marked confidential, without disclosing the identity of each specific customer. Subject to and without waiver of the foregoing objection, Vectren South is providing the following:

**Response:**

a. In the 2016 IRP, Vectren projected approximately □ MWs of additional large load from 6 specific customers through 2020. In the time since filing our IRP, we have updated information from these large customers and now anticipate more than tripling the □ MWs to over □ MWs by 2022. The information below is an update to our 2016 IRP expectations.
   - The largest of these loads (□ MWs) was expected in 2020. While the construction timeline has shifted to 2022, we now expect a □ MW load from this project as this customer has elected to not build on site generation.
   - The second largest load was from an existing customer. We expected □ MWs of additional load by 2018, and this incremental load has already been created.
   - Another customer planned to build two new sites at □ MW a piece (□ MW total). One of these new sites has been constructed and has load of
approximately 1 MW. The other site is still being evaluated and has not been built.

- We projected 1 MWs from another new site. The facility has opened and currently has peak demand of 1 MWs; however, the facility has not yet been opened a full year.
- We projected 1 MWs from another site by 2018. This site is almost complete. The revised projection is approximately 1 MW for this facility.
- Another existing customer planned for an additional 1 MW. While they made upgrades to their facility for this growth, the load did not materialize.
- Since the IRP, another of our largest existing customers now expects to add 1 MWs of load by the end of 2019 (1 MWs in 2018 and another 1 MWs in 2019). Also, two other existing customers have indicated that they will need an additional 1 MWs by the end of 2022.

Apart from these identified additions, Vectren South’s Economic Development department continues to work to attract prospective customers to SW Indiana. Based on current discussions with this prospective customer group, the total potential new demand is approximately 1 MW. Based upon this current project pipeline, Vectren South reasonably anticipates new projects, beyond those listed above, to provide increased demand in the range of 1 MWs to 1 MWs by 2024.

b. See objection above. See answer to part a above regarding new load information. Future load information is derived from confidential conversations and negotiations with individual customers and is treated as confidential and commercially sensitive customer information that is not disclosed.

**Supplemental Response:**

Vectren South only reports on customers and their MWs that represent the firm load Vectren South would serve. All identified customers would be retail customers of Vectren South.
ATTACHMENT TFC-18
CAC-VW 5.15a (Supplemental)

Information Requested:

5.15 Please refer to the Company’s response to IG Data Request 4.7.

   a. Were the capital costs of the pipeline included in the NPV of revenue requirements for the CCGT being proposed in this filing?
      i. If so, please provide these costs and locate where they are incorporated into the NPV of revenue requirements.
      ii. If not, please explain why not.

Information Provided:

   a. Yes, pipeline costs were included in the NPV calculation as part of the Fixed O&M cost associated with the CCGT. The assumed costs were provided as part of the workpapers associated with Matthew Lind’s testimony. The levelized pipeline costs can be found on the “CCGT Costs” tab of the provided workpapers as part of the Firm Gas Reservation cost.

Supplemental Response:

   a. The total estimated capital cost of the pipeline Vectren South anticipates constructing to serve the proposed CCGT is identified in Petitioner’s Exhibit No. 12, Attachment SAH-2 (Confidential). Please see the response to CAC-VW Request 5.2 including CONFIDENTIAL Attachment CAC DR 5.2-5.3-R1.xls for the formulas showing the gas pipeline costs for the 2x1 F-Class CCGT .05 duct fired unit associated with the 2016 IRP. Column C, rows 195-204 separate the Texas Infrastructure, the Texas Gas FT Demand Cost and the Vectren Infrastructure on a cost per dekatherm basis. Note that Vectren South outlined the availability of this information in the response to CAC-VW Request 10.1. Vectren South also provided in response to CAC-VW Request 10.1 Confidential attachment CAC DR 10.1-R1.xlsx which includes the same information for the 2017 Update.
ATTACHMENT TFC-19
4-7. Please refer to Mr. Hoover’s Direct Testimony at page 4. What ratemaking treatment will Vectren seek for recovery of the cost of construction of the lateral transmission pipeline from TGT’s pipeline to the proposed Brown CCGT?

Objections:

Response:

A contractual arrangement will be entered into whereby Vectren South Gas will provide gas to the CCGT. The contractual arrangement will be similar to the contract Vectren North entered into with IPL to provide gas service to the Eagle Valley CCGT. Vectren South Electric will include the contract costs in its FAC for recovery as part of the costs for fuel to serve the CCGT.
ATTACHMENT TFC-20
PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY,
    Petition for Approval of a Generation Resource
    Transaction and Related Relief.

COMMISSION ORDER

January 26, 2018
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APPENDIX A PROCEDURAL HISTORY OF THE CASE.
PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 26th day of January 2018.

CASE NO. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY,
Petition for Approval of a Generation Resource Transaction and Related Relief.

COMMISSION ORDER

The Commission does not grant the Petition as filed; however, the Commission authorizes Monongahela Power Company (Mon Power) to purchase the 1,300 MW Pleasants Power Station (Pleasants) from its affiliate, Allegheny Energy Supply Company (AE Supply), subject to certain significant conditions. The conditions require limitations on the cost to customers based on the market value of Pleasants capacity and energy, limitations on recovery of closing costs if the plant is retired early, limitation on recovery of all closing costs related to the McElroy’s Run Impoundment and Dam, protection against costs related to prior operations of the plant and prior or current operations of the McElroy’s Run Impoundment and Dam, all as more fully described in the Order.

I. INTRODUCTION

On March 7, 2017, Mon Power and The Potomac Edison Company (PE) (together the Companies) filed a joint petition (Petition) for approval of a generation resource transaction. Based on the Companies’ projected load growth, the Companies anticipate a capacity deficit of 1,005 megawatts (MW) by 2020, assuming Mon Power sells its interest in the Bath County facility. This deficit grows to 1,439 MW by 2027 under the Companies’ projections. Mon Power, in conjunction with an outside expert, developed a request for proposals (RFP) to solicit bids to reduce or eliminate this projected deficit. AE Supply, an affiliate of the Companies and owner of Pleasants, was deemed to have submitted the most attractive proposal. AE Supply has offered to sell Mon Power 100 percent ownership of Pleasants for $195 million.

In the Petition, the Companies request a Commission Order approving the proposed transaction and seek rates to be implemented at closing that will result in an

1 On April 3, 2017, the Companies filed notice that a proposed sale of Mon Power’s interest in the Bath County pumped storage project located in Warm Springs, Virginia, would not occur at this time.
immediate net revenue decrease of 1.6 percent. The net rate decrease includes an increase in the base rate component of the Companies’ rates and a more than offsetting decrease in the fuel, purchased power and off-system sales component of the Companies’ rates. The fuel, purchased power and off-system sales component of rates are determined and updated annually in an “Expanded Net Energy Cost” (ENEC) proceeding. Since the ENEC component of the Companies’ rates related to Pleasants will likely change annually, it is not known if the 1.6 percent net rate decrease will continue at that level in the future. The Companies request a temporary transaction surcharge be implemented at the closing of the transaction that would remain in place until new base rates are implemented. In addition to the surcharge, the Companies propose an offsetting ENEC decrease until the next ENEC adjustment expected on January 1, 2019. Petition at 8-9.

II. BACKGROUND AND DISPARATE POSITIONS OF THE PARTIES

The Petition by the Companies for approval to purchase Pleasants (the Transaction) from AE Supply brings into focus the collision of opposing viewpoints voiced in this proceeding by each party and their consternation over alternative viewpoints of other parties.

This proceeding exemplifies the most difficult type of case for the Commission. On the one hand, the outcome has potential adverse consequences to employees at Pleasants and their families and those working in support industries for Pleasants, to local, regional and even state economies, and to activities and the services that the Pleasants’ jobs and taxes allow other political subdivisions to provide. On the other hand, opponents argue that the Transaction is “risky” and that granting the Transaction could have potential adverse rate and regulatory impacts on the customers of the Companies and on the Companies. These conflicting concerns are reflected in the sheer volume of prefiled testimony, the length of hearing transcripts and the magnitude and intensity of the briefs filed by the parties.2

The positions of the parties and their disparate interests, detailed in their testimony and briefs, reflect the diametrically opposed viewpoints of the Petitioners, the West Virginia Coal Association (WVCA), and the West Virginia Business and Industry Council (WVBIC) as contrasted with the positions of the Staff of the Commission (Staff), and the Intervenors who oppose the Transaction, the Consumer Advocate Division (CAD); Longview Power, LLC (Longview); West Virginia Solar United Neighborhoods/Community Power Network and the West Virginia Citizens Action Group (WVSUN/CAG); ESC Harrison County Power, LLC (HCP) and ESC Brooke County Power I, LLC (BCP) (together, HCP/BCP); Sierra Club and the West Virginia

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2 Initial and Reply Briefs totaled nearly 450 pages; prefiled direct and rebuttal testimony totaled over 1,500 pages; the transcripts of the public comment and evidentiary hearing totaled over 1,500 pages, or a grand total of approximately 3,500 pages. By way of comparison, War and Peace, a novel by the Russian author Leo Tolstoy, is about 1,300 pages without end notes.
Energy Users Group (WVEUG) (being sometimes collectively referred to as Intervenors).³

It is not only the parties that disagree on the Transaction. The following sharply worded comments on the need for, or wisdom of, the Transaction reflect divergent positions obtained in public comment hearings conducted in this case by the Commission at Morgantown, Parkersburg and Martinsburg. Although not evidence, these comments provide insight on the generally fractured public reaction to the proposal.

**Environmental**

Comments of Jason Lockard  
SLS Land and Energy Development  
*Morgantown Tr. at 38:* Approving this transfer will allow an exceptional power plant, one that already exceeds environmental standards, to continue operating in West Virginia.

Comments of Doug Renner, mechanic at the Pleasants Power Station  
*Morgantown Tr. at 22:* For its age, Pleasants is probably one of your more environmentally friendly plants that you have in West Virginia.

Comments of George Powell  
*Martinsburg Tr. at 17:* In 2006 the Pleasants plant had CO₂ emissions of 7,992,029 tons, sulfur dioxide emissions of 42,867 tons, nitrous oxide emissions of 9,512 tons and mercury emissions in 2005 of 328 pounds. These are environmental factors that kill 13,000 people a year in this country from power plants. There’s a tremendous human cost to these coal-fired plants and we have to move into a direction that has cleaner energy for our people, for our children, for our grandchildren.

Comments of April Keating  
*Morgantown Tr. at 45:* We have to watch out for our water and our public health. Evidence shows that coal poisons communities. Even if this plant follows all of the regulations, we know that a lot of the regulations are not sufficient.

³ On December 11, 2017, Longview requested leave to withdraw its intervention in and be relieved from further participation in this case. The Commission will grant the request to withdraw. Longview’s election to withdraw was made after testimony was filed, after discovery and after the evidentiary hearing and briefing were completed. While that is unusual, the Commission will grant the request, but the Commission clarifies that, although Longview is no longer a party to the case, it was a party prior to and during the evidentiary hearing, the Longview testimony was submitted and subject to cross examination pursuant to Commission process, and it is evidence that remains a part of the record in this case.
### Business Development

**Comments of Patsy Trecost, former Delegate, WV House of Delegates**

Morgantown Tr. at 12: We’re talking about 240 middle-class families with good job and benefits, but the impact for the community is much larger. Those families go to the grocery store and the car lot. Then, they purchase property, hire a contractor to build a home, and start a life for themselves.

**Comments of Mark Brazaitis**

Deputy Mayor of Morgantown, WV

Morgantown Tr. at 72: We need to attract top companies to our state and many of them have policies in place wherein they want renewable energy. The purchase of the Pleasants plant by Mon Power would be a step away from attracting those companies we desperately need to employ our citizens.

**Comments of Eileen Curfman**

Martinsburg Tr. at 45-46: Customers are going to end up spending more for their electric bills to pay for this mistake. Our money could be spent on projects that bring us clean, efficient energy that create new jobs in expanding industries like solar and wind that would give our young people a future instead of hanging onto the few coal jobs that remain.

### Rate Impact

**Comments of Jody Murphy, Deputy Director, Pleasants Chamber of Commerce, Parkersburg Tr. at 55:** The rate increase being discussed is $69 per year, or $5 per month. I’ll pay that gladly if it keeps 240 people employed. But, that rate increase is not true. Based on an economic study, the residential rate is expected to decrease by $1 per month and the large industrial rate is expected to decrease three percent per month.

**Comments of Bill Ambrose**

Parkersburg Tr. at 88: The Competitive market that Allegheny Energy Supply is in does not provide enough income for the plant to be profitable. The regulated environment of West Virginia would mandate rate increases until such time as the plant became profitable.

**Comments of Chris Craig**

Martinsburg Tr. at 58: FirstEnergy is attempting to transfer an unprofitable, dirty plant from one subsidiary to another so the ratepayers of West Virginia can bail them out of their own unwise investments and outdated technology. This follows a similar transfer of the Harrison power station in 2013 that, according to the institute for energy economics and financial analysis, cost customers more than $160 million.
### Employment

**Comments of Eric Crossman, Principal**
Belmont Elementary School  
Morgantown Tr. at 15: The 240 jobs matter to our community.

**Comments of Jason Lockard**
SLS Land and Energy Development  
Morgantown Tr. at 38: To us, the Pleasants Transaction represents the chance to secure existing, high quality utility jobs that support hundreds, possibly thousands of jobs at companies that service the plant.

**Comments of Kevin Campbell**
Morgantown Tr. at 43: I feel for the people of Pleasants County and would like to see them all keep their jobs. And, they can keep those jobs as long as FirstEnergy retains the plant. But, to dump it on West Virginia ratepayers and expect us to cover the bill so that FirstEnergy stockholders can get dividends is just wrong.

### Need for More Generation Capacity and Energy

**Comments of John Fitzpatrick**
Mayor, City of Elmont, WV  
Parkersburg Tr. at 29: Mon Power has shown that it needs more capacity to meet customer energy needs in years to come. The Pleasants Power Station is clearly the most cost effective purchase available to provide continued access to reliable, affordable, electricity.

**Comments of Guilia Mannaria**
Parkersburg Tr. at 27: This shortfall only occurs if Mon Power/PE sees demand grow by more than two percent each year.

**Comments of Consuelo Newman**
Martinsburg Tr. at 63: Haven’t we had enough of being stuck with corporate refuse? Are we not willing to make sound business decisions without being swayed by corporate and political expediency? Are we to be swayed by every company that dangles the carrot of jobs being given or taken away? We do not need this plant. Mon Power and PE are able to purchase electric power from the PJM grid if needed.

### Value to Stakeholders

**Comments of Mike Wells**
Superintendent of Pleasants County Schools  
Parkersburg Tr. at 49-50: If the plant closes, Pleasants County will lose $5.5 million in taxes to our school system as well as our community and county government. If the plant closes, it would impact school enrollment, which is already decreasing.

**Comments of Erik Engle**
Parkersburg Tr. at 19: This transfer from the Ohio unregulated energy market to the West Virginia regulated energy market is about maintaining profitability for the Executives and Board of FirstEnergy. It is not about what is best for those who receive services from FirstEnergy’s subsidiaries in West Virginia.
The Commission has thoroughly reviewed the entire record, including the testimony, exhibits and briefs of all parties. We cannot specifically mention each and every piece of testimony, exhibit, or argument in our discussion in this Order, but all positions were fully considered. Although not a complete summary of the positions of the Parties, the following excerpts from the briefs and testimony of the parties provide a further glimpse of the chasm that separates the Companies from Staff and the Intervenors in this case (we offer these excerpts on pages six through eleven without comment, other than caveat lector):

A. POSITIONS OF PARTIES URGING APPROVAL OF THE TRANSACTION

1. The Companies:

[T]he Transaction will bring many benefits to the State beyond the positive rate impact. Acquiring Pleasants will help preserve employment at Pleasants and at the mines and services suppliers it relies upon — protecting $400 million in annual economic impact and approximately 600 West Virginia jobs (including 240 at Pleasants alone) at a time when the State's struggling economy is finally showing signs of life. Dr. John Deskins, director of the West Virginia University Bureau of Business and Economic Research ("BBER"), calculated and supported this economic impact figure, and leaders of the West Virginia Coal Association and the West Virginia Business and Industry Council emphatically supported the Transaction for its economic development and job preservation attributes. Another key benefit is Pleasants itself: it is a strong performing asset, and having previously owned it for decades, Mon Power knows it well. Pleasants is well maintained, has a full complement of environmental controls, is even newer than Mon Power's two other baseload facilities, and has benefited from a highly structured maintenance program administered by a dedicated work force.

Yet acquiring Pleasants is not an economic preservation initiative. Instead, the Companies' proposal arises from a legislatively-mandated integrated resource planning [IRP] process, repeated analyses of the Companies' capacity position, PJM market developments such as Capacity Performance, and a structured and independent RFP process. This process, which extends back to 2015 when the West Virginia Legislature's IRP legislation (W. Va. Code § 24-2-19 ("IRP Act")) went into effect, resulted in the identification of Pleasants as the most cost-effective means to address a looming capacity deficiency. It reflects the Companies' efforts to fulfill their obligations as Commission-regulated electric utilities to own capacity resources sufficient to ensure a continuing physical hedge against PJM market risk — obligations that this Commission enunciated in its October 2013 order approving Mon Power's acquisition of the Harrison plant and that the West Virginia Legislature reinforced in the IRP Act.
Companies Initial Brief at 2-3 (footnotes omitted) (briefs of the Parties will be cited by abbreviation by party, whether Initial or Reply and page number, such as “Cos. Init. Br. at 2-3”) (prefiled testimony of the parties will be cited by witness, exhibit and page number, such as “WVCA WBR-D at 4” and transcript references will be cited by Transcript volume and page number, such as “Tr. I at 32”).

2. The WVCA:

Of the nearly 3.5 million tons [of coal] bought and burned annually [at Pleasants], currently approximately 80% is coming from operations in West Virginia. West Virginia coal companies compete with other neighboring states’ coal, such as Ohio coal production located very near to Pleasants. But it is good for West Virginia miners, and related industries and consumers, that Pleasants is primarily buying and burning West Virginia coal, similar to Mon Power plants.

Pleasants Power is critically important to companies producing coal in central and northern West Virginia because it provides certainty for coal suppliers, coal consumers, and prevents the loss of hundreds of coal jobs. It helps the local and state economies, including the troubled West Virginia state budget.

[It] [the Transaction] will preserve a market for nearly 3-4 million tons of coal, as well as the jobs associated with the production, cleaning and transportation of the coal to the Pleasants Plant and the tax revenue that accompanies that economic activity. The ancillary workforce created and supported by coal mining employment is probably about double the number employed by producing the 3-4 million tons of coal needed by Pleasants per year. By moving the Pleasants Plant to the regulated baseload of West Virginia’s utilities, that would bring more stability, certainty, and dependability to the West Virginia coal industry, the local community, and West Virginia users of electricity.

WVCA WBR-D at 4-5.

3. The WVBIC:

First, it is easy to see how Pleasants’ continued operation contributes to preserving employment opportunities for the West Virginia workforce. In the direct testimony of John Deskins filed with the Application in this case, he calculates that a closure or deactivation of Pleasants would result in a loss of nearly $400 million in annual economic impact, with a job loss of
approximately 600 people and $48.2 million in employee compensation. These numbers are staggering, and [WVBIC] believes that among the Commission’s considerations in this case, the preservation of this economic activity should be a very substantial factor. To maximize job development opportunities, [WVBIC] has encouraged state leaders to promote regulatory consistency and to incorporate economic impact assessments in legislative deliberations, investigating the net immediate and long-term effects of legislative proposals. We believe that in the Commission’s consideration of this Application, these factors should also come into play (and judging by past Commission decisions such as Mon Power’s acquisition of an interest in the Harrison power station, we believe the Commission has done so in the past).

The second focus area for [WVBIC] is fiscal responsibility. The Commission is certainly aware that recent headwinds in revenue collections have complicated the efforts of Governor Justice and West Virginia lawmakers to manage the State’s budget. West Virginia can ill afford to overlook current contributors to the state and local tax base in West Virginia. Dr. Deskins calculated that the overall economic activity associated with Pleasants’ continued operation is estimated to be nearly $20 million dollars annually in selected state tax revenue, including $12 million dollars in B & O tax alone.

Third, [WVBIC] and its members have advocated infrastructure improvement as a critical underpinning of West Virginia’s economic future. Financing short and long-term infrastructure improvements and investigating opportunities to encourage such investment is in the interest of every West Virginian. Of course, maintaining a healthy tax base and supporting high-paying employment opportunities is critical to state efforts to invest in the future through infrastructure improvement.

WVBIC CH-D at 3-4.

B. POSITIONS OF PARTIES URGING DISAPPROVAL OF THE TRANSACTION

1. The Staff:

The Commission is faced with an incredibly difficult decision in this case where [the Companies] . . . are seeking prior consent and approval to enter into an agreement to purchase the Pleasants generating plant from Allegheny Energy [Supply] (AES), an unregulated affiliate. Granting approval of this transaction comes with certain risks tied to assumptions about load growth and increasing PJM market prices. Once the transaction has been approved, it is like jumping off a cliff, and those assumptions better be correct or it could be extremely costly for ratepayers and the State as a whole. Denying approval of the transaction, however, comes with its
own set of risks of exposure to the PJM markets and the potential loss of a valuable economic asset. In this brief, Staff provides the Commission a blueprint of the interplay amongst those competing risks and benefits. In the end, Staff concludes the risks associated with purchasing this plant outweigh the potential benefits the transaction could supply and the risks associated with denial are risks worth taking. Staff believes the Companies, their ratepayers and the State as a whole would be better off with the Companies relying on market purchases to fulfill any capacity or energy shortfall that occurs in the near term, with the opportunity to revisit that decision at any time. Staff recommends the Commission conclude approving this transaction is not reasonable and that it will adversely affect the public in the State. Staff recommends the Commission deny approval of the transaction under the standard espoused in West Virginia Code §24-2-12.

Staff Init. Br. at 1-2.

2. The CAD:

The transaction . . . should not be approved [because] the statutory requirements of W. Va. Code §24-2-12 have not been met; the transaction will adversely affect the consuming public because the transaction will burden ratepayers with the cost of maintaining and operating an approximately 37-year-old, uncompetitive coal plant that cannot be sold to a fair market purchaser; the terms and conditions of the transaction are not reasonable because the acquisition of the Pleasants Power plant is not the most cost-efficient way to meet the Companies’ future energy needs; and the transaction does not satisfy the undue influence test because the RFP was biased in favor of Pleasants and the RFP was administered by an “independent” company which has millions of dollars of contracts with FirstEnergy (the Seller) and ran an RFP process designed to achieve a specific result.

For these reasons, it is the position of the [CAD] . . . that Mon Power's acquisition of the Pleasants plant is not in the best interests of Mon Power's customers, which is and should be the primary consideration in this case. Further, the proposed transaction, as currently configured, fails the undue influence test. The transaction should be denied.

CAD Init. Br. at 2-3.

3. Longview:

[T]he transaction as requested is not supported by the facts. Rather, the evidence shows that: 1. the asserted need for Pleasants as a capacity hedge is not supported by the evidence; 2. the process utilized by The
Companies to fill this asserted need was flawed; and 3. even if the Commission believes it is appropriate to consider approval of the requested acquisition, such approval should not be granted until a full engineering analysis has been conducted of the facility to be acquired. Further, the evidence shows that if approved, it is likely that ratepayers will be asked to fully absorb above-market costs for their electricity and ultimately bear the cost of rehabilitating an aging power production facility. Finally, the Commission should refrain from issuing its decision until The Companies' companion FERC proceeding is resolved.

Longview Init. Br. at 2.

4. HCP/BCP:

A key component to any good portfolio approach to achieving rate stability is diversification. As Mon Power discusses in their response to the West Virginia PSC Staff First Request for Information, the predominant fuel of new generation in PJM is natural gas and wind. The decision to add new wind and natural gas capacity is based on these fuel sources having the lowest energy production cost and most favorable economics. A PPA [purchased power agreement] with new state of the art gas plants is a good way for Mon Power to diversify the fuel profile in its generation portfolio. Counter to Mon Power's position, it seems to make little sense from a low cost rate stability perspective to continue to add more coal to Mon Power's generation portfolio. [Citation omitted.]

Further, PPAs can be structured so that Mon Power can benefit from off-system sales. A PPA can be structured so that Mon Power contracts for the ability to dispatch the plant for more energy than they project that they require. This would provide Mon Power the opportunity to sell the power into the PJM market for off-system sales so that they can realize a profit from those sales when they are economic.

HCP/BCP Init. Br. at 7.

5. WVEUG:

This case presents a number of complicated and difficult questions for the . . . [Commission] . . . . The questions posed pertain to the fair value of the Plant, the efficacy of the Request for Proposals (“RFP”) conducted by Mon Power, the net present value (“NPV”) impact that the transaction may have on West Virginia citizens, the competitiveness of the Plant in the PJM Interconnection, LLC (“PJM”) market, and even the potential impact that the Plant's closure might have on the West Virginia economy. These questions ultimately present the issue of the reasonableness of a large, multi-state corporation transferring a generation asset from a wholesale
supply arm, where the asset has been deemed to be too risky, to a fully-regulated distribution utility, where the costs of the Plant are guaranteed to be recovered from a captive ratepayer base.

WVEUG Init. Br. at 1.

6. Sierra Club:

With its proposal to purchase the Pleasants Power Station, Mon Power has managed to unite a diverse assemblage of groups that represent widely differing viewpoints. Environmental groups, renewable energy advocates, large industrial energy users, residential customers, power-plant owners, citizen watch-dogs, and even the Commission's own staff have come together with a single-coherent message: the proposed purchase of the Pleasants plant is bad for West Virginia.

Intervenors in this action are not natural allies. The witnesses they present, however, are remarkably consistent in their testimony regarding flaws in Mon Power's petition. Almost without exception, witnesses for these parties agree on the following: 1) Mon Power has exaggerated (if not artificially manufactured) the need for future capacity; 2) the method Mon Power used to find assets to meet its purported capacity shortfall was extremely limited (if not outright biased); and, most importantly, 3) the asset chosen as a result of this method represents a serious risk to West Virginia ratepayers.

Sierra Club Init. Br. at 1 (italics in original text).

7. WVSUN/CAG:

The Companies' proposal reflects FirstEnergy's so-called exit strategy from the competitive power business. As a merchant plant, the profitability of Pleasants is tied to the revenues it receives from the wholesale markets. AE Supply (and, ultimately, FirstEnergy and its shareholders) bear the market risks associated with the plant. In recent years, market conditions have turned unfavorable for aging coal plants like Pleasants as a result of lower market prices for energy, capacity, natural gas, and renewable resources. Faced with this situation, FirstEnergy now seeks to transfer the plant to its regulated utility subsidiaries, the Companies, whose customers would bear the plant's market risks. If approved, the transaction would entail a complete shift of cost and risk from FirstEnergy shareholders to West Virginia ratepayers. As such, the beneficiaries of this transaction are FirstEnergy and its shareholders, not West Virginia ratepayers.

WVSUN/CAG Init. Br. at 1.
III. JURISDICTION OF THE COMMISSION

The record is replete with arguments about why the Commission should or should not approve the Transaction, but no party seriously contested the right of the Commission, in the first instance, to decide this case under W.Va. Code §24-2-12 and other pertinent provisions of Chapter 24 of the West Virginia Code. The Parties, however, have their own interpretations of what the West Virginia Code mandates or authorizes this Commission to do in this case.

All Parties acknowledged that the provisions of W.Va. Code §24-2-12 apply and were not at all reluctant to advise the Commission (either narrowly or broadly) of the meaning and import of the statutory authority of the Commission with respect to the Transaction:

If the Transaction provides economic and customer benefits, the price is fair, and the factors set forth in §24-2-12 are met, then the seller's motivation should be of no concern and the Commission should approve the Transaction.

Cos. Init. Br. at 54.

Because the proposed transaction would involve Mon Power's acquisition of Pleasants from AE Supply, a FirstEnergy corporate affiliate, the Companies must obtain the Commission's prior consent and approval. W. Va. Code §24-2-12(f). Such approval can only be granted if the Companies establish that 1) "the terms and conditions thereof are reasonable," 2) neither party to the transaction has "an undue advantage over the other," and 3) the transaction does "not adversely affect the public in this state." W. Va. Code §24-2-12 (emphasis added.)

WVSUN/CAG Init. Br. at 3.

Asset transfers, such as the one now sought by FirstEnergy, may be approved only if the party seeking approval of the transfer makes a "proper showing" both (1) "that the terms and conditions thereof are reasonable," and (2) "that neither party is given an undue advantage over the other, and do not adversely affect the public in this state." W. Va. Code § 24-2-12. Such asset transfers are, moreover, "void to the extent that the interests of the public in this state are adversely affected." Id. Accordingly, absent a showing [by] Mon Power that the proposed transfer will not harm the public interest the Petition should be denied.

Sierra Club Init. Br. at 4.

The controlling statute for this proposed affiliated transaction is W. Va. Code §24-2-12. "The commission may grant its consent . . . upon a
proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this state.” The Commission previously described review under this statute as a forward-looking evaluation of functioning of the utility after the transaction is closed. The Commission stated,

The other two tests for evaluating utility agreements under W. Va. Code §24-2-12 require the Commission evaluate and assess whether the terms and conditions of the transaction are reasonable and whether the transaction adversely affects the public in this state. These two conditions are in a sense intertwined, and it is difficult to see how unreasonable terms and conditions would not adversely affect the public in this state. While this test is an attempt to assess the transaction as structured, it also has a “forward-looking” element to it and requires that the Commission evaluate how the new utility will function after the transaction is closed.

Staff Init. Br. at 12.

The CAD takes no prisoners in its attempt to “advise” the Commission of its responsibilities. In its Reply Brief, the CAD emphasizes the gravity of the situation by stating that, if this Transaction is approved, “the harm that redounds to West Virginia captive ratepayers will be a legacy of this Commission.” CAD Rep. Br. at 1.

As indicated above, the polar star guiding the Commission in cases such as the instant one is the protection of ratepayers from the affiliate transactions. The bulk of the evidence shows that the transaction at issue will not benefit ratepayers, but rather burden them with the significant financial support of an uncompetitive, unnecessary, and aging coal plant with operating costs which will only continue to increase. While the companies claim that no other bids come anywhere near the low, winning bid of Pleasants, the harm to ratepayers is caused by the narrow RFP that ensured that Pleasants would have no meaningful competition, and therefore, would win. The evaluation of the bids is just further evidence that the RFP was not objective or resulted [sic] of an arm’s length transaction between the Companies and affiliate seller, AE Supply.

CAD Init. Br. at 6.

The Commission routinely confronts the oft-used terms of W.Va. Code §24-2-12 that require a utility seeking an affiliate transaction such as the one before us to make a “proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State.” These terms are de rigueur statements in petitions in all W.Va. Code §24-2-12 filings and in filings in this case. While these terms are obviously the essence of W.Va. Code §24-2-12, they are not, and cannot be, precisely measured and
must be considered in conjunction with the facts of each transaction and in the light of other provisions of Chapter 24 and decisions of the Courts. It is only in the context of the facts and circumstances of a particular transaction that these terms take on substance and meaning.

Further, our specific charge in applying W.Va. Code §24-2-12 must also be viewed through the lens of W.Va. Code §24-1-1, the statutory provision that describes the Legislative purpose and policy for the existence of the Commission. It is vital to remember that the critical language of W.Va. Code §24-1-1(b), as it relates to this case and to W.Va. Code §24-2-12, is that the Commission, in making its deliberations and decisions, should

- Exercise legislative powers delegated to it by the Legislature; and
- Appraise and balance the interests of current and future ratepayers, the State’s economy and the utilities subject to its jurisdiction.4

In this case, the Commission has had an enormous amount of testimony from a plethora of experts, all suggesting that they know (and are willing to explain to the Commission) exactly the deficiencies and risks5 inherent with the Companies’ case. We will discuss these arguments later in the Order (and the responsive position of the Companies), but in most instances, these experts, with the exception of Staff witness Terry Eads, offered no hard review or specific financial analysis of the Companies’ proposal. They relied, instead, on their backgrounds and special expertise to advise the Commission about what they think should be, or should have been, done and what they perceived as shortcomings or failures of the Transaction of the analysis.

Many of the Companies’ supporting arguments for the acquisition are based on its witnesses’ views of the PJM market for capacity and energy. Many of the Intervenors oppose the Transaction based on their views of the same PJM market, and these views are significantly different from those presented by the Companies. Unfortunately, no one knows what the markets will do.

The Staff agreed:

Crystal balls do not exist. Any one telling this Commission for certain this transaction is a sure winner or a sure loser is fooling themselves. No one really knows what the future holds. The Commission must carefully consider what is evident from the past, be mindful of the

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4 The Legislature creates the Public Service Commission to exercise the legislative powers delegated to it. The Public Service Commission is charged with the responsibility for appraising and balancing the interests of current and future utility service customers, the general interests of the state’s economy and the interests of the utilities subject to its jurisdiction in its deliberations and decisions. W.Va. Code §24-1-1(b).

likely future and be careful not to bind ratepayers to unnecessary long-term risks. Our recent past with these types of transactions tells us we should tread lightly, because even though the Staff analysis shows this transaction is a positive, there are very real risks that could quickly turn the positive into a negative.

Staff Init. Br. at 29.

As we indicated, there are no precise metrics against which we can assess every transaction that comes before the Commission under W.Va. Code §24-2-12 or that we can use to label these transactions as either “pure and holy” or the “devil’s spawn.” The Commission must examine each transaction in the light of the facts, always mindful of our statutory purposes and authorities. We measure, we balance, we assess countervailing interests, and we apply our best judgment. We have found that there is generally no single item or factor that is the “on/off” switch for approval and disapproval of these types of transactions.

We consider the record and the provisions of W.Va. Code §24-2-12 and utilize the balancing of interests required under W.Va. Code §24-1-1(b). Unfortunately, most of the Intervenors seem to have discounted the legislative guidance under W.Va. Code §24-1-1(b), particularly for the benefits provided, and focused only on W.Va. Code §24-2-12. There was little, if any, analysis provided by the Intervenors about the balancing of the interests of current and future ratepayers, the State’s economy and the utilities subject to our jurisdiction.

The Companies, in fact, commented in their Initial Brief specifically on that lack of evidence or discussion about benefits from the Transaction:

Pleasants opponents all but ignore the benefits the Transaction will provide to customers. Holly C. Kauffinan, President of West Virginia Operations, identified these benefits in her direct testimony. First and foremost, the Transaction will cover the Companies’ capacity deficiency through 2027 based on current load forecasts. The acquisition will also provide the physical hedge against volatile market prices that Mr. Ruberto explained, the opportunity for net revenues from generation sales that will serve as direct offsets to ENEC costs, and an enhancement of Mon Power's asset base and overall capitalization that could benefit customers through more favorable financing terms. And, the transaction that provides these benefits will also permit an overall reduction in customer rates, as the projected ENEC rate reduction will more than offset the impact of the Temporary Surcharge. Kauffman direct testimony (Co. Ex. HCK-D) at 9-10.
2. The Transaction will benefit the State of West Virginia.

The Transaction’s benefits to the State are manifest. Approving the Transaction and maintaining plant operations will preserve hundreds of jobs (at the plant, in mining, and in other supporting businesses) and positively impact the state’s economy. Dr. Deskins and witnesses for the West Virginia Business & Industry Council and the West Virginia Coal Association have attested to this. For example, at the hearing, Dr. Deskins highlighted how a Pleasants closure would affect West Virginia’s employment levels:

A. Just for scale, during the suffering that our state has seen from 2012 through the middle part of last year, we lost about 26,000 jobs.

Q. That’s statewide?

A. Statewide. But in the recovery that we’ve seen over the last year or so, we’ve gained back 4,500 jobs. So if we were to lose 600 jobs, you just think about how much it would reduce that 4,500 improvement that we’ve seen over the last year.

Tr. I at 282. Chris Hamilton, Chairman of the West Virginia Business & Industry Council, contended that “jobs, development, infrastructure improvement, and fiscal responsibility – are all advanced through Pleasants’ continued operation.” Hamilton direct testimony (WVBIC Ex. CH-D) at 1. Bill Raney, President of the West Virginia Coal Association, stated [that the] continued operation of Pleasants “provides certainty for coal suppliers, coal consumers, and prevents the loss of hundreds of coal jobs.” Raney direct testimony (WVCA Ex. WBR-D) at 4. Conversely, at hearing Mr. Raney expressed his concern if the Transaction is not approved:

[M]y fear is that it would be, that it’s likely to close. And, you know, the implication of that is the – or the [multiplier] effect of that is you take 500, 600 coal miners and you’re putting them out of work. That’s the real interest of us being involved in this case.

Tr. V at 14. It is no surprise, then, that the Transaction enjoys broad support among those for whom jobs, tax base, and economic development are important considerations.

Conversely, Transaction opponents ask the Commission to determine that if no one can prove Pleasants will close, then the benefits of its continued operations are illusory. Certainly the shut-down of Hatfield Power Station, numerous West Virginia power stations, and power stations
across the region are real, not illusory. Moreover, the loss of baseload generation has caused great concern now at PJM and the Federal government. The U.S. Department of Energy’s proposal to provide incentives to baseload coal and nuclear plants to protect the resiliency of the power grid is an example of this concern. Tr. V (Hamilton) at 19.

Gambling on the future of Pleasants does not trouble intervenors such as WVSUN-CAG and Sierra Club, whose objective is to shutter Pleasants. Mr. Comings, the Sierra Club witness, acknowledged Sierra Club’s “Beyond Coal” campaign, which keeps a running total of the coal plants it claims to have help kill and a countdown of the remaining plants it hopes to defeat. His client has “targets for coal retirement[s],” he said. Tr. III (Comings) at 170-71. In fact, perhaps the strongest indication that the future of Pleasants is uncertain is Sierra Club’s extensive participation in this case. Sierra Club did not intervene because it is concerned with the Companies’ customers, the stability of their rates, or the State’s economic well-being. Sierra Club’s narrow-minded fixation is on stopping anything it believes might lead to the continued operation of a coal plant. Simply put, if closing Pleasants were not a potential outcome, Sierra Club would not be in this case.

Cos. Init. Br. at 41-43.

We have found one of the curious anomalies of major regulatory proceedings before this Commission to be the apparent reluctance of parties to afford weight to “public policy considerations” for a Transaction, but which they readily recognize for ratemaking considerations. The Commission has experienced no similar reluctance in small transactions where the Commission gives significant credence and import to the loss or gain of employees or other factors such as the location or opening of another office in West Virginia that might impact a community or cause an increase or retention of local employees. Part of that reluctance in larger transactions may spring from the difficulty of weighing or balancing those local or regional externalities against rate or financial impacts that may fall on a large regional or statewide customer base, but we have viewed externalities that implicate the statutory purpose set forth in W.Va. Code §24-1-1(b) as a valid concern and factors in considering transactions. These factors, which are “external” from the interests of current ratepayers, are in the interest of future ratepayers, the interest of the State’s economy and the interests of the utility, which were clearly considered of import to the Legislature when enacting W.Va. Code §24-1-1(b).7

6 These public considerations are sometimes referred to as “externalities,” a shorthand expression to describe an array of non-ratemaking implications about employment and jobs, enhancing and preserving the attractiveness of the State as a place for industry to do business, attracting new offices, creating productive capacity, tax base, and support to local and regional charities and providing governmental financial support and a host of other outcomes, other than rate impact, that can occur because of Commission proceedings.

7 The Commission when considering the outcome of cases has considered these types of external factors. Eastern Systems Corp. and Monongahela Power Co., Case No. 00-0067-G-PC (Comm’n Order 5/11/00);
In this instance, the immediate local, regional or (arguably) statewide externalities to the Transaction are significant. We are not contending that those externalities, taken alone, tip the balance in favor of approving the Transaction, but we do believe that they are genuine, germane and real factors that the Commission can and should consider, weigh and balance in making its decision to approve, conditionally approve, or deny this, and other, petitions.

We discussed at length the nature of the Commission’s authority in the Commission case Century Aluminum, Case No. 12-0613-E-PC (Order of October 4, 2012) (“hereinafter Century Aluminum Order at __”), http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=354671, involving a request to implement a special rate for energy-intensive industrial customers under the provisions of the Energy Intensive Industrial Consumer Revitalization Tax Credit Act (W.Va. Code §11-13CC-1); and an amendment to W.Va. Code §24-2-1j. As we stated in Century Aluminum:

After enactment of the 1913 legislation, various cases were brought before the Court challenging the authority of the Commission to fix rates. Among other things, the Court held that the Legislature’s delegation of authority to the Commission was constitutional; that the rate orders of the Commission were akin to an act of the Legislature; that the Legislature intended the Commission to be the body in State government that would determine the public interest from the perspective of the regulated utilities, current and future ratepayers and the State; and that, because of the legislative nature of the Commission orders, the Court’s review (which was not reviewed upon appeal, but rather reviewed by original process under W.Va. Code §24-5-1) was limited so as not to give the Court the power to substitute its judgment for that of the Commission. United Fuel Gas Co. v. Public Serv. Comm’n, 73 W.Va. 571, 80 S.E. 931 (1914). The Court, in United Fuel, recognized that the Legislature was directing the Commission to assume duties that were important, technical and complex.\(^8\)

\(^8\) The West Virginia Supreme Court observed (and the Commission is partial to this observation):

The salaries which the statute attaches to the office of the Commissioners, and the nature of the subjects to be dealt with by them, all imply that only persons of the requisite qualifications should be appointed, and that after appointment they should by investigation and study become further qualified by learning and experience, indeed should become experts upon all subjects and businesses coming within their jurisdiction.

United Fuel Gas Co. v. Public Serv. Comm’n at 581-582.
In furtherance of the Commission’s legislative responsibilities, our analysis and rulings on the Transaction are not limited to examining whether the Transaction makes only economic or rate and ratemaking sense. We can also, within the authority granted us by the West Virginia Code, examine and balance externalities to help us assess the impact and merit of transactions that come before us as long as our decisions examine and balance fairness and reasonableness of the transaction and balance the interests of current and future utility service customers, the general interests of the State’s economy and the interests of the utilities as a part of our examination of the affiliated contract to determine whether “the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State.” We believe that these externalities are valid factors for consideration in determining whether to approve the Transaction.

The Legislature has taken significant steps to structure the Commission to safeguard the “public interest” for the ratepayers, the regulated utilities, and the State’s economy, recognizing that those public interests are entitled to the safeguards of due process and equal protection and the protection from undue or unreasonable discrimination.

As we indicated in Century Aluminum:

The West Virginia Supreme Court quoted with approval a statement of the United States Supreme Court holding that:

[T]he rate-making power necessarily implies a range of legislative discretion; and, so long as the legislative action is within its proper sphere, the courts are not entitled to interpose and upon their own investigation of traffic conditions and transportation problems to substitute their judgment with respect to the reasonableness of rates for that of the legislature or of the railroad commission exercising its delegated power.


Century Aluminum Order at 12.

We believe the W.Va. Code §24-2-12 provision about “undue advantage” is frequently misunderstood. While we are cautious in assessing the reasonableness and fairness of transactions, we believe the provision that “neither party has been given an undue advantage over the other” involves an after the fact assessment of the transaction terms and conditions and is not meant to bar or make all affiliated transactions unfair or suspect. Several parties have suggested that this means that affiliated transactions are almost unfair per se and that there is a much higher test on fairness or reasonableness because a transaction involves an affiliate. We disagree. See discussion supra at 47-49.
IV. PROCEDURAL HISTORY

The Procedural History, including parties, filing dates, list of witnesses and notices made in this case, is set forth in Appendix A attached to and incorporated into this Order.

V. ISSUES PRESENTED BY THE PARTIES

In this section, the Commission will outline most of the significant issues identified by the Parties in the record.

A. Is There a Need for Capacity?

1. The Companies Argue that the Commission and the IRP Act Require Additional Capacity.

   The Companies argue that they need additional capacity. They also urge that language in the Harrison Order\(^\text{10}\) and the legislative requirement for an IRP require the Companies to ensure the ownership of capacity in excess of load (Cos. Init. Br. at 6-8):

   Even though the Harrison acquisition would give Mon Power a ratio of installed capacity to load well over 100%, the Commission recognized that “[t]he addition of baseload units results in a jump in reserve capacity that is then gradually reduced over time as internal load grows.”

   Cos. Init. Br. at 7 (citing Harrison Order at 24).

   The Companies also note that the Commission in Harrison found that customers receive “the benefit of off-system sales that are made from the reserve capacity.” Id. (citing Harrison Order at 24).

   Staff argues that the Companies do not need 1,300 MW of capacity within the next ten years, but acknowledges that the Companies may need some level of capacity in the short term. Staff Init. Br. at 5. Although Staff did not project specific capacity needs for the Companies, WVSUN/CAG projected that the Companies’ peak demand will not meaningfully exceed its currently-owned capacity until 2021 with the projected deficit climbing to only 267 MW by 2025. WVSUN/CAG Init. Br. at 16; WVSUN/CAG Cross Ex. 2 at 89.

2. What is the Projected Load Growth in West Virginia Territory?

   According to the Companies, projections of vigorous growth in the service territories have caused their projected capacity shortfall to appear sooner than previously

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predicted. Bradley D. Eberts, Manager of Load Forecasting at FirstEnergy Service Company, testified about the Companies’ load peak demand forecasts, incorporating expected rates of economic growth from BBER’s 2017 West Virginia Economic Outlook report and adjustments for projected industrial energy usage based on information developed by the Companies’ customer support representatives. Cos. Ex. BDE-D at 5-6 and 8-10. Dr. Deskins, who used the BBER information attributed to the counties within the Companies’ service territories, found that between 2016 and 2031, economic progress would be more optimistic for most counties served by the Companies than for West Virginia as a whole, stating:

The Companies’ service territories will be buoyed by segments of the state’s economy that should see sustained growth during the next 15 years. These include the natural gas industry, as continued development of the Marcellus and Utica Shale create growth opportunities throughout the state, particularly in the Northern Panhandle and portions of the North Central Region. The North Central Region’s economy should also experience relatively steady growth over the course of the outlook period thanks to its relatively diverse economic base, pool of skilled and educated labor as well as infrastructure improvements that open access to commercial and industrial development. The state’s Eastern Panhandle Region is also expected to realize a stronger pace of growth compared to the state average as it is connected to the highly-developed Greater Washington D.C. area’s economy, and also enjoys healthy population growth thanks to net in-migration of people from higher cost-of-living areas in neighboring Maryland and Virginia.

Cos. Ex. JD-D at 7.

Staff counters that the Companies are projecting an unprecedented level of load growth within the next ten years during a time of flat load growth across the PJM footprint. Staff Init. Br. at 5. Staff noted that Companies’ witness Eberts testified that the Companies’ winter peak is expected to increase from 2,867 MW in the 2016/17 delivery year (DY)11 to 3,752 MW by the 2027/28 DY – a thirty-three percent increase in winter peak. Furthermore, the Companies project winter peak to grow from the same 2,867 MW in the 2016/17 DY to 3,421 MW in the 2020/21 DY – nearly 600 MW in only four years. Staff Init. Br. at 6; Cos. Ex. BDE-D at 3. By comparison, in the Harrison case (Case No. 12-1571-E-PC), the Companies predicted summer peak to grow from 2,578 MW in 2012 to 3,025 MW in 2026, a more modest growth of 447 MW over fourteen years. The analysis switches from winter peak to summer peak between the present case and the Harrison case because the Companies used summer peak in the Harrison case.

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11 PJM uses a split calendar year planning year, which is referred to as a Delivery Year (DY). PJM defines the DY as the twelve-month period from June 1 to May 30 of the following year.
Staff argued that the Companies are projecting this load growth will be driven mainly by the shale activities in northern and central West Virginia without losing any load to the natural gas industry or other factors. Staff Init. Br. at 6. Staff argued that it is not credible that the natural gas will continue to expand without any impact on the Companies’ operations or that the natural gas expansion will not impact the coal industry and its ancillary businesses. Id. The Companies’ NPV analysis is predicated on rising natural gas prices. Staff argued that the Companies cannot have it both ways – either the load will increase because of expansion of natural gas facilities and downward pressure on natural gas prices will continue or natural gas expansion will slow and the load will not materialize. Staff Init. Br. at 6.

3. Is there a Capacity Shortfall?

Mon Power issued its IRP in December 2015, but states that it continued to evaluate its generation portfolio, with a new emphasis on the recently-implemented PJM “Capacity Performance” (CP) market design approved by FERC in June 2015. Cos. Init. Br. at 10. CP rules provide that generator resources with capacity obligation that fail to perform when needed to maintain reliability during peak demand periods are subject to significant penalties. Cos. Ex. JAR-D at 5, citing PJM Interconnection, LLC, 151 FERC ¶ 61,208 (2015), order on reh’g, 155 FERC ¶ 61,157 (2016). Mon Power determined that the CP market would have a significant effect on the value of its direct interest in the Bath County pump storage project located in Warm Springs, Virginia, possibly eliminating it from being counted as replacement capacity for Mon Power generation resources in the APS Zone. Cos. Init. Br. at 10. This development caused the Companies to update their load and capacity forecasts, resulting in a projected capacity shortfall of approximately 785 MW by DY 2020-21 and 1,219 MW by DY 2027-28. Id. at 11.

The Companies argue that capacity resource planning based on PJM summer peaks, rather than the winter peaks actually used by the Companies, would substantially underestimate the Companies’ actual peak demands and would fail to account for the important differences between PJM’s broad APS Zone forecast and the service territry-specific economic growth, distributed solar generation penetration, and weather factors considered by Mr. Eberts. Cos. Init. Br. at 11; Cos. Ex. BDE-R at 2-9. The Companies are winter-peaking utilities and argue that the IRP Act requires them to focus on their actual peaks. JAR-R at 5. The Companies argue that the difference between their winter and summer peaks is a relatively insignificant amount in terms of long-term resource planning, but insist that the capacity projections based on the Companies’ actual peaks best reflect the Companies’ appropriate capacity levels and reserve margins and best address their customers’ specific needs. Cos. Init. Br. at 12.

Staff, on the other hand, argues that using winter peak loads instead of the traditional summer peak loads to justify the need for additional capacity makes the proposed transfer of Pleasants appear more favorable. Staff Init. Br. at 7. Staff notes that PJM is a summer-peaking entity, and if a capacity shortfall occurs in the winter, PJM will have plenty of cheap and available capacity for the Companies to acquire. Id. Staff
argues that fulfilling a winter capacity shortfall through the PJM markets makes more sense than acquiring a physical asset to satisfy a winter capacity shortfall. Id. Staff also questions whether adding a reserve margin to the winter peak is appropriate just because PJM requires enough capacity to meet its summer peak plus a reserve margin of approximately sixteen percent. A sixteen percent reserve margin in the summer means a much larger margin in the winter. At no time during the forecast period does the Companies’ summer peak plus reserve margin drop below its winter peak. Staff Init. Br. at 7; also WVSUN/CAG Cr. Ex. 1. Staff recommends that the Commission determine load growth and capacity needs for the Companies based on the Companies’ summer peak with the appropriate reserve margin which trends 250-350 MW lower than the winter peaks. Id. Staff also argues that the Companies’ ratepayers will become unwilling market players, forced into unnecessary risks by decisions outside of their control. For this reason, Staff argues that the proposed transfer violates W. Va. Code §24-2-12. Staff Init. Br. at 8.

CAD also argued that the Companies inflated their projected capacity obligation by calculating their capacity needs based on winter peak load within the Companies’ service territory. Like Staff, CAD contended that this is contrary to PJM rules which base future capacity needs on summer peak load. CAD noted that in a September 6, 2016 filing in Case No. 16-1074-E-P, the Companies asserted that they had a capacity surplus according to the most recent Base Residual Auction (BRA) conducted for the 2019/2020 delivery year. CAD Init. Br. at 7. CAD witness Ms. Medine testified that “the Pleasants capacity exceeded the current deficit even with the sale of Bath County. Without this sale, it greatly exceeds the current deficit.” CAD Init. Br. at 8; CAD Ex. ESM-D at 57. Mr. Gabel, the witness for Longview, concurred with Ms. Medine. Longview Ex. SG-D at 7.

CAD noted that FirstEnergy acknowledged in its most recent Form 10-K Report and in its July 2017 Earnings Call that over the past several years there has been a decrease in demand and excess generation supply in the PJM region that has resulted in an extended period of low power and capacity prices. CAD Init. Br. at 8-9 (citing FirstEnergy 10-K FY 2016 at 4 (2/21/17) available at https://seekingalpha.com/filings/pdf/11872287.pdf; FirstEnergy Q2 2017 Results – Earnings Call Transcript (7/23/17) available at https://seekingalpha.com/article/4092032-firstenergy-fe-q2-2017-results-earnings-call-transcript).

Longview also argued that the Companies do not need additional capacity. The Companies failed to follow the PJM formula which uses a summer peak analysis that accounts for winter needs within the region. Longview Ex. SG-D at 20. Additionally, Longview argued that the Companies based their projection of capacity need on anticipated economic growth in West Virginia that is not supported by the record.

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12 PJM conducts an annual Base Residual Auction to procure capacity resource commitments needed to satisfy the PJM region’s projected capacity needs for the Delivery Year, three years in the future from the auction date.
Longview Init. Br. at 3. Longview noted that the Companies failed to take into account the fact that PJM already considers load growth in the service area into their projections; therefore, the Companies essentially double-counted the localized, anticipated capacity need. Id.; Longview Ex. SG-D at 21-22. Longview also argued that the load forecast and fleet capacity as calculated by the Companies artificially exaggerates the difference between the forecasted capacity need and the Companies’ generation capacity. Longview Ex. SG-D at 20.

B. Pleasants as a Hedge

The Companies contend that it is important for them to have a physical hedge against market volatility and cite to the Harrison Order and the IRP statute for support. Cos. Init. Br. at 2-3, 12-13.

The value of a physical hedge is that Mon Power has control over these high-load, high-price situations, rather than being at the mercy of the market when they occur. If Mon Power needs to purchase energy from the market during one of these situations to provide for the Companies’ customers’ needs, it has the benefit of also being able to sell into the market at the same high prices. This allows the revenues generated at the high prices to counter the high costs of supplying customer needs during the same periods. Without the physical hedge that capacity ownership provides, Mon Power must buy the high-priced energy to serve customer load but does not have corresponding revenues from its own market sales during the same periods. This leaves customers exposed – they end up paying for the difference in ENEC rates.

Cos. Ex. JAR-R at 12-13. The Companies note that WVEUG witness Stephen Baron also emphasized the nature and benefits of this hedge, differentiating the price protection the hedge provides from PJM’s requirements that are intended to insure system reliability:

The Pleasants acquisition is really a physical hedge against the PJM market purchases that serve the Companies’ customers. It is PJM’s responsibility to insure adequate reliability in the APS zone in which the Companies operate; however, PJM does not provide any price protection to the Companies’ customers that would mitigate the impact of higher PJM market capacity and energy prices. This is the role of Mon Power’s owned and controlled capacity resources. By selling the output of these resources into the PJM capacity and energy market, and crediting the revenues in the ENEC, the Companies’ owned capacity acts as a physical hedge to market purchases.
C. The RFP Process

The Companies were under no Commission or statutory requirement to issue an RFP and the failure to do so is not a violation of our rules. As the Commission has indicated in the past, the RFP process is not required, and it does not substitute for an in-depth Commission review of affiliated transactions under W.Va. Code §24-2-12. We developed a complete record and subjected witnesses to cross-examination by the Parties and questions from the Commission. There was considerable comment and criticism of the Companies’ use of the RFP process. The Companies argued that the RFP process was independent, unbiased and produced a fair result. The Companies suggested that several of the parties in this case have recommended an RFP process. In the Harrison case, Staff, CAD, WVCAG, Sierra Club and WVEUG all asserted that an RFP should have been used to identify the lowest cost resources to meet a capacity shortfall and to ascertain the fair market price of those resources. Cos. Init. Br. at 14. The Companies noted that in certain discovery responses some parties agreed that RFPs in general are valuable, but these same parties now argue that this RFP did not provide benefits.

D. Selecting Charles River Associates (CRA)

There was also considerable criticism by some parties about the selection of Charles River Associates (CRA). Some Intervenors argued that CRA should not have been selected for the critical assignment of developing and managing a fair and balanced bidding process.

Staff and CAD suggested that the hiring of CRA was suspect because CRA had millions of dollars in ongoing contracts with so many FirstEnergy affiliates that Mr. Lee could not identify them all. Tr. II at 98-99.

The Companies supported the selection of CRA. Mon Power pointed out that it initiated the RFP process by interviewing RFP provider candidates and selecting CRA to manage an independent RFP process. Cos. Init. Br. at 16. Mr. Ruberto and others

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13 MP/PE had no legal obligation to issue an RFP prior to filing this case and the failure to issue an RFP does not constitute a violation of W.Va. Code §24-2-12. Harrison Order at 28.

14 The Companies noted that WVSUN/CAG, Sierra Club, and CAD generally supported an RFP as a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both; helpful in demonstrating what options are available in the market; allowing a regulator to determine the costs and benefits of available options; helpful in establishing the reasonableness of a transaction; helpful in establishing the market value of the asset to be acquired; and helpful to assure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer. Cos. Init. Br. at 15; citing JAR-R, Ex. JAR-I at WVSUN/CAG discovery responses (DR) 6 and 7, Sierra Club DR 20, and CAD DR 18.
personally interviewed four potential RFP administrators to identify and select the most experienced, capable company to do the job. Id., citing Tr. I at 42-43. Mr. Ruberto recommended to Mon Power that it retain CRA and remained the principal contact with CRA throughout the RFP process. Tr. I at 47-49.

The Companies argued that CRA is well qualified and experienced in conducting IRPs. They explained that CRA had conducted dozens of competitive procurements on behalf of electric utilities and hundreds for clients across all industries. Cos. Ex. RJL-D at 2. Mon Power further explained that it had retained CRA and directed it to design an RFP that met all standards for fairness and insured no preference to any party. Cos. Ex. JAR-R at 15. The Companies contend that, other than expressing a preference for physical assets in the APS Zone because of PJM’s rules on substituting units during critical hours, they entrusted CRA to design the RFP, identify potential bidders, administer the process, and evaluate the bids. The Companies provided testimony that CRA contacted twenty-eight potential sellers of capacity and demand response. CRA undertook bidder pre-qualifications screening and bidder “help line” administration and responded to bidder questions, with Mon Power input as necessary. RJL-D at 6-7. The Companies argued that Mr. Ruberto and CRA ensured that the RFP satisfied the FERC Ameren principles designed to determine whether an RFP process is fair and devoid of undue advantage or preference to affiliates. Cos. Init. Br. at 17. FERC has now ruled that Mon Power did not meet all of the Ameren principles in its FERC proceeding. Monongahela Power Co. and Allegheny Energy Supply Co., 162 FERC ¶ 61,015 (2018) at P 81 (issued January 12, 2018).

Staff, CAD and others asserted that CRA did not act as an independent third party, but rather as a clearing house for bids and a calculator of the cost of each bid to customers on a NPV basis. Staff asserted that the pertinent design criteria were decided by the Companies, not CRA. Staff Init. Br. at 11. CAD argued that the RFP gave undue advantage to AE Supply because Mon Power worked closely with CRA to establish the timing and scope of the RFP and the methodology that would be used to evaluate the bids. CAD Ex. ESM-D at 4.

Staff argued that the restrictive parameters placed on the RFP made it impossible for CRA to create a level playing field that did not favor the Companies’ affiliates. Staff noted that Mr. Ruberto testified that he required CRA to seek bids from entities that could supply 1,300 MW of power from a physical generating asset in the APS Zone (Staff Init. Br. at 12; citing Tr. I at 45-46) and that CRA had no input into these limitations (id., citing Tr. II at 38-41, 43, 53-54, 56-60, and 63 (Lee testimony)). Additionally, Staff argued that Mr. Ruberto testified that he had ongoing discussions with CRA regarding the details of the RFP. Id., citing Tr. I at 55. Staff argued that those RFP conditions accomplished two goals: (i) ruling out the acquisition of power from any source other than a physical asset and (ii) essentially describing the Pleasants plant exactly. Staff Init. Br. at 12.

CAD argued that CRA also favored Pleasants by failing to consider the significant age difference in Pleasants and Longview. Pleasants is approximately thirty years older
than Longview and will have to be replaced sooner. CAD Init. Br. at 22. CAD also argued that the Companies failed to show a sound reason for limiting bids to the APS Zone. CAD Init. Br. at 23.

E. Preferences for Physical Generation Assets

In addition to the arguments that the criteria and conditions placed on the capacity proposal tilted the playing field in favor of the affiliated Pleasants plant, other criticisms were levied against the Mon Power preference for physical assets that it could purchase. HCP and BCP argued that Mon Power’s refusal to consider a Power Purchase Agreement (PPA) was short-sighted because HCP and BCP could provide Mon Power with a PPA for capacity and/or energy that can be structured to be much less costly and with far lower risks to the Mon Power ratepayers than the purchase of Pleasants. HCP and BCP contend that with a PPA, Mon Power could manage power price volatility and offered their argument that structuring a PPA for capacity separate from a PPA for energy could be useful for the Companies because their capacity shortfall is far greater than their projected energy shortfall. They also argued that Mon Power would not have any up-front capital costs, maintenance costs or decommissioning costs. HCP/BCP Br. at 5 and 6.

In response to the criticism of requiring physical generation, the Companies argued that the preference for a physical asset was based in part on the 2015 IRP, in which Mon Power concluded that “[t]he lowest [cost] evaluated option to address Mon Power’s needs appears to be the purchase of existing generating facilities. This option would require an agreement between Mon Power and any seller of the price that allows this option to remain the best solution.” Cos. Init. Br. at 17 (citing Monongahela Power Co. and The Potomac Edison Co., Case No. 15-2002-E-P, IRP filed 12/30/15 at 57).

The Companies stated on the record that PJM’s new CP market design includes significant penalties to encourage performance by capacity resources during critical reliability events:

The failure to deliver energy during such events – referred to as “Performance Assessment Hours” – can result in penalties, and those could amount to more than a resource’s yearly capacity revenue. Moreover, there are no meaningful exceptions that would excuse a capacity resource from such penalties. Therefore, it is critical that Mon Power have the operational flexibility to dispatch its capacity resources to meet these stringent Capacity Performance requirements. Accordingly, Mon Power decided to acquire fully-dispatchable capacity resources with reliable, year-round fuel supply availability and/or other operational characteristics to enhance reliability and availability.

Cos. Ex. JAR-D at 8-9.
The Companies argued that they had valid reasons to acquire a physical asset rather than power promised through a PPA. The 2015 IRP concluded that existing generation facilities likely would be the best option. Cos. Init. Br. at 18. Mr. Ruberto testified that owning an asset provides greater control over operations, maintenance, fuel procurement and capacity improvements, and a plant owner can modify facility operations to better suit market conditions and derive greater economic value from a facility – especially in the context of the operation of a fleet of assets within the same zone. Cos. Ex. JAR-D at 11; Tr. I at 68-73.

The Companies also argued that economies of scale arising from a larger fleet can reasonably be expected to help Pleasants, Fort Martin and Harrison operate more cost-effectively. Cos. Init. Br. at 18; Cos. Ex. JAR-D at 17, Tr. I at 68-75 (discussing the preference of owning a physical asset rather than purchasing power under a PPA). If contractual provisions are added to a PPA to address Mon Power’s operational and control concerns, those provisions will affect Mon Power’s cost and obligations. Cos. Ex. JAR-R at 17; Tr. I at 75. Mr. Ruberto testified that PPAs involve nonperformance, financial and bankruptcy risks if the terms of the PPA become unfavorable to the generator and the generator is unwilling or unable to continue operations. Cos. Ex. JAR-R at 18.

The Companies maintain that PJM rules effectively “allow a capacity resource to ‘net’ performance across multiple units, provided those units are located in the same PJM load zone.” Cos. Ex. JAR-D at 10, citing PJM Manual 18, Section 8.9. Resource performance during Performance Assessment Hours effectively can be netted from a performance risk management standpoint because PJM rules permit retroactive replacement of one resource’s under-performance with another resource’s over-performance if the resources are subject to the same Performance Assessment Hour. Cos. Ex. JAR-R at 18-19. Additionally, resources that over-perform during Performance Assessment Hours (PAH) have the opportunity to earn bonus payments. Cos. Ex. JAR-R at 19. For example, if a PAH occurs in the APS Zone, the risk that one unit may under-perform can be hedged by having other units with the ability to over-perform and collect bonus payments. The Companies acknowledged that although these bonuses were unlikely to offset penalties on a one-on-one basis, they are still a valuable hedge against CP penalty risk.

F. ABB Pricing and NPV Analyses

The Companies noted that the CRA evaluation and calculation of the costs and NPV of total costs of the various bids utilized forecast inputs from an established and independent provider, ABB. Companies testified that “[i]n the Spring and Fall of each year, ABB develops electricity, fuel, and environmental price forecasts for its North American Power Reference Case covering 73 market areas.” Cos. Ex. TS-D at 3.

The Companies argued that CRA administered the RFP fairly and provided no undue advantage to any RFP participant. The Companies argued that the one-week
prequalification period, beginning December 16, 2016, and ending December 23, 2016, was sufficient in light of the direct notification that CRA provided to resource owners and the perfunctory information the prequalification required. Cos. Init. Br. at 21. The Companies also noted that one entity that missed the prequalification date was still permitted to submit a bid. Tr. I at 234. Mr. Lee testified for the Companies that the seven-week period for RFP responses was consistent with capacity resource RFPs for other utilities and no bidders expressed any concerns about the timeline being a barrier to participation. Cos. Ex. RJL-R at 3-4; Tr. II at 51. Criticism of the scoring process was unpersuasive, according to the Companies, because the information provided to potential bidders about the valuation and scoring was consistent with industry practice in competitive solicitations. Cos. Init. Br. at 22. Sophisticated parties contemplating participation in an RFP of this type generally know that there are many different factors to be weighed in evaluating dissimilar assets. Id.; Cos. Ex. RJL-D, attachment 1 at section 4.

The ABB projections used by CRA and calculation of NPV were disputed by other parties. Longview Power witness Steven Gabel argued that the Companies greatly overstated their ability to sell extra capacity into the wholesale market at a profit. He noted that the BRA for FY 2020/2021 was held in May 2017 and capacity prices cleared at just $76.53 per MW-day compared to ABB’s forecast of $148.92 per MW-day. Longview Ex. SG-D at 7-8; Cos. Init. Br. at 27.

CAD argued that CRA had available, and should have used, a more recent ABB price forecast. CAD Init. Br. at 24. CAD also stated its belief that in addition to the ABB capacity price forecast conflicting with market reality, it conflicted with views publicly expressed by FirstEnergy. CAD contended that during an earnings call regarding the results of the third quarter of 2016, a FirstEnergy representative stated that PJM’s competitive market conditions continued to deteriorate, punctuated by weak power prices, insufficient results from recent capacity auctions and anemic demand forecasts and that these conditions led the company to announce that it would expeditiously move away from Competitive markets – a plan which included the proposed sale of Pleasants to Mon Power. CAD Init. Br. at 11, citing FirstEnergy Third Quarter Earnings Call transcript, November 4, 2016.

HCP and BCP argued that new state-of-the-art natural gas plants have much greater operational flexibility and can run efficiently as baseload plants or quickly change energy production levels to respond to changing load conditions on the grid if called to do so. HCP/BCP Br. at 4. HCP/BCP witness Andrew Dorn stated that when asked to fluctuate output based on grid conditions, coal plants experience more wear and tear than the new state-of-the-art gas plants that were designed with operation flexibility in mind. This, they contend, reduces the useful life of the equipment and significantly increases maintenance costs. HCP/BCP Ex. AWD-D at 4.
G. Cost of Pleasants Relative to Other Proposals Received and NPV Analysis of Pleasants Relative to the PJM Market

Mr. Lee testified for the Companies’ that CRA’s dispatch model was appropriate. Multiple dispatch models are available for industry use and one is not necessarily superior to another. Cos. Ex. RJL-R at 17. CRA’s dispatch model was tailored to the purpose of its analysis – to compare the relative economics of each of the plants bid into the RFP under consistent market conditions. Id. at 18. The Companies’ witness testified that integrated market modeling, as described by Ms. Medine, CAD’s witness, would have added significant cost, but little incremental benefit.

When we developed the RFP process, we did not know how many bids we would receive or the location of each of the facilities offered. Calibrating the model inputs and assumptions to ensure a reasonable capacity balance would have been time consuming and costly, and the primary purpose of the calibration would have been to generate reasonable market prices for power – essentially the same data as was provided by ABB. Like the CRA dispatch model, these integrated models require input assumptions that are typically derived from third-party forecasts. Integrated models do not somehow eliminate questions related to forecast accuracy, and in the context of a comparative evaluation of bids in an RFP, they increase concerns about forecast consistency.

Cos. Ex. RJL-R at 19. The Companies also argue that Ms. Medine did not present an integrated market model as a part of her testimony, address any of the problems outlined above or show that using a different model would have made any difference. Cos. Init. Br. at 24.

The Companies further assert that there is also no single industry-accepted customer impact period to be used in an NPV analysis. Id. at 25. Mr. Lee selected a fifteen-year period because it was long enough “to understand the relative economics of the competing bids,” allowing projected facility operations to reach a steady, long-term state under the forecasted market conditions. Cos. Ex. RJL-R at 8-9. The Companies argue that beyond this period, assumptions about performance factors become much more speculative as they move into the future, and cost factors have a comparatively small impact on the NPV because of discounting. Cos. Init. Br. at 25. Additionally, even if a longer period, such as twenty years, had been used, according to the Companies, the difference in the NPV positions for the bids would not have been materially different because the Pleasants NPV per kW unforced capacity (UCAP) was far higher than its RFP competitors. Cos. Ex. RJL-D, Ex. RJL-1 at Table 2.1.

To run the NPV analysis, CRA needed a set of natural gas, energy and capacity prices. ABB is a respected, independent source of market forecasts, and no one claimed that ABB’s approach is biased toward or against any market outcome. When ABB
prepared the Spring 2016 Reference Case, neither ABB nor CRA could have known that CRA would later use those forecasts in a Mon Power RFP. Cos. Init. Br. at 25-26.

Mr. Sweet testified for the Companies that historically low natural gas prices cannot be expected for the foreseeable future based on ABB fundamentals-based modeling. ABB considers market fundamentals such as projected production levels, the relationship between current prices and sustained growth over the long term, debt levels of U.S. oil and gas exploration and production companies, and the likelihood that higher intensity techniques will be needed causing diminishing returns to scale. Cos. Ex. TS-R at 3-4. Mr. Sweet noted that ABB considers gas infrastructure projects in its forecasting, including construction costs and pipeline reservation rates that were not considered by other witnesses, such as Mr. Schlissel and Mr. Comings. Cos. Init. Br. at 27; Cos. Ex. TS-R at 9-10. The Companies argue that criticism of ABB’s capacity price projections were clearly hindsight-based and centered on a single data point: a divergence between the actual RPM clearing price for DY 2020-21 (approximately $77/MW day) from the May 2017 BRA and ABB’s forecasted price of $149/MW day, that was projected in the spring of 2016, prior to the May 2016 auction. Cos. Init. Br. at 27. The Companies argue that the capacity price projections made by Mr. Schlissel and Mr. Comings are suspect on their face because they forecast capacity prices in the out years (DY 2028-29 through 2032-33) at levels no higher than the price range prevailing in the last six auctions (roughly between $100 and $160 per MW day). Cos. Cross Ex. 7.

The Companies also contend that CRA’s plant performance and cost assumptions were valid. Mr. Lee’s discussion of CRA’s capacity factors stressed that they were outputs of the modeling, not inputs based on recent observed performance. Cos. Ex. RJL-R at 25-26 and Figure 2. Mr. Lee explained that capacity factors for baseload plants typically are not the most important factor related to plant profitability in the energy market:

Plants in organized markets tend to earn a large portion of their energy market profits during a relatively small number of high-priced hours. In many operating hours, plants’ marginal costs are close to their energy market revenues, meaning that whether the plant is running or not would not have a significant profitability impact. As a result, a small deviation in operating cost assumptions may have a dramatic impact on estimated capacity factors but very little impact on overall margins.

Id. at 27-28 and Figure 3 (showing that eliminating twenty percent of the dispatch hours only reduced two percent or less of the energy margins earned by the facility over the course of the year).

Mr. Lee also criticized the rationale offered by Longview witnesses Mr. Gabel and Mr. Kumar that CRA should have favored industry-wide performance averages or costs at other similar facilities over costs derived from actual operating performance of the facility in question. Mr. Lee notes that operating costs at power plants are not uniform
and substituting item-level costs from one facility into cash flow estimates of another facility “creates risk of double counting or missing certain cash flows due to classification inconsistencies” and thus misses true plant-level variations in data. Cos. Ex. RJL-R at 15-16.

Mr. Lee testified that a series of scenario analyses taking into account a range of price assumptions would not have altered the relative economics of the NPV analysis for each of the proposals received because there are “infinite numbers of potential scenarios for domestic power markets,” and it would have been unrealistic and unnecessary to model every possible scenario. Cos. Ex. RJL-R at 24-25. He also testified that additional scenarios would have complicated the bid evaluation by requiring CRA to develop a complicated set of rules for evaluating each bid under a set of multiple NPV values. Id. The Companies note that Mr. Eads, witness for Staff, ran thirty scenarios using a range of forecasted information and assumptions, after making adjustments to capital investment, capacity factor, heat rate, fixed O&M expenses, and depreciable life, and twenty-five of the thirty scenarios still projected a positive NPV. Staff Ex. TRE-D at 6-10 and attachment 1.

Furthermore, the Companies argued that CRA appropriately excluded costs that would have been either improper to consider in a fifteen-year analysis or were too uncertain to be included. Cos. Init. Br. at 31.

The Companies argued that the CRA correctly addressed the in-state fuel consumption factor. The in-state fuel factor in the RFP scoring would not have materially affected the RFP outcome, no matter what scores Pleasants and Longview received on it. Cos. Init. Br. at 32. The Companies noted that Pleasants is currently sourcing over eighty percent of its coal from West Virginia while Longview sourced all or nearly all of its coal from Pennsylvania. Additionally, the Companies argued that the Longview proposal did not provide any detail on costs associated with potential sourcing of fuel from within West Virginia. Id. at 33.

Staff argued that if the Commission determines that the Companies have a need for additional capacity and the RFP process was not so flawed as to render it useless, the Commission must then determine whether the acquisition of the Pleasants Plant is the best and most appropriate solution. Staff Init. Br. at 13. Mr. Eads developed an NPV analysis that began with the CRA analysis which relied on the ABB market forecast. Mr. Eads then made adjustments that he felt more accurately reflected the likely operation of the three conforming bidders. The impact of the adjustments was to lower the NPV of Pleasants from the $696 million calculated by CRA to $356 million. The adjustments also slightly improved the NPV of the combined-cycle gas plant and slightly lowered the NPV of Longview. Staff Ex. TRE-D at 11.

Mr. Eads also modeled a number of scenarios using his numbers related to the operation of the three plants and substituted those numbers into several PJM market forecasts from ABB, AEP and Navigant. Under his analysis, Pleasants was the clear
winner. Staff Ex. TRE-D at 24-25. Mr. Eads then used an average of the CRA/ABB forecast and the AEP Mid-Band forecast in an effort to provide a balanced approach between the multiple market forecasts. Under this analysis, the Pleasants acquisition has an NPV of a positive $278.4 million. Id. at 28-30.

After comparing the cost of Pleasants to projected market costs, Mr. Eads indicated that although Pleasants showed a positive result compared to the market, the amount of the benefit, in his opinion, was not significant enough versus the risks associated with owning Pleasants for him to unequivocally recommend the Pleasants Transaction.\(^\text{15}\) The risks included the potential of acquiring too much capacity, selecting the wrong type of capacity, selecting a generating source that requires a more expensive fuel source, unanticipated environmental costs related to the fuel source, fuel supply disruptions, obsolescence causing premature retirement and price volatility. Staff Ex. TRE-D at 35. Mr. Eads further testified that purchasing needs from the marketplace could avoid some of those concerns. Staff Ex. TRE-D at 36.

H. Value and Condition of Pleasants

The Companies note the relatively low price for Pleasants of $150/kW. Cos. Init. Br. at 35. The Companies argue that the Pleasants purchase price is market-derived, lower than other bids, and very low when compared with other West Virginia power plant net book values in recent transactions. Cos. Init. Br. at 33. The Companies also argue that an impairment analysis, as suggested by Mr. Baron, witness for WVEUG, is essentially an appraisal of an asset’s value made necessary when there is no actual market value available. The Companies contend that using a competitive RFP process resulted in a presumptively valid, market-derived price. Id. The Companies argue that asset sales in PJM West, as referenced by Ms. Medine and Mr. Schlissel, were not reliable bases for determining Pleasants’ fair market value because there was no evidence that these situations were comparable to Pleasants. Cos. Init. Br. at 34. The Companies suggest that the 2013 Pleasants transaction and the 2013 Harrison transaction at $733/kW and $565/kW respectively, offer more constructive guidance on the current value of Pleasants. Cos. Init. Br. at 34-35, citing Harrison Order at 14 and Exhibit B, p. 7 of Appendix A.

Mr. Ruberto testified that FirstEnergy’s decision to leave the competitive generation business should not be the basis to determine Pleasants’ projected profitability and market value. Cos. Init. Br. at 35. Mr. Ruberto testified:

The difference in value that a buyer and a seller assign to a particular asset is the basis of all market exchanges. Buyers and sellers have different

\(^{15}\) “While $278 million is a decent benefit, it would only take a few additional years of lower than expected PJM Market prices, or a jump in coal prices, to reduce the benefit to near or below zero and result in a net increase in customer rates during the initial years. This being the case, I am torn between Pleasants and the PJM Market.” Staff Ex. TRE-D at 36.
economic circumstances and different needs. Mon Power is a vertically integrated utility that has a need for capacity to serve its customers and the customer of PE-WV. Mon Power’s cost of capital and its operational and financial priorities are likely to differ from those of entities that are not vertically integrated utilities.

Cos. Ex. JAR-R at 36. There is no reason to believe that AE Supply has the same costs of debt and equity capital that the Companies have, or that its investment horizon and investment priorities are the same as the Companies’ priorities. Cos. Init. Br. at 36.

The Companies further contend that Pleasants is a valuable asset with many years of service life ahead of it. It is a well-maintained, modernized facility. Id. at 37. Mr. Evans testified that the preventive maintenance program used by the facility is modeled from the Electric Power Research Institute. Tr. II at 370-71. Pleasants inspects critical equipment, such as transformers, to ensure reliability and prepare for high-impact, low-probability events. Id. at 368. Pleasants conducts scheduled outages on each unit every three years and performs replacements as necessary. Id. at 348. These practices have allowed Pleasants to operate efficiently and prolong its useful life. Cos. Init. Br. at 38. Additionally, Pleasants has ensured its viability through strategic capital investments, including replacement of boiler components and distributed control systems. It is also in compliance with environmental rules. Cos. Ex. DE-R at 3-4.

The Companies also obtained an independent evaluation of Pleasants by Black & Veatch, a recognized industry expert. Cos. Init. Br. at 39. Black & Veatch concluded that:

[T]he facility is well-maintained and capable of providing reliable service for many years. It currently has few operating limitations and despite its nearly 40 year age has reasonable costs related to operation and maintenance which appear to be very effective in maintaining efficiency, reliability and availability levels in line with those represented in the response.

Cos. Ex. KPL-D at attachment KPL-1, §1.1. Mr. Leutheuser, who managed the review of Pleasants for Black & Veatch, testified that the various capital projects undertaken at Pleasants over the years “demonstrate an ongoing modernization of the plant that addresses operating problems and regulatory compliance.” Cos. Ex. KPL-R at 3.

The Companies argue that the plant will provide significant customer benefits including (i) capacity deficiency for the Companies will be covered through 2027 based on current load forecasts, (ii) the acquisition will provide a physical hedge against volatile market prices, (iii) the opportunity for net revenues from generation sales will serve as direct offsets to ENEC costs, and (iv) an enhancement of Mon Power’s asset base and overall capitalization could benefit customers through more favorable financing terms. Cos. Init. Br. at 41. Further, the Companies argued that the transfer will permit an
overall reduction in customer rates as the projected ENEC rate reduction will more than offset the impact of the Temporary Surcharge. Cos. Ex. HCK-D at 9-10.

The Companies also argue that the Transaction will benefit the State of West Virginia. Approving the transfer and maintaining plant operations will preserve hundreds of jobs at the plant, in mining, and in other supporting businesses that would positively impact the State’s economy. Cos. Init. Br. at 42.

Staff witness Walker noted some areas of concern with the condition of the boilers. Staff Ex. DEW-D at 5, 8-11. Additionally, he expressed concern that Pleasants is forty years old and, when built, had a life expectancy of forty years. Staff noted that it is possible the plant may operate for another twenty years, but there could be high maintenance costs, multiple outages and load curtailments. Id. at 13.

Although the Companies plan to depreciate the Pleasants plant over twenty-seven years, because of the age of the plant and other unknown circumstances, the plant could close prematurely if Pleasants becomes uneconomic to operate or faces environmental restraints that cause it to close. If this occurs, Staff argues that ratepayers would still be responsible for the undepreciated rate base. This risk would not be present with a PPA or reliance on the market. Staff Init. Br. at 21.

HCP/BCP witness Dorn testified that the lack of gas plants in West Virginia, as opposed to the development and construction of numerous new combined-cycle natural gas power plants in Ohio and Pennsylvania, is because of the regulatory climate in West Virginia. Mr. Dorn testified that granting this Transaction could jeopardize future investment in gas plants in the State because it may be viewed by financial markets as an irrational uneconomic state-level subsidy. Approval of the deal would send a signal to the financial markets that West Virginia has a high degree of regulatory uncertainty, and it would discourage significant capital investments in West Virginia when neighboring states with access to the same gas and power markets have proven regulatory track records for approval of construction of natural gas power plants. HCP/BCP Ex. AWD-D at 6-7; HCP/BCP Init. Br. at 8.

CAD contested the value of Pleasants as a modernized facility. The Pleasants facility is old. Longview witness Burnett indicated that his analysis of the historical operating hours, capital expenditures, operations and maintenance budgets, outage data and other information available to the Parties does not clearly identify what maintenance has been performed over the years to justify characterizing Pleasants as a modern plant that will be reliable for another twenty years. Longview Ex. TB-D at 9. Mr. Burnett noted recent equipment failures and significant maintenance to ensure reasonable reliability of the plant. Mr. Burnett suggests that these maintenance efforts and costs will

16 In response to questions from the Commission, Mr. Dorn agreed that there had been no delays in the processing of siting certificates for two gas-fired power plants under development by his Company and that two such plants had been certificated and one was on track for Commission action. Tr. II at 34.
increase because the plant operations and the majority of the equipment are still original and have not been changed. Longview Ex. TB-D at 32-33. Staff witness Walker noted that the finishing superheater for the Unit One boiler was replaced with a less tolerant steel in 2010 and the boiler is currently experiencing tube failures because of the material. Staff Ex. DEW-D at 9. Mr. Walker testified that the original boiler tubes were at the end of their life expectancy of forty years and a rough estimate for the replacement of the boiler tubes in the finishing superheater would be approximately $9 million per unit. Staff Ex. DEW-D at 10. Dale Evans, Technical Services Manager at the Pleasants Plant, testified that the plant was continually evaluating plant components and performing life-extension or capital replacements when and where necessary. Cos. Ex. DE-R at 2. Mr. Evans specifically refuted that the boilers were problematic, stating instead that they are in good shape and could last for many years. Id. at 10.

CAD witness, Ms. Medine, testified that the certain coal supplies assigned to Pleasants are above-market by almost $13 per ton. She described this as problematic for two reasons. First, she argued that capacity and energy market prices have been low and that Pleasants’ ability to dispatch could be impaired by having an above-market price contract for coal. Second, she noted that the Companies will be asking for recovery of fuel costs through the ENEC and the above-market coal pricing increases the price ratepayers will be paying for power. CAD Ex. ESM-D at 36.

CAD Init. Br. at 15-16; CAD Ex. ESM-D at 33-35, 37.

Staff witness, Mr. Short, testified that, as West Virginia utilities have continued to rely primarily on coal-fired generation over the last ten years, the average retail price of electricity in West Virginia has increased 77.5 percent. In contrast, the average retail price of electricity in the United States has increased by only 15.6 percent with a move from predominantly coal to natural gas. Staff Ex. RRS-D at 10.17

Mr. Burnett and Mr. Kumar testified that, although they had made no examination of Pleasants, a more thorough engineering and operations review was warranted to fully analyze the historical spending at the plant and to best determine a realistic view of anticipated future needed expense. Longview Exs. TB-D at 25 and NK-D at 43. Mr. Burnett testified that the plant’s major components will continue to have failures. Longview Ex. TB-D at 16.

Mr. Kumar testified that the number of hours Pleasants operates at lower load (cycling) is increasing. Longview Ex. NK-D at 25-26; Tr. III at 256. Also, the Black and

17 The Commission notes that the percentages quoted may appear to show increases in West Virginia that are five times greater than the national average. The rates in West Virginia were much lower than the national average ten years ago, so the percentage increases calculated on the lower West Virginia rates, as a percentage, appear severe. Looking at the absolute increase, however, the average West Virginia rate has increased by around 3.5 cents per kWh, or just over two times the national average increase of 1.6 cents per kWh. Even with the larger absolute increase, West Virginia electric rates are still below the national average.
Veatch report, relied upon by the Companies as an engineering assessment, did not address the risks of a high-impact, low-probability (HILP) event. Mr. Kumar testified that older units have a much higher chance of experiencing HILP-related forced outages. Longview Ex. NK-D at 36-37.

I. The McElroy’s Run Impoundment and Dam

According to Companies, McElroy’s Run Impoundment and the associated dam (McElroy’s Run Impoundment and Dam) is safe and structurally sound and is needed for operations. The impoundment has operated without incident since the inception of the plant. Cos. Init. Br. at 39. McElroy’s Run has a confirmed 10.67 years of storage space and operation in the facility. Tr. II (Evans Testimony) at 341. The Companies acknowledge that the impoundment is classified by the U.S. Army Corps of Engineers classification system as a “high hazard.” Mr. Evans, however, explained that this classification is not indicative of the operational condition or safety of the impoundment, but merely means that if such a dam was to fail, loss of human life would likely occur – an unlikely outcome since the Pleasants site encompasses the impoundment, which has a maximum water depth of four feet, and all of that land is between the impoundment and the Ohio River. Tr. II at 81, Tr. III at 308, and Tr. IV at 30-31. Staff witness Dove visited the impoundment site and testified that he believed it was in good condition. Staff Ex. DWD-D at 32.

Mr. Evans, Technical Services Manager for Pleasants, in discussing generally the environmental record of the station, stated:

We are in compliance and, in fact, we --- we went over three years without any reportable environmental occurrence at that station. Our safety record is just as good and we have gone over three years --- we went over three years without a reportable safety incident at that station.

Evans, Tr. II at 364.

Mr. Dove testified that the estimated closure and post-closure costs for the impoundment are approximately $43.8 million. This estimate was not based on the preparation or review of a closure plan for the McElroy’s Run Impoundment, but was estimated based on the bond requirement on a similar impoundment in Pennsylvania. Mr. Dove used a similar methodology to arrive at an estimated $21.8 million

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18 Mr. Dove examined the closure plan for The Little Blue Run (LBR) Disposal Area adjacent to the FirstEnergy Bruce Mansfield Plant in Pennsylvania. He determined that plan was similar to the closure/post-closure plan for the McElroy’s Impoundment. He simply divided the estimated bond amount for the LBR Disposal Area of $162,272,180 by the total number of LBR acres (936 acres) to arrive at an estimated cost of $173,368 per acre for closure/post-closure costs. He then applied this cost to the 253 acre McElroy’s Run footprint to arrive at the closure/post-closure cost estimate of $43.8 million.
closure/post-closure cost for the Pleasants landfill. Staff Ex. DWD-D at 29. According to Mr. Dove, ratepayers would have to pay these costs.

Staff argued that the potential liabilities associated with the ownership of the impoundment are unknown. Staff witness Dove testified that the Tennessee Valley Authority was recently required to line an impoundment, not because of current problems, but because of the likelihood of future problems. A similar order for the Pleasants plant, if ever issued, would increase the costs of the impoundment. Staff Ex. DWD-D at 32-33. Staff argued that the impoundment should not be transferred if it will not be used and useful because of the high closure costs (approximately $43 million) and limited amount of volume left in the impoundment. Tr. IV at 35-39, 41.

J. Risk Sharing

The Companies argue that if the transfer occurs, the costs and subsequent market operation of Pleasants should be governed by the same regulatory framework for cost recovery that governs all of Mon Power's other generating units. Cos. Init. Br. at 44. West Virginia rate regulation is based on the cost-of-service model with fuel and purchased power costs reconciled and recovered through the ENEC. Id. The Companies contend that their Fort Martin and Harrison Power Stations are subject to cost-of-service based rate regulation, even though 100 percent of the market risk attendant to their operations is borne by customers, and there is no certainty that they will produce a net NPV benefit for customers over their service lives. Id. The Companies distinguish the acquisition premium in Harrison from the proposed risk assignment in this case. Cos. Init. Br. at 44-45.

The Companies argue that the proposed risk assignment is contrary to the legal rate structure and regulatory paradigm in West Virginia that a utility recovers its costs for assets deemed prudent and has an opportunity to earn a fair return on that asset. Id. at 45. The Companies assert that some intervenors want to shift market risk to the utility without providing the higher cost of debt and higher cost of equity that would normally occur for an entity that is exposed to the market. Id. The Staff, WVEUG, and WVSUN/CAG risk-sharing proposals are also unwarranted because they use the PJM market as a benchmark for the Companies' entitlement to cost recovery. Id. at 46. Companies argue that these intervenor proposals do not represent a fair allocation of market benefits and risks.

Mr. Eads testified that the Staff Utilities Division would support the purchase of Pleasants if the ratepayers were shielded from the risks discussed in the NPV Analysis section above. Staff Ex. TRE-D at 35-36. If the market experienced a few years of lower-than-expected PJM market prices or a jump in coal prices, the Pleasants Transaction would be a negative asset. For example, Pleasants would have a negative $234 million NPV using the AEP low band market forecast. Staff Ex. TRE-D at 36. Staff contended that most analysts would agree that the cost of natural gas is currently driving prices in the PJM region.
Staff witness deGruyter, the Commission gas industry witness, stated his belief that natural gas prices will remain essentially flat for the next five to ten years. Staff Ex. EFD-D at 5-6; Tr. IV at 15. Mr. deGruyter stated that he believed assumptions about rising natural gas costs due to the development of multiple intrastate natural gas pipelines are incorrect. He testified that “the general feeling in the industry” is that when the pipelines are completed, more wells will be drilled and more gas will be available for market, thereby keeping downward pressure on prices. Staff Ex. EFD-D at 5-6; Tr. IV at 17. Staff argued that if these assumptions about gas prices are correct, the alleged benefit to ratepayers in the near- and mid-term could be diminished because the majority of the projected revenue comes through the energy market. Staff Init. Br. at 18. Additionally, there is a risk of higher-than-expected coal prices that could come about as the supply of coal becomes short as more and more coal mines shut down and the risk of the plant not being able to physically perform at expected levels because of aging equipment which could affect the plant’s revenues. Id.

Staff said that the ratepayers should be shielded from the risk of owning Pleasants versus reliance on the market through a mechanism that limits ratepayer exposure to the lower of market costs versus the costs of owning Pleasants. Staff Ex. RRS-D at 15-17. This risk sharing proposal would benefit the Companies by allowing them to share in projected additional revenues. Staff Init. Br. at 25. Staff argued that, given the recent generation transactions, the Commission should condition approval on some sort of market risk sharing mechanism. Staff Init. Br. at 26.

Staff testified that another condition to protect ratepayers from unnecessary risk is the exclusion of the impoundment from the Transaction. Mr. Dove testified that the Companies should not take on the impoundment unless it is essential to the operation of the plant. Staff Ex. DWD-D at 35. Mr. Evans testified for the Companies that in the future, the plant would change entirely to a dry impoundment operation by installing the best available technology at that point. Cos. Ex. DE-D at 12. Furthermore, the impoundment is approximately ninety-four percent full. If the Companies acquire the Impoundment, they should only be liable for six percent of the costs of the impoundment. Staff Init. Br. at 27. Additionally, an indemnification agreement like the one ordered in the Mitchell transaction, Case No. 14-0546-E-PC, should be required. Id.

Staff also recommended rate protection as described in the testimony of Mr. Oxley, including denying the proposed true-up for the surcharge proposed by the Companies. The Commission has not traditionally allowed for the true-up of these types of costs that are generally under the utility’s control, with the exception of the Harrison case in which the Commission approved a settlement that included a true-up. Mr. Oxley also recommended that the requested return on equity (ROE) be adjusted to 9.75 percent because that represents the most recent allowed ROE in a litigated rate case. Further, Mr. Oxley recommended that the proposed rate decrease not be fully implemented in case the Companies’ calculations are incorrect. Staff Ex. ELO-D at 8-12; Staff Init. Br. at 28.
K. Possible Delay of the Transfer

The Companies argue that a possible conditional approval that would require delaying for a period of time the closing on the Transaction to await subsequent market results is infeasible and unwise for a variety of reasons. AE Supply may not wait the prescribed amount of delay time and may instead look for another buyer, close the Pleasants plant or sell the plant for a higher price. Cos. Init. Br. at 49-50. A delay would jeopardize the benefits of the transfer, and there is no guarantee that the issues in the regulatory and market landscape for generators in PJM would be resolved. Id. at 50.

Staff supports the proposed review period. Alternatively, Staff suggested that the Companies be required to issue a new, more inclusive and robust RFP. A new RFP would allow some time to see if the Companies’ projections are correct and a fuller RFP would allow the entire marketplace to speak for itself. Staff Init. Br. at 29.

L. Temporary Surcharge and Ratemaking

The Companies testify that cost recovery is necessary, and the incremental costs normally recovered in base rates should be recovered immediately through a surcharge (Temporary Surcharge). The Companies propose that the Temporary Surcharge be trued-up to reflect changes in base costs until their next base rate case. The Companies also argue that a ten percent return on equity is more reasonable than proposals by other parties and the Commission should use the ten percent ROE for the limited duration of the Temporary Surcharge. Cos. Ex. REV-D at 11-12; Cos. Ex. REV-R at 5-6; Cos. Init. Br. at 52.

Staff did not oppose the Temporary Surcharge but did oppose the annual true-up mechanism and the return on equity used by the Companies in calculating the temporary surcharge. Staff argued that the true-up mechanism was an unusual departure from base rate establishment of revenue requirements and cited Commission Orders involving acquisition of generation plants by Appalachian Power Company and Wheeling Power Company where the Commission denied a true-up mechanism. Staff Ex. ELO-D at 5-10.

WVEUG opposed the Temporary Surcharge. Instead, WVEUG recommended a deferral of the fixed, base rate cost components of Pleasants’ ownership and operations and a future cost recovery determination by the Commission in a base rate case. The WVEUG witness testified that industrial customers were already paying rates that exceeded their reasonably allocated revenue requirements and that class cost allocation should be resolved along with a determination of the allocation of the base rate cost components related to Pleasants. WVEUG Ex. SJB-D at 33.

VI. DISCUSSION

We listened to the testimony of the witnesses, read pre-filed material, exhibits and briefs, and reviewed the issues in this case. Although there was a massive amount of
both prefried and hearing testimony, we are troubled by what we perceive the lack of hard
financial analyses, with the exception of Staff witness Eads. It is difficult to participate
in the hearings, review the enormous record in this proceeding and not conclude that, to
large degree, the proceeding and the positions of the parties can be fairly summarized as
dueling experts on the issues of each party in the case. The Discussion of the Issues in
this Order evidences the stark contrast between the parties, but much of that contrast is in
the nature of “did too” and “did not” statements by expert witnesses, contesting what the
Companies did and why they did it. There may be nothing wrong with that, but in the
final analysis, we do not attempt to balance or assess the oscillating scales of justice
based on which side presents the most expert witnesses.19

We also do not intend to repeat the foregoing discussion of the issues set forth in
this Order, but we have considered those matters extensively and believe that the
following observations about this case are appropriate.

A. Pleasants Transaction is not the Harrison Power Transaction

Various efforts, both directly at public comment hearings,20 and obliquely through
news stories, have been made attempting to equate the proposed acquisition of Pleasants
to the Commission’s approval of the acquisition by the Companies of a 79.46 percent
ownership interest held by AE Supply in the Harrison Power Station. The Companies
attempt to find support in the Commission’s Harrison Order for owning generation
capacity, disregarding the different facts and circumstances of the Harrison case from this
case. In substance, the Companies argue that the Commission approved the Harrison
transaction and should therefore approve Pleasants as well. Cos. Init. Br. at 6-8.

The Companies’ reliance on Harrison to support the Pleasants Transaction is
misplaced. The facts and circumstances facing the Companies’ capacity and energy
needs at the time of the Harrison transaction were not at all close to the facts and
circumstances regarding capacity and energy needs presented in the record in this case.

19 That is so even where, as asserted by the Sierra Club, a “diverse assemblage of groups” have united to
oppose the transaction:

With its proposal to purchase the Pleasants Power Station, Mon Power has managed
to unite a diverse assemblage of groups that represent widely differing viewpoints.
Environmental groups, renewable energy advocates, large industrial energy users,
residential customers, power-plant owners, citizen watch-dogs, and even the
Commission’s own staff have come together with a single-coherent message: the
proposed purchase of the Pleasants plant is bad for West Virginia.

Sierra Club Opening Br. at 1 (emphasis in original).

20 This includes public comment such as that of Mr. Craig, commenting at the Martinsburg public
comment hearing that the Harrison Plant cost customers more than $160 million according to the
The Harrison transaction was approved based on the state of the facts and law in 2013/2014. The record in the Harrison case demonstrated that the Companies were facing a summer capacity shortfall; that is not a fact supported by the record in this case. We further remind the Companies that the record in the Harrison case demonstrated that the Companies were facing a significant shortfall in meeting their energy requirements with internal generation resources. That is not a fact supported by the record in this case.

Just as the Companies are wrong in trying to justify an approval of the Pleasants Transaction on the Harrison acquisition approval, so too are the attempts of some of the opposing parties who imply, without the benefit of evidence, that the Harrison acquisition was a bad decision.

Without any evidence regarding the actual and projected impact on customers due to the Harrison transaction, before and after any adjustments due to the conditions placed on full Harrison cost recovery, some parties who oppose Pleasants condemn the Harrison transaction and by association hope to cast doubt on the Pleasants Transaction. Staff Init. Br. at 2.

Those parties who oppose the Pleasants Transaction because they believe that the Harrison transaction was an unwise decision should remember that the Harrison acquisition was supported by the facts and circumstances in 2013/2014. We further remind those parties that they did not present any evidence in this proceeding that there are any long-term or continuing detriments to customers attributable to the Harrison transaction. Unsupported papers or newspaper opinion pieces that ignore the potential for future rate adjustments associated with the conditions imposed by the Commission in this Pleasants decision that were never entered into the record in any Commission proceeding, that were never subject to examination by any party or the Commission, and that were never subject to rebuttal are not evidence that could conceivably support any findings of fact or conclusions of law that must underpin legally defensible Commission decisions.

Finally, we remind the parties that the Companies; the Staff; CAD; WVEUG; Utilities Workers Union of America (UWUA); the Sierra Club; the West Virginia State Buildings and Trade Council, AFL-CIO; WVCA and Utilities Workers Union of America, AFL-CIO, and its Local 304, all joined in the Harrison Joint Stipulation and recommended to the Commission that the Commission approve the Harrison transaction based on that Stipulation. Even then the Commission placed certain conditions on the full recovery of Harrison Rate Base costs, requiring that a portion of that recovery be more than fully covered by net margins from the sale of excess capacity and energy in the PJM Markets, so that customers would not be responsible for the Acquisition Adjustment portion of the Harrison Rate Base. Only the WVCAG opposed the Joint Stipulation. Further, the Harrison Order, Commission Case No. 12-1571-E-PC, was appealed to the Supreme Court of Appeals of West Virginia by the WVCAG and was affirmed by the Supreme Court by Order in West Virginia Citizens Action Group v. Public Serv. Comm’n, 758 S.E.2d 254 (W. Va. 2014).
B. Need for Capacity

One of the major arguments of the opponents of the Transaction is the lack of need for additional capacity for Pleasants. Most parties opposing the Transaction took issue with the use of a winter peak to determine a capacity deficiency and to support a need for capacity. After the advent of PJM capacity rules, the capacity “need” of a load serving entity (LSE) is based on its load during the PJM peak summer months. No matter how much higher the Companies’ peak demand is in the winter months, it is not required by PJM rules to either own or purchase capacity to meet that winter demand. PJM acquires sufficient capacity to serve its summer peak plus a reasonable reserve margin. Because PJM has lower winter peaks, the capacity it has acquired to meet the summer peak is more than enough capacity to serve the winter peaks of all of its members, including the Companies.

Mon Power supports its decision to own capacity in excess of its PJM requirement by arguing that language in the Harrison Order and the statutory IRP language require the Companies “to ensure the ownership of capacity in excess of load, now and in the future, especially taking into account necessary reserve margins of 16.6 percent.” We do not agree with that argument. The statutory IRP language is:

The plan shall compare projected peak demands with current and planned capacity resources in order to develop a portfolio of resources that represents a reasonable balance of cost and risk for the utility and its customers in meeting future demand for the provision of adequate and reliable service to its electric customers as specified by the Public Service Commission.


There is nothing in the Harrison Order or the above-quoted language, or any other portion of the IRP statute, that requires an electric utility to own capacity to meet its load requirement. In addition, while “projected peak demands” are required by the statute, the planned capacity resources are left to the discretion of the utility, subject to the requirement that the portfolio of capacity resources provides adequate and reliable service and represents a reasonable balance of costs and risks. The utility may decide, as Mon Power has, to own capacity to meet the peak load or it may decide to meet the load with a “portfolio of resources” that is a combination of owned capacity and purchased power. Purchased power may include purchases from the PJM Market.

It is the responsibility of the Commission to approve or disapprove those utility contracts and agreements that are subject to our jurisdiction and to allow cost recovery of reasonable and prudently-incurred costs. This proceeding is part of that Commission process in which we must determine the prudence of the Companies’ decision, considering the statutory tests specified in W.Va. Code §24-2-12, §24-1-1, and other
applicable Sections of the Code. Our decision is not preordained by a statutory requirement that the Companies meet their winter peak with owned generation capacity; moreover, we do not agree that language in the Harrison Order directed Mon Power to meet future winter peak requirements with generation capacity that it owns.

The facts and circumstances of the Companies’ capacity and energy needs at the time of the Harrison acquisition in 2012 were significantly different from the Companies’ current needs. When we were considering the Harrison acquisition, the Companies presented evidence that they were unable to meet their summer capacity requirements under PJM rules. They made no attempt to justify the need for capacity on a shortfall in meeting winter load requirements that were also in excess of summer load requirements. Thus, in the Harrison case we were addressing only a capacity shortfall vis-à-vis PJM requirements. In addition, the evidence presented in the Harrison case demonstrated that the Companies could not meet annual energy requirements. With Harrison, the Companies could not only meet annual energy requirements, but would also have significant excess energy generation capability, above internal energy requirements.

The Companies did not attempt to support the current proposed Pleasants Transaction based on a need for energy. In fact, the Companies projected their energy needs around 16 million MWh, growing to 17.5 million MWh by 2020 and to 20 million MWh by 2030. Cos. Ex. BDE-D at BDE-2. In Harrison, the Companies projected that, after approval of the Harrison transaction (which was approved and consummated), energy generation would be around 23.3 million MWh per year. Thus, because of vastly differing facts, circumstances and evidence, the Companies cannot find support in the language of the Harrison Order for the need to own Pleasants.

Aside from their interpretation of W.Va. Code §24-2-19(d) and the language from the Harrison Order, the Companies made other and new arguments for owning capacity to meet internal winter peak load requirements. The Companies did not present a compelling case with supporting evidence for the need to acquire their own capacity, although they strongly supported the benefits of owning Pleasants versus owning any other capacity available through the RFP. The Companies set the stage for need in their Petition when they state:

The need to cover this capacity deficit is the primary motivation for Mon Power’s proposal to acquire Pleasants, and this need alone serves as the compelling reason for the Commission to approve it.

Petition at 5.

The need for the capacity and some basic detail of the Pleasants capacity is further mentioned in direct testimony of Ms. Kauffman:

Through the Transaction, Mon Power will acquire an additional 1,300 MW of installed generation capacity (expected 1,159 MW unforced capacity) in
order to provide the energy and capacity needed to meet the Companies’ projected requirements through 2022, minimizing or eliminating the need to rely on market purchases during that period.

Cos. Ex. HCK-D at 5.

The Companies attempt to justify their need for capacity to serve peak load in the winter, which is not required by PJM, with certain market rules of PJM that established the capacity resources needed to serve summer load. For example, Mr. Ruberto testified:

Mon Power determined that the [PJM] Capacity Performance market design would have a significant impact on the value of Mon Power’s indirect interest in the Bath County Pumped Storage Project (the “Bath County Project”) located in Warm Springs, Virginia. Mon Power’s interest in the Bath County Project represents 487 MW of capacity. Mon Power concluded that this capacity value would be reduced by approximately 50% beginning in the 2020-2021 PJM Delivery Year due to certain availability requirements imposed on Capacity Performance resources related to system emergencies.

Cos. Ex. JAR-D at 6.

Although the PJM Market Rules and availability requirements are important in evaluating the extent to which capacity should be offered for sale in the PJM Market, those rules do not affect the capacity that is actually available to serve internal load. The Bath County facility has the capacity to serve 487 MW of internal load, regardless of adjustments in its PJM Market capacity bid increment due to concerns over Capacity Performance rules of PJM.

It appears to the Commission that the Companies have mixed and mismatched their desire to meet internal load with owned-capacity at the time of their winter peak with the PJM requirement to have available a PJM-assigned capacity level based on summer peaks. This mismatch results in a significant overstatement of the amount of installed capacity needed to meet reliably the internal winter peak and provide a reasonable reserve margin.

After forecasting a winter peak, the Companies factor the projected peak upward by 16.6 percent to provide for reserve margins. Cos. Ex. BDE-D at BDE-1. For example, Mr. Eberts projected a winter peak demand in 2020/2021 of 3,421 MW. He added a 16.6 percent reserve margin to that number to arrive at a “Peak Demand plus Reserve Margin” of 3,988 MW. Assuming that a 16.6 percent reserve margin is reasonable, and further assuming that owned-capacity should be available to meet internal load plus a reasonable reserve margin, the math employed by Mr. Eberts may determine a reasonable target for installed capacity (ICAP). The Companies, however, do not compare the 3,988 MW projected winter peak plus a 16.6 percent reserve margin
to installed capacity. They instead compare that peak to the UCAP values assigned to their capacity by PJM that are expected to be 2,983 MW, excluding Bath County. The Companies thus assume that their capacity deficiency in the winter of 2020/2021 is going to be 1,005 MW, excluding Bath County. Cos. Ex. JAR-D at 7.

We question this mixed comparison of PJM UCAP values that PJM will use to determine whether the Companies are meeting their summer peak load requirements, to the Companies’ winter load projections, plus a 16.6 percent reserve margin. That comparison is not reasonable for purposes of evaluating whether the Companies own and have under contract sufficient capacity to meet their load requirements plus a reasonable reserve margin.

Historically, the Commission has calculated the deficiency by comparing the Companies’ peak, adjusted upward for a reasonable reserve margin, to their installed capacity (including contract capacity). The Companies, however, did not present evidence on their installed capacity.

Using the Companies’ UCAP approach to measure the sufficiency of capacity to meet their winter peak load requirements might be reasonable with a more realistic reserve margin calculation. Mon Power, however, did not present evidence of a more realistic reserve margin taking the UCAP downgrading of its capacity into consideration, or what methodology PJM applies to arrive at the peak load requirement for an LSE. That is not surprising because PJM would not normally be making a load plus reserve projection for winter months. Without ICAP information in the record, which we could compare to the projected winter peak plus a 16.6 percent reserve margin, and without evidence on a winter peak plus a more realistic reserve margin to compare to UCAP, we are left to calculate a more realistic deficiency by comparing the unadjusted projected winter peak to UCAP.

The Companies have a projected peak demand in the winter of 2020/2021 of 3,421 MW. Comparing that number to the 2,983 UCAP value of owned and contracted capacity, excluding Bath County, results in a deficiency of 438 MW instead of 1,005 MW. The addition of 487 MW of Bath County that was completely omitted from the Companies’ projected capacity resources results in a small surplus. When the winter supply/demand balance does become negative, it is not likely to grow near to the level of supply provided by Pleasants. The prudence of acquiring 1,300 MW of capacity to meet a winter supply deficiency that is much smaller than that amount, and which is not required under PJM Rules, is not clear, particularly considering that the Companies have a large surplus of expected energy generation in excess of their internal needs, even before the acquisition of such a large block of additional generating capacity.

Although the Companies may have overstated their case for needing to own additional capacity at any level, let alone at the level of 1,300 MW, they nevertheless made a case that ownership of that much capacity would benefit West Virginia ratepayers in several ways. There would eventually be a summer capacity shortfall of PJM
requirements in the absence of the Pleasants Transaction and that will have to be met by some capacity acquisition. The expected excess energy that will be produced by additional owned capacity that is not needed to serve internal load can, at the right prices, be sold in the PJM energy market at a net margin that will benefit West Virginia customers. The probability of having permanent excess energy over native load requirements to sell at a profit to benefit customers and also having temporary excess capacity over native load requirements to sell at a profit to benefit customers was described by Ms. Kauffman:

[T]he Transaction will provide the opportunity for energy sales (and for capacity sales initially) over and above those needed to provide the Companies' customer requirements. The net revenues from energy sales and/or capacity will be direct offsets to ENEC expenses, and have the potential to materially reduce customer rates.

Cos. Ex. HCK-D at 10.

The Companies have exercised their discretion to choose to own Pleasants. While we find that the need to own Pleasants is not nearly as great or critical as Mon Power has argued, the prudence and risk of the decision lies in a balancing of a number of factors, including the impact on ratepayers. The rate base and fixed operating expenses of owning Pleasants will cost ratepayers approximately $111 million per year. Cos. Ex. REV-D, at REV-1. These costs are projected by the Companies to be offset initially by net margins from PJM capacity, energy and ancillary service transactions of approximately $135 million per year. Id. at REV-10. The Companies project even larger net margin benefits to “materially reduce customer rates” in the future. We must consider the likelihood of realizing these benefits to determine if the Transaction is in, or contrary to, the public interest.

C. The RFP Process, Selection of CRA and Affiliated Transactions

The Intervenors urged throughout the hearing and in their briefs that (i) the affiliated relationship between the Companies and FirstEnergy; (ii) the selection of the submission from FirstEnergy corporate affiliate, AE Supply, as the proposal to be accepted; (iii) the fact that CRA had performed similar undertakings for FirstEnergy or its affiliates in the past; and (iv) a number of other claimed dangers of dealing with an affiliate, make this a transaction that the Commission should not approve. While strongly worded, many, if not most, of the assertions about undue influence or lack of a level playing field were simply bald, conclusory statements or assertions about specters, possibilities or likelihoods of undue influence. At best they were not probative, meaningful or supported by persuasive testimony and at worst were just plain incorrect under the West Virginia statutory and case law.

In fact, the Commission notes that the Companies could have simply negotiated the Transaction directly and were not required to use an RFP. They did so because of past complaints and arguments raised in cases in which the Companies did not use an
RFP. Monongahela Power Company and The Potomac Edison Co., Case No. 12-1571-EP-PC (Commission Order October 7, 2013) (Harrison Order); aff'd. West Virginia Citizen Action Group v. Public Serv. Comm’n of W. Va., 233 W. Va. 327, 337, 758 S.E.2d 254, 265 (2014). Furthermore, the mere existence of the need for approval of a W.Va. Code §24-2-12 transaction (and the existence of an affiliated relationship) is not a basis to reject an affiliated transaction or affiliated relationship absent a showing of fraud, abuse or undue influence. Such a requirement distorts the meaning and intent of W.Va. Code §24-2-12 and flies in the face of the holding of the Supreme Court in the Harrison Order.

The Commission must examine any affiliated transaction (as we do any other W.Va. Code §24-2-12 transaction) and is required to apply to that transaction a level of due diligence consistent with the requirements of W.Va. Code §§24-2-12 and 24-1-1. Affiliated transactions are not prohibited, nor is there anything inherently evil or improper about affiliated transactions. A review of an affiliated transaction is a results-oriented analysis that determines whether the requirements of W.Va. Code §24-2-12 are met and not simply whether there is the existence of an affiliated relationship. While there has been much asserted about the affiliated relationships, we see nothing in the record to establish that the negotiated terms of the Transaction between the affiliated parties are fraudulent, abusive, the product of undue influence, or a basis for denying the Transaction.

Staff and CAD argued that using CRA was improper, or at least suspicious, because CRA had millions of dollars in contracts with FirstEnergy. Staff appears to be concerned that CRA could not be an independent evaluator of bids that included bids from another FirstEnergy affiliate. This concern is not supported by any proof that CRA acted unscrupulously or in any way deliberately tilted its evaluation in favor of the Pleasants bid. We do not find any wrongdoing or imprudence in using CRA, which is a large multi-national firm providing many clients with many services. Absent some showing of fraud or abuse, we will not impute bad intentions to CRA just because of its business relationship with FirstEnergy; moreover, the Staff witness confirmed that the

21 On the contrary, the West Virginia Supreme Court, in discussing similar arguments made about affiliated transactions stated:

This Court finds that there is evidence to support the Commission’s finding that the transaction at issue did not provide an unfair advantage to any of the parties. Significantly, inter-affiliate transactions are not per se invalid under W.Va. Code § 24-2-12. Moreover, this Court has found it proper for the Commission to approve inter-affiliate transactions. See United Fuel Gas Co. v. PSC, 154 W.Va. 221, 174 S.E.2d 304 (1969) (reversing the PSC’s denial of a realignment plan between public utilities all of which were subsidiaries of a parent holding corporation). The Commission specifically found that the transaction at issue does not give one party an undue advantage over another party, and the petitioner has failed to convince us that this finding is in error.

Pleasants bid was far superior to other bids received in producing the lowest cost to the Companies.

Finally, there is some consternation from opposing parties that the bid structure limited bids to “bricks and mortar” generation that would be owned by Mon Power. By then requiring a facility to be located in the APS Zone of PJM, these opposing parties complain that the bid structure virtually assured that Pleasants would be the winning bidder.

The Commission does not find these arguments to be persuasive reasons for denying the Transaction. We believe that the issue before us is whether the proposed Transaction will be a reliable and economical source of capacity and energy that does not unreasonably burden ratepayers with excessive, or imprudent costs. Further, as we have indicated, the Transaction will be weighed and balanced against the public benefits and the impact on current and future ratepayers and the State. As we have addressed below, the primary test we will use to determine the economic benefits of the Transaction is the relationship of base and ENEC cost of ownership and operation of Pleasants as measured against the PJM Market and the benefits of ENEC credits that can be derived to benefit customers when excess energy and capacity not needed to serve native load is sold in the market at a positive net margin.

D. Risk Sharing as a Condition of the Transaction

The word “risk” took on a pervasiveness and ubiquity in this case that was mind numbing. Never has one word or phrase been so overused in briefs and testimony before this Commission. Virtually all of the Intervenors and the Staff suggested at the hearing and in briefing that any and all aspects of the Transaction expose the ratepayers to “too much risk” and hence a fortiori any approval of the Transaction was unacceptable without some level of greater “risk sharing” by the Companies.

This “risk analysis” included suggestions by CAD, Staff, WVEUG and others that the Transaction should not be approved because of the one-sided nature of that risk sharing. There were over 450 references to the “risk” of the Transaction peppered in the briefs of the parties to say nothing about the prefiled and hearing testimony. According to the Staff and Intervenors, those risks arose from many (and more accurately based on a review of the briefs) all phases or aspects of the Transaction.

Every aspect of every business, including the sale of public utility services, can be stated as a risk, to wit: risks that economy will go bad, no one will buy the product, no one will make money, suppliers will raise prices for commodities, customers will leave the state, products will be defective, alternative products might come into existence, severe weather may disrupt facilities, etc.

The Commission faces arguments in this case about real, but in many instances, speculative, uncertain, potential or possible risks that run a broad spectrum of magnitude
and likelihood. Those arguments, if adopted wholesale by the Commission, could be the basis to preclude the Commission from approving almost any other transactions in the future. A transaction does not need to be “risk free” before we approve it. There will always be some level of financial, business or regulatory risk inherent in any transaction that we examine under W.Va. Code §24-2-12. Ratepayers face risk in the service they receive from public utilities. We cannot insulate the ratepayers from all risk.

Rates of public utilities are affected by any number of unanticipated needs for capital improvements, escalating O&M expenses, and a host of other items that impact the utility’s cost of service by escalating expenses or depressing revenues. Never in a transaction of relatively recent vintage has there been an attempt to assert that every potential risk was grounds for denying the transaction. It is prudent to consider, contemplate and to safeguard against risk that is reasonably likely to occur. Our concern in this case is the eagerness and united front that “a diverse assemblage of groups that represent widely differing viewpoints” have indicated is too much risk and that the Commission must guard against all of it.

In this case, Pleasants is being offered for sale to the Companies at what would seem to be a favorable price, significantly below the depreciated original cost of the assets. The Commission has reviewed all of the testimony and briefs in this case and concludes that there is potential value and merit to the current and future ratepayers, the utility and the State to approve the Transaction, subject to certain conditions, notwithstanding some of the asserted risks to ratepayers. We can attempt to take reasonable steps to recognize and minimize those risks.

E. Possible Conditions for the Transaction

Several parties in this case have proposed mechanisms that would tie the rate allowance for future Pleasants revenue requirements on a market comparison. The Staff proposal is for a ten-year limitation on Pleasants cost recovery such that the amounts paid by customers in any year would not exceed the value of the Pleasants capacity and energy sold into the PJM Market.

As described by Mr. Short, the condition applied to cost recovery would be quantified by comparing the net operating costs incurred “as a result of acquiring Pleasants” to the total revenue received from PJM “associated with power from Pleasants.” If the net operating costs are less than the total PJM revenues, the acquisition of Pleasants would prove to be superior to the market option, and there would be no adjustment to disallow full cost recovery. If, however, the net operating costs in any year are greater than the total PJM revenues, the acquisition of Pleasants would prove to be worse than relying on the market, and an adjustment should be made to limit the rate burden on customers to the cost that is equivalent to the market cost.

To offset the risk to the Companies that they may receive rate recovery that is less than full traditional revenue requirements if the market costs are lower than the costs
associated with ownership of Pleasants, Mr. Short proposed that the Companies receive 25 percent of the excess if market values are higher than the base rate and net ENEC costs associated with Pleasants. This 25 percent would be available for two years after acquisition, and would reduce to 20 percent in the third and fourth years after acquisition, 15 percent in the fifth and sixth year, 10 percent in the seventh and eighth years, and 5 percent in the ninth and tenth year.

WVEUG witness Baron proposed a different risk sharing approach whereby the Companies would be responsible for 25 percent of any excess Pleasants full revenue requirements over the market value of Pleasants capacity and energy, and the Companies could retain 25 percent of the benefit of any excess market value over Pleasants full requirements revenue requirements. WVEUG Ex. SJB-D at 29. Mr. Baron also suggested that the 25 percent share of benefits and detriments could be phased out over a ten-year period. Id. at 31.

The Companies argued that the proposal to subject full cost recovery of Pleasants to conditions such as those proposed by Staff or WVEUG is unreasonable and contravenes the cost recovery model applicable to utility investments and to Mon Power’s other generating stations. Cos. Init. Br. at 44. The Companies see no distinguishing factors that would justify differing ratemaking treatment of the costs of Pleasants from those of Harrison and Fort Martin. They point out that except for a condition applicable to the full recovery of the Acquisition Adjustment on Harrison, the market risk attendant to the operations of Harrison and Fort Martin are borne by the customers. The Companies believe that the Parties hope to extract a concession in return for Transaction approval. Id.

The Commission does not accept these arguments by the Companies. We agree with Staff witness Eads regarding a new choice for supply:

In the past, there were effectively only three choices of supply available from which a utility could choose and on which a decision by the Commission was required - build generation, buy generation or enter into a bilateral contract for firm power. Risk avoidance was a significant component of the decision process. Those risks involved such aspects as:

- The potential of acquiring, and having to pay, for more capacity than customers might require.
- The potential for selecting the wrong type of capacity (peaking or base load).
- Selecting a generating source which ultimately requires a more expensive fuel supply.
- Unanticipated environmental requirements and restrictions that alter the original anticipated value of the source.

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- Fuel supply disruptions.
- Obsolescence causing premature retirement.
- Price volatility.

Today a fourth choice exists with a much more limited risk profile — the PJM Market. While not risk free, electing to purchase power in the market would avoid many of the risks associated with traditional sources. For the most part, the primary risk of the market would involve the lack of control over what is to be paid and some measure of possible price volatility.

Staff Ex. TRE-D at 35.

The Commission notes that the circumstances regarding need for capacity and energy are also different in this case from the circumstances underlying the decisions to build capacity in the past or to acquire capacity through the Fort Martin and Harrison bi-directional transfer cases. These changed circumstances and the availability of the PJM Market Option for power supply represent a significant distinguishing factor from past decisions to build or contract for capacity and energy.

The Companies also argue that the Staff proposal is unfairly tilted toward customers. They argue that underwriting 100 percent of detriments relative to the market while receiving 25 percent, or less, of any benefits relative to the market is an unfair, asymmetrical, proposal. We considered that argument in developing an alternative cost recovery condition.

The Commission, during the hearing, asked about an alternative concept that would finalize an approval for the Transaction, but require a delay to determine the direction of the market and to test the reasonableness of the Companies projected NPV benefits of Pleasants, vis-à-vis the market option. Tr. V at 64-74.

The Commission discussed with Mr. Schlissel, the witness for WVSUN/CAG, the extent of the Commission’s specific legislative authority to enter an order granting approval of the Transaction now, conditioned only on (i) delaying or deferring the consummation of the Transaction until a date certain and (ii) on certification by the Companies and AE Supply that certain objective parameters have been met. Id. That proposal would allow time, at least in the near term, to see if the positive scenario portrayed by the Petitioners or the gloom or doom scenario of the Intervenors actually comes to pass, or at least to see the direction in which the trends are heading. If the Transaction, after a period of eighteen to twenty-four months, continues to remain positive, and the Petitioners could certify that the Transaction had been positive for the Companies and other stakeholders for that period of time, based on objective criteria fixed at the time of the Order, the Companies could close on the Transaction. On the other hand, if the Petitioners were unable to so certify, the Transaction could not be closed.
Even though this approach would have approved the Transaction (subject only to conditions of no significant changes in the ability of Mon Power to sell excess capacity and energy in the PJM market, free of any new restrictions or limitations, and that Mon Power’s projections of customer benefits remained realistic and possible), apparently no one warmed to that approach. The Companies identified factors that they contended made the arrangement “infeasible and even unwise.” Cos. Init. Br. at 49. We tend to believe that the Companies overstated the infeasibility and lack of wisdom in current approval of the Transaction with a conditional delay in closing.

The Companies suggest that AE Supply is not likely to accept a delay when its plan is to rid itself of its competitive generation business. Cos. Init. Br. at 49. They also suggest that there is no provision for delay in the Purchase Agreement, and even if it was willing to delay, AE Supply might not hold its sale offer at $195 million.

The Companies further criticize a delay on the grounds that it would jeopardize benefits of a planned rate reduction for 2018, and the positive impact of known increases in capacity prices in 2017-18 and 2018-19 will be lost as well. The Companies also expressed concern for AE Supply operating the plant under a cloud of uncertainty occasioned by a delay, and pointed out that this Commission has no jurisdiction to order AE Supply to operate the plant as would be expected in the normal course of an ongoing business. The Companies suggest in the Initial Brief that the hypothesized delay will present many more pitfalls than advantages. Cos. Init. Br. at 51.

We certainly cannot force the Companies to accept that proposal. We do offer the following comments on the problems identified by the Companies.

First, nothing prevented the Companies from requesting clarification of whether the Commission contemplated future “attendant conditions” before this response. The Commission, moreover, never contemplated ordering AE Supply to accept a delay. Accepting a current approval with a conditional delay in closing would always have been a decision that was left to the business judgment of AE Supply.

Second, if the Parties had asked, the Commission could have indicated that our approval with a closing delay would have been conditioned on the $195 million price. If that was unacceptable to AE Supply, AE Supply would be free to decline or petition for modification.

Third, while it is true that a delayed closing would also delay the rate modifications proposed by the Companies in this proceeding, if the Commission had approved acquisition, but with a delayed closing, foregoing the projected market benefits of Pleasants in 2018 would have been within our prerogative if we believed that was the best way to assure the reasonableness of future benefits projected by the Companies.
Fourth, clarification of the current market policy uncertainties that may eventually be resolved in a manner detrimental to West Virginia ratepayers is precisely what is needed to allow the closing to proceed. Commission approval would have been given, and clarification of current market policy and initiative uncertainties would not have overturned that approval unless the clarification showed the likelihood of detriments that would render going through with the closing as being contrary to the public interest. Any new market policies or initiatives that appeared contrary to the interest of West Virginia ratepayers could occasion further Commission consideration of the transaction, but that would only affirm the prudence of the Commission's conditional closing delay.

Fifth, AE Supply would have been free to operate the plant at its discretion. Acceptance of the delay would be up to AE Supply. If AE Supply accepted the delay, operated the plant in a manner that would jeopardize the capabilities of the plant to continue to run as contemplated by the Companies and the Commission, it would do so at its own peril of jeopardizing the closing.

The suggested approach would have provided a possible path for consummation of the Transaction, absent significant changes demonstrating that projected net customer benefits were not likely achievable. In that event, there might have been further Commission consideration of the transaction, but that consideration would be much more limited in scope than this proceeding. In the event that circumstances were such that the projected net benefits to customers were so unlikely that the Commission must stop the closing of the Transaction, that fact would benefit customers and affirm the prudence of the Commission's conditional closing delay.

VII. SUMMARY AND GENERAL DECISION

Although, as discussed in the Introduction, there are potential external benefits to the economy of the State, the local and regional areas around the Pleasants power plant, plant employees, and present and future ratepayers, these benefits do not outweigh the potential detriments to customers. We appreciate the efforts of the Companies to assure us that the NPV of costs and net market transactions from Pleasants ownership will be a significant positive value which will benefit customers. We have determined, however, that the uncertainties of achieving those net benefits, at the level projected by the Companies, are high. PJM market prices have been low in recent years. It appears that there is a high likelihood of an extended period of low PJM market prices and continuing evolution of PJM Market rules may not be tilting in a direction that will allow benefits to the extent projected by the Companies.

Because the Companies have steadfastly supported the reasonableness of their market analyses and the projections of a significantly positive NPV of Pleasants net cost, they should support their analyses by accepting some responsibility if market prices stay low or Pleasants costs escalate. A commitment by the Companies and FirstEnergy to that effect will remove our concerns, at least to the point of removing concerns that the NPV of Pleasants could prove to be a huge negative number, shouldered solely by ratepayers.
The Commission believes that the facts and circumstances of this case, and considering the alternative market option that is readily available to the Companies, require a departure from the historic capacity acquisition adjudication where the only reasonable options were construction or acquisition of rate based generation resources or long-term fixed requirements contracts for power supply.

Load serving entities now have a reasonably secure market option where capacity and energy are available at competitive prices that many believe have resulted in, and will continue to result in, the benefits of competitive pricing by the most efficient and economical resources. The market may serve as a point of reference against which the prudence of the historical model of self-generation by our electric utilities may be measured and evaluated.

The Commission is concerned that the trend in PJM market prices is not showing the signs of the upturn projected by the Companies that would produce the $636 million NPV benefit of Pleasants ownership suggested by Mon Power. The average day-ahead energy market prices have dropped into the low $30 per MWh range in recent years and do not show significant signs of recovery.

PJM Capacity Prices tend to move irregularly, but the trend has definitely turned down. Capacity prices per Megawatt Day are $126, $136, $59, $120, $164, $100, and $77 in delivery years beginning in 2014 through 2020, respectively.

These actual recent PJM market price data support a requirement that the Companies provide something more than educated speculation of increasing market prices and a $636 million NPV benefit of Pleasants ownership versus reliance on the market.

The Commission cannot force the Companies and FirstEnergy to back their projections of market prices with guarantees. We do, however, find that the lack of immediate need for capacity to meet PJM summer capacity requirements, the lack of need for energy to meet internal load requirements, the uncertainty of a benefit and amount of benefit from market transactions made possible by Pleasants ownership, and the certainty of the availability of the PJM market to meet any winter internal load or summer capacity obligations if and when such occur, lead us to conclude that the proposed acquisition of Pleasants is contrary to the public interest unless the Companies and FirstEnergy agree to shoulder the responsibility of the excess cost of Pleasants, vis-à-vis the market, if their projections are significantly in error.

The Commission does not expect the Companies and FirstEnergy to underwrite their projections absolutely. In other words, there does not need to be a guarantee of a $636 million NPV benefit for customers; neither do we expect an agreement that does not allow a fair opportunity for the Companies to recoup cost recovery foregone during periods of low market prices during periods of high market prices. We do find, however,
that a guarantee that the Companies will compensate customers during any year that market prices produce capacity and energy revenues from Pleasants that are below the full revenue requirements imposed on customers due to Pleasants is not only reasonable, but also it is appropriate for a finding that this particular transaction is not contrary to the public interest.

On the flip side, we find that it would be fair and reasonable to allow the Companies to record a deferred debit, regulatory asset, on their books equal to the amounts, if any, of compensation to customers when market revenues are insufficient to cover Pleasants costs and be allowed to recover such deferrals by retaining positive margins received from PJM in a subsequent year or years, up to the level of accumulated deferrals.

For example, if in the first year after acquisition, the base and ENEC Pleasants cost responsibilities paid by customers is $300 million, and the value of Pleasants capacity and energy sold in the PJM market is $280 million, the Companies would incur an obligation to return $20 million to customers, as directed by the Commission. If that $20 million is returned to customers in the form of rate credits, and the next year the Pleasants cost responsibilities paid by customers is $300 million, and the value of Pleasants capacity and energy in the PJM market is $305 million, the $5 million margin that would normally be credited to the benefit of customers would, instead, be retained by the Companies. That would leave the Companies with $15 million of potential future market benefits that they could retain. If in the third year, the Pleasants cost responsibilities of customers is $300 million, and the value of Pleasants capacity and energy in the PJM market is $340 million, the Companies could retain $15 million of the benefit and the remaining $25 million would be credited to customers using the normal ENEC credit mechanism, or, if the ENEC is no longer in effect, any other rate-setting mechanism as directed by the Commission.\(^{22}\)

\(^{22}\) We note that the condition and calculation methodology herein described is not the same as the condition placed on Mon Power for full recovery of the Acquisition Adjustment allowed in the Harrison case. In the Harrison case, we established a requirement that net margins attributable to Harrison market transactions that result in net revenue requirements credits that benefit customers must equal two times the annual revenue requirement on the Harrison Acquisition Adjustment before Mon Power could fully recover those revenue requirements. The intent and purpose of the Harrison guarantee, which required a net benefit to customers, is different from the guarantee that this Transaction is conditioned on, which requires market revenue equal to the total cost of Pleasants or a deferral of excess Pleasants costs above market revenue.
A. McElroy’s Run Impoundment and Dam

Turning to the McElroy's Run Impoundment and Dam, the Commission determines that there is sufficient concern regarding the issue of liability that there should be protections for the ratepayers from the impact of any future liability regarding the McElroy's Run Impoundment and Dam. The Commission will require that Companies submit appropriate agreements executed between Mon Power and a qualified FirstEnergy corporate entity that will exist in the future, pursuant to which that entity will indemnify, defend at its expense, and save Mon Power and its ratepayers harmless from any liabilities, costs, and claims, including judgments, fines, and penalties, or other costs or expenses, imposed upon Mon Power to the extent related to the Pleasants Plant or its operations prior to the transfer from AE Supply to Mon Power and the McElroy’s Run Impoundment and Dam, whenever arising.

Because indemnity agreements can be complex, contentious and complicated and can take on a life of their own, we will not herein spell out the terms that we expect in the indemnity agreement. What we require is that the indemnity should fully protect Mon Power and its ratepayers from any liability associated with the Pleasants Plant or its operations, including the McElroy's Run Impoundment and Dam, prior to the transfer of ownership, and also cover the McElroy's Run Impoundment and Dam subsequent to the transfer.

B. Temporary Surcharge and Ratemaking

Regarding recovery of costs, the Commission will allow the Companies to add a Temporary Surcharge to their tariffs. The Temporary Surcharge must be recalculated to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017.24 The revenue requirements and rates established at closing will not be subject to either prospective revision or retrospective true-up during their pendency. All base revenue requirements for Pleasants will be rolled into base rates in the Companies’ next base rate case and the Temporary Surcharge will cease at that time. It is reasonable, in consideration of testimony by WVEUG witness Mr. Baron asserting that industrial class base rates established in the last base rate case exceeded their cost of service, and referencing testimony by Companies’ witness Wise in the most recent base rate case, Case No. 14-0702-E-42T (Commission Order, February 3, 2015, at 11) acknowledging that possibility, to require the Companies to defer Temporary Surcharge amounts billed to their industrial rate schedules. WVEUG Ex. SJB-D at 33. The deferred balance may

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23 The McElroy’s Run Impoundment consists of a constructed impoundment area of approximately 253 acres behind a dam. Staff Ex. DWD-D at 5. Testimony referenced the McElroy’s Run Impoundment. When the Commission refers to McElroy’s Run Impoundment and Dam in the discussion, findings, conclusions and ordering paragraphs, we are referring to the dam, impoundment area and any related structures and improvements.

24 This recalculation requirement applies only to the Temporary Surcharge Calculation and will not affect future Commission determinations in the currently pending Commission General Order No. 236.1 proceeding.
accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case of the Companies following this Order. The deferral will allow industrial customers an opportunity to present their case regarding base industrial revenue requirements on a prospective basis. The Commission will not reallocate or assign the deferred industrial temporary surcharges to other classes of customers in the next base rate case, regardless of the prospective industrial revenue requirements the Commission determines to be just and reasonable in the next base rate case.

C. Continued Operations

As discussed above, the Commission considers factors other than impact on ratepayers to determine the interests of customers, the economy of the state, and local economies as part of the decision making process. We have determined that the immediate local, regional and statewide externalities to the Transaction are positive and significant. While these benefits, taken alone, are not sufficient to tip the balance from detriments to ratepayers to benefits from approving the Transaction, the external benefits are genuine, germane and real factors that the Commission considered, and which added weight to our decision to conditionally approve the Transaction. These external benefits, however, disappear if the Companies do not operate Pleasants for an extensive period of time.

The Companies have spoken glowingly of their maintenance programs and ability to extend the life of a generating facility far beyond its original engineering service life. The Companies have stated that Pleasants is a valuable asset with many years of service life ahead. They have argued that they need an asset that can meet capacity and energy needs years into the future, and Pleasants will deliver on that need. Pleasants, they argue, is a well-maintained, modernized facility capable of continuing operations for many years to come. Cos. Init. Br. at 37.

The Commission is relying on the continuing operations of Pleasants for many years to produce the benefits to the state and local economies that were factors in our decision to conditionally approve the Transaction. But beyond that, we also expect reasonable assurances of continued operations well into the future to protect customers against costs associated with premature retirement.

The Companies are in control of the initial decision for premature retirement and can make that an easy decision if they do not operate and maintain the plant as they have described in the record in this case. Their present practices which extend the service life of Pleasants, rather than shorten it include: maintenance practices based upon industry best practices, including a Major Component Integrity Assurance program (defines inspection requirements and intervals on plant equipment), Component Health Reports (summarizes failure history, inspection results and recommended future actions to enable proper outage planning), Advanced Pattern Recognition (real-time modeling system that

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analyzes plant operating inputs and anticipates necessary inspection or maintenance activities to prevent failure), Original Equipment Manufacturer advisories to ensure proper maintenance of facilities, robust plant operator training program with an on-site simulator, daily work management practices, and outage work management practices. Cos. Ex. DE-R at 2, 5-7.

In addition, the Companies witness, Evans, touted preventive maintenance at the plant, testifying:

We develop maintenance basis templates for the equipment and systems in that plant and we have preventative maintenance programs in place according to those templates . . . .

Tr. II at 371 (Evans).

The Companies also indicated how new equipment is constantly supplied to assure continuing operations. They stated:

Pleasants has ensured its viability through strategic capital investments over its lifetime. Plant personnel continually assess major components and perform life-extensions and capital placements when and where necessary. Examples include replacements of boiler components, feedwater heaters, and main turbine rotor trains; upgrades of generator rotor components and distributed control systems; and infrastructure investments such as a new stack. Pleasants has also invested capital to ensure that it remains up-to-date from an environmental compliance perspective.

Cos. Init. Br. at 38.

To provide protection to ratepayers, reasonable assurance of continuing external benefits for at least a reasonable period of time, and incentive for Mon Power to operate and maintain Pleasants consistent with the Companies’ testimony and statements as summarized above, the Commission will require the Companies to agree to a condition that recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to sliding scale limitation, and closure and post-closure costs of the McElroy’s Run Impoundment and Dam that exceed such costs already provided for in depreciation rates will not be passed on to West Virginia retail ratepayers at all.

Specifically, if the plant closes within the first eight years after transfer of ownership, no portion of undepreciated Pleasants capital costs or closing costs will be subject to recovery from customers. The percentage of reasonable closing costs and undepreciated capital costs, excluding any closure and post-closure costs related to the McElroy’s Run Impoundment and Dam, that will be subject to recovery from customers will increase by twenty percentage points at the beginning of the ninth year after transfer of ownership, and each two years thereafter. Thus, as of the beginning of the seventeenth
year after transfer of ownership, one-hundred percent of undepreciated capital costs and reasonable closing costs, excluding any closure and post-closure costs related to the McElroy’s Run Impoundment and Dam, shall be subject to recovery from customers.

Except for the limit on recovery of closure and post-closure costs related to the McElroy’s Run Impoundment and Dam, the limitation on the percentage subject to recovery from customers will not apply if the Companies make a filing for full recovery and the Commission determines that the closing is required because of new environmental, regulatory or any other laws or government regulations that require a closing of the plant.

The amount and timing of recovery of undepreciated capital costs and reasonable closing costs shall be subject to a future order of the Commission based on a finding that the costs to be recovered are reasonable and prudently incurred.

**VIII. CAD MOTION TO DISMISS**

On January 12, 2018, the Federal Energy Regulatory Commission issued its Order Rejecting Disposition and Acquisition of Generation Facilities and Dismissing Assumption of Liabilities (FERC Order). 162 FERC ¶ 61,015 (2018). In the FERC Order, FERC denied without prejudice authorization for the Transaction because the Applicants had not demonstrated that the Transaction is consistent with the public interest. On January 18, 2018, CAD filed a Motion to Dismiss in this Commission’s case asserting that, because the FERC had denied authorization for the Transaction, this Commission’s case is moot and should be dismissed. On January 22, 2018, Staff filed a Support of and Addition to the CAD Motion to Dismiss. On January 24, 2018, WVEUG filed a letter in support of the CAD and Staff positions.

On January 23, 2018, the Companies filed a letter in opposition to the Motion to Dismiss, noting that the FERC proceeding is not closed. The Companies requested that the Commission leave this docket open until the Companies have reached affirmative decisions on how to proceed and appropriate further action is taken by FERC.

We understand that the time for filing a Motion for Reconsideration with FERC has not yet expired and we acknowledge the Companies’ request to leave this docket open. The Commission had the benefit of the FERC Order prior to finalizing this Order. Given that, we believe that it is appropriate for this Commission to complete its work on the Petition in this case and issue this Order so that FERC can have this Commission’s thoughts on this matter. We, therefore, deny the CAD Motion to Dismiss and the related filings by Staff and WVEUG in support of the CAD Motion. When the Commission issues a decision on the merits, we typically close our docket as a procedural matter. By issuing a final order in this case, we are not depriving any party of any right provided by statute or rule. The parties have all options provided by Rule 19 of the Commission Rules of Practice and Procedure, 150 CSR 1, and the West Virginia Code.
IX. FINDINGS OF FACT

1. PJM is a summer peaking entity. Cos. Ex. BDE-R at 2-9; Longview Ex. SG-D at 20; Sierra Club Ex. TC-D at 7; WVSUN/CAG Ex. DAS-D at 12.

2. After the advent of PJM capacity rules, the capacity requirements of an LSE are based on its load during the PJM peak summer months and PJM rules do not require Mon Power to own or purchase capacity to meet its winter peak demand. WVSUN/CAG Ex. DAS-D at 12-13.

3. PJM has capacity to serve the winter peaks of all of its members, including the Companies. Staff Init. Br. at 7.

4. PJM is required to assure sufficient capacity to serve its summer peak plus a reasonable reserve margin.

5. The Bath County facility has the capacity to serve 487 MW of internal load. Cos. Ex. JAR-D at 6.

6. The Companies’ projected peak demand of 3,421 MW in the winter of 2020/2021 as compared with the 2,983 UCAP value of owned and contracted capacity (excluding Bath County) indicates a deficiency of only 438 MW instead of 1005 MW. Including Bath County leaves a modest surplus of 49 MW. Cos. Ex. JAR-D at 7.

7. In the past, there effectively were only three choices of supply available that a utility could choose – build generation, buy generation, or enter into a bilateral contract for firm power. The PJM Market is a choice for supply with a more limited risk profile than previous choices. Staff Ex. TRE-D at 35.

8. Purchased power, while not risk-free in the market, avoids some of the risks associated with traditional sources. The primary risk of the market is lack of control over price and price volatility. Staff Ex. TRE-D at 35.

9. The Companies’ 2015 IRP concluded that existing generation facilities would likely be the lowest cost option for additional capacity. Monongahela Power Co. and The Potomac Edison Co., Case No. 15-2002-E-P (IRP filed on 12/30/15 at 57).

10. The purchase price for the Pleasants Plant is $195 million, or $150/kW. Petition at 7; Cos. Init. Br. at 35.

11. PJM market prices have been relatively low in recent years. Sierra Club Ex. TC-D at 14, citing FirstEnergy 2017 10K at 4 (http://investors.firstenergcorp.com/Docs#gsc.tab=0).
12. PJM market prices are not trending upward and, under current trends, will not produce the $636 million NPV benefit of Pleasants ownership suggested in the Petition. Sierra Club Ex. TC-D; WVSUN/CAG Ex. DAS-D.


14. Unlike the record in this case, the record in the Harrison case established a need for Harrison capacity to meet summer peaks as required by PJM and the energy shortfalls that were facing the Companies if they did not acquire Harrison. Id.

15. Unlike the record in this case, in the Harrison case the record reflected that the Companies were facing a significant shortfall in meeting their energy requirements with internal generation resources. Id.

16. The Companies do not have an immediate need for capacity to meet PJM summer capacity requirements or internal load requirements. WVEUG Ex. SJB-D at 9, Fig. 1; Longview Ex. SG-D at 19-23; Sierra Club Ex. TC-D at 7-12; WVSUN/CAG Ex. DAS-D at 7-17.

17. Excess energy produced by additional owned capacity not required to serve internal load can, at the right prices and circumstances, be sold into the PJM energy market at a net margin to benefit West Virginia customers. Cos. Ex. HCK-D at 10.

18. The costs of the Transaction can be offset initially by projected net margins from PJM capacity, energy, and ancillary service transactions of approximately $135 million per year with the possibility of even larger net margin benefits that could reduce customer rates in the future.

19. The preventive maintenance program used by the Pleasants Plant is modeled from the Electric Power Research Institute. Pleasants inspects critical equipment, such as transformers, to ensure reliability and prepare for high-impact, low-probability events. Tr. II at 370-71 and 368, respectively.

20. Pleasants conducts scheduled outages on each unit every three years and performs replacements as necessary. Tr. II at 348.

21. Various externalities related to an array of non-ratemaking implications about employment and jobs, enhancing and preserving the attractiveness of the State as a place for industry to do business, maintaining productive capacity, tax base, and support to local and regional charities and providing governmental financial support and a host of other outcomes, other than rate impact, tend to support the Transaction.
22. The beneficial impact of those externalities lasts only as long as the Companies operate Pleasants.

23. The Pleasants Plant is in reasonably good condition and the present practices and preventive maintenance at Pleasants will extend its potential life.

X. CONCLUSIONS OF LAW

1. The Companies could have negotiated the Transaction directly and were not required to use an RFP by West Virginia Code or case law.

2. The existence of the need for approval of a W.Va. Code §24-2-12 transaction and the existence of an affiliated relationship are not a basis to reject an affiliated transaction or affiliated relationship, absent a showing of fraud, abuse or undue influence.

3. The Commission must examine virtually all affiliated transactions and is required to apply to those transactions a level of due diligence consistent with the requirements of W.Va. Code §§24-2-12 and 24-1-1.

4. Affiliated transactions are not prohibited, nor is there anything inherently improper about affiliated transactions. A review of an affiliated transaction is a results-oriented analysis that determines whether a proposed affiliated transaction satisfies the requirements of W.Va. Code §24-2-12 and not simply whether there is the existence of an affiliated relationship.

5. There is nothing in the record to establish that the negotiated terms of the Transaction between the affiliated parties are fraudulent, abusive, the product of undue influence, or a basis for denying the Transaction.

6. The record does not reflect that CRA acted unscrupulously or deliberately skewed its evaluation in favor of the Pleasants bid.

7. The record in the case does not establish an immediate need for capacity from the Pleasants Plant to meet summer peaks as required by PJM.

8. The record in this case does not reflect that the Companies have a shortfall in meeting their energy requirements with internal generation resources.

9. Neither the Harrison Order nor the IRP Act requires an electric utility to own capacity to meet its load requirement and the utility can arrange to meet its load from a number of reasonable options, including purchases from the PJM Market.
10. While projections of peak demands are required by W.Va. Code §24-2-19(d), the planned capacity resources are left to the discretion of the utility, subject to the requirement that the portfolio of capacity resources provides adequate and reliable service and represents a reasonable balance of costs and risks. The utility may decide to own capacity to meet the peak load, or it may decide to meet the load with a combination of owned capacity and purchased power. Purchased power may include purchases from the PJM Market.

11. The Companies’ comparison of projected winter peaks plus a 16.6 percent reserve margin to the PJM UCAP values, which PJM uses to determine capacity resources needed to satisfy a PJM-assigned capacity level based on summer peaks, is a mismatch and results in a significant overstatement of the amount of installed capacity needed to reliably meet internal winter peak and provide a reasonable reserve margin.

12. The Companies’ comparison of PJM UCAP values to the Companies’ winter load projections, plus a 16.6 percent reserve margin, is not a reasonable basis to evaluate whether the Companies have sufficient owned and contracted capacity resources to meet their load requirements plus a reasonable reserve margin.

13. Without ICAP information in the record, which we could compare to the projected winter peak plus a 16.6 percent reserve margin, and without evidence on a winter peak plus a more realistic reserve margin to compare to UCAP, it is reasonable to calculate a more realistic deficiency by comparing the unadjusted projected winter peak to UCAP.

14. The prudence of the Transaction to acquire 1,300 MW of capacity to meet a winter supply deficiency that is much smaller than 1,300 MW, and that is not required under PJM Rules, is questionable, particularly considering that the Companies have a large surplus of expected energy generation in excess of their internal needs, even before the Transaction.

15. The current likelihood of a period of low PJM market prices and the continuing evolution of PJM Market rules may not support the benefits of the Transaction to the extent projected by the Companies.

16. Considering the alternative PJM market option readily available to the Companies, the facts and circumstances of this case require a departure from the historic capacity acquisition adjudication in which the only reasonable options were construction or acquisition of rate-based generation resources or long-term fixed requirements contracts for power supply.

17. The current and projected cost of acquiring power from the market may serve as a point of reference against which the prudence of continuing the historical practice of self-generation by our electric utilities may be measured and evaluated.
18. The Commission may consider the likelihood of realizing revenue from PJM capacity, energy, and ancillary service transactions to determine if the Pleasants Transaction is in the public interest.

19. An agreement from the Companies and FirstEnergy to recover from customers no more than the value of Pleasants capacity, energy and ancillary services sold in the PJM Market is necessary to protect customers from unjust, unreasonable, and excessive rates and to allow this Commission to determine that the Transaction is in the public interest.

20. Under the circumstances of this case, including the limitation on cost recovery to the value of Pleasants capacity, energy and ancillary service sales in the PJM Market, the Companies should be allowed to record a deferred debit, regulatory asset on their books equal to the amounts, if any, of compensation to customers when market revenues are insufficient to cover Pleasants costs and then be allowed to recover such deferrals by retaining positive margins received from PJM in a subsequent year or years up to the level of accumulated deferrals.

21. The Longview request to withdraw its intervention will be granted, and inasmuch as Longview fully participated in the case and the intervention was not withdrawn until after the close of the record, the testimony and evidence presented by Longview will remain a part of the record in this case.

22. The Commission has jurisdiction over this case pursuant to W.Va. Code §24-2-12 which requires prior Commission approval to enter into a contract with an affiliated corporation, person, or interest “upon proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State.”

23. There are immediate local, regional and statewide externalities to the Transaction that are positive and significant and lend support to the decision to approve the Transaction as conditioned in this Order.

24. The prudence and risk of the decision on whether to approve the Pleasants Transaction lies in a balancing of a number of factors including the impact of the Transaction on ratepayers.

25. It is prudent to consider, contemplate and attempt to safeguard against risk that is reasonably likely to occur.

26. The primary test to determine the economic benefits of the Pleasants Transaction is the relationship of base and ENEC cost of owning and operating the plant as measured against the PJM Market and the benefits of reduced rates that can be derived for customers when excess energy and capacity, not needed to serve native load, and ancillary services, are sold in the market at a positive net margin.
27. The proposed Transaction, with the implementation of the conditions imposed by the Commission, should be a reliable and economical source of capacity and energy that will not burden ratepayers with excessive, unreasonable or imprudent costs.

28. Because (i) the Companies do not have an immediate need for capacity to meet PJM summer capacity requirements; (ii) the Companies do not have a need for energy to meet internal load requirements; (iii) the uncertainty of a benefit and amount of benefit from market transactions made possible by Pleasants ownership; and (iv) the certainty of the availability of the PJM market to meet winter internal load or summer capacity obligations if and when such need would occur for the Companies, the proposed acquisition of Pleasants is contrary to the public interest, unless the Companies and FirstEnergy agree to shoulder the responsibility of the excess cost of Pleasants, vis-à-vis the market, if their projections are significantly in error.

29. Because there is sufficient concern regarding the issue of liability for the McElroy’s Run Impoundment and Dam, there should be protections put in place for the Companies and the ratepayers against the impact of any liability from the McElroy’s Run Impoundment and Dam.

30. The Companies should enter into an indemnity agreement with a qualified FirstEnergy corporate entity to protect Mon Power and its ratepayers from any liability associated with the Pleasants Plant or its operations prior to the transfer of ownership, and covering any liability for the McElroy’s Run Impoundment and Dam, as further described in this Order.

31. To assure continued external benefits for at least a reasonable period of time, protect ratepayers, and as an incentive for the Companies to operate and maintain Pleasants consistent with their testimony and arguments, the Companies should agree to a condition that recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to a sliding scale limitation as described in the Order.

32. Under the circumstances of this case, including the contemporaneous ENEC net credits, the Companies should add a Temporary Surcharge to their tariffs.

33. The Companies should recalculate the Temporary Surcharge to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017.

34. The Temporary Surcharge should be continued without prospective revision or retrospective true-up until base rates are established in the Companies next base rate case.

35. The Companies should defer Temporary Surcharge amounts billed to their industrial rate schedules, provided that the deferred balance include a carrying charge at a
simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case following this Order. Deferred industrial Temporary Surcharges will not be reallocated or assigned to other classes of customers in the next base rate case, regardless of the prospective industrial revenue requirements determined to be just and reasonable in that case.

X. ORDER

IT IS THEREFORE ORDERED that the Petition of Monongahela Power Company and The Potomac Edison Company is denied as filed.

IT IS FURTHER ORDERED, however, that the Commission approves a transfer of the Pleasants Plant from AE Supply to Monongahela Power Company if the parties to the transfer agree to the conditions set forth below and further described in Section VII of this Order:

a) The Companies will compensate customers through prospective rate credits as determined by the Commission for any year that market sales from Pleasants produce revenues that are below the full revenue requirements imposed on customers due to Pleasants. The first determination of the outcome of this condition will cover the first full twelve-month period following the consummation of the Transaction, or such longer period as the Commission determines will accommodate a review and decision synchronized with the Companies’ annual ENEC proceedings. Thereafter, proceedings addressing this condition will be conducted in separate annual proceedings on the same timeline as the annual ENEC cases.

b) The Companies will defer Temporary Surcharge amounts billed to their industrial rate schedules. The deferred balance may accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case following this Order.

c) Mon Power and a qualified FirstEnergy corporate entity that will exist in the future will submit for review and approval agreements pursuant to which the entity will indemnify, defend at its expense, and save Mon Power and its ratepayers harmless from any liabilities, costs, and claims, including judgments, fines, and penalties, or other costs or expenses, imposed upon Mon Power to the extent related to the Pleasants Plant or its operations prior to the transfer from AE Supply to Mon Power and the McElroy’s Run Impoundment and Dam, whenever arising.
d) Recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to sliding scale limitations, as further described in this Order at Section VII, and closure and post-closure costs of the McElroy's Run Impoundment and Dam that exceed such costs already provided for in depreciation rates will not be passed on to West Virginia retail ratepayers, at all.

IT IS FURTHER ORDERED that, except for the limit on recovery of closure and post-closure costs related to the McElroy's Run Impoundment and Dam, the limitation on the percentage subject to recovery from customers shall not apply if the Companies make a filing for full recovery and the Commission determines that the closing is required because of new environmental, regulatory or any other laws or government regulations that require a closing of the plant.

IT IS FURTHER ORDERED that the amount and timing of recovery of undepreciated capital costs and reasonable closing costs of Pleasants, to the extent allowed under the conditions outlined above, shall be subject to a future order of the Commission based on a finding that the costs to be recovered are reasonable and prudently incurred.

IT IS FURTHER ORDERED that a Temporary Surcharge is authorized upon closing, conditioned on a recalculation of the Temporary Surcharge rates to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017 and a contemporaneous reduction in ENEC rates as proposed by the Companies and as further described in this Order. The Pleasants base revenue requirements and rates established at closing will not be subject to either prospective revision or retrospective true-up during their pendency. All base revenue requirements for Pleasants will be rolled into base rates in the Companies next base rate case and the Temporary Surcharge shall cease at that time.

IT IS FURTHER ORDERED that the Companies shall defer Temporary Surcharge amounts billed to their industrial rate schedules. The deferred balance may accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers, without reallocation or reassignment to other customers, over such period as is directed by the Commission in the first base rate case following this Order.

IT IS FURTHER ORDERED that Monongahela Power Company and The Potomac Edison Company shall, within thirty days of issuance of this Order, file recalculated revenue requirements and proposed tariff sheets in accordance with this Order.
IT IS FURTHER ORDERED that Monongahela Power and a FirstEnergy Corporation entity that will exist in the future shall file within thirty days of this Order the indemnity agreements required by this Order.

IT IS FURTHER ORDERED that, on or after the date the Transaction is consummated, Monongahela Power Company and The Potomac Edison Company shall file an original and six copies of appropriately notated revised tariff sheets setting forth the approved surcharge, to be effective on the closing date of the Transaction.

IT IS FURTHER ORDERED that the Companies make a closed entry filing notifying the Commission of the date of closing.

IT IS FURTHER ORDERED that the Longview Power, LLC Motion to Withdraw as an Intervenor in this case is granted. The testimony and evidence presented by Longview shall remain a part of the record in this case.

IT IS FURTHER ORDERED that the Motion to Dismiss filed by the Consumer Advocate Division and the supporting motions filed by Commission Staff and WVEUG are denied.

IT IS FURTHER ORDERED that the Executive Secretary maintain the information filed under seal in this proceeding separate and apart from the remnant of the case file pending a further Commission Order issued after review of any request to inspect or copy the sealed information.

IT IS FURTHER ORDERED that this proceeding be removed from the Commission docket of active cases on entry of this Order.
IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste.

Ingrid Ferrell  
Executive Secretary

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PROCEDURAL HISTORY OF THE CASE

Public Notice


Interventions

The following parties were granted intervenor status in this case: CAD, WVSUN/CAG, WVEUG, Longview, Sierra Club, HCP and BCP, WVCA, and WVBIC. Commission Orders entered April 14, 2017, May 11, 2017, June 1, 2017, and August 30, 2017.

On December 11, 2017, well after entering pre-filed testimony and presenting testimony during the evidentiary hearing, Longview filed a request to withdraw its intervention in the case. Longview stated its support for the Companies’ Petition.

Motions for Protective Treatment

The Commission deferred ruling on Motions for Protective Treatment filed by the Companies on April 10, 2017, and August 2, 2017. Commission Orders, April 14 and August 21, 2017. The Companies sought protective treatment for direct testimony and exhibits filed by the Companies and (i) Competitive Operational Information, (ii) Competitive RFP and Bid Analysis Information, (iii) Natural Gas, Capacity, and Electricity Price Forecast Information, and (iv) Business Expansion Information. No other parties objected to either Motion.

On September 20, 2017, WVEUG filed a Motion seeking protective treatment for the information submitted in response to Question 21 of the Companies’ first discovery
requests. The information was compiled by Michael Messer in his position with WVEUG member Linde LLC. Mr. Messer testified on the effect that the proposed sale may have on Linde. The information for which WVEUG seeks protective treatment pertains to operating costs and the prices paid to Mon Power for electric service. No other party has objected to the request for protective treatment. The Commission ruled from the bench that it would defer ruling on the Motion for Protective Treatment until such time as an objection was raised or a WV FOIA request for the information was filed. Tr. I at 19.

Public Comment

The Companies published Notice of Public Comment Hearings in The Journal (Berkeley County), The Exponent-Telegram (Harrison County), The Inter-Mountain (Randolph County), The Dominion Post (Monongalia County), The Parkersburg News and Sentinel (Wood County), The Times West Virginian (Marion County), The Weirton Daily Times (Hancock County), The West Virginia Daily News (Greenbrier County), The News Tribune (Mineral County), and The Charleston Gazette Mail (Kanawha County, with statewide distribution) on June 9 and 16, 2017. Commission Order, June 1, 2017; Affidavits of Publication, July 3, 2017.

Public comment hearings were held in the service territory of the Companies: (i) the Parkersburg Municipal Building Council Chambers on 3rd and Avery Streets in Parkersburg, West Virginia, on September 6, 2017, at 6:00 p.m.; (ii) the Martinsburg City Building, Municipal Courtroom, 232 North Queen Street, on September 11, 2017, at 7:00 p.m.; and (iii) the Monongalia County Judicial Center, Judge Tucker’s Courtroom, 75 High Street, Morgantown on September 12, 2017, at 6:00 p.m. The public comment hearings were well-attended and approximately 35 people spoke at each hearing.

Pre-filed Testimony

On March 7, 2017, the Companies pre-filed the Direct Testimony of its witnesses:

1. Bradley D. Eberts – Manager of Load Forecasting, FirstEnergy Service Company; providing a fifteen-year forecast (2017-2031) of the Companies’ load peak demand and energy requirements and the methodologies used to develop them. The forecasts included both winter and summer peaks.

2. John Deskins – Director of the Bureau of Business and Economic Research and Associate Professor of Economics at West Virginia University College of Business and Economics; testifying on (i) the historical and fifteen-year forecast (2016-2031) for the Companies’ West Virginia service territory to be used for modeling their load and energy forecast and (ii) the economic impact to the local, regional, and state economies of the Pleasants facility.
3. **Holly C. Kaufmann** – President, West Virginia Operations, Monongahela Power Company; providing an overview of the Petition, the needs of the Companies and the customers, and the Companies’ process of seeking additional generation resources and demand response.

4. **Robert J. Lee** – Vice President in the Auctions and Competitive Bidding Practice at Charles River Associates; describing his role and CRA’s role in the Request for Proposals process, how the RFP was created, and how the RFP was fair and competitive.

5. **Kurt P. Leutheuser** – Project Manager for Black & Veatch; providing a general overview of the technical evaluation of the Pleasants proposal and a physical site visit made on February 20, 2017.

6. **Jay A. Ruberto** – Director, Regulated Generation and Dispatch for FirstEnergy Service Company; describing Mon Power and the process by which it determined it would need to acquire additional resources to meet future capacity needs and Mon Power’s efforts to satisfy its projected need.

7. **Thomas Sweet** – Director, Global Reference Case, Enterprise Software for ABB Inc.; providing a general overview of the 2016 energy and capacity forecasts provided by CRA and addressing the methodology and specific components of those forecasts.

8. **Raymond E. Valdes** – Director, Rates and Regulatory Affairs, FirstEnergy Service Company; testifying on the development of the proposed temporary surcharge, calculation of recommended reductions in ENEC rates, and the net effect of these proposed rate changes.

On August 25, 2017, Staff pre-filed the Direct Testimony of its witnesses:

1. **Eric F. deGruyter** – Technical Analyst, Engineering Division, Public Service Commission of West Virginia; testifying on the Request for Proposals and the load forecast driven by the natural gas activities and growth in Mon Power’s West Virginia service territory.

2. **David Dove** – Engineer Senior/Manager, Engineering Division, Public Service Commission of West Virginia; testifying on the McElroy’s Run Impoundment and Pleasants Landfill connected to the Pleasants facility.

3. **Terry R. Eads** – Director, Utilities Division, Public Service Commission of West Virginia; testifying on the Utilities Division’s overall position regarding the requested transfer of Pleasants, including a review of the economic models, adjustments to the CRA economic models, presentation of alternative capacity,
energy and fuel forecasts, forecast supported by the Utilities Division, and
discussing and analyzing alternative arrangements to meet Mon Power’s
growing customer capacity and energy requirements.

4. Edwin L. Oxley – Utilities Analyst, Utilities Division, Public Service
Commission of West Virginia; testifying on the rate proposals made by the
Companies effective on completion of the Transaction to purchase Pleasants.

5. Randall R. Short – Deputy Director, Carrier and Consumer Operations,
Utilities Division, Public Service Commission of West Virginia; collectively
presenting the overall Staff recommendation based on the testimony of the
various Staff witnesses in this case.

6. Donald E. Walker – Technical Analyst, Engineering Division, Public Service
Commission of West Virginia; evaluating the physical plant for any
deficiencies in performance, maintenance, and operations of the two 650 MW
generating units.

On August 25, 2017, Longview pre-filed the Direct Testimony of its witnesses:

1. Thomas Burnett – Technical Director – Power Generation, Engineering Group,
Intertek AIM; identifying concerns regarding the representation of the
condition and information concerning Pleasants, including a discussion of
fossil power plant components and design, effects of operating practices and
plant condition determining plant reliability and useful life, and the operating
regime of Pleasants.

2. Steven Gabel – President, Gabel Associates, Inc.; providing an overview of the
petition filed by the Companies, including the reasonableness of the customer
impact analysis filed by the Companies, whether the installed capacity size of
the proposed Transaction is a reasonable commitment to make on behalf of
ratepayers, and whether the Companies’ process for entering into the proposed
Transaction is reasonable and designed to bring about the best results for
ratepayers and West Virginia.

3. Nikhil Kumar – Managing Director, Intertek AIM; testifying on the current
condition of Pleasants regarding industry trends, benchmark historical
operations against peer units, historical and projected plant operating costs, and
assessing the reasonableness of the assumptions used in the NPV analysis
performed by CRA.
On August 25, 2017, HCP and BCP pre-filed the Direct Testimony of its witness:

**Andrew W. Dorn, IV** – President, Energy Solutions Consortium, LLC; testifying on the natural gas power plant development projects of ESC Harrison County Power, LLC, and ESC Brooke County Power, LLC, and explaining how these alternatives are better than Pleasants.

On August 25, 2017, CAD pre-filed the Direct Testimony of its witness:

**Emily S. Medine** – employed by Energy Ventures Analysis, Inc.; testifying on all aspects of the proposed transfer of Pleasants.

On August 25, 2017, Sierra Club pre-filed the Direct Testimony of its witness:

**Tyler Comings** – Independent Contractor for synapse Energy Economics; testifying on the transfer of Pleasants with a focus on the Companies’ capacity requirements and the economic analysis conducted by CRA.

On August 25, 2017, WVBIC pre-filed the Direct Testimony of its witness:

**Chris Hamilton** – Chairman, West Virginia Business & Industry Council; testifying about the importance to the State of preserving Pleasants.

On August 25, 2017, WVCA pre-filed the Direct Testimony of its witness:

**William B. Raney** – President, West Virginia Coal Association; testifying about coal production and Pleasants.

On August 25, 2017, WVEUG pre-filed the Direct Testimony of its witnesses:

1. **Stephen J. Baron** – President and a principal at J. Kennedy and Associates; testifying generally on the proposed Pleasants transfer, including the economics of the Transaction, the possible impact on the Companies’ customers, the proposed ratemaking treatment, and the analysis by CRA.

2. **Lane Kollen** – Vice President and a principal at J. Kennedy and Associates; testifying on the accounting for the Pleasants transfer and the appropriate ratemaking for accumulated deferred income taxes if the Transaction is approved.

3. **Michael K. Messer** – Manager, Energy and Regulatory Affairs for Linde, LLC, and Chair of WVEUG; testifying from the perspective of a large industrial customer on the potential impact of the Pleasants Transaction on economic and operational decisions.
On August 25, 2017, WVSUN/CAG pre-filed the Direct Testimony of its witness:

David Schlissel – President, Schlissel Technical Consulting, Inc.; Analyzing all aspects of the proposed transfer Pleasants.

On September 18, 2017, the Companies pre-filed the Rebuttal Testimony of its witnesses:


2. Dale Evans – Employed by FirstEnergy Service Company as the Technical Service Manager, Pleasants Power Station; responding to characterizations of the Pleasants plant as a deteriorating asset facing significant performance issues regarding investment and plant reliability, maintenance and operations and management costs, operating parameters, turbine efficiency and heat rate, boiler, and waste disposal and environmental costs.

3. Robert J. Lee – Responding to direct testimony of witnesses for Longview, WVSUN/CAG, the Sierra Club, and CAD regarding design and administration of the RFP and CRA’s scoring of bids.

4. Kurt P. Leutheuser – Responding to claims by Mr. Kumar and Mr. Burnett that Pleasants is an inadequate generating asset.

5. Jay A. Ruberto – Addressing a variety of testimony from Intervenors including determination of capacity deficiency, value of a physical hedge, allegations of bias and undue advantage, NPV calculation criticisms, price criticisms, the value of Pleasants, customer benefit, and Pleasants’ contribution to the State.

6. Thomas Sweet – Responding to the testimony of Mr. Schlissel, Ms. Medine, and Mr. Comings.

7. Raymond E. Valdes – Addressing the rate-related recommendations of witnesses Mr. Oxley, Mr. Short, Mr. Eads, Mr. Baron, Mr. Kollen, and Mr. Schlissel.

On September 18, 2017, Longview pre-filed Rebuttal Testimony of:

Steven Gabel – Addressing aspects of Staff and CAD witness direct testimony.
On September 18, 2017, WVEUG pre-filed Rebuttal Testimony of:

Stephen J. Baron – Responding to a variety of witnesses on the reasonableness of the Pleasants acquisition, its potential impact on ratepayers, and rate recovery issues.

Evidentiary Hearing


It was anticipated that the evidentiary hearing would conclude in three days; however, two extra days of hearing were necessary (September 29, 2017, and October 10, 2017). The Companies, Staff, CAD, WVEUG, WVSUN/CAG, Sierra Club, Longview Power, and HCP/BCP filed initial briefs on October 19, 2017, and reply briefs on October 26, 2017. WVBIC and WVCA did not file post-hearing briefs.

The Commission reviewed the 155-page Petition, including exhibits, pre-filed direct testimonies and exhibits consisting of approximately 1,376 pages of record evidence. The Commission also conducted three public comment hearings resulting in 250 pages of transcript of public testimony for and against the proposed sale, and an evidentiary hearing that resulted in five transcripts consisting of 1,211 pages and hundreds of pages of exhibits. The Commission also reviewed the initial and reply briefs filed by the Parties and consisting of approximately 400 pages of argument.
ATTACHMENT TFC-21
POTENTIAL FOR PEAK DEMAND REDUCTION IN INDIANA

Prepared for Indiana Advanced Energy Economy by Demand Side Analytics, LLC

February 2018
Acknowledgements

Principal Consultants

- Jesse Smith
- Josh Bode

Quantitative Analyst

- Steve Morris

This study was developed using anonymized data from ecobee thermostat customers participating in Donate Your Data.
EXECUTIVE SUMMARY

Energy costs are an important component of the operating budget of homes and businesses across Indiana, giving all Hoosiers an interest in opportunities to reduce their energy costs. Those costs are unavoidably impacted by utility infrastructure investments, which are largely driven by peak loads. Approximately 10% of infrastructure investments focus on serving load in just 1% of hours of the year. As such, strategic peak demand reductions can help avoid or defer capital-intensive system upgrades and save hundreds of millions of dollars over the next decade. This analysis, commissioned by Advanced Energy Economy Institute (AEE Institute) on behalf of AEE Indiana, examines the magnitude and economic opportunity of three specific demand reduction strategies in Indiana.

Demand response (DR) strategies that shave peak loads or shift them to off-peak hours can be cost-effective alternatives to costly construction of new generation resources that sit idle most of the year. Energy storage technologies like batteries achieve similar benefits by storing energy at times when it is plentiful for use during peak hours. These alternatives to additional generating capacity can also avoid the need for transmission and distribution infrastructure investments that would similarly be needed to meet demand during just a relatively few peak hours. DR options can also be added incrementally, to match the need.

The biennial Integrated Resource Planning (IRP) process in Indiana is used as a platform for the state’s investor-owned utilities (IOUs) to document the electric power requirements of their service territories and put forth, in transparent fashion, strategies to satisfy those needs. The types of demand reduction strategies included, and the level of incorporation of DR resources in prior IRPs, have varied significantly across the Indiana IOUs. Duke, NIPSCO, and Indiana Michigan Power have secured several hundred megawatts (MW) of load reduction capability from a relatively small number of large industrial customers. Duke, Indianapolis Power and Light (IPL), and Vectren have established residential air conditioner cycling programs that range from 20 MW to 60 MW of load reduction capability.

This paper provides a statewide analysis of three strategies the research team believes warrant focused consideration by system planners in future IRP cycles – commercial and industrial (C&I) load curtailment, residential connected thermostats, and battery storage.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.

The optimal role of DR in the resource mix is largely a function of its costs relative to traditional solutions. A primary goal of the IRP process is to ensure adequate resources to confidently meet demand for electricity at the
lowest cost. Ideally, this means supply-side resources and demand-side resources are placed side-by-side and selected based on levelized cost. To illustrate the sensitivity of DR potential to the cost of alternative resources, we modeled DR potential using three avoided cost scenarios:

- **Low Avoided Cost**: Assumes recent historic Midwest market prices for generation capacity avoided by DR investments and no value on the transmission and distribution system. Reductions valued at approximately $15/kW-year.

- **Medium Avoided Cost**: Includes approximately $60/kW-year for avoided generation capacity, consistent with tighter supply, and $10/kW-year each for benefits on the transmission and distribution (T&D) systems.

- **High Avoided Cost**: Assumes the traditional solution is construction of a new natural gas-fired power plant, with $100/kW-year for generation and $20/kW-year for benefits on the T&D systems.

Avoided costs are a key determinant of DR potential because they govern the equipment cost and/or incentive that can cost-effectively be made to participants to secure load reductions. When avoided costs support a more generous offer, participation rates increase and DR potential increases. Several avoided costs for demand-side management (DSM) published by IOUs in their most recent IRPs generally fell in a range between our Medium and High scenarios, indicating that these are representative of expected costs in Indiana.

### Commercial and Industrial (C&I) Sectors DR Potential

Indiana’s commercial and industrial sectors spent $11.3 billion on electricity in 2015, consuming over 144,000 GWh, according to the U.S. Energy Information Administration. For the Medium Avoided Cost scenario, the research team estimates 2,159 MW of DR potential in Indiana by 2027 for a day-ahead notification program – nearly 20% of forecasted summer peak demand for the C&I sectors, and resulting in savings over ten years of $485 million on a net present value (NPV) basis. For a day-of notification program, the 2027 potential is 1,203 MW – lower than the day-ahead estimate, but still almost 10% of summer peak demand, and providing $272 million in NPV benefits over 10 years. Savings are even greater under the High Avoided Cost scenario: $1.6 billion for the day-ahead program, $907 million for day-of.

Figure 1 shows DR market potential estimates for 2027 by avoided cost scenario, notification level, and sector. Table 1 shows the present value (in 2018 dollars) of the net benefits (benefits minus costs) of a 10-year C&I DR program by avoided cost scenario for day-ahead and day-of notification programs.
Figure 1: 2027 DR Potential Estimates by Avoided Cost Scenario

Table 1 - Present Value of Net Benefits by Avoided Cost Scenario - Ten Year C&I DR Program

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<tbody>
<tr>
<td>Low</td>
<td>$15</td>
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<tr>
<td>Medium</td>
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<td>$272</td>
</tr>
<tr>
<td>High</td>
<td>$1,615</td>
<td>$907</td>
</tr>
</tbody>
</table>
All of the DR market potential estimates shown are highly cost-effective by the standard measures applied by utilities and regulators, with Utility Cost Test\(^1\) ratios ranging from 1.61 on the low end to 1.94 on the high end.

**Residential Sector DR Potential**

The adoption of internet-connected ‘smart’ thermostats such as those offered by Nest and Ecobee is growing due to customer demand as well as utility support for energy efficiency and DSM investment. These devices present an opportunity to scale residential DR resources at low cost. Because adoption of connected thermostats is driven by customer preferences, the utility costs of equipment and installation are lower than for traditional air conditioner cycling switches, such as those used in existing residential DR programs administered by several Indiana utilities. This presents a significant opportunity for increasing DR penetration in the residential sector. Smart thermostat capabilities like ‘pre-cooling’ of homes prior to DR events help improve participant comfort and enhance customer satisfaction.

Table 2 shows the significant opportunity presented by smart thermostats in Indiana over the next decade. Statewide, the aggregate estimated cost-effective achievable potential by 2027 is 230 MW under the Medium Avoided Cost scenario, leading to enrollment of 214,000 devices, net benefits of $73 million over the 10-year study horizon, and a strong benefit-cost ratio of 2.44 under the Utility Cost Test. Said another way, reducing peak load by using connected thermostats will lead to lower utility costs and lower customer bills than building new peaking power plants to address power plant retirements or increases in load. Under the High Avoided Cost scenario, demand reductions of over 530 MW – the peak production equivalent of five mid-sized power plants – can be attained, yielding $344 million in savings over the next 10 years.

**Table 2 - Connected Thermostat 10-Year Cost-Effectiveness and Market Potential by Avoided Cost Scenario**

<table>
<thead>
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<tbody>
<tr>
<td>Low</td>
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<td>$541.4</td>
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<td>$343.7</td>
<td>2.74</td>
</tr>
</tbody>
</table>

\(^1\) The Utility Cost Test (UCT) assesses cost-effectiveness from the perspective of the utility. Utility system benefits are compared to the cost of acquiring the resource. Any benefit-cost ratio greater than 1 means the program is cost effective.
Emerging Technology: Energy Storage

On energy storage, this report focuses on battery storage potential and cost-effectiveness from a utility perspective. The estimates of battery potential are incremental to the two customer-sited DR options explored in the residential and C&I sections of the report – that is, what cost-effective savings could be obtained from battery storage investments over and above those provided by DR initiatives.

Because energy storage is a relatively new technology, market potential estimates are inherently uncertain. Two key factors drive the potential for cost-effective battery storage – the price trends in battery storage technology and location-specific T&D deferral value. While other benefits from batteries were included in the analysis, in Indiana, avoided energy costs and avoided capacity costs alone are insufficient to make batteries cost-effective at current prices. As a result, cost-effectiveness for battery storage depends on identifying locations where it can help to defer or avoid transmission and/or distribution infrastructure investments. As costs drop, as they are projected to do over the forecast period, battery storage becomes cost-effective in an increasing number of locations – and for a greater share of peak demand.

Table 3 summarizes the estimated cumulative cost-effective potential for battery storage by 2027. For the Medium Avoided Cost scenario, 139 MW of cost-effective battery storage is projected, lowering utility and customer costs by $103 million over 10 years. Under the High Avoided Cost scenario, we estimate approximately 329 MW of cost-effective battery storage potential, delivering $311 million in net benefits. There is no cost-effective battery storage potential under the Low Avoided Cost scenario, which includes relatively low capacity prices and no transmission and distribution avoided costs.

Table 3 – Battery Storage Potential and Cost-Effectiveness

<table>
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<th></th>
<th></th>
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</thead>
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<td>$0.0</td>
<td>$0.0</td>
<td>N/A</td>
</tr>
<tr>
<td>Medium</td>
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<td>$103</td>
<td>1.41</td>
</tr>
<tr>
<td>High</td>
<td>329</td>
<td>$917</td>
<td>$606</td>
<td>$311</td>
<td>1.51</td>
</tr>
</tbody>
</table>
Key Findings

Key findings from the analysis include:

There is significant remaining DR potential in the commercial and industrial sectors. Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power under existing tariffs. But there remains considerable C&I potential, largely concentrated in Vectren and Indianapolis Power and Light service territories. Our modeling estimates show that, if fully realized, a day-ahead C&I demand response program could create $485 million in net benefits over the next 10 years in the Medium Avoided Cost scenario. In the High Avoided Cost scenario, we estimate $1.6 billion in savings over the next 10 years.

As air conditioning usage is a primary driver of summer peak demand, connected thermostats represent a significant opportunity to reduce residential energy use and provide savings. Over the next 10 years, we estimate that connected thermostat DR could save Indiana ratepayers $73 million in a Medium Avoided Cost scenario and $344 million in a High Avoided Cost scenario.

The potential for cost-effective battery storage to produce savings grows as battery costs decrease. Indiana avoided energy costs and avoided capacity costs alone are insufficient to make batteries cost-effective currently. Battery storage cost-effective potential depends highly on identifying locations where it can maximize its value, and these opportunities increase as the cost of battery storage falls as projected. A total of 139 MW and 329 MW of cost-effective battery storage is estimated under the Medium and High Avoided Cost scenarios, producing cumulative savings of $103 million and $311 million, respectively, over the next 10 years.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.
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INTRODUCTION

Figure 2 illustrates a fundamental aspect of current power system planning in Indiana – a significant share of the system capacity is built to meet demand in a very small number of hours. Load duration curves sort electricity demand from highest to lowest and are a good way to visualize how ‘peaky’ a system is. Figure 2 focuses on the top 2.5% of hours in the summer and winter seasons, and shows that Indiana about 8-10% of infrastructure requirements and costs are needed to meet demand in this very small number of hours.

Figure 2: Indiana Normalized Load Duration Curve 2015-2016

Since the electricity system is sized to meet demand at all hours of the day, peak demand reductions improve the economic efficiency of the system by reducing the need for capital-intensive infrastructure investment and improving the utilization of existing generation, transmission and distribution assets. Demand response (DR) is a demand-side electricity resource that serves as an alternative to traditional supply side electricity resources, including coal, natural gas, and nuclear power plants, or renewable power generation (solar, wind, etc.). DR entails using less electricity during key hours when electricity prices are high, and/or the electric grid is at risk of having demand exceed supply. This can be achieved in a variety of ways across the residential, commercial, and industrial customer classes. Common strategies include reducing air conditioning load by changing thermostat setpoints or restricting Heating Ventilation and Air Conditioning (HVAC) equipment runtime, shifting energy-intensive production to off-peak hours, shutting down production entirely, and by sending price signals that encourage lower usage during defined DR events (e.g., time-of-use rates, peak time rebates, and critical peak pricing). Customers who participate in DR programs typically receive a monetary incentive for their participation.

The primary benefit streams from DR include:
The need for peaker plants, which sit idle for most of the year, can be deferred or perhaps eliminated entirely. This has both financial and environmental benefits. Not constructing the peaker plants means the costs associated with constructing the plants will be avoided, which translates to fewer costs that need to be recovered from electricity ratepayers. Additionally, any environmental impacts associated with peaker plant construction and operation would be reduced.

Reducing peak demand helps avoid the use of existing generating units with higher marginal costs. In a competitive market setting, this translates to lower wholesale prices for electricity and in a vertically integrated setting, it translates to lower cost of service. In either market structure, reductions in peak demand help to lower retail electricity rates – which is a benefit to all customers. To illustrate the magnitude of this benefit, the New York Public Service Commission stated in a 2015 Order that, “If, for example, the 100 hours of greatest peak demand were flattened, long term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year.”

If demand reductions are targeted to constrained locations of the transmission and distribution network, costly infrastructure upgrades can be deferred, or even avoided. The value of these demand reductions is inherently location-specific.

This report examines the demand response potential for two established strategies at a statewide level – C&I load curtailment and control of residential air conditioning (AC). Indiana has several legacy AC cycling programs that use radio frequency to directly control AC usage, but we have chosen to look at the potential from connected “smart” thermostats, which have several key technical and economic advantages over the legacy direct load control equipment. Examining these strategies on a statewide basis likely misses some of the nuance utilities might wish to consider in an Integrated Resource Plan proceeding, but underscores the importance of considering these opportunities alongside traditional supply-side options to find the right resource mix for each service territory.

This report also includes an investigation of an emerging opportunity for grid-scale energy storage. Storage technologies like batteries allow electric energy to be stored when it is cheap and/or plentiful and injected back into the system at times when supply is scarce, costs are high, or local areas of the grid are constrained. Like the more established DR strategies, the result is a flattening of the costly peaks shown in Figure 2. As battery prices are forecasted to decline over the study horizon, our estimates of economic potential associated with grid-scale storage increase.
INDIANA LOAD PROFILE

Electricity load in Indiana is served primarily by five investor-owned utilities (IOUs): Indiana Michigan Power (I&M), Northern Indiana Public Service Company (NIPSCO), Duke Energy Indiana (DEI), Indianapolis Power & Light (IPL), and Vectren (formerly Southern Indiana Gas & Elec Co). Figure 3 shows the service territories for these five power companies. Although several counties in Indiana are served by multiple IOUs, for simplicity, the map assigns each county to the primary IOU.

Figure 3: Indiana Electric Utility Service Areas
The IOUs in Indiana are served by two regional transmission organizations (RTOs): PJM Interconnection (PJM) and the Midcontinent Independent System Operator (MISO). I&M falls under PJM territory and the other four electric utility companies fall under MISO’s load resource zone 6 (LRZ6). LRZ6 also contains a small pocket of northwestern Kentucky.

Indiana’s electricity demand peaks in both the summer and winter, which implies that system load is associated with outdoor weather conditions. (For details on how the research team assembled a historic load profile for Indiana, see Appendix A.) Figure 4 shows the average load, peak load, and load factor for each month from January 2015 to September 2017. Note that load factor is the ratio of the average load to the peak load and is a proxy for overall plant and T&D asset utilization. Indiana load factors are lowest during summer months, indicating these months have the highest peaks and may benefit the most from DR activities.

Figure 4: System Utilization by Month

![System Utilization by Month](image)

To explore the relationship between load and outdoor weather conditions, the research team downloaded historical weather data for several of the largest cities in Indiana, then used the population sizes of these cities to create a weighted weather profile for Indiana. Figure 5 compares average daily temperatures in Indiana to maximum daily statewide demand. Not surprisingly, the figure suggests warmer weather and cooler weather are related to higher demand. End uses that drive the peak, like central air conditioning, are thus excellent
targets for demand reduction strategies. Although Indiana’s summer peak typically exceeds the winter peak by approximately 10%, the winter peak during the 2014-2015 ‘polar vortex’ approached summer peaking levels, indicating that DR could also be beneficial during winter months.

Figure 5: Weather Sensitivity of Indiana Loads
ECONOMIC MODELING

Market potential studies typically examine potential across technical, economic, and achievable potential scenarios. This report directly models achievable potential by first establishing customer incentives that will lead to cost-effective outcomes, and then estimating the customer adoption at those incentive levels. This section documents the assumptions used in the analysis.

Avoided Costs

The economic potential for demand response is ultimately driven by its cost compared to the alternatives. In a system with a surplus of existing supply-side resources, the monetary value of peak demand reductions is limited. Conversely, when utilities are facing costly system upgrades to meet load, peak demand reductions are quite valuable. This study uses a modeling approach where the avoided cost, i.e., the cost of the traditional solution that is avoided by using DR, is a primary independent variable in the estimation of DR potential. The research team developed low, medium, and high avoided cost scenarios and calculated DR potential for each.

AVOIDED COST OF GENERATION CAPACITY

From an economic perspective, one of the primary benefits of a demand response program is avoiding, or deferring, generation capacity costs. That is, DR programs are an alternative to construction of new generation plants or securing generation capacity via wholesale markets. The question then becomes: How should these avoided costs be valued? The avoided cost assumption is one of the most critical assumptions in this report, as it will factor into estimates of DR potential, estimates of net benefits, and cost-effectiveness models. To inform this assumption, the research team leveraged historic PJM and MISO capacity market clearing prices and Cost of New Entry (CONE) forecasts for the next three delivery years, as described in more detail below.

In examining historic clearing prices, the research team noted that these varied considerably from year-to-year. For example, over the past fourteen years, PJM clearing prices ranged from $6 per kW-year to $63 per kW-year. Similarly, MISO clearing prices ranged from less than $1 per kW-year up to $26 per kW-year. Instead of trying to forecast a single value stream for this key assumption over the study horizon, the research team elected to estimate DR potential and cost-effectiveness across three different avoided cost scenarios: Low Avoided Cost, Medium Avoided Cost, and High Avoided Cost. By year and avoided cost scenario, Table shows our estimates of avoided cost of generation capacity over the study horizon. A discussion of each scenario follows. Note that our avoided cost estimates escalate by 2% annually over the study horizon.
The Low Avoided Cost scenario assumes that MISO and PJM clearing prices for the next decade will remain in line with recent historical clearing prices. The starting point for this scenario ($13.89 per kW-year) is a function of the average MISO clearing price over the past four delivery years ($8.55 per kW-year) and the average PJM clearing price over the last fourteen delivery years ($35.61 per kW-year). Market clearing prices for capacity are likely not the best proxy in Indiana where the major utilities are vertically integrated and generation capacity is secured primarily through a regulated Integrated Resource Planning (IRP) process rather than a competitive market. This is particularly true of MISO utilities where the forward capacity auction process is less developed than the one in PJM.

The starting point for the High Avoided Cost scenario ($98.96 per kW-year) is a function of CONE estimates for MISO LRZ6 and for PJM. Cost of New Entry (CONE) is an industry planning parameter that estimates the first-year revenue needed to build a new power plant based on expected capital construction costs, and lifetime earnings and maintenance assumptions. Simply put, the High Avoided Cost scenario estimates potential and cost-effectiveness of demand reduction strategies assuming the alternative is to construct an infrequently used natural gas plant. Note that our high avoided costs are similar to the avoided generation capacity costs filed by NIPSCO and Vectren in their 2016 IRPs (Table 4). Duke and IPL stated in their most recent IRPs that avoided costs are confidential and thus they did not include values in their public filings.
Table 4: 2017 Avoided Costs ($/kW-year) as Filed in IRP

<table>
<thead>
<tr>
<th>Utility</th>
<th>Generation Capacity</th>
<th>Transmission Capacity</th>
<th>Distribution Capacity</th>
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<tbody>
<tr>
<td>NIPSCO³</td>
<td>$122.92</td>
<td>$2.42</td>
<td>$46.32</td>
</tr>
<tr>
<td>Vectren⁴</td>
<td>$91.82</td>
<td></td>
<td>$9.18</td>
</tr>
</tbody>
</table>

The starting point for the Medium Avoided Cost scenario ($56.43 per kW-year) is simply the average of the starting points for the Low and High Avoided Cost scenarios. The research team feels that the Medium scenario bests represents the options facing system planners in Indiana, so many of the more detailed results presented in the sections to follow will highlight this scenario.

**OTHER AVOIDED COSTS**

Although avoided generation capacity costs are the primary benefits in reducing peak demand, there are other monetary benefits associated with demand response programs. Table 5 lists the assumptions for avoided costs of transmission and distribution capacity and Table 6 shows the avoided cost of energy. Our modeling assumes energy neutral demand reductions where demand reduced during peak hours is offset by an increase during off-peak hours. The energy benefit of this shift is monetized as the difference between assumed average summer on-peak and off-peak wholesale energy prices.

The avoided cost of transmission and distribution capacity values shown in Table 5 are system-wide average assumptions. In reality, Indiana’s power system is made up of a majority of locations with little or no T&D value and a few pockets where the avoided cost is several hundred dollars per kW-year. System-wide averages are used for the C&I and residential DR modeling, while the energy storage modeling assumes batteries would only be sited in the areas of the grid where expensive upgrades could be avoided or deferred via reductions in peak demand.

---

³ Table 5-12 of NIPSCO’s 2016 Integrated Resource Plan.
⁴ Figure 10.13 of Vectren’s 2016 Integrated Resource Plan.
Table 5: 2018 Avoided T&D Assumptions by Avoided Cost Scenario ($/kW-year)

<table>
<thead>
<tr>
<th>Avoided Cost Scenario</th>
<th>Avoided Transmission</th>
<th>Avoided Distribution</th>
<th>Avoided T&amp;D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Medium</td>
<td>$10</td>
<td>$10</td>
<td>$20</td>
</tr>
<tr>
<td>High</td>
<td>$20</td>
<td>$20</td>
<td>$40</td>
</tr>
</tbody>
</table>

(T&D = Transmission and Distribution)

Table 6: 2018 Avoided Cost of Energy Assumptions

<table>
<thead>
<tr>
<th>Summer Off-Peak Energy ($/MWh)</th>
<th>Summer On-Peak Energy ($/MWh)</th>
<th>Avoided Energy Costs ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$30.00</td>
<td>$50.00</td>
<td>$20.00</td>
</tr>
</tbody>
</table>

Cost Effectiveness

The research team elected to use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to evaluate the cost-effectiveness of the demand response options. A UCT ratio less than one indicates that the program costs exceed the program benefits, a UCT value equal to one indicates that the program costs and benefits are identical, and a UCT ratio greater than one indicates that the benefits exceed the program costs. In calculating UCT ratios, note that all costs and benefits over the study horizon were expressed in 2018 dollars. To this end, a discount rate of 8% was used to reflect a typical weighted cost of capital of an investor-owned utility. For information on the costs that factor into UCT ratios, see Appendix C: Cost Effectiveness.
COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE

Indiana’s economy has a large manufacturing component driven by steel production, automotive and farm equipment, petrochemicals, medical equipment, and pharmaceuticals. Energy-intensive industrial facilities account for approximately one-third of the summer peak demand for electricity in the state and thus present a significant opportunity for demand response. Many large energy users will commit to shed load upon request in exchange for payment or bill credit.

Existing Resources

The research team reviewed the most recent Integrated Resource Plans submitted by each of the five IOUs in Indiana and documented the amount of non-residential DR in each filing and compared it to summer peak demand forecast for 2018. Table 7 reveals a varied approach to C&I load curtailment across the state.

Table 7: Existing Non-Residential Demand Response by IOU

<table>
<thead>
<tr>
<th>Investor Owned Utility</th>
<th>C&amp;I DR Total (MW)</th>
<th>2018 Peak Demand Forecast (MW)</th>
<th>C&amp;I DR Capability (Percent of Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duke Energy Indiana</td>
<td>694</td>
<td>6,613</td>
<td>10.5%</td>
</tr>
<tr>
<td>NIPSCO</td>
<td>530</td>
<td>3,160</td>
<td>16.8%</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>298</td>
<td>4,434</td>
<td>6.7%</td>
</tr>
<tr>
<td>Vectren</td>
<td>35</td>
<td>1,104</td>
<td>3.2%</td>
</tr>
<tr>
<td>IPL</td>
<td>1</td>
<td>2,864</td>
<td>0.03%</td>
</tr>
<tr>
<td>IOU Total</td>
<td>1,558</td>
<td>18,175</td>
<td>8.6%</td>
</tr>
</tbody>
</table>

While Duke, NIPSCO, and I&M have well-developed portfolios of non-residential DR resources, Vectren and IPL show limited contribution to resource adequacy from C&I demand response. The characteristics of these existing resources also vary across the state:

Duke Energy Indiana’s DR strategy includes both day-ahead economic dispatch triggered by market prices and emergency dispatch triggered by MISO.

NIPSCO’s portfolio includes a variety of DR options on various tariff riders that dictate the number of hours of availability annually, notification time, and participant compensation via demand charge credit.
I&M secures load reduction commitments from large C&I customers as a capacity resource and the aggregated reductions are factored into PJM’s forward planning parameters. I&M’s portfolio is concentrated among a small number of large customers, with over 200 of the nearly 300 MWs coming from just three customers. PJM regulations require rapid response (30 minutes), but dispatch has been infrequent historically, with most years having no activity other than a test event.

Vectren’s 2016 IRP includes 35 MW of C&I demand response from five large customers. These sites receive a credit for commitment to reduce load under certain conditions. The IRP also notes that Vectren’s tariff “includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market.”

IPL lists just 0.9 MW of non-residential DR in its 2016 IRP, noting that EPA regulations on diesel generators led to the departure of most historic participants.

It is important to note that the estimates of DR potential discussed in the sections to follow are not incremental to these existing programs. That is, we are not estimating how much DR potential exists beyond the existing resources noted in Table 7. Rather, these are estimates of total DR potential using a more generalized methodology.

Modeling Demand Response Potential

Demand response potential from large businesses – and the cost to acquire it – is driven by a few key factors. These key factors and the directional effect they have on DR potential are shown in Figure 6.

Figure 6: Drivers of DR Potential

Estimating demand response potential at different levels of these four critical inputs would result in a dizzying array of DR potential estimates. To limit the range of DR potential estimates, the research team made several assumptions regarding program design. Program design refers to how a demand response program is implemented, including how much notification time the participants receive, how many DR events will be called, how long the DR events last, and what sort of incentive payment participants receive. Assumptions regarding each of the four DR
levers are discussed in Appendix E: Modeling Demand Response Potential.

Table 8 briefly describes some of the most relevant inputs the research team used in estimating DR potential and cost-effectiveness.

<table>
<thead>
<tr>
<th>Input Variable</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoided Cost Scenario</td>
<td>Three levels considered – Low, Medium, and High. Avoided costs are escalated by 2% annually.</td>
</tr>
<tr>
<td>Notification Design</td>
<td>Two levels considered – Day-Ahead notification and Day-Of notification.</td>
</tr>
<tr>
<td>Participant Incentive</td>
<td>Each avoided cost scenario has its own incentive level, and incentive levels are escalated by 2% annually. Incentives were derived through a simulation described in Appendix E: Modeling Demand Response Potential</td>
</tr>
<tr>
<td>Total Dispatch Hours</td>
<td>Eight events, each three hours long, for a total of 24 dispatch hours. This assumption was informed by historical load data and historical MISO and PJM LMPs.</td>
</tr>
<tr>
<td>Indiana Peak Load Forecast</td>
<td>Assembled based on MISO and PJM load forecasts, EIA energy sales records, and assumptions about load factor by sector</td>
</tr>
<tr>
<td>Price Elasticity of Demand</td>
<td>Elasticity values are taken from the DR Potential Study Report for Pennsylvania, composed by GDS Associates and Nexant.⁵</td>
</tr>
</tbody>
</table>

Results

DEMAND RESPONSE POTENTIAL

As discussed in previous sections, estimates of C&I DR potential are driven by avoided cost assumptions and the amount of notification participants receive. Broken down by sector and by level of notification, Table 9 shows estimates of DR potential across the study horizon for the Medium Avoided Cost scenario.⁶ For comparison, Table 9 also shows the peak load forecast that the research team developed for the C&I sectors. As expected, DR potential is significantly greater for the day-ahead notification level, as the extra notification time gives participants more flexibility in adjusting their staffing and operational schedules, which will lead to higher participation levels and larger load reduction commitments. Note that in 2027, which is the final year in the study horizon, the estimated C&I DR potential for the Medium Avoided Cost scenario with day-ahead notification is approximately 2,160 MW – this is just shy of 10% of the estimated peak load in Indiana for that year.

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⁵ Available at http://www.puc.pa.gov/pcdocs/1345077.docx
⁶ Readers can find similar tables for the Low and High Avoided Cost scenarios in Appendix F: C&I DR Potential Tables.
Table 9: DR Potential (MW) for Medium Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load Forecast (MW)</th>
<th>Commercial DR Potential (MW)</th>
<th>Industrial DR Potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Commercial</td>
<td>Industrial</td>
<td>Day-ahead</td>
</tr>
<tr>
<td>2018</td>
<td>4,616</td>
<td>6,939</td>
<td>574</td>
</tr>
<tr>
<td>2019</td>
<td>4,678</td>
<td>7,033</td>
<td>582</td>
</tr>
<tr>
<td>2020</td>
<td>4,730</td>
<td>7,111</td>
<td>589</td>
</tr>
<tr>
<td>2021</td>
<td>4,784</td>
<td>7,191</td>
<td>595</td>
</tr>
<tr>
<td>2022</td>
<td>4,836</td>
<td>7,270</td>
<td>602</td>
</tr>
<tr>
<td>2023</td>
<td>4,887</td>
<td>7,346</td>
<td>608</td>
</tr>
<tr>
<td>2024</td>
<td>4,941</td>
<td>7,428</td>
<td>615</td>
</tr>
<tr>
<td>2025</td>
<td>4,993</td>
<td>7,506</td>
<td>621</td>
</tr>
<tr>
<td>2026</td>
<td>5,048</td>
<td>7,588</td>
<td>628</td>
</tr>
<tr>
<td>2027</td>
<td>5,102</td>
<td>7,670</td>
<td>635</td>
</tr>
</tbody>
</table>

Figure 7 shows average annual DR potential over the study horizon, broken down by avoided cost scenario, level of notification, and sector. This figure highlights how important the avoided cost and notification time assumptions are. To illustrate the impacts of these assumptions, consider the two ends of the spectrum. For the Low Avoided Cost scenario with a Day-of notification time, our estimate of average annual C&I DR potential is 212 MW, or approximately 2% of the average forecasted C&I peak load over the same period. For the High Avoided Cost scenario with a Day-ahead notification time, our estimate of average annual C&I DR potential is 3,733 MW, or approximately 31% of the average forecasted C&I peak load over the same period.
Finally, Table 10 shows DR potential estimates by avoided cost scenario, level of notification, and sector for just the last year of the study horizon (2027). Table 10 also shows a total C&I DR potential estimate, as well as what percentage of the total statewide 2027 peak (commercial, industrial, and residential) the DR estimate represents. On the high end, the High Avoided Cost scenario coupled with a day-ahead notification design results in an estimate of DR potential that represents about 17.5% of the forecasted peak. On the low end, the Low Avoided Cost assumption coupled with a day-of notification design results in an estimate of DR potential that represents about 1% of the forecasted peak. In the middle, the Medium Avoided Cost scenario coupled with a day-ahead program design results in an estimate of DR potential that represents almost 10% of the forecasted system peak, demonstrating that DR can meet a significant portion of projected peak demand.
Table 10: 2027 DR Potential by Avoided Cost Scenario, Notification Level, and Sector

<table>
<thead>
<tr>
<th>Avoided Cost Scenario</th>
<th>Notification Level</th>
<th>Commercial DR Potential (MW)</th>
<th>Industrial DR Potential (MW)</th>
<th>Total C&amp;I DR Potential (MW)</th>
<th>Percentage of 2027 Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>Day-ahead</td>
<td>108</td>
<td>292</td>
<td>401</td>
<td>1.8%</td>
</tr>
<tr>
<td></td>
<td>Day-of</td>
<td>65</td>
<td>157</td>
<td>222</td>
<td>1.0%</td>
</tr>
<tr>
<td>Medium</td>
<td>Day-ahead</td>
<td>635</td>
<td>1,524</td>
<td>2,159</td>
<td>9.6%</td>
</tr>
<tr>
<td></td>
<td>Day-of</td>
<td>382</td>
<td>821</td>
<td>1,203</td>
<td>5.4%</td>
</tr>
<tr>
<td>High</td>
<td>Day-ahead</td>
<td>1,161</td>
<td>2,755</td>
<td>3,917</td>
<td>17.5%</td>
</tr>
<tr>
<td></td>
<td>Day-of</td>
<td>699</td>
<td>1,484</td>
<td>2,183</td>
<td>9.7%</td>
</tr>
</tbody>
</table>

COSTS AND BENEFITS

All the C&I DR program design and avoided cost variations presented in this study are cost-effective, with UCT ratios ranging from 1.61 on the low end to 1.94 on the high end. Like DR potential, the costs and benefits associated with DR are influenced by the avoided cost assumptions and the level of notification that the DR participants receive. Table 11 shows average annual net benefits over the study horizon by avoided cost assumption and notification design. Appendix G includes a complete set of costs, benefits, and net benefits by avoided cost scenario and notification time. For a medium avoided cost assumption and a day-ahead program design, our model predicts an average annual net benefit of $74.2 million over the 10-year study horizon.

Table 11: Average Annual Net Benefits by Avoided Cost Assumption and Notification Design

<table>
<thead>
<tr>
<th>Avoided Cost Scenario</th>
<th>Average Annual Net Benefits ($ Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Day-ahead Notification</td>
</tr>
<tr>
<td>Low</td>
<td>$2.3</td>
</tr>
<tr>
<td>Medium</td>
<td>$74.2</td>
</tr>
<tr>
<td>High</td>
<td>$247.1</td>
</tr>
</tbody>
</table>

In a utility IRP setting, the net benefits calculation would be performed differently, but would produce a similar result. Planners would likely run two scenarios to fulfill the resource requirements – one with DR options and one without. In the scenario with DR resources available, presumably DR would displace certain higher-cost supply-side resources in the
stack and lead to a lower total investment to meet the needs outlined in the IRP. The cost profiles of the two scenarios would then be compared to assess the net economic benefit of including DR in the resource mix.
RESIDENTIAL DEMAND RESPONSE

With a population of 6.6 million, Indiana has 2.8 million residential accounts, who spent $2.85 billion on electricity in 2015 and consumed 32,604 GWh. Approximately 85% of residents in Indiana have central air conditioning. Not surprisingly, residential customers use more power when it is extremely hot and contribute more to peak demand, which drives the need for additional generation, transmission, and distribution infrastructure.

Figure 8 shows the relationship between residential air conditioning and Indiana peak loads. It was developed using system load data from PJM and MISO and air conditioning runtime data from homes with Ecobee thermostats. Indiana weather data is merged to create the right side of Figure 8 and illustrate the sensitivity of air conditioning to weather conditions. Based on our analysis of these data sources, we estimated that residential central air conditioning accounted for approximately 20% of Indiana’s peak load in 2016. 2016 was a cooler weather year, suggesting that the contribution of residential air conditioning to peak load is typically higher than our estimate for 2016. Because residential air conditioning is a major driver of the system-wide peak, if managed, it can reduce the need to build additional infrastructure to accommodate additional peak load. Because air conditioner use is higher when weather is more extreme, reductions from residential air conditioners can be larger precisely when resources are needed most.

Figure 8: Residential Air Conditioning, Indiana Peak Loads, and Weather Sensitivity
Existing Programs

Several utilities in Indiana have existing residential customer programs designed to curtail peak demand. These programs focus on recruiting customers to install devices that allow utilities to scale down air conditioner or water heater energy use when demand is high. Table 12 summarizes the characteristics of residential customer load control or smart thermostat DR programs in Indiana.

<table>
<thead>
<tr>
<th>Utility</th>
<th># of Electric Residential Customers (2015)</th>
<th>Central Air Conditioner Saturation Estimate</th>
<th>Number of Program Participants</th>
<th>Existing Load Reduction Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duke Energy Indiana</td>
<td>699,440</td>
<td>74%-90%</td>
<td>54,000</td>
<td>61 MW</td>
</tr>
<tr>
<td>I&amp;M</td>
<td>401,544</td>
<td>74%-90%</td>
<td>1,000</td>
<td>1 MW</td>
</tr>
<tr>
<td>IPL</td>
<td>431,182</td>
<td>74%-90%</td>
<td>50,000</td>
<td>45 MW</td>
</tr>
<tr>
<td>NIPSCO</td>
<td>404,889</td>
<td>74%-90%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vectren</td>
<td>129,113</td>
<td>74%-92%</td>
<td>23,000</td>
<td>19 MW</td>
</tr>
<tr>
<td>Other</td>
<td>738, 693</td>
<td>74%-92%</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,804,861</td>
<td></td>
<td>128,000</td>
<td>126 MW</td>
</tr>
</tbody>
</table>

Existing load management programs are expected to be the most cost-effective residential demand response resource over the study horizon because the equipment and installation costs are sunk. Going forward, however, the main residential demand response potential is expected to be connected thermostats, as described below.

---

*7 2015 EIA sales data by utility and state (Form 826)
8 Based on U.S. Census American Housing Surveys from Metropolitan Statistical Areas near Indiana. Since a survey was not implemented in Indiana we used 2015 survey data for Chicago (71.4%), Cincinnati (81.4%) and Detroit (74.1%), and 2013 survey data from Louisville (90.2%). Because of its lower rate of multi-family housing, we expected Indiana air conditioner saturation to be in the upper range of the estimates from the above metropolitan statistical areas.*
Market Adoption of Connected Thermostats

Several vendors produce and market internet-connected ‘smart’ thermostats directly to residential customers nationwide – Nest and Ecobee are two prominent examples. These devices are typically sold as home energy management tools that target energy savings for homeowners through occupancy detection, auxiliary heat lockout, and economizer capabilities. Because the adoption of connected thermostats is driven by customer preferences, the utility costs of equipment and installation are lower and present a significant opportunity for increasing DR penetration. Additionally, most Indiana IOUs already offer energy efficiency rebates for the purchase and installation of connected thermostats.

As of August 2017, there were approximately 43,000 Nest and Ecobee thermostats in Indiana and homes with a connected thermostat had an average of 1.2 thermostats per household.\(^9\) Currently, around 1.5% of Indiana households have connected thermostats. However, their penetration is expected to climb significantly – one 2016 study estimates that “In the next decade, smart thermostats are expected to account for almost half of annual thermostat shipments”.\(^10\) Still, adoption of smart thermostats in Indiana has been slower. Utility rebates increase adoption, but most residential customers in Indiana do not purchase thermostats of any kind within a year.

Figure 9 shows the projected penetration of connected thermostats. The penetration is driven by two factors: cumulative sales of new thermostats and the market share of connected thermostats. In each year, we assume that 1 in 15 of Indiana’s 2.38 million homes with central air conditioners will replace their thermostats. With an average of 1.05 air conditioners per home, this leads to 166,600 new thermostat sales per year. Connected thermostats are projected to grow in market share from 11% of new thermostat sales and reach a limit of 70% of overall new sales. How fast the market share is attained, however, depends on the upfront costs to customers. Rebates and upstream incentives for connected thermostats can drive down customer costs and influence how fast they penetrate households. The Low andMedium Avoided Cost scenarios assume customers who install smart thermostats are recruited after they have made their purchases. Under this assumption, thermostat market share as percentage of total new sales is expected to reach 70% by 2027, leading to 0.89 million connected thermostats in 30.3% of Indiana households. In contrast, the High Avoided Cost scenario assumes a point-of-sale discount, in the form of a rebate contingent on enrollment in DR programs, that covers all or nearly all the thermostat cost. Under this more aggressive scenario, the market share is assumed to reach 70% by 2022, leading to 1.07 million connected thermostats in 36.5% of Indiana households.

\(^9\) Data supplied by Nest and Ecobee via email.
\(^10\) https://www.navigantresearch.com/newsroom/annual-revenue-for-communicating-and-smart-thermostats-is-expected-to-reach-4-4-billion-in-2025
Ultimately, the share of connected thermostats enrolled in demand response programs will depend on incentive levels, marketing intensity, and whether enrollment offers are presented after the fact or at the point of sale. Higher incentive levels and higher enrollment levels are feasible when avoided costs are higher; as a result, the Low, Medium, and High Avoided Cost scenarios assume increasingly generous offers to participants. The existing research shows that larger, one-time incentives are more cost-effective and lead to higher enrollment than smaller recurring payments, but both designs are common. For our modeling, program cost and enrollment assumptions were mapped to the avoided cost scenarios as follows:

**Low Avoided Cost** – Assumes all enrollment is implemented by utilities with after-the-fact enrollment using a one-time incentive level of $50. Under this tactic, 15% of households with connected thermostats who are made the offer are expected to enroll, assuming multiple marketing attempts.

**Medium Avoided Cost** – Assumes a higher, one-time incentive level of $100 and collaboration with thermostat manufacturers, with enrollment implemented after the fact. Under this tactic, 30% of households with connected thermostats are expected to enroll, assuming multiple marketing attempts.

**High Avoided Cost** – Assumes a one-time incentive payment of $250 offered at the time
of purchase in the form of a rebate or a free utility-supplied thermostat. To receive the rebate/device, customers must link their device to the demand response program but can override dispatch signals on an event by event basis. Under this tactic, the market share of smart thermostats accelerates and 60% of households with connected thermostats are projected to enroll in demand response.

**Analysis of Regional Heating and Cooling Loads**

To estimate the potential load reduction per device, the research team relied on Ecobee’s Donate Your Data portal. The Ecobee data included anonymized thermostat run time and temperature setting data on a five-minute basis from over 560 devices in Indiana, Ohio and Illinois (minus Chicago). Run time data describes the share of total seconds in a time interval an air conditioner is on. The runtime data was converted to kW (assuming a connected load of 3 kW) and used to better understand the diversity of air conditioner use and temperature set points.

Targeting high-use customers and avoiding ones who use little or no air conditioning when the system peaks can have a substantial impact on the net benefits and achievable potential. Because of the large number of customers, the Ecobee dataset was well-suited for exploring the diversity of air conditioner use and assessing if specific segments are or are not cost-effective. For each device, the load patterns were analyzed on the top six Indiana system load days of 2016, assuming sustained load reductions of four hours per event.

Figure 10 shows the distribution of air conditioner use coincident with Indiana system load peaks. Indiana system loads peak between 2pm and 6pm, and most residential air conditioners peak around the same time. Less than 10% of air conditioner units are off on peak days. In addition to customers who keep their air conditioner units off, some households operate air conditioners in the evening, after the system peak has occurred. The implications for targeting and market potential is simple – avoiding homes with little or no coincident air conditioner usage leads to larger per-device reductions and is more cost-effective than enrolling all customers. Without smart meters, however, the ability to precisely target is imperfect because analysis of billing data can only reveal the magnitude of cooling loads, not the timing (e.g. a home may use a lot air conditioning, but not at times that are coincident with system peaks).
Figure 10: Distribution of Air Conditioner Demand (kW) Coincident with Indiana System Peaks

Figure 11 is drawn from an ongoing connected thermostat pilot in a state in the U.S. Southeast that is testing different thermostat temperature setback strategies during 3-hour DR events. The plot shows the results for all thermostats inclusive of customers who opted out partway through events. In all cases, the demand reductions exceed 50% when temperature setpoints were set back 4 degrees, but the 2/3/4\(^n\) degree offset strategy provided the most consistent reductions across events. Based on these actual thermostat DR performance estimates, the research team assumed attainable air conditioner load reductions to be 55% of air conditioner demand. This is reduced slightly to account for those customers who may opt out during the demand reduction events.

\(^{11}\) During the first hour of a DR event the thermostat setpoint is increased 2 degrees (F). In the second hour it is increased an additional 1 degree to 3 degrees above normal. In the third hour, the setpoint is increased an additional 1 degree to 4 degrees of the scheduled setpoint for the hour.
Figure 11: Percent Reductions from Connected Thermostats using Different Operating Strategies

Cost Effectiveness

Figure 12 summarizes the results and lists the 10-year costs, benefits, and net benefits (benefits minus costs). Costs and benefits from 2019 to 2027 are converted to net present value ($2018) using an 8% discount rate. In aggregate, the estimated cost-effective achievable potential by 2027 is 230 MW at the generator\textsuperscript{12} under the Medium Avoided Cost scenario, based on an enrollment of 214,000 devices, yielding net benefits of $73 million and a strong benefit-cost ratio of 2.45 under the Utility Cost Test. Reducing peak load by using connected thermostats will lead to lower utility costs and lower customer bills than building new peaking power plants to address power plant retirements or increases in load. Under the High Avoided Cost scenario, demand reductions of over 580 MW – which is the peak production equivalent of five mid-sized power plants – can be attained, yielding $374 million in savings over 10 years with a similarly strong benefit-cost ratio of 2.73.

\textsuperscript{12} A line loss factor of 8% is assumed in the model.
These results are based on estimates of demand reduction potential for each of ten equally sized groups, based on coincident air conditioner use. Table 13 shows the cost-effectiveness of enrolling customers in each of these groups. Customers who were not cost-effective were not included in the estimate of achievable market potential.

Table 13: Per Device Cost-Effectiveness by Air Conditioner Use Group

<table>
<thead>
<tr>
<th>Group</th>
<th>AC Load</th>
<th>Load Impact per Device</th>
<th>Low Avoided Costs</th>
<th>Medium Avoided Costs</th>
<th>High Avoided Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Marginal Benefits</td>
<td>Marginal Costs[1]</td>
<td>UCT Ratio</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Top 10%</td>
<td>2.85</td>
<td>1.41</td>
<td>$161</td>
<td>$102</td>
<td>1.57</td>
</tr>
<tr>
<td>10-20%</td>
<td>2.55</td>
<td>1.26</td>
<td>$144</td>
<td>$102</td>
<td>1.40</td>
</tr>
<tr>
<td>20-30%</td>
<td>2.32</td>
<td>1.15</td>
<td>$131</td>
<td>$102</td>
<td>1.28</td>
</tr>
<tr>
<td>30-40%</td>
<td>2.12</td>
<td>1.05</td>
<td>$119</td>
<td>$102</td>
<td>1.17</td>
</tr>
<tr>
<td>40-50%</td>
<td>1.90</td>
<td>0.94</td>
<td>$107</td>
<td>$102</td>
<td>1.05</td>
</tr>
<tr>
<td>50-60%</td>
<td>1.69</td>
<td>0.84</td>
<td>$95</td>
<td>$102</td>
<td>0.93</td>
</tr>
<tr>
<td>60-70%</td>
<td>1.43</td>
<td>0.71</td>
<td>$81</td>
<td>$102</td>
<td>0.79</td>
</tr>
<tr>
<td>70-80%</td>
<td>1.18</td>
<td>0.58</td>
<td>$67</td>
<td>$102</td>
<td>0.65</td>
</tr>
<tr>
<td>80-90%</td>
<td>0.77</td>
<td>0.38</td>
<td>$43</td>
<td>$102</td>
<td>0.42</td>
</tr>
<tr>
<td>Bottom 10%</td>
<td>0.08</td>
<td>0.04</td>
<td>$4</td>
<td>$102</td>
<td>0.04</td>
</tr>
</tbody>
</table>

[1] Marginal costs do not include non-volumetric overhead costs associate with administering programs.
ENERGY STORAGE

The electric grid is unique among our major energy sources in that the system always must be in balance – supply must match demand, essentially in real time. Because the cost of energy storage was, for the most part, prohibitive in the past, generation, transmission, and distribution infrastructure was sized to meet extreme peak demand. While generation and transmission are typically sized based on system peak, distribution infrastructure is sized based on local peaks, which can be quite diverse. The result has been large investments in infrastructure to meet extreme peaks that occur rarely, once every five or ten years.

Battery energy storage technology has advanced rapidly in the past five years and costs have been declining. In several locations, substantial amounts of behind-the-meter storage are being used to alleviate constraints. The most prominent example is Southern California Edison’s procurement of 235 MW of battery storage to help alleviate constraints created by the sudden retirement of over 2,000 MW of nuclear power.

Batteries can be located behind-the-meter at customer facilities or on utility property such as substations. Energy storage can provide concrete benefits to customers – in the form of reliability improvements and bill management – and concrete benefits to the utility, including reductions in the need to build additional generation, deferred or avoided transmission and distribution infrastructure costs, and the ability to store cheaper electricity generated off-peak for use during higher-cost periods. In addition, batteries can deliver fast response services required to ensure reliability and power quality and can enhance the ability of the grid to integrate higher levels of variable resources such as wind and solar.

Because it is a relatively new technology, market potential estimates for battery storage are inherently uncertain. This assessment focuses specifically on battery storage potential and cost-effectiveness from a utility perspective. It includes reductions in the need to build additional generation, deferred or avoided transmission and distribution infrastructure costs, and lower energy costs. The battery storage potential is incremental to the demand response potential from C&I and residential customers. Two key factors drive the potential for cost-effective battery storage – the price trends for the technology and the location-specific T&D deferral value. Cost-effectiveness for battery storage depends highly on identifying locations where it can deliver value by helping defer or avoid transmission and/or distribution infrastructure costs. In this study, the avoided cost of generation capacity and difference between on-peak and off-peak energy prices are not sufficient benefits streams at current battery prices – concentrated T&D avoided costs are needed.
Indiana is home to a Battery Innovation Center\(^\text{13}\) and has a substantial manufacturing economy. Thus, increased adoption of battery technology presents an opportunity both for the electric system as well as the state’s manufacturing sector, if the state continues to position itself as a leader in grid-scale storage technologies.

**Battery Storage Costs and Price Trends**

Battery storage costs have been decreasing due to active competition among battery manufacturers and are projected to continue decreasing due to efficiencies of production at larger scales. Batteries can be produced from several materials, but based on recent trends, Lithium-Ion batteries have outpaced other materials in lowering costs.

For battery storage costs, we relied on existing research on battery storage costs based on a recent study for the utility PacifiCorp. The costs are driven by three main components: the maximum output of the battery (kW), the total storage capability (expressed in kWh), and the installation, operation, and maintenance costs. Appendix H shows the battery cost estimates by battery material and battery component as well as the projected battery storage cost curves.

For this study, the costs for a battery capable of sustaining maximum output for 4 consecutive hours was estimated and converted to a levelized cost per kW-year expressed in 2018 dollars. In doing so we assume the cost for equipment – the battery, inverter, control system, and balance of system – decrease over time as battery production scales, while installation and operation and maintenance cost remain stable. In addition, we assume a battery life of 10 years over the course of which the battery storage capacity degrades to 90% of the initial installed kW due to use.

Table 14 shows the 10-year levelized cost by year, inclusive of operations and maintenance cost, assuming a battery capable of sustaining the maximum output for four continuous hours, if needed.

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\(^{13}\) http://www.bicindiana.com
**Table 14: Estimated Battery Storage 10-year Levelized Cost per kW-year**

<table>
<thead>
<tr>
<th>Installation Year</th>
<th>Levelized Cost per kW-year</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>$345</td>
</tr>
<tr>
<td>2019</td>
<td>$319</td>
</tr>
<tr>
<td>2020</td>
<td>$295</td>
</tr>
<tr>
<td>2021</td>
<td>$274</td>
</tr>
<tr>
<td>2022</td>
<td>$255</td>
</tr>
<tr>
<td>2023</td>
<td>$238</td>
</tr>
<tr>
<td>2024</td>
<td>$223</td>
</tr>
<tr>
<td>2025</td>
<td>$209</td>
</tr>
<tr>
<td>2026</td>
<td>$197</td>
</tr>
<tr>
<td>2027</td>
<td>$186</td>
</tr>
<tr>
<td>2028</td>
<td>$176</td>
</tr>
</tbody>
</table>

**Battery Storage Locational Benefits**

Although T&D avoided costs estimates historically have been estimated on a system-wide basis, in practice T&D infrastructure investments associated with system expansion are highly location-specific and associated with specific pockets of growth. In areas with excess distribution capacity – or areas where local, coincident peaks are declining or growing slowly – the value of distribution capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of distribution capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial period of time. The same is true of transmission related constraints.

Growth related T&D investments tend to affect only 5% to 10% of a utility’s service territory over the course of a 5-year period. Without targeting those locations, the T&D avoided cost potential is unrealized or diluted. The implication is that T&D avoided costs are highly concentrated and are only realized if resources are placed in the right locations and are reliably available at the right times. For example, if the system-wide avoided T&D value is an average of $20/kW-year but is concentrated in 5% of the utility service territory, it means that, on average, the value is $400/kW-year at those locations. This is a more involved analysis than the more traditional use of system-wide avoided T&D costs, which was employed for the residential and C&I DR potential. Because battery storage potential is highly dependent on targeting the right locations, a more granular approach was employed.

The value of avoided T&D costs varies significantly across local areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether infrastructure upgrades can be avoided or for how long they can be deferred;
The amount of existing capacity and its ability to support additional load without upgrades;
The magnitude, timing, and cost of projected T&D infrastructure upgrades; and
The design of the distribution system (e.g. radial vs. networked)

The main conclusion is that battery storage can be cost-effective if placed at the right locations and used to defer or avoid T&D infrastructure costs in addition to providing system benefits such as peaking capacity and shifting of energy use from high cost to lower cost periods. The following assumptions drive the results for the Medium and High Avoided Cost scenarios, which include T&D avoided costs. The Low Avoided Cost scenario assumed no T&D benefits so was excluded from the storage analysis because without T&D value, it was assumed for this study that there is no cost-effective battery potential.

Medium Avoided Cost Scenario - T&D avoided costs are concentrated in 5% of the service territory. Given the $20/kW-year combined value of T&D avoided costs, on average, the location specific value at these locations is $400/kW-year ($20 ÷ 5%). Because there is some variation by location, the value was assumed to have the distribution show in Figure 13. Where T&D infrastructure can be deferred or avoided, we assume that on average batteries can help defer projects by 5 years by shaving 10% of the peak value. The generation capacity values and on-peak/off-peak energy price differential from the Medium Avoided Cost scenario, detailed in the Section Economic Modeling, were also applied.

High Avoided Cost Scenario - T&D avoided costs are concentrated in 10% of the service territory. Given the $40/kW-year combined value of T&D avoided costs, on average, the location specific value at these locations is $400/kW-year ($40 ÷ 10%). Because there is some variation by location, the value was assumed to have the distribution show in Figure 13. The distribution is the same as in the Medium Avoided Cost scenario, but a larger share of the territory has T&D value. In other words, the cost of T&D equipment is the same but more equipment overall is needed in the High Avoided Cost scenario. Where T&D infrastructure can be deferred or avoided, we assume that on average batteries can help defer projects by 5 years by shaving 10% of the peak value. All other system values from the High Avoided Cost scenario were also applied.
Cost-Effective Potential

Table 15 summarizes the results. Not surprisingly, the amount of incremental cost-effective battery storage grows as battery costs are projected to decrease. Because of the diversity in locational value, battery storage is not cost-effective in most locations, but as costs drop it becomes cost-effective in an increasing share of the territory. By 2027, in the Medium Avoided Cost scenario we estimate there is 139 MW of battery storage potential yielding $102.9 million in net benefits to ratepayers. Under the High Avoided Cost scenario, 329 MW of cost-effective battery potential is estimated, producing net benefits of $311 million. Table 16 shows the cost-effectiveness on per kW basis. Very importantly, we assume that only cost-effective locations are targeted.
## Table 15: Estimated Cumulative Battery Storage Potential and Cost-Effectiveness

<table>
<thead>
<tr>
<th>Installation Year</th>
<th>Medium Avoided Cost Scenario</th>
<th>High Avoided Cost Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>6</td>
<td>$19</td>
</tr>
<tr>
<td>2019</td>
<td>15</td>
<td>$43</td>
</tr>
<tr>
<td>2020</td>
<td>26</td>
<td>$73</td>
</tr>
<tr>
<td>2021</td>
<td>39</td>
<td>$107</td>
</tr>
<tr>
<td>2022</td>
<td>54</td>
<td>$145</td>
</tr>
<tr>
<td>2023</td>
<td>69</td>
<td>$184</td>
</tr>
<tr>
<td>2024</td>
<td>86</td>
<td>$225</td>
</tr>
<tr>
<td>2025</td>
<td>103</td>
<td>$267</td>
</tr>
<tr>
<td>2026</td>
<td>121</td>
<td>$310</td>
</tr>
<tr>
<td>2027</td>
<td>139</td>
<td>$353</td>
</tr>
</tbody>
</table>

## Table 16: Battery Storage Cost-Effectiveness per kW (assumes only cost-effective locations are targeted)

<table>
<thead>
<tr>
<th>Installation Year</th>
<th>Levelized cost per kW-year</th>
<th>Medium Avoided Cost Scenario</th>
<th>High Avoided Cost Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>% of cost-effective locations [1]</td>
<td>NPV Benefits per kW</td>
<td>NPV Costs per kW</td>
</tr>
<tr>
<td>2018</td>
<td>$345</td>
<td>1.69%</td>
<td>$2,950</td>
</tr>
<tr>
<td>2020</td>
<td>$295</td>
<td>2.88%</td>
<td>$2,719</td>
</tr>
<tr>
<td>2021</td>
<td>$274</td>
<td>3.44%</td>
<td>$2,622</td>
</tr>
<tr>
<td>2022</td>
<td>$255</td>
<td>3.82%</td>
<td>$2,558</td>
</tr>
<tr>
<td>2023</td>
<td>$238</td>
<td>4.14%</td>
<td>$2,503</td>
</tr>
<tr>
<td>2024</td>
<td>$223</td>
<td>4.40%</td>
<td>$2,457</td>
</tr>
<tr>
<td>2025</td>
<td>$209</td>
<td>4.54%</td>
<td>$2,431</td>
</tr>
<tr>
<td>2026</td>
<td>$197</td>
<td>4.65%</td>
<td>$2,408</td>
</tr>
<tr>
<td>2027</td>
<td>$186</td>
<td>4.74%</td>
<td>$2,390</td>
</tr>
</tbody>
</table>

[1] While the sites are cost-effective, because of the traditional 5 years planning horizon, it was assumed that only 1 in 5 projects were completed in a year.
CONCLUSIONS

This report provides a technical and economic analysis of three peak demand reduction strategies that have the potential to play a significant role in Indiana’s electric resource mix in the future. Key findings from the analysis include:

**There is significant DR potential among the commercial and industrial sectors.** Most of the C&I potential identified in the Medium Avoided Cost scenario appears to have been realized by Duke, NIPSCO, and Indiana Michigan Power. The remaining non-residential potential is largely concentrated in Vectren and Indianapolis Power and Light service territories. Our modeling estimates show that, if fully realized, a day-ahead C&I demand response program could create $485 million in net benefits over the next ten years in the Medium Avoided Cost scenario. In the High Avoided Cost scenario, we estimate $1.6 billion in savings over the next ten years. C&I DR potential is lower in our analysis of a day-of notification program design, but still significant at 1,203 MW in the Medium Avoided Cost scenario and 2,183 MW in the High Avoided Cost scenario.

As air conditioning usage is a primary driver of summer peak demand, connected thermostats represent a significant opportunity to reduce residential energy use and provide savings. The increased adoption of connected thermostats presents a significant opportunity to shape the loads of this key end-use. By incentivizing adoption of the devices in exchange for permission to modify setpoints during peak hours, IOUs can accelerate the penetration of connected thermostats and have several hundred MW of controllable demand that is highly coincident with peaking conditions. Over the next ten years, we estimate connected thermostat DR could save Indiana ratepayers $73 million in a Medium Avoided Cost scenario and $344 million in a High Avoided Cost scenario. Avoided costs are a major driver of connected thermostat potential: we estimate 84 MW, 229 MW, and 553 MW in the Low, Medium, and High Avoided Cost scenarios, respectively.

The potential for cost-effective battery storage to produce savings grows as battery costs decrease. Siting battery storage installations in areas of the grid where upgrades can be avoided or deferred through reductions in peak demand is critical. If the right locations are identified, we estimate an opportunity for 139 MW of cost-effective battery installations – at a cumulative savings over ten years of $103 million to Indiana ratepayers in the Medium Avoided Cost scenario. The opportunity grows in the High Avoided Cost scenario to 329 MW of battery installations saving a total of $311 million.

Overall, this analysis shows that cost-effective DR and energy storage in Indiana have the potential to generate net benefits ranging from $448 million to $2.3 billion over 10 years, in scenarios representative of expected avoided costs in Indiana.
APPENDIX

A. Historical Load Profile for Indiana

The research team leveraged two publicly available sources to assemble a load profile for Indiana. The first source was MISO’s historical load database. From this database, the research team downloaded LRZ6 hourly load data from 1/14/2015 to 9/30/2017. So that our 2015 record would be complete, loads for the first thirteen days of January 2015 were estimated. Because LRZ6 contains Indiana and also a small part of Kentucky, the research team distributed 90% of LRZ6 load to Indiana and 10% to Kentucky.

The second source was PJM’s historical load database. From this database, the research team downloaded hourly load data for Indiana Michigan Power (I&M), which services the areas of Indiana that are not part of MISO’s LRZ6. To distribute I&M load between Indiana and Michigan, the research team used I&M’s customer distribution as a proxy for load distribution. Approximately 78% of I&M customers are in Indiana, so we attributed 78% of the I&M’s historical load data to Indiana. The I&M load data covered a period from 6/1/2015 to 9/30/2017. To obtain a complete record for 2015, the research team leveraged load data from American Electric Power (AEP), which was available for the entirety of 2015. (Note that I&M is a subsidiary of AEP, so load for AEP is equal to the sum of load for I&M and the load for several other utilities.) The relationship between I&M load data and AEP load data was then used to estimate I&M load for the first five months of 2015.

Finally, we constructed hourly estimates of Indiana’s statewide load from 1/1/2015 to 9/30/2017 as follows:

\[
\text{Indiana Load} = 0.90 \times (LRZ6 \text{ Load}) + 0.78 \times (I&M \text{ Load})
\]

B. Peak Load Forecast and Disaggregation

The research team assembled a peak load forecast for Indiana in a manner that emulated the way we assembled the historical load profile – retrieve and then combine publicly available MISO and PJM data. The peak load forecast draws primarily from two sources: MISO’s 2016 Independent Load Forecast and PJM’s 2017 Independent Load Forecast.

\[\text{Source: Indiana Department of Commerce, Energy Division, November 2015.}\]

14 https://www.misoenergy.org/Library/Repository/Market%20Reports/YYYYMMDD_df_al.xls
From MISO’s 2016 Independent Load Forecast, the research team drew summer and winter non-coincident peak demand forecasts for LRZ6. The authors of the Independent Load Forecast provided two sets of forecasts – one set contained adjustments for energy efficiency, demand response, and distributed generation while the other did not. For our study, the research team is using the unadjusted forecasts. Note that all forecasts in the 2016 Independent Load Forecast run through 2026.

From PJM’s 2017 Load Forecast Report, the research team drew summer and winter peak forecasts for American Electric Power (AEP). Note that PJM’s 2017 Load Forecast Report reports peaks for each month rather than each season, so the research team treated the peaks of the summer months and winter months as the overall summer and winter peaks, respectively. Also note that I&M is a subsidiary of AEP, so the research team used historical PJM data to help assign a portion of the AEP peak forecast to I&M.

With peak load forecasts for LRZ6 and I&M, the research team used the formula $0.90 \times \text{LRZ6 Load} + 0.78 \times \text{I&M Load}$ to estimate peak load forecasts for Indiana. Table 17 shows our summer and winter peak forecasts, as well as the components used in creating the forecasts. Note that 2027 LRZ6 peaks were not part of MISO’s 2016 Independent Load Forecast, so those are estimated based on the observed growth rate in LRZ6’s summer and winter peaks.

### Table 17: Estimated Indiana Peak Load Forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>LRZ6 Summer Peak</th>
<th>LRZ6 Winter Peak</th>
<th>I&amp;M Summer Peak</th>
<th>I&amp;M Winter Peak</th>
<th>Indiana Summer Peak</th>
<th>Indiana Winter Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>18,354</td>
<td>17,825</td>
<td>4,855</td>
<td>4,645</td>
<td>20,306</td>
<td>19,665</td>
</tr>
<tr>
<td>2019</td>
<td>18,635</td>
<td>18,079</td>
<td>4,881</td>
<td>4,690</td>
<td>20,579</td>
<td>19,929</td>
</tr>
<tr>
<td>2020</td>
<td>18,904</td>
<td>18,320</td>
<td>4,864</td>
<td>4,686</td>
<td>20,808</td>
<td>20,143</td>
</tr>
<tr>
<td>2021</td>
<td>19,166</td>
<td>18,552</td>
<td>4,863</td>
<td>4,680</td>
<td>21,043</td>
<td>20,347</td>
</tr>
<tr>
<td>2022</td>
<td>19,408</td>
<td>18,764</td>
<td>4,878</td>
<td>4,703</td>
<td>21,273</td>
<td>20,557</td>
</tr>
<tr>
<td>2023</td>
<td>19,643</td>
<td>18,967</td>
<td>4,895</td>
<td>4,723</td>
<td>21,497</td>
<td>20,755</td>
</tr>
<tr>
<td>2024</td>
<td>19,879</td>
<td>19,171</td>
<td>4,927</td>
<td>4,757</td>
<td>21,734</td>
<td>20,965</td>
</tr>
<tr>
<td>2025</td>
<td>20,115</td>
<td>19,373</td>
<td>4,949</td>
<td>4,777</td>
<td>21,963</td>
<td>21,162</td>
</tr>
<tr>
<td>2026</td>
<td>20,354</td>
<td>19,578</td>
<td>4,982</td>
<td>4,811</td>
<td>22,204</td>
<td>21,373</td>
</tr>
<tr>
<td>2027</td>
<td>20,596</td>
<td>19,811</td>
<td>5,008</td>
<td>4,842</td>
<td>22,443</td>
<td>21,607</td>
</tr>
</tbody>
</table>

The next step in our analysis was to disaggregate the peak load forecast by sector (residential, commercial, and industrial). The goal in this effort was to inform DR strategies for the various sectors, as DR potential is certainly related to peak load. The primary source used in disaggregating the peak load forecast was the U.S. Energy Information Administration’s (EIA) 2016 Monthly Electric Power Industry Report. This report estimates monthly sales dollars and monthly MWh for each utility in each state and includes separate monthly estimates for the residential, commercial, and industrial sectors. The research team used this information to calculate energy shares for each sector. Because each sector has a unique load factor, we could not assume that the distribution of peak load is equal to the distribution of energy consumption. To convert energy shares to peak load shares, the research team had to make assumptions regarding the load factor for each sector. Our estimates for the peak load share of each sector are shown in Table 18. We are assuming the distribution of peak demand remains static over the study horizon.

Table 18: Peak Load Disaggregation

<table>
<thead>
<tr>
<th>Sector</th>
<th>Energy Share</th>
<th>Load Factor</th>
<th>Peak Load Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>33%</td>
<td>0.50</td>
<td>43%</td>
</tr>
<tr>
<td>Commercial</td>
<td>25%</td>
<td>0.60</td>
<td>23%</td>
</tr>
<tr>
<td>Industrial</td>
<td>42%</td>
<td>0.80</td>
<td>34%</td>
</tr>
<tr>
<td>Total or Average</td>
<td>100%</td>
<td>0.65</td>
<td>100%</td>
</tr>
</tbody>
</table>

C. Cost Effectiveness

The research team elected to use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to evaluate the cost-effectiveness of the demand response options. The costs that factor into the UCT ratio include participant incentives and estimates of the administrative costs tied to operating the DR program. Note that participant incentives represent most of the total cost associated with the DR program. Examples of administrative costs are fees paid to an implementation contractor and salaries of utility staff. Any costs related to marketing or recruiting would be categorized as administrative costs as well.

The benefits that factor into the UCT ratio include the avoided cost of generation capacity, the avoided cost of transmission and

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19 https://www.eia.gov/electricity/data/eia861m/xls/f8262016.xls

20 Calculated as energy share/(sector load factor/total load factor)
distribution capacity (where appropriate), and the on-peak/off-peak differential in energy cost. Each of these benefits was discussed in some detail in Section 0. It is important to note that the modeling approach taken in this report does not seek to maximize demand reduction potential. Instead, our goal is to maximize net benefits. A design that results in a UCT ratio of 1 would maximize DR potential, but create no net economic benefit for the state, as measured by the UCT.

D. Elasticity of Demand

The analytical approach used for C&I demand response is a ‘top-down’ method that uses price elasticity of demand coefficients to model DR potential under various conditions. Price elasticity of demand is the percentage change in the quantity of electricity demanded divided by the percentage change in the price of DR (e.g. factoring the DR incentive into the cost of power). Elasticity of demand coefficients will be negative, meaning the quantity of electricity demanded goes down when the price goes up. This can also be thought of as the amount of DR supplied going up when the incentive increases. The formula for elasticity is:

\[ Elasticity = \frac{\% \text{ change in Quantity}}{\% \text{ change in Price}} \]

A general formula for the percentage change in quantity (which can also be applied to the percentage change in price) is shown below.

\[ \% \text{ change in Quantity} = \frac{(New \text{ Quantity} - Original \text{ Quantity})}{Original \text{ Quantity}} * 100\% \]

In the context of demand response (DR), this formula becomes:

\[ \% \text{ change in Quantity (kW)} = \frac{(Summer \text{ peak} - DR \text{ potential}) - Summer \text{ Peak}}{Summer \text{ Peak}} * 100\% \]

Note that the elasticity formula presented at the beginning of this section can be rearranged as follows:

\[ \% \text{ change in Quantity} = (Elasticity) * (\% \text{ change in Price}) \]

Two distinct formulas for the percentage change in quantity have been presented. Setting these formulas equal to one another yields the following equation:

\[ (Elasticity) * (\% \text{ change in Price}) = \frac{(Summer \text{ peak} - DR \text{ potential}) - Summer \text{ Peak}}{Summer \text{ Peak}} * 100\% \]

The terms in this equation can be rearranged so that the only variable on the left-hand side of the equation is DR potential:
\[ DR \text{ Potential} = -\frac{(Elasticity) \times (\% \text{ change in Price}) \times \text{Summer Peak}}{100} \]

With the proper inputs, this equation can be used to estimate how much DR potential exists. To implement this equation, three inputs are needed: elasticity values, the percentage change in price of DR, and the summer peak. The research team developed estimates of summer peak demand in Appendix B. The percentage change in the price of DR is a function of retail electric rates, DR incentive payments, and the number of DR dispatch hours. These three items are either known or are being held constant in our analysis. Finally, the elasticity estimates used in our analysis are drawn from the Demand Response Potential Study Report for Pennsylvania\(^{21}\) and are shown in Table 19.

### Table 19: Elasticity Estimates by DR Dispatch Type

<table>
<thead>
<tr>
<th>Sector</th>
<th>Segment</th>
<th>Day-Ahead Notification</th>
<th>Sector Average Day-Ahead</th>
<th>Day-Of Notification</th>
<th>Sector Average Day-Of</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial</td>
<td>Education</td>
<td>-0.009</td>
<td></td>
<td>-0.003</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Grocery</td>
<td>-0.010</td>
<td></td>
<td>-0.009</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Health</td>
<td>-0.021</td>
<td>-0.015</td>
<td>-0.007</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Lodging</td>
<td>-0.010</td>
<td></td>
<td>-0.005</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Office</td>
<td>-0.010</td>
<td></td>
<td>-0.005</td>
<td>-0.009</td>
</tr>
<tr>
<td>Commercial</td>
<td>Other</td>
<td>-0.011</td>
<td></td>
<td>-0.006</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Restaurant</td>
<td>-0.010</td>
<td></td>
<td>-0.005</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Retail</td>
<td>-0.010</td>
<td></td>
<td>-0.009</td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>Warehouse</td>
<td>-0.036</td>
<td></td>
<td>-0.045</td>
<td></td>
</tr>
<tr>
<td>Industrial</td>
<td>Industrial</td>
<td>-0.013</td>
<td>-0.013</td>
<td>-0.007</td>
<td>-0.007</td>
</tr>
</tbody>
</table>

Rather than divide the peak demand forecast into separate components for each commercial segment and model the potential separately, an average elasticity value was calculated for the commercial segments and applied to the entire sector.

### E. Modeling Demand Response Potential

Demand response potential from large businesses – and the cost to acquire it – is driven by a few key factors. These key factors and the directional effect they have on DR potential are shown in Figure 14.

![Figure 14: Drivers of DR Potential](image)

Estimating demand response potential at different levels of these four critical inputs would result in a dizzying array of DR potential estimates. To limit the range of DR potential estimates, the research team had to make several assumptions regarding these four aspects of DR program design. In the sections to follow, assumptions regarding each of the four DR levers will be discussed.

### NOTIFICATION TIME

The amount of notification time that program participants are given prior to an event affects their ability to respond, as more notification time allows production and staffing schedules to be modified around the dispatch period. For this report, C&I demand response estimates are presented for two levels of notification time: day-ahead and day-of. A day-ahead notification assumes participants are given approximately 24-hours’ notice. A day-of notification assumes that participants are notified in the morning or afternoon that a demand response event will occur later that same day. Under this scenario, participants would receive a 3-to-6-hour notice.

### EVENT FREQUENCY AND DURATION

When DR events are infrequent and brief, facilities can shift energy intense processes
away from peak hours with limited disruption to the primary business. Longer and more frequent dispatches can become burdensome to participants and could act as a deterrent to demand response participation. Additionally, the greater the expected commitment in days or hours, the larger the financial incentives given to participants will need to be to offset the disruption in operations. To craft assumptions regarding event frequency and duration, the research team leveraged historical load data and historical pricing data.

According to the load profile that the research team assembled for Indiana, the state’s peak demand was recorded at 19,167 MW on July 29, 2015. Figure 15 shows the distribution of hours where statewide demand exceeded 95% of the overall peak by hour of the day and by season (from 1/1/2015 through 9/30/2017). That there were 43 such hours. During summer, these hours are concentrated between 2:00 PM and 6:00 PM. This makes sense, as demand during the summer season typically peaks in the afternoon. During winter, the hours when demand exceeded 95% of the system peak typically occurred in the morning between 7:00 AM and 10:00 AM.

The 43 hours represented in Figure 15 were spread across 13 days (4 winter days and 9 summer days). So, on average, these days saw 3.3 hours where demand exceeded 95% of the system peak. This suggests relatively short DR
events – 3 or 4 hours – would serve the region better than relatively long DR events.

Because peak loads are often associated with peak locational marginal prices (LMPs), the research team also examined historical hourly LMPs in the region. Price duration curves for the MISO\textsuperscript{22} and PJM portions of Indiana are shown in Figure 16. The dotted reference line shows the average hourly LMP across both systems from 1/1/2015 through 8/23/2017 ($28.60).

Both curves indicate that high prices are infrequent – see the steep peak in the top left corner of each price duration curve. On days where the MISO LMP exceeded $50 for at least one hour, the LMP stayed above $50 for an average of 2.38 hours. On days where the PJM LMP exceeded $50 for at least one hour, the LMP stayed above $50 for an average of 3.04 hours. Thus, responding to these hours with the high LMPs would not require exceptionally long DR events.

\textbf{Figure 16: Price Duration Curves for Indiana Portions of MISO and PJM}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{price_duration_curves.png}
\end{figure}

\textsuperscript{22} The LMPs shown for the MISO territory represent an average of the LMPs for the six local balancing authorities that make up MISO’s LRZ6.
The above analyses show that, from both an economic standpoint and a capacity standpoint, the data suggest a small number of DR dispatch hours will serve the region better than DR events spanning several dispatch hours. For this report, we have chosen to present results holding the frequency and duration of events constant at 8 events, each of 3-hour duration. This design yields 24 total hours of curtailment per year. This relatively limited commitment is an increase over how DR resources have generally been used in Indiana historically, as MISO has not dispatched emergency resources since 2006 and PJM has not made any emergency calls most years.

### INCENTIVE PAYMENTS

The incentive offered by the utility could take several forms, including direct incentive payments and bill credits. Compensation can be based on capacity, energy, or a mix of the two. This analysis models the incentive as a “reservation payment”, where the utility pays an annual incentive to the facility to curtail when called upon. We modeled three levels of payment – one each for the Low, Medium, and High Avoided Cost scenarios. Table 20 shows these payment levels for 2018. Incentive payments are escalated by 2% annually over the study horizon. A discussion of how these payment levels were determined follows.

#### Table 20: 2018 Incentive Payment Assumptions

<table>
<thead>
<tr>
<th>Avoided Cost Scenario</th>
<th>Incentive Payment ($/kW-year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>$7</td>
</tr>
<tr>
<td>Medium</td>
<td>$29</td>
</tr>
<tr>
<td>High</td>
<td>$51</td>
</tr>
</tbody>
</table>

The research team’s approach to setting incentive levels involved optimizing net benefits (benefits minus costs). In other words, our goal was to answer this question: What incentive level maximizes the net benefits to ratepayers? Note that this question is not the same as: What incentive level maximizes DR potential? Setting incentive levels too high results in high program costs that outpace the financial benefits of a demand response program. Similarly, if the incentive levels are too low, program costs will drop but program participation will drop as well. As a result, financial benefits will be hamstrung by the limited amount of DR potential.

To solve for the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the DR program. Other inputs included DR potential, number of dispatch hours (held constant at 24), avoided energy benefits, capacity benefits (avoided generation, transmission, and distribution costs), program management costs, and total incentive costs. Note that several of these inputs are tied to the incentive...
level. For example, as the incentive level increases, DR potential increases. This, in turn, influences the capacity benefits.

For the Medium Avoided Cost scenario, Figure 17 shows the relationship between the two critical variables – incentive level and net benefits. Note that the curve peaks when the incentive is $29 per kW-year. Thus, this value was used as the incentive level for the Medium Avoided Cost scenario. The research team ran identical simulations for the Low and High Avoided Cost scenarios. Those scenarios landed on optimal incentive levels of $7 per kW-year and $51 per kW-year, respectively.

Figure 17: Optimizing Net Benefits

F. C&I DR Potential Tables

The tables below provide a summary of the estimates of C&I DR market potential for all three scenarios. As discussed in the previous section, these are the estimates of the level of DR potential to correspond to the highest net benefits to Indiana residents.
### Table 21: DR Potential (MW) for Low Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load Forecast (MW)</th>
<th>Commercial DR Potential (MW)</th>
<th>Industrial DR Potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Day-ahead</td>
<td>Day-of</td>
</tr>
<tr>
<td>2018</td>
<td>20,306</td>
<td>98</td>
<td>59</td>
</tr>
<tr>
<td>2019</td>
<td>20,579</td>
<td>99</td>
<td>60</td>
</tr>
<tr>
<td>2020</td>
<td>20,808</td>
<td>101</td>
<td>61</td>
</tr>
<tr>
<td>2021</td>
<td>21,043</td>
<td>102</td>
<td>61</td>
</tr>
<tr>
<td>2022</td>
<td>21,273</td>
<td>103</td>
<td>62</td>
</tr>
<tr>
<td>2023</td>
<td>21,497</td>
<td>104</td>
<td>63</td>
</tr>
<tr>
<td>2024</td>
<td>21,734</td>
<td>105</td>
<td>63</td>
</tr>
<tr>
<td>2025</td>
<td>21,963</td>
<td>106</td>
<td>64</td>
</tr>
<tr>
<td>2026</td>
<td>22,204</td>
<td>107</td>
<td>65</td>
</tr>
<tr>
<td>2027</td>
<td>22,443</td>
<td>108</td>
<td>65</td>
</tr>
</tbody>
</table>

### Table 22: DR Potential (MW) for Medium Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load Forecast (MW)</th>
<th>Commercial DR Potential (MW)</th>
<th>Industrial DR Potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Day-ahead</td>
<td>Day-of</td>
</tr>
<tr>
<td>2018</td>
<td>20,306</td>
<td>574</td>
<td>346</td>
</tr>
<tr>
<td>2019</td>
<td>20,579</td>
<td>582</td>
<td>351</td>
</tr>
<tr>
<td>2020</td>
<td>20,808</td>
<td>589</td>
<td>354</td>
</tr>
<tr>
<td>2021</td>
<td>21,043</td>
<td>595</td>
<td>358</td>
</tr>
<tr>
<td>2022</td>
<td>21,273</td>
<td>602</td>
<td>362</td>
</tr>
<tr>
<td>2023</td>
<td>21,497</td>
<td>608</td>
<td>366</td>
</tr>
<tr>
<td>2024</td>
<td>21,734</td>
<td>615</td>
<td>370</td>
</tr>
<tr>
<td>2025</td>
<td>21,963</td>
<td>621</td>
<td>374</td>
</tr>
<tr>
<td>2026</td>
<td>22,204</td>
<td>628</td>
<td>378</td>
</tr>
<tr>
<td>2027</td>
<td>22,443</td>
<td>635</td>
<td>382</td>
</tr>
</tbody>
</table>
### Table 23: DR Potential (MW) for High Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load Forecast (MW)</th>
<th>Commercial DR Potential (MW)</th>
<th>Industrial DR Potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Day-ahead</td>
<td>Day-of</td>
</tr>
<tr>
<td>2018</td>
<td>20,306</td>
<td>1,051</td>
<td>633</td>
</tr>
<tr>
<td>2019</td>
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<td>2020</td>
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<td>1,077</td>
<td>648</td>
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<td>21,043</td>
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<td>21,273</td>
<td>1,101</td>
<td>663</td>
</tr>
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<td>1,113</td>
<td>670</td>
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<td>2024</td>
<td>21,734</td>
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<td>677</td>
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<td>21,963</td>
<td>1,137</td>
<td>684</td>
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<tr>
<td>2026</td>
<td>22,204</td>
<td>1,149</td>
<td>692</td>
</tr>
<tr>
<td>2027</td>
<td>22,443</td>
<td>1,161</td>
<td>699</td>
</tr>
</tbody>
</table>

### G. Cost and Benefit Tables

The tables below provide a summary of the costs and benefits associated with the estimates of C&I DR market potential for all three scenarios. In calculating these average annual net benefits, the dollar amounts were not discounted to net present value – each year’s costs and benefits were compared in the year they occur.
Table 24: Costs and Benefits ($Million) for Low Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Day-ahead Notification</th>
<th></th>
<th>Day-of Notification</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Costs</td>
<td>Benefits</td>
<td>Net Benefits</td>
<td>Costs</td>
</tr>
<tr>
<td>2018</td>
<td>$3.2</td>
<td>$5.2</td>
<td>$2.0</td>
<td>$1.8</td>
</tr>
<tr>
<td>2019</td>
<td>$3.3</td>
<td>$5.4</td>
<td>$2.0</td>
<td>$1.9</td>
</tr>
<tr>
<td>2020</td>
<td>$3.4</td>
<td>$5.6</td>
<td>$2.1</td>
<td>$1.9</td>
</tr>
<tr>
<td>2021</td>
<td>$3.6</td>
<td>$5.7</td>
<td>$2.2</td>
<td>$2.0</td>
</tr>
<tr>
<td>2022</td>
<td>$3.7</td>
<td>$5.9</td>
<td>$2.2</td>
<td>$2.0</td>
</tr>
<tr>
<td>2023</td>
<td>$3.8</td>
<td>$6.1</td>
<td>$2.3</td>
<td>$2.1</td>
</tr>
<tr>
<td>2024</td>
<td>$3.9</td>
<td>$6.3</td>
<td>$2.4</td>
<td>$2.2</td>
</tr>
<tr>
<td>2025</td>
<td>$4.0</td>
<td>$6.5</td>
<td>$2.5</td>
<td>$2.2</td>
</tr>
<tr>
<td>2026</td>
<td>$4.1</td>
<td>$6.7</td>
<td>$2.5</td>
<td>$2.3</td>
</tr>
<tr>
<td>2027</td>
<td>$4.3</td>
<td>$6.9</td>
<td>$2.6</td>
<td>$2.4</td>
</tr>
</tbody>
</table>

Table 25: Costs and Benefits ($M) for Medium Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Day-ahead Notification</th>
<th></th>
<th>Day-of Notification</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Costs</td>
<td>Benefits</td>
<td>Net Benefits</td>
<td>Costs</td>
</tr>
<tr>
<td>2018</td>
<td>$72</td>
<td>$136</td>
<td>$64</td>
<td>$40</td>
</tr>
<tr>
<td>2019</td>
<td>$75</td>
<td>$141</td>
<td>$66</td>
<td>$42</td>
</tr>
<tr>
<td>2020</td>
<td>$77</td>
<td>$146</td>
<td>$69</td>
<td>$43</td>
</tr>
<tr>
<td>2021</td>
<td>$79</td>
<td>$150</td>
<td>$71</td>
<td>$44</td>
</tr>
<tr>
<td>2022</td>
<td>$82</td>
<td>$155</td>
<td>$73</td>
<td>$46</td>
</tr>
<tr>
<td>2023</td>
<td>$84</td>
<td>$160</td>
<td>$75</td>
<td>$47</td>
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<tr>
<td>2024</td>
<td>$87</td>
<td>$165</td>
<td>$77</td>
<td>$49</td>
</tr>
<tr>
<td>2025</td>
<td>$90</td>
<td>$170</td>
<td>$80</td>
<td>$50</td>
</tr>
<tr>
<td>2026</td>
<td>$93</td>
<td>$175</td>
<td>$82</td>
<td>$52</td>
</tr>
<tr>
<td>2027</td>
<td>$95</td>
<td>$180</td>
<td>$85</td>
<td>$53</td>
</tr>
</tbody>
</table>
Table 26: Costs and Benefits ($M) for High Avoided Cost Scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Day-ahead Notification</th>
<th>Day-of Notification</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Costs</td>
<td>Benefits</td>
</tr>
<tr>
<td>2018</td>
<td>$231</td>
<td>$444</td>
</tr>
<tr>
<td>2019</td>
<td>$238</td>
<td>$459</td>
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<tr>
<td>2020</td>
<td>$246</td>
<td>$474</td>
</tr>
<tr>
<td>2021</td>
<td>$253</td>
<td>$489</td>
</tr>
<tr>
<td>2022</td>
<td>$261</td>
<td>$504</td>
</tr>
<tr>
<td>2023</td>
<td>$269</td>
<td>$519</td>
</tr>
<tr>
<td>2024</td>
<td>$278</td>
<td>$536</td>
</tr>
<tr>
<td>2025</td>
<td>$286</td>
<td>$552</td>
</tr>
<tr>
<td>2026</td>
<td>$295</td>
<td>$569</td>
</tr>
<tr>
<td>2027</td>
<td>$304</td>
<td>$587</td>
</tr>
</tbody>
</table>

H. Battery Storage Current and Projected Costs Detail

For battery storage costs, we relied on existing research on battery storage costs based on a recent study for the utility PacifiCorp that included costs for seven different battery technologies. Because lithium NCM and LiFePO4 batteries are currently more cost-effective, we relied on their average cost in estimating market potential. However, the table and figure below include costs and cost trends for all seven battery technologies included in the PacifiCorp study.
Table 27: Energy storage system cost estimates

<table>
<thead>
<tr>
<th>Cost Parameter/ Technology</th>
<th>Lithium-Ion NCM</th>
<th>Lithium-Ion LiFePO4</th>
<th>Lithium-Ion LTO</th>
<th>NaS</th>
<th>VRB</th>
<th>ZnBr</th>
<th>Zinc-air</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy storage equipment cost ($/kWh)</td>
<td>$325-$450</td>
<td>$350-$525</td>
<td>$500-$850</td>
<td>$800-$1000</td>
<td>$500-$700</td>
<td>$525-$725</td>
<td>$200-$400</td>
</tr>
<tr>
<td>Power conversion system equipment cost ($/kW)</td>
<td>$350-$500</td>
<td>$350-$500</td>
<td>$350-$500</td>
<td>$500-$750</td>
<td>$500-$750</td>
<td>$500-$750</td>
<td>$350-$500</td>
</tr>
<tr>
<td>Power control system cost ($/kW)</td>
<td>$80-$120</td>
<td>$80-$120</td>
<td>$80-$120</td>
<td>$80-$120</td>
<td>$100-$140</td>
<td>$100-$140</td>
<td>$100-$140</td>
</tr>
<tr>
<td>Balance of system ($/kW)</td>
<td>$80-$100</td>
<td>$80-$100</td>
<td>$80-$100</td>
<td>$100-$125</td>
<td>$100-$125</td>
<td>$100-$125</td>
<td>$80-$100</td>
</tr>
<tr>
<td>Installation ($/kWh)</td>
<td>$120-$180</td>
<td>$120-$180</td>
<td>$120-$180</td>
<td>$140-$200</td>
<td>$140-$200</td>
<td>$140-$200</td>
<td>$120-$180</td>
</tr>
<tr>
<td>Fixed O&amp;M cost ($/kW-yr)</td>
<td>$6-$11</td>
<td>$6-$11</td>
<td>$6-$11</td>
<td>$7-$12</td>
<td>$7-$12</td>
<td>$7-$12</td>
<td>$6 - $12</td>
</tr>
</tbody>
</table>


Figure 18: Battery Storage Equipment Cost Trends