SECTION 1: INTRODUCTION

On November 1, 2015, Duke Energy Indiana, LLC (Duke or DEI), and Indiana Michigan Power Company (I&M) released their 2015 Integrated Resource Plans (IRPs). Sommer Energy, LLC, and Mims Consulting, LLC, were retained to assist the Joint Commenters (Citizens Action Coalition, Earthjustice, Indiana Distributed Energy Alliance, Michael A. Mullett, Sierra Club, and Valley Watch) with their review of these IRPs. This report constitutes the results of our review.

In Section 2, we address the inclusion of energy efficiency as a resource within the IRPs. We find that the evaluation of supply and demand-side resources is still not consistent and comparable primarily because the amount of energy efficiency in the IRPs is severely constrained and because energy efficiency was inappropriately screened out before it could be included in IRP modeling.

In Section 3, we review the utilities' assumptions regarding new wind and solar resources. In general, we find that cost assumptions are too high, capacity factors too low, and that the newly renewed tax credits incentivizing wind and solar resources were not taken into account.

In Section 4, our focus turns to load forecasting and reserve margin requirements with a particular emphasis on Duke. We believe that Duke's load forecast is overly optimistic and that it has not properly modeled the reserve margin requirements established by MISO.

In Section 5, we address I&M's IRP modeling. We found serious flaws and deficiencies in I&M's modeling, although we could not review all of I&M's input and output modeling files. The economics of I&M's preferred plan is based upon a presumption that it can sell large quantities of surplus power at a significant profit for decades to come. Its preferred plan also continues the operation of both Rockport units despite their lack of profitability and the necessity of spending significant sums to add pollution controls. The modeling was also biased against the alternatives by overly constrained assumptions, including those applied to renewables.

In Section 6, we discuss the flaws and deficiencies in Duke's IRP modeling. Though it attempted to model the requirements of the Clean Power Plan (CPP), it is not clear what that modeling was actually intended to represent. Duke's modeling also shows that a number of its units are not profitable to operate. Finally and perhaps most egregiously, its modeling was severely constrained by forcing most resource choices in the runs, despite seemingly unequivocal statements by Duke to the contrary.

Taken together, all of these flaws should repudiate any suggestion that the utilities' plans would be least cost and least risk for ratepayers.

SECTION 2: ENERGY EFFICIENCY

I. Introduction and Recommendations

Indiana's Integrated Resource Plan regulations require utilities to demonstrate that they have evaluated supply side and demand side resource alternatives on a consistent and comparable basis.[1] The purpose of moving away from evaluating efficiency as a static load reduction, and towards evaluating this resource on a consistent and comparable basis to supply side resources, is to place demand side resources on a level playing field with supply side resources in the IRP, and appropriately capture all of the costs and benefits of demand side resources. Such a methodology is an important step forward in Indiana energy policy, and we applaud the State of Indiana for promoting this endeavor, which allows appropriate consideration of demand side resources in long term planning.

However, as in years past,[2] Duke and I&M did not evaluate supply and demand side resources in a consistent and comparable manner in their 2015 IRPs. The utilities' modeling fell short of a comparable analysis between supply and demand side resources for two major reasons: (1) the utilities severely constrained the total amount of energy efficiency available to the model; and (2) the utilities prescreened demand side resources for cost-effectiveness before making them an available resource for the model. As a result of these constraints, the utilities' preferred portfolios are likely more costly due to their underinvestment in cost-effective demand side resources.

Based on our review of the DEI and I&M IRPs,

1. We recommend that the Director's Draft Report request that the utilities publicly provide their energy efficiency impacts in an annual, incremental format with corresponding costs, in addition to the current cumulative format, when the Comments on the Draft Report are due. In addition, the utilities should publicly provide their energy efficiency assumptions, including if the impacts are net or gross, at the meter or generator, and if the impacts are annualized, hourly or another format.
2. We recommend that the utilities evaluate their efficiency potential by bundling the measures from the technical potential analysis, not from program plans (DEI) or achievable potential (I&M).
3. We recommend that the Director's Draft Report request that DEI publicly provide data to substantiate how much energy efficiency was eliminated by using this prescreening methodology when Comments on the Draft Report are due.
4. We strongly recommend that the Director's Draft Report request the utilities rerun the models and eliminate this benefit-cost calculation requirement, instead requiring that energy efficiency be fully included in IRP modeling and screened for economics in the IRP, not externally. The

[1] 170 IAC 4-7-8 Resource integration.

[2] Commission Electricity Director's Report Regarding 2013 Integrated Resource Plans, pages 4 – 5, available at: http://www.in.gov/iurc/files/Director_2013_IRP_Report_-_Final_4-30-14.pdf.

utilities should provide this information in their Comments on the Draft Report.

II. Overview of DEI and I&M Preferred Plan Energy Efficiency Impacts and Costs

It appears that DEI's IRP preferred plan EE impacts are similar to the proposed DSM plan goals as presented in IURC Cause No. 43955 DSM 3, and that I&M's 2016 IRP EE impacts (through its load forecast adjustment)[3] are lower than its proposed DSM plan impacts in IURC Cause No. 43827 DSM 5. This is disappointing as it appears that DEI and I&M have constrained efficiency so much, through a plethora of assumptions, that their models indicate that only the level of efficiency available today is an accurate portrayal of the amount of efficiency available for the next two decades. This is indicative of both a lack of investigation into emerging and future technologies on the demand side and a self-fulfilling prophecy of energy efficiency being a finite resource. Simply put, the results of DEI and I&M's IRP modeling indicate that the utilities did not model demand and supply side resources comparably, and that the utilities are once again underestimating the amount of efficiency available in their long term plans.

The outcome of the utilities' incremental EE impacts in their IRP preferred plans for 2016-2018 is shown in Table 2.1. The table is limited to 2016-2018 because we were unable to accurately calculate the incremental EE impacts in DEI and I&M's IRP plans over the IRP timeframe.[4] It appears that DEI and I&M are both using lower EE impacts in their IRP models than in their DSM Plans, [5] and that I&M grossly underestimated the cumulative impacts of its demand side programs prior to 2016 (discussed more below). It is valuable to calculate incremental impacts because it allows stakeholders to compare the utilities' long term planning with what is actually happening today in their utility energy efficiency programs.

[3] I&M 2015 IRP, Volume II, Appendix A-12.
[4] DEI did provide its energy efficiency impacts in incremental terms but the data did not match the System Optimizer outputs. In a discovery response, that was received too late to use in these comments, it indicated that the difference between the EE impacts spreadsheets provided and the System Optimizer outputs were due to one set of data being net of freeriders, and hourly EE impacts, and the other set of data being gross of freeriders and annualized. We were not able to verify this with our own analysis due to time constraints.
[5] *See* FN 4, DEI has clarified that all energy efficiency data sources are the same data, but it does not appear any of that data matches with the DSM filing.

Table 2.1. Proposed Incremental EE Impacts in DSM Plan and IRP (GWh)

	DEI		I&M	
	DSM[6]	**IRP**[7]	**DSM**[8]	**IRP**[9]
2016	206	[redacted]	141	[redacted] [10]
2017	208	[redacted]	N/A	[redacted]
2018	196	[redacted]	N/A	[redacted]

The utilities reported their EE impacts in their IRPs in cumulative numbers, shown in Table 2.2. DEI anticipates achieving between [redacted]% of their load with energy efficiency between 2020-2035, and I&M [redacted]%. DEI is investing approximately ten times more capital than I&M in energy efficiency from 2020-2035, due to I&M reducing its capital investment in energy efficiency each year after 2020.

Table 2.2 Cumulative Impacts of EE in Preferred Plan IRPs

	DEI			I&M		
	GWh	**% of annual load**	**$M (NPV)**	**GWh**	**%**	**$M (NPV)**
2020	[redacted]	[redacted]	[redacted] [11]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]		[redacted]	[redacted]	
2030	[redacted]	[redacted]		[redacted]	[redacted]	
2035	[redacted]	[redacted]		[redacted]	[redacted]	

We recommend that the Director's Draft Report request that the utilities publicly provide their energy efficiency impacts in an annual, incremental format with corresponding costs, in addition to the current cumulative format, when the Comments on the Draft Report are due. In addition, the utilities should state their assumptions regarding the efficiency data, including if the impacts are net or gross, at the meter or generator, and if the impacts are annualized, hourly or another format.

[6] IURC Cause No. 43955 DSM 3, Petitioner's Exhibit E, page 3.
[7] DEI Informal Discovery Response, Confidential Attachment CAC 1.1, "e.2 DEI EE Bundles for 2015 IRP.xlsx." Incremental energy efficiency impacts of the IRP are calculated by subtracting 2015 cumulative savings from 2016 cumulative savings, for each year in the table. This takes into account the impact of measure degradation.
[8] IURC Cause No. 43827 DSM 5, Petitioner's Exhibit 1, Attachment JCW-2.
[9] Base Band Preferred Plan, calculated for efficiency only.
[10] *See* discussion below for how energy efficiency was incorporated into the load forecast for 2016 and 2017.
[11] DEI Confidential Attachment CAC 1.1, "f.1. 2015 Capital Costs.xlsx," S2P5 tab.

III. The Utilities Constrained the Amount of Efficiency Available to the Model

The first step in evaluating a resource for integrated resource planning is to determine how much of the resource is available in a utility's service territory. The utilities used differing methodologies to determine their respective Technical EE Potential, and the subsequent use of it in their IRP models is insufficient for the purposes of modeling supply side and demand side resources comparably and consistently.

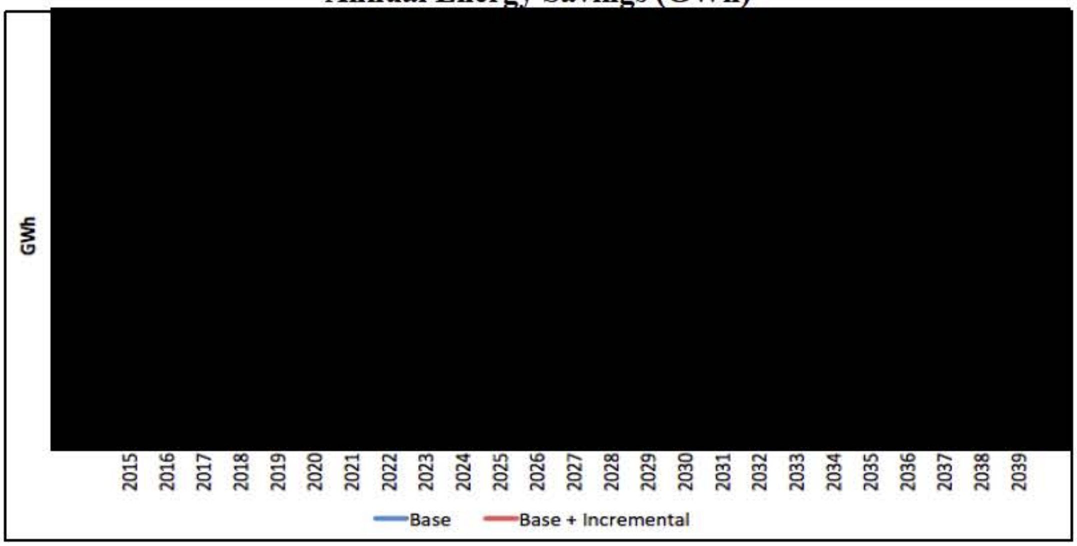
a. DEI Unreasonably Limited the Amount of EE Available for EE Bundles

Our major concern with DEI's demand side IRP modeling is that the Company limited the amount of demand side resources available to the system prior to being "incorporated into the optimization process of the IRP analysis."[12] DEI limited the amount of demand side resources available to the model by creating future EE impacts only from its current and planned programs.[13] By limiting efficiency impacts in the IRP based on the current and proposed portfolio impacts, DEI is effectively using the same methodology it has in years past—hard coding the amount of efficiency available—but calling it something new.[14]

For example, in DEI's efficiency modeling data, its annual "Base Portfolio" and "Incremental Portfolio" EE inputs are [redacted], shown in Figure 2.1. This indicates that in DEI's "Base Portfolio," it assumes that it will reach [redacted] GWh of incremental savings in 2018, and then hold those savings constant for the duration of the IRP timeframe. When coupled with its annual capital investment for EE in the Preferred Portfolio, DEI anticipates the same amount of EE impacts each year, at an increasing cost.

[12] DEI 2015 IRP, page 45.
[13] DEI 2015 IRP, page 76.
[14] In the IURC Electricity Division Director's IRP Report on DEI's 2013 IRP, the Director stated, "We acknowledge the difficulty of developing long term assumptions for something as complex and ever changing as EE opportunities, but it is not clear an appropriate solution is to hardwire specific EE impacts." Page 5.

Confidential Figure 2.1. DEI Base Portfolio and Incremental Portfolio, Annual Energy Savings (GWh)



The basis for the energy efficiency impacts in DEI's IRP, and the explanation for the long, flat tail in Figure 2.1, is stated as follows:

> For periods beyond 2018, the assumption was made that the composition and size of the future annual portfolio impacts were the same as in the 2018 portfolio…The Incremental sub-portfolios were created using the assumption that additional participation would be obtained for the same programs that exist in the Base Portfolio…[15]

DEI did not substantiate how the sole use of its existing and proposed energy efficiency program offerings creates a comparable and consistent IRP analysis between supply and demand side resources. By using its current and proposed energy efficiency offerings, DEI is allowing its efficiency program design team to dictate long-term resource investment decisions. The assumptions built into DEI's current portfolio will be carried forward for the next twenty-four years. There is no reasonable explanation for constraining a resource model because of poor program design or implementation, certainly factors that influenced the size and scope of DEI's proposed 2016-2018 portfolio. The result of using these inputs is not an optimized system; it is a system that has been inaccurately modeled and will cost unnecessarily more. DEI did not explain why it used programs that are available today to determine future available savings, and also did not explain why it is an appropriate assumption.

In order to understand how flawed this assumption is, it is important to consider how DEI arrived at its current and proposed portfolio offerings, which it developed based on six criteria:[16]

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[15] DEI 2015 IRP, pages 76-77.
[16] IURC Cause No. 43955 DSM 3, Petitioner's Exhibit A, pp. 7-8.

1. The performance of the current portfolio of programs being offered to DEI customers in 2015;
2. An opportunity to go further into our C&I vertical markets such as retail, education, distribution and small commercial/industrial in an effort to offset a part of the effects of the opt out approved in SEA 340;
3. To open up new channels of marketing for existing and new measures in the residential market;
4. Advancements in technology;
5. The changing market place for both residential and non-residential customers; and,
6. Experience in other Duke Energy jurisdictions.

None of these criteria designed for DEI's current portfolio of programs are appropriate for constraining efficiency resources in an IRP prior to comparison and optimization with other resources. By beginning with a constrained efficiency future, defined by existing and proposed programs, DEI is eliminating the majority of energy efficiency impacts that are available in its service territory. This methodology creates an artificial constraint and arbitrarily reduces the amount of efficiency that the model could select. DEI did not provide data to substantiate how much energy efficiency was eliminated with this methodology. We would recommend that the Director's Draft Report request that DEI publicly provide this information at the time when Comments on the Draft Report are due.

i. <u>DEI's Market Potential Action Plan is Conservative</u>

Quantitatively, the impact of DEI's IRP methodology is that DEI's EE Bundles contain, at most, [redacted]% of the Technical Potential identified in DEI's Market Potential Action Plan. While restricting the model to [redacted]% of the Technical Potential in the next twenty-four years is indicative of DEI's flawed EE assumptions, it is important to recognize that, more broadly, potential studies are inherently conservative. The Regulatory Assistance Project released a report on February 1, 2016, that discussed, among other things, the conservative nature of potential studies, in the context of achieving 30% electric savings in ten years. The report discusses the value of potential studies, and then goes on to state:

> Much can be learned from these studies. They provide useful insights into which measures are cost-effective and which are not – at least by <u>today's</u> savings levels and prices, and <u>today's</u> estimates of avoided costs…That said, efficiency potential studies have not proven to be very useful at providing insights into the bigger question they are commonly undertaken to address: How much savings can be cost-effectively achieved over the next decade (or more)?[17]

[17] Chris Neme & Jim Grevatt, 30 Percent Electric Savings in Ten Years. Regulatory Assistance Project, February 1, 2016. Appendix A. Emphasis added. Available at: http://www.raponline.org/document/download/id/7944.

Further, there are several other studies that have documented why potential studies underestimate long-term energy efficiency potential.[18] Despite these reports finding that potential studies consistently underestimate efficiency, DEI is assuming it will only be able to capture a fraction of its conservative estimate.

In addition, based on the language in DEI's IRP,[19] it appears DEI did not create a placeholder for efficiency to grow over time due to emerging technologies or reductions in cost of existing technologies. This assumption is contrary to national experience, which is that "low-hanging" fruit grows back – meaning that incremental savings will continue to increase over time. For example, many utilities have retrofitted commercial customers' fluorescent lighting with high performance T8s, and it is is often assumed that there are not future commercial lighting gains. However, this assumption ignores advances in LED technology, specifically LED troffers that can save 2-4 times more energy than high performance T8s.[20] This type of technology was not included in DEI's potential study, so is not part of DEI's IRP EE modeling. This is just one example of a DEI conservative assumption in its potential study that trickled down to the IRP planning.[21]

ii. DEI's IRP EE Bundles Excluded Savings Identified in the Conservative DEI Market Potential Action Plan

DEI's Market Potential Action Plan ("Potential Study") was used to inform both DEI's proposed 2016-2018 efficiency programs and DEI's IRP. The Potential Study's Maximum Achievable Potential was used for the design of the 2016-2018 efficiency programs, which is a subset of the Technical Potential.[22] However, in order to evaluate demand side resources on a comparable and consistent basis as supply side in DEI's IRP modeling, DEI should have used the Potential Study's Technical Potential, which is the most appropriate of the four potentials to use in crafting IRP energy efficiency bundles.[23]

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[18] For example, see: Goldstein, D. (2008) Extreme Efficiency: How Far Can We Go if We Really Need To? 2008 ACEEE Summer Study on EE in Buildings. Volume 10, pp. 44-56, available at http://aceee.org/files/proceedings/2008/data/papers/10_435.pdf; and Kramer, C. & Reed, G (2012), Ten Pitfalls of Potential Studies. Montpelier, VT: The Regulatory Assistance Project, available at: file:///C:/Users/Jennifer/Documents/IRP/2015%20Indiana%20IRPs/Draft%20Comments/EnergyFutures_KramerReed_TenPitfallsESdraft2_2012_OCT_24.pdf.

[19] DEI 2015 IRP, pages 76-77.

[20] RAP, 30 Percent Electric Savings in 10 Years, Appendix E.

[21] An additional example can be found in the Pacific Northwest, where the Northwest Power and Conservation Council has found increasing amounts of energy efficiency in each Power Plan conducted since the 1980s. In the Sixth Power Plan, the NWPCC found that "the achievable technical potential of efficiency improvements increased from the Fifth Power Plan levels due to advancing technology, reduced cost, and estimates in new areas."

[22] The Technical Potential is screened for economics and market barriers, and is then classified as the Maximum Achievable Potential. As will be discussed more below, it is inappropriate to use an economic screen prior to bundling demand side resources together and making them available to the IRP model for selection.

[23] It is worth noting that even this estimate of energy efficiency potential is conservative because of the bias towards analyzing measures that fall below DEI's avoided cost today in the Potential

The amount of energy efficiency available to DEI's IRP model is far below the amount identified as Technical Potential, or technically achievable, in DEI's Potential Study, as shown in Confidential Table 2.3.

Confidential Table 2.3. Comparison of DEI Potential Study Technical Potential and IRP Maximum EE Bundles (GWh)

	2018	2023	2033
Action Plan Technical Potential[24]	7297	7771	8843
DEI Preferred Portfolio [25]	[redacted]	[redacted]	[redacted]
Preferred Plan as Percent of Technical Achievable	[redacted]	[redacted]	[redacted]

In stark contrast, utilities that have been modeling energy efficiency as a resource, and are national leaders on energy efficiency, assume a much higher amount of the Technical Potential will be captured in twenty years. The Pacific Northwest Power and Conservation Council, which has been modeling energy efficiency as a resource for many years, uses the assumption that 85% of the Technical Potential will be captured in a twenty-year time frame. PacifiCorp, a utility in the NW Power and Conservation Council's planning area implemented this guidance in its 2015 IRP. PacifiCorp began its IRP EE analysis with its Technical Potential, which represents the "total universe of possible savings before adjustments" to determine how much EE to include in its IRP modeling. After PacifiCorp determined the Technical Potential:

> [T]o account for the practical limits associated with acquiring all available resources in any year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's aggressive regional planning assumptions, it was assumed that 85% of technical potential for discretionary (retrofit) resources and 77 percent of

Study. While this is a reasonable constraint for short term planning, it limits the amount of energy efficiency potential in the future because measures that are too expensive today are not evaluated for the twenty-five year IRP time frame.

[24] IURC Cause No. 43955 DSM 2, Petitioner's Exhibit A-2, Duke Energy Indiana's Market Assessment and Action Plan for Electric DSM Programs, Table 14, available online starting at page 41: https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801b6310.

[25] DEI Confidential Attachment to CAC Informal Discovery 1.1, "e.2 DEI EE bundles for 2015 IRP.xlsx."

lost opportunity (new construction or equipment upgrade on failure) could be achievable over the 20 year planning period.[26]

In addition to excluding savings identified in the Technical Potential from the IRP modeling process, DEI's EE IRP analysis did not even consider all of the measures included in Potential Study's Maximum Achievable Potential, a subset of Technical Potential. This is shown in Table 2.4, where DEI's Potential Study identified that the Company could achieve more than twice as much efficiency as what is proposed in their 2016-2018 DSM plan – and which is the basis for their EE IRP analysis.

Table 2.4. DEI Proposed Efficiency Goals and Potential Study Savings

	2016		2017		2018	
Proposed Goal[27]	206	0.7%	208	0.7%	196	0.6%
Potential Study[28]	436	1.5%	483	1.7%	534	1.9%

In sum, DEI's use of its existing and proposed DSM programs is a poor methodology to determine future energy efficiency impacts. DEI is allowing its efficiency program design team to dictate long-term resource investment decisions. DEI will thus carry forward until 2039 the faulty assumptions built into its current portfolio. Consequently, DEI barely scraped the surface of modeling the EE impacts in its own Potential Study's Technical Potential analysis, and used a portfolio that is middle of the road in performance to forecast future EE impacts.

b. I&M's Reliance on National Potential Study and Limited Inclusion of EE Measures Was Inappropriate

We have four major concerns with I&M's modeling as it relates to EE, all of which result in a reduced amount of efficiency to incorporate into the IRP's efficiency bundles. First, the discussion above regarding the inherently conservative nature of potential studies also applies with the potential study that I&M used. Ultimately, in identifying long term energy efficiency potential, studies focused on measures that are cost effective today, based on today's avoided costs, will not accurately reflect all available cost-effective energy efficiency in the future.

The other concerns are more specific to the national EPRI Study that I&M used and I&M's analysis, all of which result in a fraction of the total amount of energy efficiency impacts being analyzed. Our concerns are that: (i) the use of a national potential study that does not rely on Indiana cost data may overstate energy efficiency

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[26] PacifiCorp, 2015 IRP Volume I. March 31, 2015. Pages 123-124. Available at http://www.pacificorp.com/es/irp.html.
[27] IURC Cause No. 43955 DSM 3, Petitioner's Exhibit E (Goldenberg Supplemental), page 3. Savings as percent of 2014 total sales.
[28] IURC Cause No. 43955 DSM 2, Petitioner's Exhibit A-2 (Duke Energy Indiana: Market Assessment and Action Plan for Electric DSM Programs), page 4, Table 3, GWh at the meter, available at: https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801b6310 (CAC Administrative Notice Exhibit 2).

incremental measure costs; (ii) existing programs were not appropriately incorporated into I&M's load forecast or the IRP EE modeling; and (iii) many measures that are available and cost-effective today were not included in the IRP analysis.

i. EPRI Study Is Not Representative of Indiana Experience

I&M used a different methodology to evaluate EE in it is IRP than did DEI. I&M relied on *U.S. Energy Efficiency Potential Through 2035* ("EPRI Study"), a national energy efficiency potential study conducted by the Electric Power Research Institute ("EPRI") to determine its Technical Potential for IRP modeling.[29] EPRI's analysis on demand side resource potential is generally known to be conservative as it is a research non-profit with predominately electric utility members including AEP, Duke Energy and Southern Company. It is unclear from I&M's IRP how it modified or applied EPRI's national findings to its Indiana jurisdiction. Undoubtedly, many assumptions were made using national level data, and it is questionable why I&M chose this high level review of demand side options as the basis for modeling energy efficiency as a resource in Indiana.

I&M based its incremental cost estimates on the EPRI Study, and the costs are not specific to the region.[30] The EPRI Study energy efficiency incremental cost estimates are derived from a proprietary database so there is no publicly available information on the sources of the measures' incremental costs.[31] There are also no definitions or explanations of the measures included in the EPRI Study, making comparisons among measures challenging, particularly in a stakeholder participation process such as this. For example, it is unclear what size a "unit" is in regard to residential windows, or how much pipe a "unit" of hot water heater pipe wrap covers. Similarly, it is challenging to determine if the Air Conditioning Maintenance discussed in the EPRI Study is comparable to the Residential HVAC Maintenance/Tune Up measure in the Indiana Technical Resource Manual 2.2 ("Indiana TRM 2.2") when there is no qualitative explanation of the energy efficiency measure in the EPRI Study. Regardless of all these challenges, it remains clear that the EPRI incremental cost information does not align with the Indiana TRM 2.2 or the incremental costs found in the 2016 I&M DSM Plan filing.

[29] *U.S. Energy Efficiency Potential Through 2035 ("EPRI).* Palo Alto, CA: 2014. 1025477.
[30] EPRI. Palo Alto, CA: 2014. 1025477.
[31] *Id.* page 2-14.

Table 2.5. Comparison of Residential Energy Efficiency Measure Incremental Cost

Measure	Indiana TRM 2.2 Incremental Cost	DSM Plan Incremental Cost[32]	IRP Incremental Cost
Thermal Shell Measures			
Window[33]	$495[34]	N/A	$561[35]
Duct Sealing and Insulation/Duct Repair	$71.45	N/A	$239[36]
Water Heating Measures			
Energy Star HP Hot Water Heater	$700[37]	$1489	$1203[38]
Energy Star Dishwasher	$211[39]	N/A	$89[40]
Faucet Aerator	$2[41]	$1.28 - $2.78	$1[42]
Hot Water Pipe Insulation[43]	$27[44]	$8.35	$15[45]
Showerhead	$18.50[46]	$3.86	$3[47]

[32] IURC Cause No. 43827 DSM 5, I&M Workpaper "I&M DSM 5 2016 Plan Exhibits_9_10_15 Attach Final," Tab 2016 Res. Home Energy Products.
[33] Assume that one window is 15 SF and that an average house has 22 windows. http://www.energystar.gov/ia/partners/prod_development/revisions/downloads/windows_doors/ESWDS-ReviewOfCost_EffectivenessAnalysis.pdf
[34] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, page 60. Energy Star Windows, $150/100 SF.
[35] EPRI Study, Table E-6, page E-13, Double Pane Window. Residential Central A/C Cooling End Use. $170 per unit, assuming that a unit is a 100 SF.
[36] EPRI Study, Table E-6, page E-13, Residential Central AC Space Cooling Measures.
[37] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, Indiana TRM 2.2, pp. 64-67. Heat Pump Water Heaters, Domestic Hot Water Measure category.
[38] EPRI Study, Table E-10, page E-18, Water Heater EF=2, Residential Water Heating Measures End Use. Energy Star Electric Hot Water Heaters energy factor requirements are currently greater than or equal to 2.0 for less than 55 gallons, and 2.2 for more than 55 gallons.
[39] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp.20-21. Energy Star Dishwasher Deemed Measure Cost.
[40] EPRI Study, Table E-10, page E-18, Residential Water Heating Measures.
[41] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 68-72. Low Flow Faucet Aerator, Domestic Hot Water Measure Category.
[42] EPRI Study, Table E-10, page E-18, Residential Water Heating Measures End Use.
[43] Assuming three feet of insulation.
[44] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 77-79. Domestic Hot Water Pipe Insulation (retrofit), Domestic Hot Water Measure Category.
[45] EPRI Study, Table E-10, page E-18, Pipe Insulation, Residential Water Heating Measures End Use.
[46] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 73-76. Low-Flow Showerhead, Domestic Hot Water Measure Category.
[47] EPRI Study, Table E-10, page E-18, Low-Flow Showerheads, Residential Water Heating Measures End Use.

Appliance Measures			
Energy Star Dishwasher	$211[48]	N/A	$8[49]
Residential ECM/Furnace Fan	$250[50]	$280	$101[51]
Energy Star Refrigerator	$30[52]	N/A	$212[53]
High Efficiency Refrigerator	$140 (CEE Tier 2)	N/A	$437
Energy Star Clothes Washer[54]	$210.12[55]	N/A	$650[56]
High Efficiency Clothes Washer	$215.90 (CEE Tier 2)	N/A	$700-800
Heating/Cooling[57]			
AC Maintenance	$64	N/A	$335[58]
SEER 15	$588	N/A	$800
SEER 16	$893	N/A	$1200
SEER 18	$1490	N/A	$2000
SEER 20	$2085	N/A	$2500
SEER 21	$2270	N/A	$3000
Lighting			
Screw in LEDs[59]	N/A	$7	$5

ii. 2017 Energy Efficiency Impacts Excluded from IRP Modeling and Load Forecast

It does not appear that I&M's 2016 DSM plan, and cumulative impacts of its historic EE programs, were used in the IRP EE modeling, or appropriately incorporated into the load forecast DSM adjustment. First, the Company did not model demand side and supply side resources in 2016 and 2017, stating in the IRP, "It is assumed that the incremental programs modeled would be effective in 2018."[60] This violates the

[48] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 20-21. Energy Star Dishwasher Deemed Measure Cost.
[49] EPRI Study, Table E-11, page E-20, Residential Appliance Measures.
[50] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 114-115. Residential Electronically Commutated Motors, HVAC Measure Category.
[51] EPRI Study, Table E-11, page E-20, Furnace Fans – ECM, residential appliances end use.
[52] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 9-12. Refrigerator Deemed Measure Cost for Energy Star Unit and CEE Tier 2 Unit.
[53] EPRI Study, table E-11, page E-19
[54] EPRI Study, Incentive level for a clothes washer with MEF 2.0. Current Energy Star requirements are 2.06 – 2.38.
[55] IURC Cause No. 44634, CAC Exhibit 1, Attachment NM-23, Indiana TRM 2.2, July 28, 2015, pp. 16-19; Clothes Washer Deemed Measure Cost for Energy Star Unit and CEE Tier 2 Unit.
[56] EPRI Study, Table E-11, page E-19, Residential Appliances Measures.
[57] All SEER calculations made assuming a 2.5 ton A/C unit.
[58] EPRI Study, Table E-6, page E-13, Residential Central AC Space Cooling Measures.
[59] Assuming a 9.5 A Lamp LED.
[60] I&M 2015 IRP, page 91.

requirement that utilities evaluate supply-side and demand-side resource alternatives on a consistent and comparable basis.[61]

Table 2.6 shows that in 2017, the incremental impacts of the load forecast and the reported DSM incremental impacts from I&M's DSM Scorecards. This table shows that the incremental load forecast savings in 2017 are negative, indicating that there is no additional energy efficiency in I&M's load forecast for 2017. We presume this is because I&M attempted to incorporate the impacts of both historic and future EE in its load forecast, but appears to have completely excluded any energy efficiency impacts associated with 2017.

In addition, I&M also appears to have grossly underestimated the cumulative impacts of its demand side programs prior to 2016. Even with the conservative, simplifying assumption that all impacts from DSM installed in 2012 expire in 2017, the cumulative impacts of the DSM programs are more than four times higher than what I&M included in the DSM adjustment to their IRP forecast.

Table 2.6. I&M DSM and Load Forecast Incremental and Cumulative Impacts (GWh)

	DSM		Load Forecast[62]	
	Incremental	**Cumulative**	**Incremental**	**Cumulative**
2012	71	71	0	0
2013	209	280	0	0
2014	117	398	0	0
2015	153	551	0	0
2016	141	692	<191	191
2017	0	621	-50	141

iii. I&M's Existing Measures Excluded from IRP Analysis

It does not appear that I&M modeled the impacts from its existing programs in its IRP. In the IRP, I&M states:

> To determine the economic demand-side EE activity to be modeled that would be over and above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs…The current programs target end-uses in both [residential and commercial] sectors. Future incremental EE activity can further target those areas or address other end-uses. To determine which end-uses are targeted, and in what amounts, I&M looked to the 2014 EPRI Report.[63]

[61] 170 IAC 4-7-8.
[62] I&M 2015 IRP, Appendix A-12; Informal discovery,"2015 IM Load Forecast Details.xlsx."
[63] I&M 2015 IRP at page 92 (emphasis added).

Yet I&M's current program offerings are noticeably absent from the EE bundles (and subsequent IRP EE selection), as shown in Tables 2.7-2.10. I&M already offers several of the residential HVAC measures at a higher efficiency level than what was included in the IRP, for example, SEER 15 heat pumps are the lowest tier in I&M's current Home Energy Products program, but are the cap on the IRP measure. In fact, I&M offers incentives for SEER 17-23 ductless heat pumps in its program today, but those savings are not evaluated in the IRP. The lack of current program offerings being evaluated in the IRP is particularly uneconomic because of the 2016 proposed pilot programs – the Small Business Efficiency Pilot and the Home Comfort & Efficiency Pilot program, which would apparently be piloted for 2016 and then eliminated based on the data in the IRP EE bundles.

Table 2.7. Comparison of Excerpt of 43827 DSM 5 Plan and IRP Modeled Residential EE Measures

End Use	DSM Plan Measures	IRP Bundle Measures
Lighting	• 7W-55W Specialty LED • 9.5W-18W A Lamp LED • 9W-42W Spiral CFL • 7W-55W Specialty CFL • LED night light	• 12W LED
Building Envelope	• SEER 15 heat pumps • SEER 16 heat pumps • SEER 17 heat pumps • SEER 18 heat pumps • ECM/Furnace Fan • Central AC SEER 15 and above • Duct and air sealing • SEER 17-23 ductless heat pumps • Infiltration reduction • Ceiling Insulation • Sidewall Insulation • Knee wall insulation • Programmable thermostat	• SEER 15 heat pump • Foundation insulation • Furnace Fan • AC Maintenance • Reflective Roof • Double Pane Windows • Duct Repair • Infiltration Control
Appliances	• Pool pumps • Energy Star Fan • Energy Star Dehumidifier • Removal secondary refrigerators and freezers	• Efficient Dishwasher • Energy Star Freezer
Hot Water	• Faucet aerator • Low Flow showerhead • Pipe Wrap	• EF = 2 Water Heating • Pipe insulation • Faucet Aerator • Low Flow Showerhead

Behavioral	• Behavioral based savings	• Not included in IRP EE bundles

It is worth noting that I&M did not include in its IRP modeling the measure that represents the single largest savings program in its current 2016 portfolio, which is its residential behavioral program. Table 2.8 shows I&M's Home Energy Reports program energy impacts, and the percentage of the portfolio the program comprises. As shown, the program represents an increasing percentage of the Company's total DSM portfolio in 2016, yet this measure was not included in an energy efficiency bundle, despite the EPRI Study containing an "Enhanced Customer Bill Presentment" measure.[64]

Table 2.8. Home Energy Reports in I&M DSM Plan (IURC Cause No. 43827DSM5)

	GWh	% of Total DSM Plan Savings
2014 (Actual)	24	20%
2015 (Goal)	33	21%
2016 (Goal)	43	30%

I&M included very few commercial energy efficiency measures in its IRP EE bundles, **and did not include any commercial efficiency in its preferred plan**. There are dozens of commercial measures that were excluded from the analysis.

Table 2.9. Comparison of Excerpt of 43827 DSM 5 Plan and IRP Modeled Commercial EE Measures

Program Name	DSM Measures[65]	IRP Measures
Work Prescriptive Rebate	• Efficient lighting • LED Exit Signs • LED Traffic Lights • Energy Star Package Refrigeration • Energy Star Food Prep and Holding Equipment • ECM motors • VFDs • Occupancy Sensors • Plug load occupancy sensors • Refrigeration upgrades	• PC Energy Star • Other electronic Energy Star • Screw in lighting (Halogen/EISA Tier 2 to LED) • Linear fluorescent lighting • Heat Pump COP = 3.4
Work Custom Rebate	• Custom C&I efficiency projects including lighting, lighting controls,	

[64] *U.S. Energy Efficiency Potential Through 2035 ("EPRI).* Palo Alto, CA: 2014. 1025477. Appendix E, Table E-13.
[65] IURC Cause No. 43827 DSM 5, Petitioner's Exhibit 1, Attachment JCW-13.

	process improvements	
Work Direct Install	• Outdoor lighting • LED in refrigerated space • ECM • Vending machine occupancy sensors • Refrigerated display case lighting • Anti sweat heater controls • Fan controls • Night covers • Auto door closers on walk in refrigerators • Floating pressure controls • Floating suction controls • LED case lighting • Motion sensors on LED cases	
Small Business Efficiency Pilot	• Behavior based savings • Online audit	

Similar to the behavioral program, the measures from I&M's highest impact commercial program, renamed the Work Custom Rebate program in 2016, do not appear to have been compiled into EE bundles, or made available for the IRP model to select. Together with the Home Energy Reports, I&M did not model measures that account for over 50% of the 2016 DSM Portfolio.

Table 2.10. Work Custom Rebate in I&M's DSM Plan (Goals)

	GWh	% of Total Plan
2015	15	13%
2016	33	23%

In conclusion, (i) I&M's use of the EPRI Study does not represent Indiana's experience with energy efficiency; (ii) I&M's load forecast appears to be incorrect because it does not properly account for current EE programs; and (iii) the Company's current energy efficiency program offerings are noticeably absent from the IRP analysis. All of these observations are indicative of a larger trend of disconnect between the IRP energy efficiency inputs, the DSM plan, and the IRP model inputs. The discussion above highlights the disparity between the load forecast and DSM filings, and the IRP EE bundles and the DSM plans.

c. DEI and I&M Both Excluded Industrial Efficiency

Beyond the discussions above, both of the utilities constrained the amount of Long Term EE Potential available for IRP EE bundles by excluding industrial energy efficiency. This is a significant shortcoming as, according to the U.S. Energy Information Administration, "Indiana's industrial sector, which includes manufacturing of aluminum, chemicals, glass, metal casting, and steel, consumed more energy in 2012 that the residential and commercial sector combined."[66] In 2013, industrial energy consumption in Indiana accounted for 45.7% of the overall consumption, and far more than the residential and commercial sectors combined.

DEI currently does not have energy efficiency programs to serve industrial customers at this time, and in response to an informal data request, stated that [redacted].[67] It is unclear how DEI incorporated the industrial EE into its IRP load forecast that was not included in its EE bundles.

I&M entirely excluded the entire industrial sector, stating:

> Industrial programs were not developed or modeled based on the thought that industrial customers, by and large, will "self-invest" in energy efficiency measures based on unique economic merit *irrespective* of the existence of utility-sponsored program activity.[68]

I&M did not provide analytical support for this statement. Also, it is not clear how, or if, industrial efficiency was incorporated into I&M's IRP load forecast.

Industrial energy efficiency is often the least expensive of all energy efficiency measures, and while there is currently policy in Indiana that allows large customers to opt-out of utility energy efficiency programs,[69] it is speculative and inappropriate to assume that policy would remain the same for twenty-five years and that at least some of those customers might not opt back in and want to be served by the programs they are helping to fund. There is no information available on how the IRP energy efficiency bundles for the utilities would have changed in make-up and cost if industrial efficiency had been included, nor is there information on the impact if the model had had those bundles available to select during the optimization process. Similar to the duplicative economic screening discussion below, there is no other resource that is eliminated or extremely constrained due to existing policy.

In sum, there were far too many assumptions and modeling constraints used by the utilities that reduced the quantity of energy efficiency measures available for efficiency bundles in their respective IRPs, and subsequently reduced the amount of energy efficiency available for the IRP model to select. This is a flaw in both DEI and

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[66] http://www.eia.gov/state/?sid=IN
[67] DEI Confidential Response to CAC 3.3.
[68] I&M 2015 IRP, pp. 89-90.
[69] Ind. Code §§ 8-1-8.5-9, -10.

I&M's methodology, and likely resulted in an underestimation of energy efficiency potential in the near term, and certainly in the long term. In the Comments on the Draft Report, the utilities should evaluate their efficiency potential, bundle the measures from the Technical Potential analysis together based on similar costs, load shapes, or both, and allow the model to select optimized resources.

IV. The Utilities Applied Duplicative Benefit-Cost Screens

After reducing their EE potential below their Technical Potential prior to creating EE bundles, the utilities further disadvantaged demand side management resources by running duplicative economic screens. This was done by both utilities by only allowing efficiency that passed benefit-cost screens to be used in creating efficiency bundles. This methodology effectively double screens energy efficiency, as efficiency is screened once before being created into bundles, and a second time, when the model optimizes for the system that has the lowest PVRR (DEI) or highest revenue (I&M). It does not appear that any other resource is treated this way in the IRP modeling.[70]

Further, using the benefit-cost screen in IRP modeling is inappropriate as the assumptions necessary to calculate the benefit-cost ratios for energy efficiency are unreasonable to make years into the future. The requirement to perform DSM cost-effectiveness tests within the IRP (but not the DSM plan) should be eliminated. These tests impose a level of screening on DSM that does not apply to supply-side resources and requires a false level of detail to even implement. Detailed, accurate estimates of program costs are typically not available until the utility devotes substantial resources to designing its program offerings. Applying these tests in an IRP would require speculation about such details for many years out, essentially the length of the planning period.

We strongly recommend that the Director's Draft Report request the utilities rerun the models and eliminate this benefit-cost calculation requirement, instead requiring that the utilities fully include energy efficiency in their IRP modeling. The utilities should provide this information in their Comments on the Draft Report.

a. DEI Provided Little Support for its Cost Analysis

DEI provided extremely limited efficiency bundle cost information, all of which was marked confidential. According to the IRP, DEI selected the Optimized CO2 + CC portfolio as its preferred plan. The Company indicated that the preferred plan selected all of the base efficiency portfolios, and three of the five incremental portfolios. DEI provided us with two spreadsheets with efficiency impact data. Due to data inconsistencies, which were explained too late to be properly addressed in these comments, we were unable to thoroughly analyze and review DEI's cost assumptions. Based on DEI's DSM Plan and the Portfolio 5, Sensitivity 2 (presumably DEI's Preferred

[70] DEI Confidential Response to CAC 3.5 indicated that Chapter 5 and Section 1 of Appendix A in the IRP discuss the screening process and [redacted] but did not provide any specific examples of these resources.

Plan) System Optimizer output file, DEI's annual cost of its preferred portfolio is slightly [redacted] than its planned 2016-2018 costs.

Table 2.11. DEI Proposed DSM and Preferred Plan EE Costs (Nominal $)

	DSM ($M)[71]	IRP ($M)[72]
2016	$31.6	$[redacted]
2017	$31.3	$[redacted]
2018	$29.8	$[redacted]

In confidential responses to CAC, DEI did provide the following information about its energy efficiency costs in the IRP modeling:

[redacted]

Unlike I&M, where the cost of the EE bundles seemingly drove the selection of EE within the IRP model, DEI appears to have hardcoded energy efficiency in its model (*see* Section 6 in this Report). It is unclear how DEI determined how much efficiency was available in each year, what level of participation was assumed in each Incremental Portfolio bundle, or how the growth rate of the EE program costs was applied in the IRP model. We recommend that DEI publicly provide this information in its Comments on the Director's Draft Report.

b. I&M's Incremental Measure Costs Appear to be Overstated.

Our major concern with I&M's EE IRP modeling is that the costs used in the IRP analysis are not based on I&M's experience or the Indiana TRM 2.2, and instead are derived from the national EPRI Study as discussed above, and appear to overstate measure costs. In the IRP, the cost of the energy efficiency measure is the primary driver for being included in a bundle, and the model's selection of a bundle. It appears that the outcome of using the EPRI data is: (1) I&M's proposed DSM plan is less expensive than the IRP; (ii) residential lighting is more than 90% of the savings and has one cost for the entire IRP planning period; (iii) it appears that I&M's model did not select any commercial efficiency measures due to high incremental costs.

71 DEI 2015 IRP, Appendix C, p. 228.
72 I&M Confidential Attachment to CAC Data Request 1.1, f.1. 2015 Capital Costs.xlsx.
73 DEI Confidential Response to CAC 3.6.
74 DEI Confidential Response to CAC 3.7.
75 DEI Confidential Response to CAC 3.8.
76 DEI Confidential Response to CAC 3.9.

i. I&M's DSM Plan Costs Are Lower than EE Costs in its IRP

Many of I&M's EE Bundle levelized costs of energy efficiency are significantly higher than the annualized cost of conserved energy in I&M's 2016 DSM Plan, shown in Table 2.12. It is not clear why the costs of the measures in the IRP are so much higher than the cost of the proposed programs, particularly as the DSM programs have more measures than the IRP bundles. The formula used to create the levelized cost of energy efficiency in I&M's IRP analysis is based on national assumptions, and the difference may be explained by the difference in incremental costs, as shown in Table 2.5 above. As discussed earlier, the high cost of the efficiency bundles reduces the feasibility of the resource being chosen by the IRP model.

Table 2.12. Residential DSM and IRP Program Annualized Cost of Conserved Energy

DSM Program[77]	DSM ($/MWh)	IRP Bundle[78]	$/MWh
Home Appliance Recycling	$42.11	**Thermal Shell Bundle AP**	[redacted]
Home Energy Products	$27.39	**Thermal Shell HAP**	[redacted]
Home Weatherproofing	$64.56	**Water Heating Bundle AP**	[redacted]
Income Qualified Weatherproofing	$108.97	**Water Heating Bundle HAP**	[redacted]
Home Energy Reports	$22.52	**Appliances Bundle AP**	[redacted]
Home online Energy Check Up	$22.29	**Appliances Bundle HAP**	[redacted]
Home New Construction	$64.40	**Heating/Cooling Bundle AP**	[redacted]
School Education	$20.73	**Heating/Cooling Bundle HAP**	[redacted]
Peak Reduction Program	$10,901.94	**Lighting Bundle AP**	[redacted]
Home Comfort & Efficiency Pilot	$496.47	**Lighting Bundle HAP**	[redacted]
Residential Portfolio	**$57.72**	**Residential Portfolio**	N/A

The same is true with the Commercial sector—the DSM plan costs are lower than the IRP cost assumptions, shown below in Table 2.13. The contrast between the DSM

[77] 43827 DSM 5, Petitioner's Exhibit 1, Attachment JCW-4.
[78] I&M Confidential Attachment to CAC Data Request 1, Indiana EE Bundles_R2.xlsx, Residential Bundles Tab.

program costs and the IRP costs are more stark for commercial than for residential. All of I&M's 2016 C&I programs cost significantly less, with the exception of the pilot program, on an annualized cost, than the IRP programs. This could explain why none of the commercial bundles were selected by the IRP model for the preferred portfolio.

Table 2.13. Commercial DSM and IRP Program Annualized Cost of Conserved Energy

DSM Program[79]	DSM ($/MWh)	IRP Bundle[80]	$/MWh
Work Prescriptive Rebates	$14.37	Heat Pump AP (Heating Cooling Bundle, single measure)	[redacted]
Work Custom Rebates	$15.22	Heat Pump HAP	[redacted]
Work Direct Install	$22.72	Office Equipment Bundle AP	[redacted]
Small Business Efficiency Pilot	$1,479.93	Office Equipment Bundle HAP	[redacted]
		Indoor Lighting Bundle AP	[redacted]
C&I Portfolio	**$15.85**	Indoor Lighting Bundle HAP	[redacted]
		Portfolio	N/A

The outcome of I&M's incremental cost assumptions is that only 21 of the 74 residential and commercial energy efficiency measures evaluated in the EPRI Study were available for creating EE bundles. Thus, I&M likely underestimated the amount of cost-effective available energy efficiency.

ii. <u>Residential Lighting Program Costs Static from 2018-2045</u>

The measure with the greatest amount of residential energy efficiency achievable potential at the lowest cost in the IRP, in the near term, is residential lighting. However, the incremental cost used in I&M's IRP does not appear to be from the EPRI analysis, as the report does not provide residential incremental lighting costs.[81] There is no information provided in the IRP about the source of this incremental cost, although it is shown in I&M's analysis to be $5.[82] Although there is no documentation of this cost, a $5 incremental cost for an 8-9 watt LED bulb is reasonable in 2016. However, this is an

[79] 43827 DSM 5, Petitioner's Exhibit 1, Attachment-JCW 4.
[80] I&M Confidential Attachment to CAC Data Request 1, Indiana EE Bundles_R2.xlsx, Commercial Bundle Tab.
[81] EPRI Study, Table E-14 and Table E-15, Residential Indoor Screw-In Lighting Measures.
[82] However, the credibility of this being the actual number used in the IRP analysis is limited as this same source indicated that the IRP residential lighting measure had a 30 year life, but residential lighting was modeled as having <15 year measure life.

unreasonable assumption for the next 30 years. The incremental cost of LEDs will drop, and while I&M may choose to adopt other lighting measures to replace an LED in its lighting program, that is not what its modeling indicates. The IRP lighting bundle only contains one measure, an LED bulb, from a halogen bulb baseline.

iii. Commercial EE Not Chosen by I&M's IRP Model

I&M's model did not choose any commercial energy efficiency in its preferred plan. This is peculiar as the commercial "Office Equipment Achievable Potential" and the residential "Appliance Achievable Potential" has the same utility installed cost, as shown in Table 2.14 below. There was no explanation in the IRP regarding the lack of commercial programs in the Preferred Plan, or why this occurred.

Table 2.14. Comparison of Commercial Energy Efficiency Incremental Measure Cost

<table>
<tr><th colspan="2">Bundle</th><th>Measures[83]</th><th>Utility Installed Cost[84] ($/kWh)</th></tr>
<tr><td colspan="4">Residential</td></tr>
<tr><td rowspan="2">1.</td><td>Thermal Shell – AP</td><td rowspan="2">1.Foundation insulation
2.Double Pane Windows
3.Duct Repair
4.Infiltration Control</td><td>$0.28</td></tr>
<tr><td>Thermal Shell – HAP</td><td>$0.42</td></tr>
<tr><td rowspan="2">2.</td><td>Water Heating – AP</td><td rowspan="2">5.EF = 2 Water Heating
6.Efficient Dishwasher
7.Faucet Aerator
8.Pipe Insulation
9.Low Flow Showerhead</td><td>$1.76</td></tr>
<tr><td>Water Heating – HAP</td><td>$2.52</td></tr>
<tr><td rowspan="2">3.</td><td>Appliances AP</td><td rowspan="2">10. Efficient Dishwasher
11. Furnace Fan
12. Energy Star Freezer</td><td>$0.26</td></tr>
<tr><td>Appliances HAP</td><td>$0.42</td></tr>
<tr><td rowspan="2">4.</td><td>Heating Cooling AP</td><td rowspan="2">13. SEER 15 Heat Pump
14. AC Maintenance
15. Reflective Roof</td><td>$1.74</td></tr>
<tr><td>Heating Cooling HAP</td><td>$2.60</td></tr>
<tr><td rowspan="2">5</td><td>Lighting AP</td><td rowspan="2">16. Screw in LEDs</td><td>$0.11</td></tr>
<tr><td>Lighting HAP</td><td>$0.16</td></tr>
</table>

[83] I&M Stakeholder Workshop, 09/28/15, slide 32.
[84] Utility installed cost, gigawatt-hour savings and bundle life from I&M Stakeholder Workshop, 06/25/15, slide 16.

.			
Commercial			
6.	Heating Cooling AP	17. Heat Pump = COP 3.4	$2.15
	Heating Cooling HAP		$3.22
7.	Office Equip AP	18. Energy Star PC 19. Other Energy Star	$0.42
	Office Equip HAP		$0.63
8.	Indoor Lighting AP	20. Screw in LEDs 21. Linear LEDs	$0.80
	Indoor Lighting HAP		$1.14

In conclusion, it appears that DEI's limited cost information indicates that the Company is using [redacted] costs than what are included in its 2016-2018 portfolio, and that I&M's incremental measure costs are overstated, resulting in fewer measures being included in bundles, and subsequently being available for the model to select.

V. Conclusion

The utilities did not comparably model supply and demand side resources because they (1) constrained the amount of efficiency available to their respective models and (2) further disadvantaged demand side management resources by running duplicative economic screens. This is disappointing as it appears that DEI and I&M have constrained efficiency so much, through a plethora of assumptions, that their models indicate that only the level of efficiency available today is an accurate portrayal of the amount of efficiency available for the next two decades. This is also indicative of both a lack of investigation into emerging and future technologies on the demand side and a self-fulfilling prophecy of energy efficiency being a finite resource, neither of which are acceptable in a properly performed IRP.

SECTION 3. RENEWABLES COST AND PERFORMANCE

I. Introduction

Between their capital cost and capacity factor assumptions, both Duke and I&M overstate the cost of new wind and solar resources. We believe the following would constitute a more reasonable set of base assumptions for these resources:

1. Solar costs at about $2,000 per kW (before the Investment Tax Credit) with a declining real price trajectory going forward.
2. Solar capacity factor at 22 percent or higher.
3. Wind costs from $30 - $40 per MWh inclusive of the full Production Tax Credit.
4. The underlying wind capital costs should be on a declining to stable trajectory.
5. Wind capacity factors ranging from 35[85] to 45 percent.
6. The companies should include both the current wind and solar tax credits in the modeling base case with a sensitivity for further extension of both.

II. Wind and Solar Capital Cost and Performance Assumptions

Duke and I&M both include wind and solar resources in their modeling in some fashion. However, their assumptions about these resources are very different. Table 3-1 compares the utility scale wind and solar cost assumptions of the two utilities and Table 3-2 compares their capacity factor assumptions.

Table 3-1. I&M and Duke Solar and Wind Costs

	I&M Solar Cost ($/kW)[86]	Duke Solar Cost ($/kW)[87]	I&M Wind Cost ($/kW)[88]		Duke Wind Cost ($/kW)[b]
			Tier 1	Tier 2	
2016	2,340	[redacted]	1,577	1,752	[redacted]
2017	2,230	same	2,483	2,558	same
2018	2,130		2,483	2,558	
2019	2,040		2,508	2,609	
2020	1,950		2,533	2,661	
2021	1,870		2,559	2,714	
2022	1,800		2,584	2,769	
2023	1,730		2,610	2,824	
2024	1,660		2,636	2,881	
2025	1,600		2,663	2,938	

[85] 35 percent is consistent with the 2014 weighted average capacity factor of projects in the Great Lakes region according to the Lawrence Berkeley National Laboratory Wind Technologies Market Report.
[86] Taken from the I&M "Solar Bundles" spreadsheet.
[87] Taken from d.1. Midwest IRP Generic Unit Summary 2015 IRP spreadsheet. Includes a $71/kW transmission adder that may not be part of I&M's estimate.
[88] Calculated based on the same methodology I&M applied to solar costs from the I&M spreadsheet "Wind Build Costs."

2026	1,550		2,689	2,997	
2027	1,490		2,716	3,057	
2028	1,440		2,743	3,118	
2029	1,390		2,771	3,180	
2030	1,350		2,798	3,244	
2031	1,350		2,826	3,309	

Table 3-2. I&M and Duke Solar and Wind Capacity Factor Assumptions

I&M Solar	Duke Solar	I&M Wind	Duke Wind
[redacted]%	[redacted]%	40 - 45%	[redacted]%

It is not clear from the information provided by either utility why there is a difference in their solar capital costs. Both are capital costs before any inclusion of the investment tax credit (ITC) and both assume a design basis of 25 MW in size. I&M's estimate is supposedly derived largely from information provided by Bloomberg New Energy Finance (BNEF). However, the narrative shared with us reported that BNEF's expectations for the levelized cost of energy (LCOE) for utility scale solar in Indiana in 2015 was $101 per MWh. I&M's cost of $2,340 per kW translates to $222 per MWh under its financial[89] and operational assumptions. Though it starts at a higher level, I&M's solar capital cost displays a trend more aligned with analyst expectations in that there is a real drop in solar prices, whereas Duke assumes no change in real price.

In addition, both utilities do not include an ITC consistent with current law. I&M does not include any ITC except in the Fleet Modification Prime and New Carbon Free portfolios (though it is unclear for how long it was extended), and Duke includes the 30 percent ITC in 2016 only, afterwards it falls to 10 percent. In December 2015, the solar ITC was renewed. Projects that begin construction before 2020 will still have 30 percent of their investment returned. Then the credit tapers after that: 26 percent for projects beginning in 2020, 22 percent for projects beginning in 2021, and 10 percent for projects starting after 2022.[90] The omission of the ITC in later years certainly leads both to overstate solar costs and thereby understate the relative value of solar as a resource.

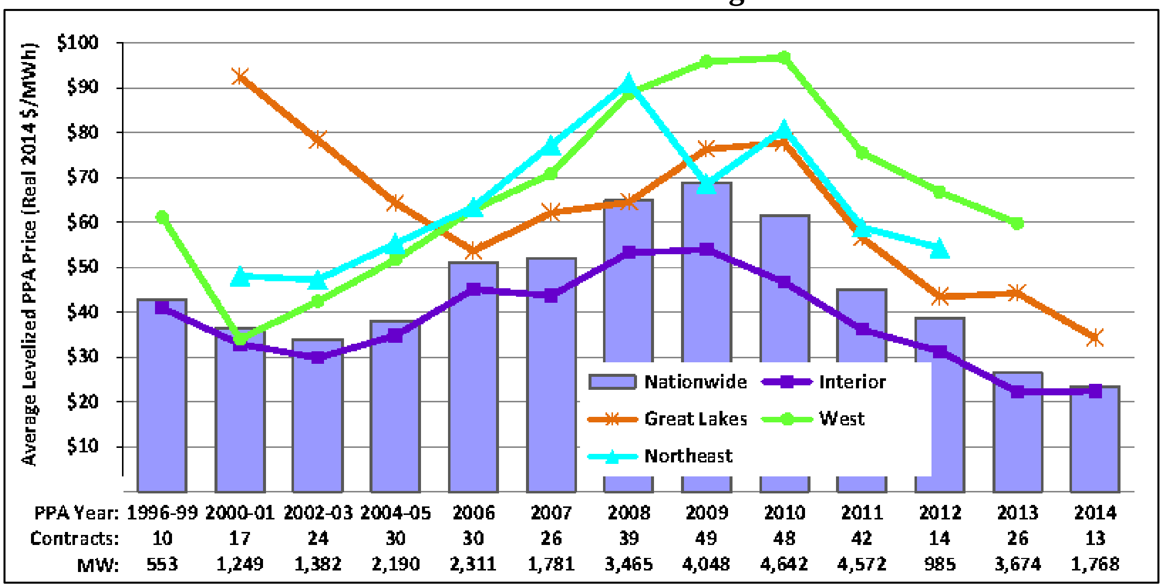
Finally, I&M has likely overstated solar costs because of its capacity factor assumption. Duke's estimate of a [redacted] percent capacity factor is more in line with what we would expect given our work on utility scale solar projects in more northern latitudes, though it may still be too low. When all these factors are combined, they are likely to result in significantly lower cost estimates. For example, in Xcel Energy's just released

[89] I&M uses a fixed charge rate (FCR) of 14.14 percent for solar projects. This appears to be based on the assumption that utility scale solar projects would be financed on I&M's balance sheet. It is possible that a PPA arrangement would contribute to a lower cost per MWh.
[90] Trabish, Herman K. "What utilities need to know about solar growth after the ITC extension." *Utility Dive*. 7 January 2016, http://www.utilitydive.com/news/what-utilities-need-to-know-about-solar-growth-after-the-itc-extension/411139/.

IRP supplement, the utility predicted that solar projects starting construction in 2016 would have a levelized cost of $67.30 per MWh, which is much lower than I&M's current estimate equivalent to $222 per MWh.

In the case of wind, I&M has a more reasonable cost trajectory, at least for the first year ($1,577 per kW is approximately $40 per MWh under I&M's financial and operational assumptions). It assumed the availability of the production tax credit (PTC) to wind projects only through the end of 2016, which translates into a significant reduction in cost compared to Duke's estimate. I&M provided its wind cost assumptions (seemingly based on the DOE Wind Vision report) in dollars per MWh only, which made it difficult to determine the installed cost per kW.[91] However, the 2017 cost of $2,483 per kW (or about $63 per MWh) may give some indication of the underlying installed cost assumption. Both I&M and Duke's cost assumptions are higher than those reported elsewhere. For example, Lawrence Berkeley National Laboratory's Wind Technologies Report found that projects installed in 2014 had a capacity-weighted average of $1710 per kW[92] and projects in the Great Lakes area had an average levelized Power Purchase Agreement price of $35 per MWh including the PTC (*see* Figure 3-1).

Figure 3-1. Generation-weighted Average Levelized Wind PPA Prices by PPA Execution Date and Region[93]



Finally, it is not clear why I&M would assume that the cost of wind will increase in the future. The major source of its cost data, the DOE Wind Vision report, seems to make the opposite conclusion and forecasts that wind prices will decline through 2022.[94]

[91] In order to make as much of an apples to apples comparison of the utilities' assumptions as possible, we had to convert I&M's assumptions into a dollar per kW figure.
[92] *See* https://emp.lbl.gov/sites/all/files/lbnl-188167_1.pdf.
[93] Wind Technologies Report at https://emp.lbl.gov/sites/all/files/lbnl-188167_1.pdf
[94] Spreadsheet labeled "Wind Bundles" provided to Joint Commenters on January 22, 2016.

Both utilities fail to fully account for the PTC renewal in December 2015. Projects that began construction in 2015 and 2016 will receive the full PTC. Projects that commence construction in 2017 receive a 20 percent lower PTC, projects in 2018 a further reduction of 20 percent, and projects in 2019 another 20 percent less until the credit terminates on January 1, 2020.[95]

Although the renewables tax credits were extended after both IRPs were issued, during stakeholder meetings, our clients asked I&M and Duke to run sensitivities with extended tax credits in anticipation of their renewal. I&M added an extension of the ITC only for an indeterminate length of time in two cases, and Duke declined to do so.

Lastly, we would note the vast difference in capacity factor assumptions made by I&M and Duke. I&M's 45 percent capacity factor number is based on the recently commissioned Headwaters Wind Farm, whereas Duke indicated that its [redacted] percent figure is based on the Benton County Wind Farm. A third and newer wind farm, Wildcat, also owned by I&M had a 38 percent capacity factor in 2014 and during the June 4, 2015 stakeholder workshop, Duke described wind as having a 35 percent capacity factor.[96] The takeaway from this data seems to be that a diversity of wind resources are available to Indiana utilities so assuming that wind resources are constrained at the bottom end of the spectrum is not reasonable.

Given the significance of these changes in the modeling for both plans, we believe rectifying these flaws would have a major impact on the modeling results.

[95] Trabish, Herman. "U.S. wind industry hits 70 GW capacity mark, celebrates tax credit extension." *Utility Dive*. 22 Dec. 2015. http://www.utilitydive.com/news/us-wind-industry-hits-70-gw-capacity-mark-celebrates-tax-credit-extensio/411224/.
[96] Volume 2 of Duke's 2015 IRP at page 78.

SECTION 4: LOAD FORECASTING AND RESERVE MARGIN REQUIREMENTS

I. Introduction

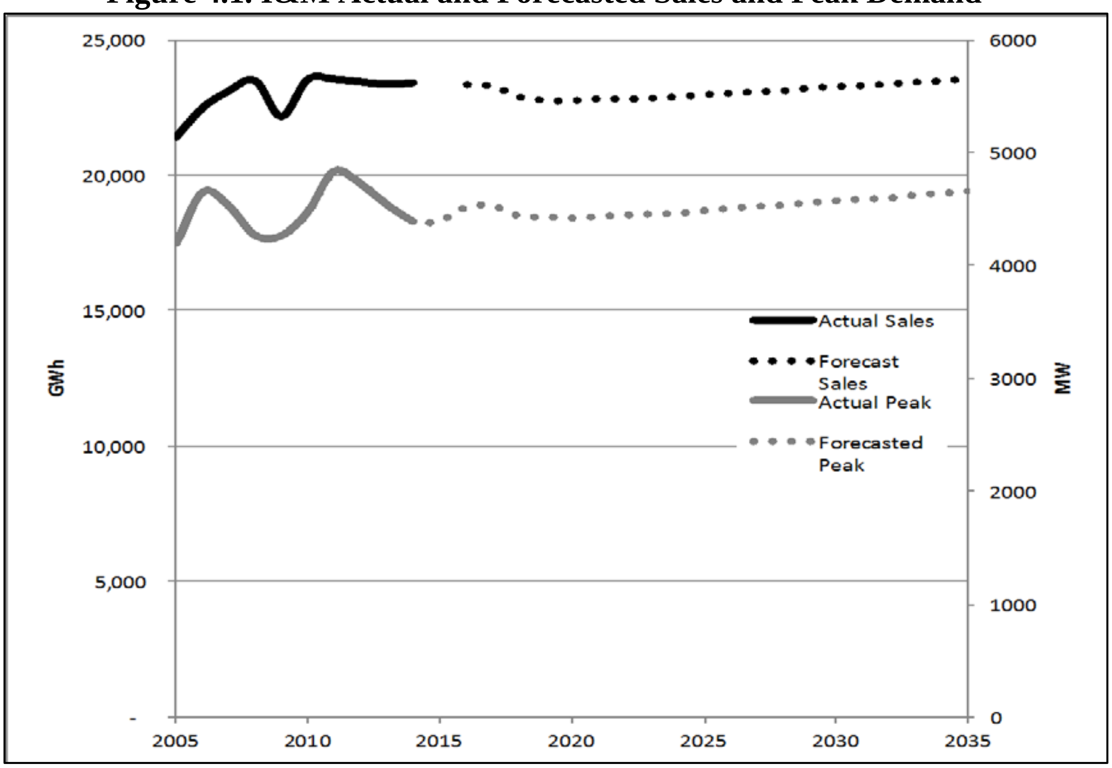
A vital input into any IRP is a forecast of future load and energy demands. A load forecast, as this information is typically called, has enormous influence on whether a utility builds, retires, or modifies capacity and therefore has a major impact on the projected cost of any potential expansion plan.

During our review of the utilities' load forecasts, we found that while I&M's load forecast is in line with expectations for weak growth in sales, Duke is projecting very robust growth. During the period from 2016 to 2035, I&M forecasts growth in sales of just 2.7 percent, while Duke forecasts growth of 12.7 percent. As discussed in detail below, we have serious concerns about the validity of Duke's forecast. Moreover, there is reason to question Duke's use of a 13.6 percent reserve margin requirement for planning purposes based on resource adequacy requirements established by MISO. That percentage should likely be lower.

II. Duke's Load Forecast Data is Inconsistent with Historically Reported Data

I&M's forecast of energy and peak demand, as well as actual data going back to 2005, are presented in Figure 4.1.

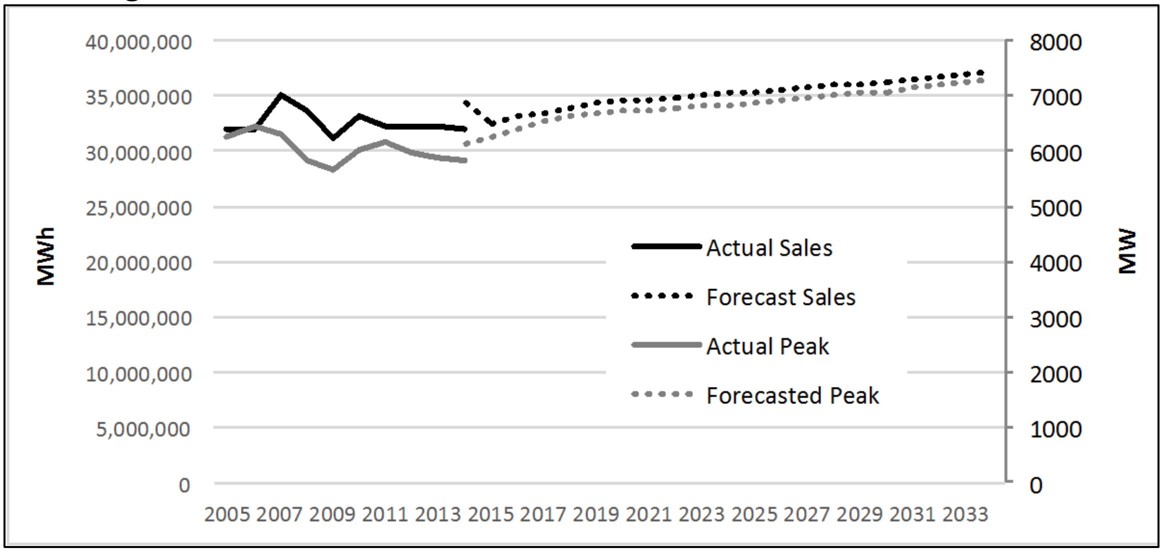
Figure 4.1. I&M Actual and Forecasted Sales and Peak Demand[97]



[97] FERC Form 1, EIA Form 861, and Exhibits A-1, and A-4, of the 2015 I&M IRP.

I&M forecasts sales and peak demand consistent with expectations around the country, i.e., static to low growth in demand for electricity demand. The near-term drop off in peak and sales, however, is in part due to the loss of one of I&M's wholesale customers.[98] Duke, on the other hand, forecasts increasing growth at a much higher rate.

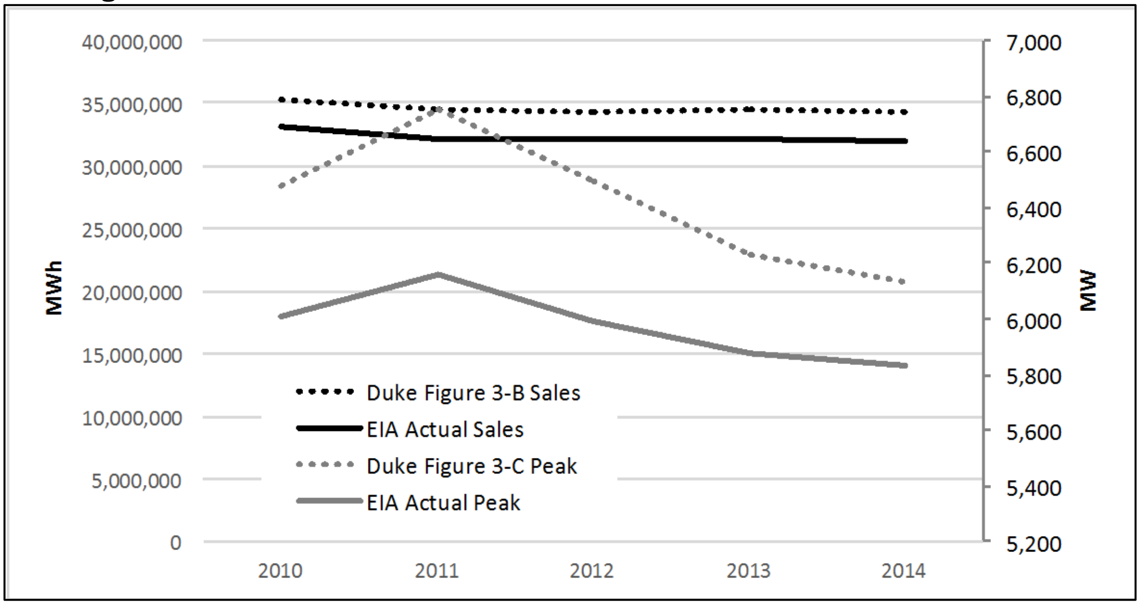
Figure 4.2. Duke Actual and Forecasted Sales and Peak, 2005 – 2030.[99]



While I&M's forecast is consistent with its recent experience of flat to declining sales, Duke's is not. At page 41 of its IRP, Duke presents its load forecast along with electricity historical sales that are materially different from what it has reported to federal agencies.[100] One can derive a utility's historic electricity sales and peak demand from FERC Form 1 and EIA Form 861. In the case of I&M, the peak data reported through EIA Form 861 exactly matches what is presented in Exhibit A-4 of the 2015 I&M IRP. Also, the sales data collected through EIA Form 861 and FERC Form 1 are very close to the historical sales data reported on I&M's Exhibit A-1, which is off by about 1 GWh in most years, except 2007 and 2009. Indeed, if the historical information about I&M's sales and peaks were overlaid in Figure 4.1 above, it would be nearly indistinguishable from the solid black and grey lines. Because utilities self-report this data to EIA and FERC, one would expect consistency with a self-developed IRP. This is not the case with Duke. Rather, the data in Duke's IRP is markedly different than in its federally reported data.

[98] Call with I&M on January 21, 2016.
[99] FERC Form 1, EIA Form 861, Figures 3-B and 3-C of the 2015 Duke IRP.
[100] Duke 2015 IRP at pg. 41.

Figure 4.3. Duke Sales and Peaks from EIA and FERC Data vs. Duke IRP



Sales are consistently overestimated in Figure 3-B of the 2015 Duke IRP by about 2.2 million MWh (*see* Figure 4.3 above). Also, peak demand is reported in Figure 3-C of the 2015 Duke IRP as 300 – 590 MW higher than Duke previously reported to the EIA (*see* Figure 4.3 above).

The difference in sales appears to be caused, at least in part, by the inclusion of all sales of electricity in the historical IRP data, regardless of the purchaser. If true, this is not an appropriate metric upon which to compare load forecasting data. IRPs are developed in order to meet the needs of customers who the utility is required to serve. Clearly, retail customers would be included in this category. Also included are sales to what are known as requirements customers. A utility's obligation to serve requirements customers is the same as or second only to retail customers. Because of this, requirements customers are appropriately included in an IRP load and energy forecast. A utility may also make sales to what are known as non-requirements customers; often these are sales of surplus power in to a wholesale market (MISO or PJM) or non-firm sales of energy. Sales to non-requirements customers should be excluded from an IRP load forecast.

Figure 4.4. Retail and Resale Sales Reported to EIA and FERC Compared to Duke IRP Historical Data

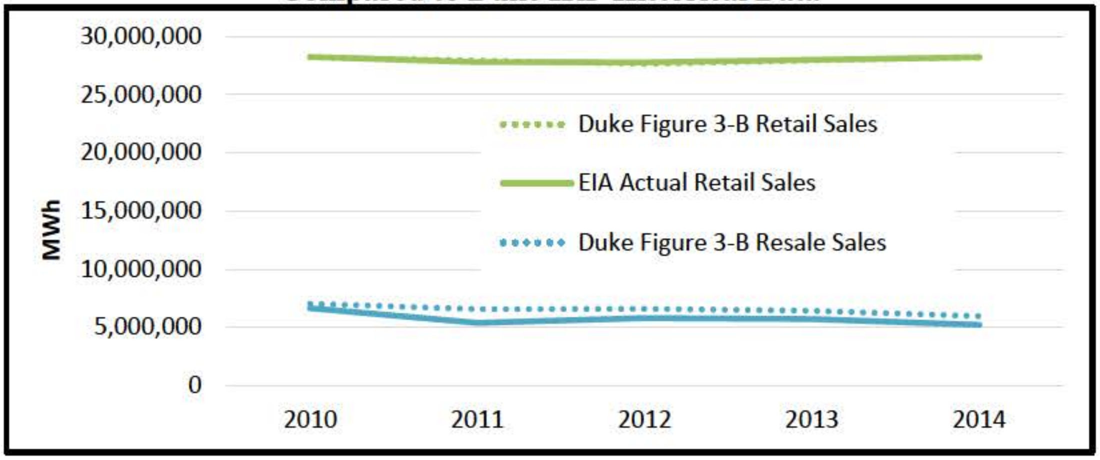


Figure 4.4 is a breakdown of the retail and resale sales data reported to EIA and FERC by Duke compared to that contained in Duke's IRP. Retail sales data reported to EIA (solid green line) and in Figure 3-B of the 2015 Duke IRP (dotted green line) are virtually indistinguishable because they are so close. Resale Sales, though distinguishable, are also still close. Note, however, that resale sales include sales to *both* requirements and non-requirements customers, which is inconsistent with the resale sales that a utility should include in an IRP load forecast. Since the Duke and EIA numbers are so similar when non-requirements sales are included, it seems likely that Duke improperly included non-requirements sales in its historical data in Figure 3-B of its IRP, explaining much of the difference between the EIA/FERC sales data and Figure 3-B in Duke's IRP.

Duke should have reported peak data to EIA including all requirements customers,[101] thus it is possible that improperly including non-requirements customers also explains the difference in peak data. Notably, the shapes of the grey and dotted grey lines in Figure 4.4 above are similar, which suggests that Duke scaled up its 2015 IRP data in some fashion. Also, demand response is not accounted for in the peak load forecast, so it may be calculated from the IRP historical data. But in order for demand response to explain the difference, it would have had to have been called upon to reduce load by 300 – 590 MW specifically at the time of the peak between 2010 – 2014.

In its response to an informal discovery request CAC 2.5, Duke listed the following as its requirements customers: [redacted]. Notably, Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy were not included despite the fact that they have been reported to FERC as requirements customers in the past. Even so, loads associated with those entities are included in the load forecast,[102] so it may simply be an oversight that WVPA, IMPA, and Hoosier

[101] *See* instructions for EIA Form 861, page 4 at https://www.eia.gov/survey/form/eia_861/instructions.pdf.
[102] Page 94 of the DEI 2015 IRP.

Energy were not mentioned in the response to CAC 2.5. We ask that Duke clarify in its Comments on the Draft Report the name of all its requirement customers and confirm that non-requirements customers are *not* included in its load forecast.

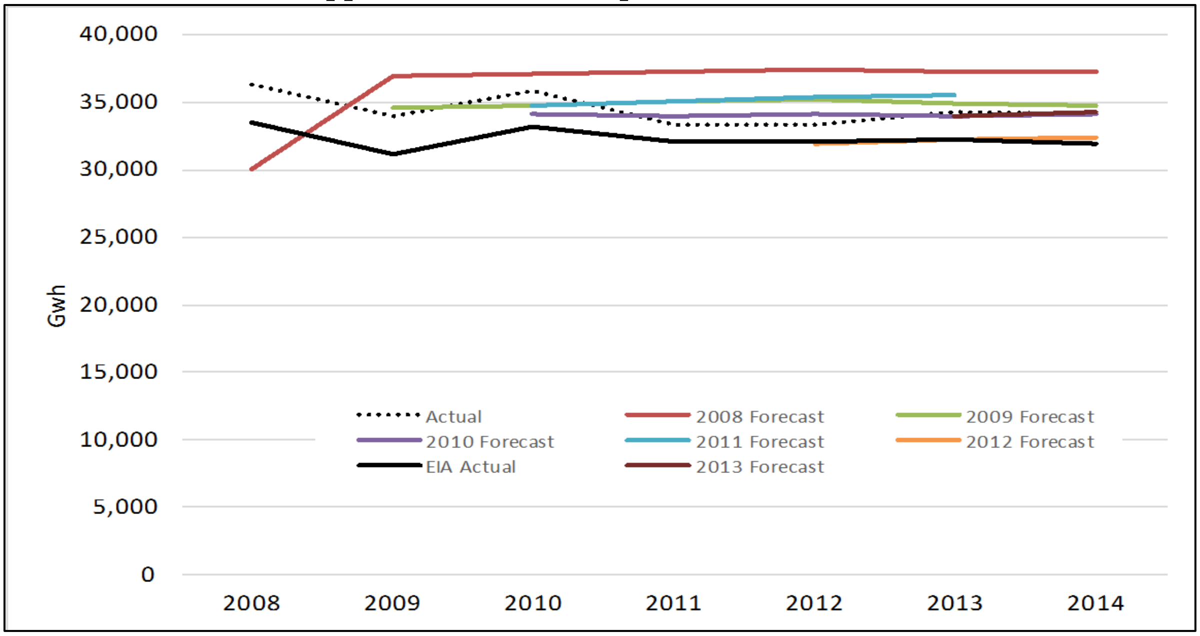
Assuming resale sales properly include only requirements customers on a going forward basis, this category of sales would not explain why such robust growth in sales is projected in comparison to historic actuals.

III. Methodological and Data Problems May Explain Duke's Overly Optimistic Load Forecast

Duke's forecasts sales use a methodology called ordinary-least squares regression. The underlying principal of this approach is that prior energy consumption can be explained by demographic, economic, and weather variables and that these relationships continue in the future.

While it may be true that "the IURC has passed judgment on the reasonableness of [Duke's] forecast and methodology several times [and that] the State Utility Forecasting Group (SUFG), though using models quite distinct from Duke Energy Indiana's, has historically produced forecasts that are similar to Duke Energy Indiana's," no specifics as to the timeframe in question or particular instances of the IURC passing "judgment on the reasonableness of [Duke's] forecast" are given. At any rate, whatever the facts may be, they do not outweigh the evidence showing Duke has overestimated sales for several years.

Figure 4.5. Only Duke's 2012 Forecast Closely Approximates Sales Reported to EIA.[103]



[103] EIA and FERC Form 1 data; page 205 of the 2015 Duke IRP.

With the exception of the 2008 forecast, Duke's recent sales forecasts[104] have been fairly close to its accounting of historical sales. However, all the forecasts have projected more sales than were reported to FERC and EIA, except the 2012 forecast. Regardless of whether one puts stock in the black line or the black dotted line there is one noticeable trend – that sales have been flat. That trend is at odds with the infinitely increasing sales trend reflected in Duke's forecast in this IRP. This dichotomy is not unusual in IRP load forecasts, but that does not mean it is real.

A key input into a load forecast regression analysis is a projection of economic and demographic factors such as non-farm employment, household income, population, etc. This data is typically purchased from a vendor such as Moody's or IHS Global Insight. In other IRPs, we found that these vendors typically predict that these variables will all improve (increase) into the future, which often contributes to the utility forecasting infinitely increasing load growth, as Duke does here. If those vendors are overly optimistic, the load forecasts will be, as well.

The Texas wholesale market operator, ERCOT, found that its economic data from Moody's overestimated a key explanatory variable in its forecast, non-farm employment,[105] leading to an overly optimistic forecast of load growth. Xcel Energy in Minnesota also found a pattern of overestimating sales due to its economic data:

> *To improve the accuracy of our sales forecast for this case, we took a number of steps to determine the root causes of our overestimation of sales, identify potential solutions, and implement those actions we believe will result in a more accurate forecast. For example, we analyzed sales variances from 2005 to 2011, which showed a distinct pattern of overestimating for most years. We also analyzed forecasts of the key economic inputs underlying our sales forecast, provided by Global Insight, which showed that the economic forecasts were overly optimistic on both the extent of the economic recession and the speed and scale of recovery. To better understand changes in customer energy use, we are monitoring end-use efficiencies and considering the potential for increases in energy efficiency beyond what we have seen historically.*
>
> *Given this information, we contracted with Itron, Inc., an industry leader in energy forecasting, to assess our forecast model and identify potential modifications that could address this overforecasting bias.* ***Itron concluded that the issue with overestimated sales forecasts is an industry-wide problem*** *[emphasis added] and affirmed that the regression*

[104] There are some anomalies between historic forecast data reported in this IRP and in prior IRPs, as well as other dockets before the IURC. We were unable to resolve these differences before filing these comments.

[105] 2013 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast available at http://www.ercot.com/gridinfo/load/2013_Long-Term_Hourly_Peak_Demand_and_Energy_Forecast.pdf.

> *techniques we use to determine our forecast are the industry standard and should not be changed. We also assessed alternatives to relying on economic data from Global Insight, but found that there are limited sources for economic forecasts that provide the full suite of forecast variables required for our forecast.*
>
> *As a result, we have not made any major changes to our sales forecast methodology or inputs. However, we have added an electric price variable to the existing model that is intended to better explain weak historical sales and, therefore, somewhat account for the over-optimism in the economic forecast. When we applied this variable in historical forecast models, it resulted in a lower model error, suggesting that its application in the current forecast will also lower model error and improve the accuracy of the forecast….*
>
> *Based on our current analysis, we believe that even if the economic recovery gained momentum, the changes in how our customers use energy would dampen sales into the future, making a significant near-term rebound in sales very unlikely.*[106]

While one may question the validity of continuing with a regression approach that is problematic when other methodologies are available such as statistically-adjusted, end-use forecasting (I&M's approach), Xcel has made endogenous adjustments to its load forecast to account for codes and standards that will affect energy consumption going forward since this testimony above was filed.[107] The only post-estimation adjustments Duke discusses in its IRP are for electric vehicles and utility-sponsored energy efficiency.

Because of the importance of economic data to other load forecasts, we asked Duke to provide the data set used in their forecast. We do not know which components of the data set were used as the key variables, i.e., the variables that "explain" future consumption. However, based on other forecasts and our knowledge of Duke's customer base, the following could be some of the likely candidates: [redacted]

[106] Testimony of Jack S. Dybalski in Minnesota Public Utilities Commission Docket No. E002/GR-12-961.
[107] Xcel Energy 2014 IRP filed on January 2, 2015.

Confidential Figure 4.6. Duke Data on Non-Agricultural Employment, 2000 – 2030.

[redacted]

Confidential Figure 4.7. Duke Data on Total Households, 2000 – 2030.

[redacted]

Confidential Figure 4.8. Duke Data on Median Household Income, 2000 – 2030.

[redacted]

Confidential Figure 4.9. Duke Data on Primary Metal Manufacturing Gross Product, 2000 – 2030.

[redacted]

Confidential Figure 4.10. Duke Data on Retail Sales, 2000 – 2030.

[redacted]

Confidential Figure 4.11. Duke Data on Total Gross Product, 2000 – 2030.

[redacted]

Since its load forecast not surprisingly seems overly optimistic, many of these variables also project optimistic growth in relation to historical growths.[108] For all the reasons discussed so far, we are concerned that Duke is materially overestimating future load growth. It is vital to rectify this problem because an overly optimistic load forecast can lead the model to overbuild the system and delay otherwise economic retirements. Duke should refile this information with its Comments on the Draft Report.

IV. Duke's Reserve Margin Requirement for Planning Purposes May Be Too High

MISO is responsible for ensuring resource adequacy among its member load-serving entities (LSEs), including Duke Energy Indiana. It performs this function, in part, by conducting yearly loss of load expectation (LOLE) studies designed to set reserve margin requirements such that the MISO system meets a 1 day in 10 years lost load standard. The reserve margin requirement set through these studies is known as the Planning Reserve Margin (PRM). It is defined on both an ICAP and UCAP basis. ICAP, meaning installed capacity, refers to the physical measure of a power plant's ability to produce energy, whereas UCAP or unforced capacity takes into account a unit's forced outage rate. Generally, a unit's UCAP value is less than its ICAP value.

At the time that Duke filed its 2015 IRP, MISO had established a 2015/2016 Planning Year[109] of PRM_{ICAP} at 14.3 percent and PRM_{UCAP} at 7.1 percent. Since then, MISO issued updated values for the 2016/2017 Planning Year of 15.2% and 7.6% for ICAP and UCAP, respectively. A load serving entity does not simply apply the PRM to its peak load in order to determine its Planning Reserve Margin Requirement (PRMR). Rather, the PRM is applied to the load serving entity's peak at the time of the MISO system peak load. This is known as the load serving entity's coincident peak load. MISO's resource adequacy construct uses UCAP, not ICAP, values to evaluate whether capacity resources are sufficient to the meet a load serving entity's Planning Reserve Margin Requirement. Most MISO utilities (Vectren, for example) not surprisingly use UCAP values when conducting resource planning because no transformation of the results is necessary to understand whether a plan meets the load serving entity's resource adequacy obligation.

Duke, however, does not model its system on a UCAP basis—it uses ICAP. While this might indeed be how Duke has historically done resource planning,[110] it obfuscates an important characteristic of a resource plan—how the plan measures up against MISO resource adequacy requirements. Before attempting to evaluate Duke's system in this regard, it is helpful to understand how the Planning Reserve Margin Requirement is determined. The Planning Reserve Margin Requirement is a load serving entity's coincident peak demand and transmission losses times one plus the Planning

[108] Because Duke does not say when this data set was produced, we do not know exactly which years are historical actuals and which are forecasted.
[109] Rather than the calendar year, the MISO Planning Year is from June to June.
[110] Page 26 of the Duke 2015 IRP.

Reserve Margin.[111] Most load serving entities produce their coincident peak demand forecast net of energy efficiency and demand response resources. For example,

If
Coincident Peak Demand of Utility Co. A (net of DR and EE) = 10 MW
Transmission Losses = 5%
MISO PY 15/16 PRM = 7.1%

Then
$$\text{PRMR} = 10 \times (1 + 7.1\%) \times (1 + 5\%) = 11.2 \text{ MW}$$

When it comes to resource planning, it is often easier to assess resource adequacy by using the utility's *non-coincident* peak demand forecast, i.e., their traditional load forecast, and modifying the Planning Reserve Margin percentage to account for diversity between the utility's peak and the MISO peak. As an example:

If
Coincidence Factor[112] of Utility Co. A = 97%
MISO PY 15/16 PRM_{UCAP} = 7.1%

Then
$$\text{PRM for resource planning} = 97\% \times (1 + 7.1\%) - 1 = 3.9\%$$

Since Duke is modeling its system on an ICAP basis, it would make the most sense for a similar methodology to apply.

Coincidence Factor = [redacted]%[113]
MISO PY 15/16 PRM_{ICAP} = 14.3%
PRM for resource planning = [redacted]

Instead, however, Duke came up with a reserve margin requirement of 13.6 percent.[114] Under Duke's base case load forecast, this increases required reserves by about [redacted] MW. It is difficult to follow the methodology used to develop the 13.6 percent requirement because the actual values used are not given. Conceptually, however, it does not match any other Planning Reserve Margin methodology we have seen in other IRPs nor any MISO document[115] or data regarding Planning Reserve Margin calculations of which we are aware, including the MISO Business Practice Manual No. 011 which addresses MISO resource adequacy.

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[111] Further detail on the calculation of the PRMR is available at page 14 of MISO Business Practice Manual (BPM) No. 011. The manual is located at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx.

[112] $\text{Coincidence Factor} = \frac{\textit{Coincident Peak Demand of LSE}}{\textit{Non-Coincident Peak Demand of LSE}}$

[113] Duke Response to CAC Informal Data Request 2.1-A.

[114] Page 26 of Duke 2015 IRP.

[115] It is possible that Duke's approach is based on a method of accounting for diversity in loads that became outdated with Planning Year 2013/2014.

For example, Duke says this formula can be used to translate from PRM_{ICAP} to PRM_{UCAP}:

> $PRM_{UCAP} = (1 - \text{MISO Average } XEFOR_d)(1 + PRM_{ICAP}) - 1$
>
> For PY15/16, the PRM_{UCAP} was 7.1%, the MISO Average $XEFOR_d$[116] was 6.95% and PRM_{ICAP} was 14.3%.[117] However,
>
> $7.1\% \neq (1 - 6.95\%)(1 + 14.3\%) - 1 = 6.4\%$

This underscores the confusion, and perhaps even mistakes, that can happen when trying to translate MISO resource adequacy requirements into an ICAP structure. Because understanding a resource plan from a UCAP perspective is so important, we asked Duke to give us the same load and capability data in Table 8–M of its 2015 IRP, but in UCAP format. Table 8-M as presented in Duke's 2015 IRP is provided on the next page for ease of comparison.

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[116] $XEFOR_d$ is the MISO system forced outage rate at all units excluding those outages that are Outside Management Control (OMC).
[117] Page 22 of MISO Business Practice Manual No. 011.

Table 8-M: Load, Capacity and Reserves Table

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Indiana 2015 IRP

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast																					
1 DEI System Peak	6,259	6,401	6,535	6,613	6,662	6,705	6,732	6,769	6,805	6,836	6,881	6,916	6,960	6,992	7,035	7,075	7,137	7,193	7,246	7,288	7,330
Reductions to Load Forecast																					
2 New Conservation Programs[a]	(9)	(31)	(56)	(83)	(110)	(134)	(159)	(162)	(183)	(195)	(210)	(223)	(228)	(228)	(232)	(235)	(238)	(241)	(244)	(248)	(250)
3 Demand Response Programs	(632)	(677)	(696)	(720)	(735)	(751)	(756)	(761)	(766)	(772)	(777)	(782)	(787)	(792)	(797)	(802)	(808)	(813)	(818)	(823)	(828)
4 Adjusted Duke System Peak	5,618	5,693	5,783	5,810	5,817	5,820	5,818	5,846	5,857	5,869	5,894	5,911	5,945	5,972	6,007	6,038	6,092	6,140	6,184	6,218	6,252
Cumulative System Capacity																					
5 Generating Capacity	7,387	7,387	6,719	6,719	6,553	6,273	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	5,957	5,957	5,957	5,957
6 Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Derates	0	0	0	0	0	(6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Capacity Retirements	0	(668)	0	(166)	(280)	0	0	0	0	0	0	0	0	0	0	0	(310)	0	0	0	0
9 Cumulative Generating Capacity	7,387	6,719	6,719	6,553	6,273	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	5,957	5,957	5,957	5,957	5,957
Purchase Contracts																					
10 Cumulative Purchase Contracts	13	21	21	21	21	21	21	19	19	19	19	19	19	6	6	6	6	6	6	6	6
11 Behind the Meter Generation	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
12 Cumulative Future Resource Additions																					
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking/Intermediate	0	0	0	0	0	448	448	448	448	448	448	448	448	448	448	448	896	896	1,104	1,104	1,104
Renewables	0	8	17	17	17	23	29	36	53	70	78	92	107	130	147	150	150	150	150	150	157
PPA & Cogen	0	0	0	0	300	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
13 Cumulative Production Capacity	7,418	6,767	6,775	6,609	6,629	6,792	6,798	6,802	6,819	6,836	6,844	6,858	6,873	6,884	6,900	6,903	7,041	7,041	7,249	7,249	7,256
Reserves																					
14 Generating Reserves	1,800	1,074	993	799	812	972	981	956	962	967	950	947	928	912	894	865	950	902	1,065	1,032	1,004
15 % Reserve Margin	32.0%	18.9%	17.2%	13.8%	14.0%	16.7%	16.9%	16.4%	16.4%	16.5%	16.1%	16.0%	15.6%	15.3%	14.9%	14.3%	15.6%	14.7%	17.2%	16.6%	16.1%
16 % Capacity Margin	24.3%	15.9%	14.7%	12.1%	12.3%	14.3%	14.4%	14.1%	14.1%	14.1%	13.9%	13.8%	13.5%	13.2%	13.0%	12.5%	13.5%	12.8%	14.7%	14.2%	13.8%

[a] Not already included in load forecast. This value is coincident with the net peak load, so it may not be the peak value for the year.

Rather than providing us the same load and capability data in Table 8–M of its 2015 IRP but in UCAP format, Duke gave us the UCAP values of its units for the 2015/2016 and 2016/2017 Planning Years, as well as the following:

Confidential Table 4.1. Partial Duke Response to CAC 2.1

[redacted]

[redacted]

The data in Confidential Table 4.1 does not explicitly say what load underlies Duke's Planning Reserve Margin Requirement and whether it is net of energy efficiency. The Commission should request that Duke clarify these points in its Comments on the Draft Report. Because the total UCAP value of Duke's units in PY16/17 is [redacted] MW, depending on its coincident peak load and using the PRM_{UCAP} of 7.6 percent established for PY16/17, Duke would have a deficit of capacity of [redacted] MW in 2017 or a surplus of about [redacted] MW. Until Duke provides further clarity, it is not clear on which side of the spectrum the actual numbers fall.

PJM, the regional transmission organization that I&M participates in, also uses a coincident peak and UCAP construct for resource adequacy, though the application is somewhat different than in MISO. It appears that I&M's IRP conforms with PJM's approach and models its units on a UCAP basis.

SECTION 5: MODELING BY I&M IN SUPPORT OF ITS IRP

I. Introduction

Our review of I&M's modeling revealed the following:

1. I&M proposes to continue a very risky strategy of selling large quantities of surplus energy.
2. The revenue from these surplus sales have a significant impact on the net present value ("NPV") of the portfolios analyzed, hiding what would otherwise be very significant differences in cost between portfolios. Also, projected revenue estimates are probably overestimated for several reasons, including failing to account for the sharing of off-system sales margins with I&M shareholders.
3. Even under I&M's assumptions, Rockport Units 1 and 2 are not profitable.
4. Rockport's heat rates may be modeled at lower than realistic levels.
5. Renewables are overly constrained in the modeling.
6. I&M's modeling does not reflect the requirements of the Clean Power Plan and the preferred plan may not leave the Company well positioned to CPP requirements.

II. Background on the PJM Wholesale Energy Market

As we will explain through this section of our report, I&M's representation of the PJM wholesale energy market critically impacts its IRP modeling conclusions.[118] Therefore, it will be helpful to first cover some key aspects of PJM.

PJM coordinates the movement of electricity in a multi-state region that extends from Pennsylvania to Virginia to Illinois. One of the many ways in which it performs this function is through scheduling of generators to meet load on a day-ahead basis. This means that it takes demand projected to occur the next day and clears generators to operate in order to serve that demand. Not all generators in PJM are necessary to serve load every hour of the year so some may not be dispatched at all, some may be only partially dispatched, and some will run at full capacity. The price paid to each generator that operates, as well as the cost of power paid by load, is called the locational marginal price (LMP).

An LMP is normally calculated at every generating unit and at other points on the grid intended to represent locations where load takes power from the grid.[119] These points are known as nodes.[120] If the transmission system were perfectly efficient, the LMP calculated at every node would be exactly the same. In reality, prices will differ across PJM because of congestion and because of transmission losses.

[118] We do not discuss PJM's capacity and ancillary services markets in this report, because revenues from those markets have little to no influence on the IRP results. I&M is a Fixed Resource Requirement (FRR) company meaning that it self-supplies capacity and can only receive capacity revenue for limited surpluses.
[119] Additional nodes may be established for other reasons not discussed here such as to price energy imports and exports.
[120] A list of nodes by state is available here: http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/pnode-by-state.ashx.

Unless there are extenuating circumstances such as transmission limitations, PJM will generally choose to dispatch the least costly units first so a unit's bid or offer price is an important determiner of whether it is dispatched or not. Offer prices are normally based on the marginal costs of the unit, that is, the costs that arise if the generator produces one more MWh of power. For coal and gas units, these are primarily fuel costs, but also include things such as the cost of sorbents used in pollution controls. Capital costs and fixed O&M costs are not accounted for in an offer price.

Every day, generators are cleared to serve load, and load purchases energy from the PJM market. In a sense, PJM views load and generators separately even if they are connected to the same utility. This is because generators are dispatched to meet load throughout PJM, and load is buying power supplied by all the generators that are dispatched, not just the generators owned by customers' respective utilities.[121] Therefore, the cost to serve I&M's load will not be the same as the revenue to I&M's generators.

III. I&M's Modeling Approach

I&M attempts to mimic PJM operations through its modeling. Using a forecasted PJM price, the cost to serve load by buying power out of PJM is explicitly calculated. And using that same price, the revenue to "generators," including energy efficiency, is calculated. I&M uses a forecast of prices at the AEP GEN hub[122] as a proxy for the LMPs that both its generators and its load will face. The cost to serve load is determined by the product of the load forecast and the forecasted AEP GEN hub price in the same time slice.[123] Similarly, generators are dispatched on the basis of whether their operating costs are lower than the forecasted AEP GEN hub price in the same time slice.

There are some important exceptions to this with respect to generators. Wind, solar, and energy efficiency are all represented as must run units.[124] This means that they will produce energy (or negawatts for efficiency) regardless of the market price for electricity. Similarly, coal and nuclear units have minimum loading levels. These units would have difficulty starting up or shutting down over short, say hourly, periods of time. In those cases, the generator's owner can designate a minimum amount of generation that must be produced from the unit, also known as the minimum loading level.[125] Thus, coal and nuclear units generally produce a minimum level of generation regardless of the clearing price. That is, regardless of whether the revenue per MWh exceeds the cost to produce that MWh.

[121] As with any transmission system, there will be transmission congestion and losses that also influence generator dispatch and the actual flow of electrons from generator to load.
[122] A hub is an aggregation of specific locational marginal price nodes.
[123] We use the term "time slice" because it is the term, rather than something more specific such as hourly, typical day, typical weekend etc., that I&M has used to discuss the time granularity of its dispatch, which is not always hourly.
[124] Confusingly, the term "must run" is used in other contexts not applicable here such as Reliability Must Run (RMR) units –units that must operate for grid reliability reasons.
[125] The minimum loading level of Rockport 1 and 2, for example, is about 545 MW_{gross} or approximately 520 MW_{net} (derived from CEMS data).

I&M's methodology is different from that of many other utilities in the sense that IRP models normally dispatch the utilities' own units to meets its own load; but some will allow sales and purchases to occur on an economic basis or when load is too low to absorb all the energy produced by must run units. Practically speaking, this could produce the same result that I&M's methodology does, but sometimes utilities place limitations on the level of sales or purchases that can be made.

It is tempting to view I&M's approach as superior because it appears to mimic real world operations. Indeed, it does provide certain advantages in that if a system is overbuilt relative to its native load (as is the case with I&M), then simulating the dispatch of units only to serve that load and/or limiting sales will probably understate the generation from I&M's units and their associated costs. On the other hand, it requires the modeler to be keenly aware of how sales can influence capacity retirement and build results. Units may be built in large part or entirely because of their ability to sell power and generate a positive increase in revenue, or units may not be retired because future revenues from those units outweigh the cost of building alternative units. In fact, I&M has told us that once its model views wind as "economic," it will build an unlimited number of units unless the modeler specifies a limitation.[126]

When sales[127] (or purchases) exert enough influence on a portfolio to affect resource choices, the modeler should be very wary of the result. Such a situation means that a particular resource choice hinges on whether the wholesale market price forecast is accurate for many years to come, which is 30 years in I&M's case. That resource choice is equivalent to making an unnecessary bet with customers' money and with a much greater volume of risk than is inherent in any other single commodity forecast (gas, coal, etc.).

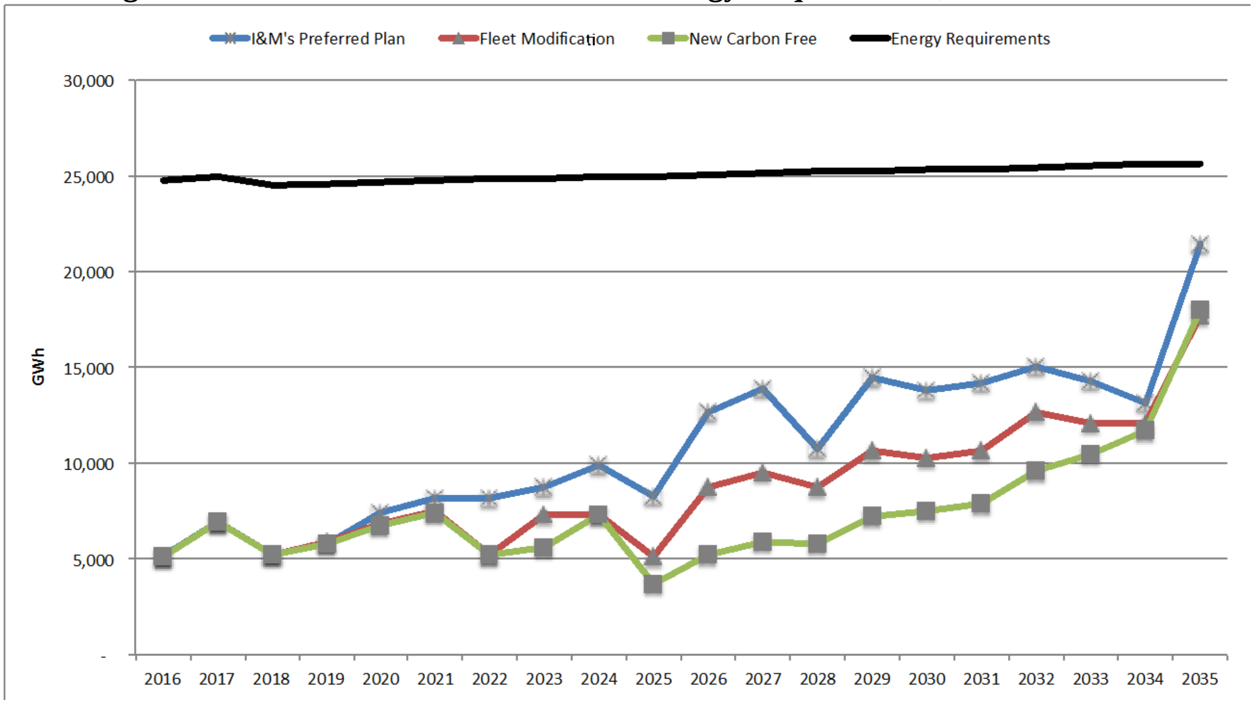
IV. Sales in the IRP Modeling Represent Significant Risk to Customers

I&M attempts to economically justify its preferred plan by banking on a practice of excessive surplus energy sales. To truly understand how risky it is for I&M ratepayers to underwrite generation that far exceeds its native load needs (as I&M's preferred plan would), it is important to remember how the PJM energy market works. Recall that PJM dispatches units on the basis of their marginal costs, which do not include capital or fixed O&M. This is critical because regardless of the revenue received, I&M ratepayers will be obligated to cover *all* generation costs, including capital and fixed O&M expenses, for the life of these plants. Betting that the market price will be high enough to justify large quantities of surplus sales is a huge risk to ratepayers.

To put it another way, consider the converse situation. If I&M proposed on the basis of its IRP modeling a plan that would require it to indefinitely purchase 20 to 50 percent of customers' energy needs out of a spot market, most stakeholders would view this as a risky and imprudent resource plan. Selling power into the PJM market in large quantities presents no less a risk for customers. And yet, this is exactly the risk I&M wants its customers to assume.

[126] Call with I&M on January 21, 2016.
[127] Throughout this section we use "sales" to mean non-firm sales of surplus energy to third parties. In I&M's modeling these sales are represented by spot sales into PJM, which are likely to make up the majority of sales that occur in reality.

Figure 5-1. Sales in Excess of Customer Energy Requirements, 2016 – 2035.[128]

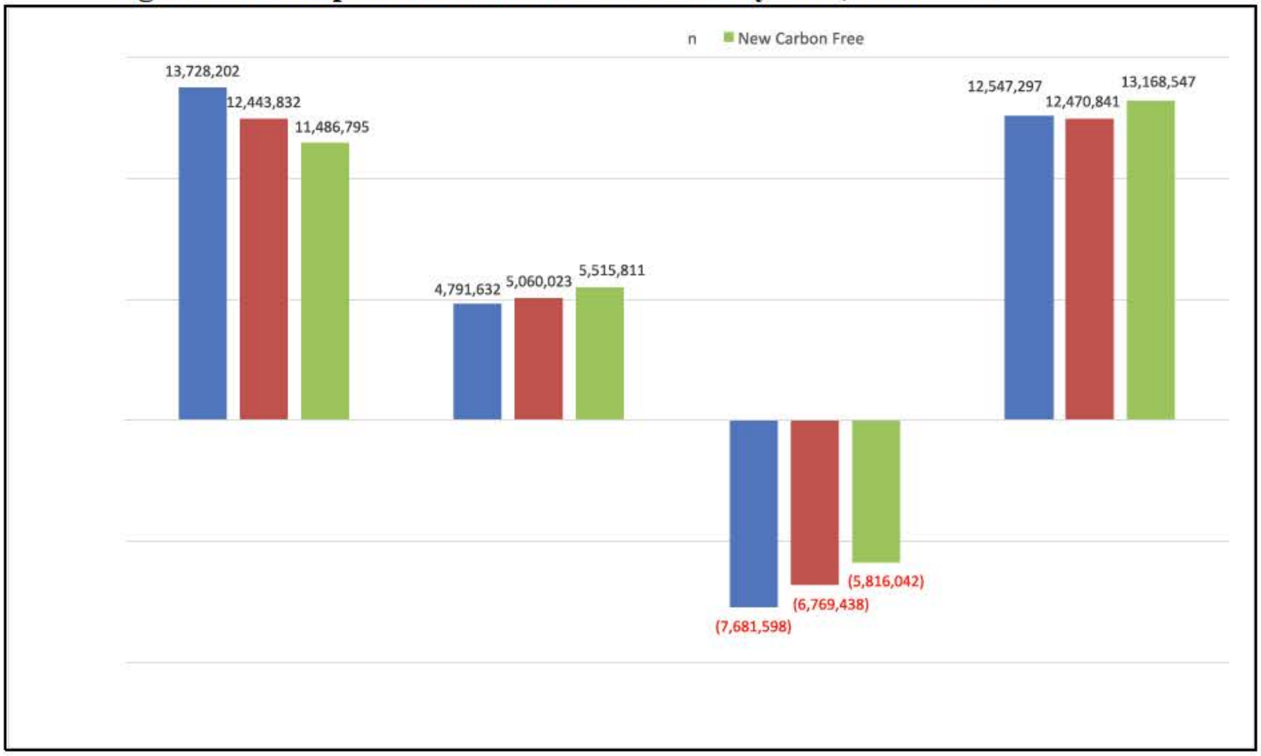


The differences between the three portfolios shown in Figure 5-1 are driven by differences in the treatment of Rockport. The Preferred Plan extends their operation including making pollution control upgrades. The Fleet Modification portfolio retires Rockport Unit 2 in 2022. The New Carbon Free portfolio retires Rockport Unit 2 in 2022, followed by Rockport Unit 1 in 2025.

Under I&M's Preferred Plan, it would sell at least 20 percent as much power as that needed to meet its own customers' native load requirements in every year between 2016 and 2035. The Fleet Modification and New Carbon Free portfolios also include large volumes of surplus sales, which means that the capacity replacing Rockport is likely being overbuilt in order to take advantage of speculative sales. This volume of sales definitely distorts the net present value calculations.

[128] "Two-pagers" for the Preferred, Fleet Modification, and New Carbon Free plans under Base Band assumptions. The public Summary tab was the source for all data.

Figure 5-2. Components of Net Present Value by Plan, 2016 – 2045.[129] [130] [131]



First, it is worth noting that I&M concluded that the Fleet Modification plan, including the retirement of one Rockport unit, is *less* expensive than its Preferred Plan. Without consideration of off-system sales, I&M's Preferred Plan is the most expensive of the three at about \$18.5 billion over the period 2016 – 2045. The Fleet Modification Plan is still cheaper at about \$17.5 billion. And the New Carbon Free plan, including early retirement of Rockport Units 1 and 2, is \$17 billion or about 9 percent cheaper than the Preferred Plan. It is entirely due to off-system sales that I&M can otherwise claim that its Preferred Plan is similar in cost to the Fleet Modification portfolio.

To understand the risk inherent in the Preferred Plan, imagine a hypothetical situation in which one 1,000 MW power plant can serve native load; but instead, the utility proposes to build 1,500 MW of total capacity since the excess is projected to make so many off-system sales that the total NPV of the plan is cheaper than simply building 1,000 MW of capacity. Like I&M's Preferred Plan, this would put ratepayers in the position of being effectively merchant generators, subject to the risks of the wholesale market.

[129] "Two-pagers" for the Preferred, Fleet Modification, and New Carbon Free plans under Base Band assumptions. The "Public Summary" tab was the source for all data.

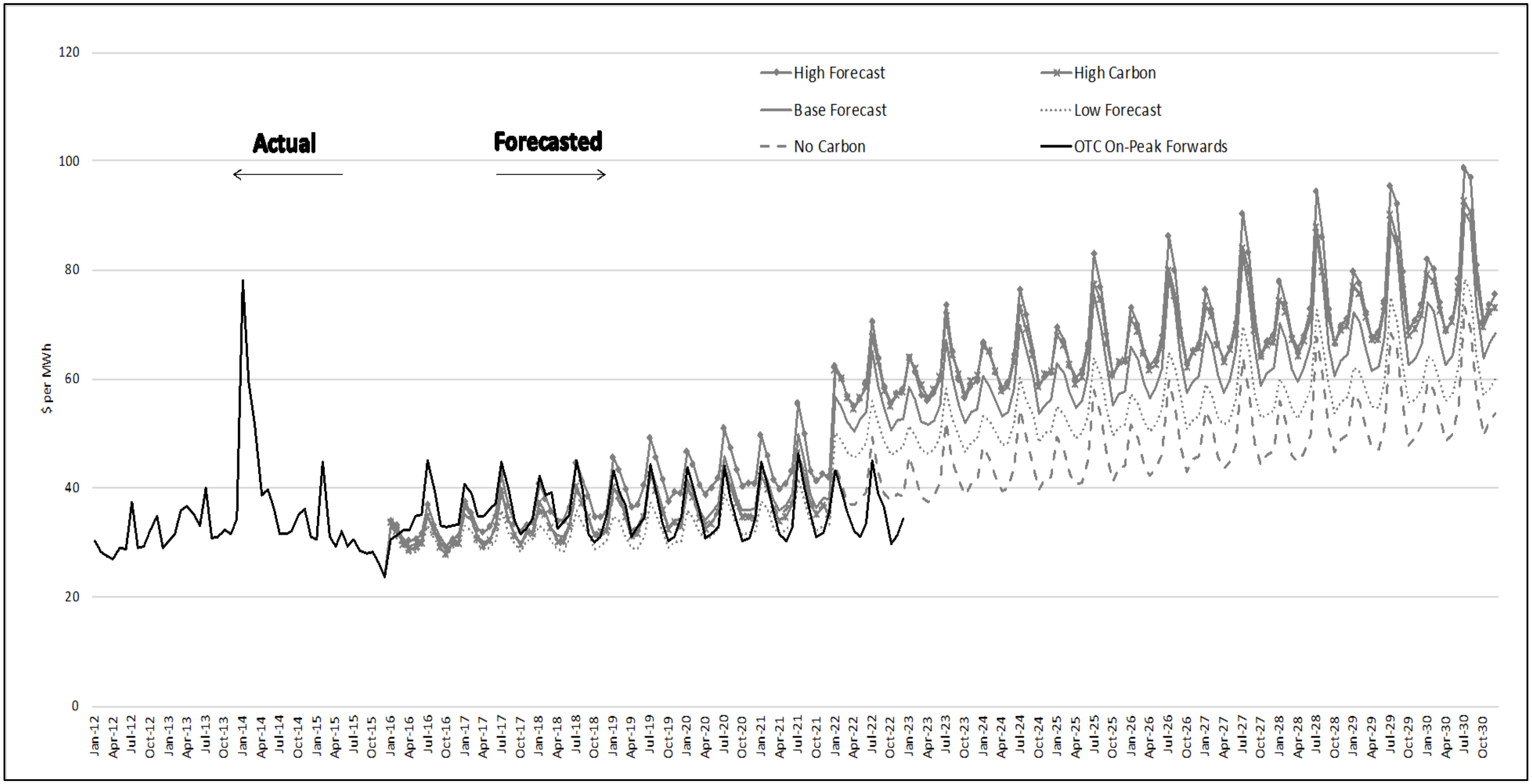
[130] Market Revenue from Surplus includes revenues from surplus energy sales plus a comparatively small amount of revenue from sales of capacity in excess of I&M's requirements.

[131] End effects are the extrapolation of the last year's worth of costs infinitely into the future and are intended to account for large capital expenditures that will not be entirely recovered during the planning period. End effects are not reflected in the operational and capital cost or market revenue from surplus totals.

In future IRPs, we would encourage I&M to consider presenting portfolio cost data at a more granular level such as in Figure 5-2 above so that key elements of the NPV are transparent. In addition, it could report the NPVs with and without sales revenue. Some Minnesota utilities completely ignore sales in their resource planning so that new units are not constructed nor the life of existing units extended on the basis of those sales. Presenting NPVs without sales would be a variation on that approach.

Because these sales arise from revenues determined by a single PJM forecast trajectory, it is also worth exploring the validity of the base band trajectory and its sensitivities. The forecasts are for the AEP GEN hub, so actual data in Figure 5-3 are also prices at the AEP GEN hub.

Figure 5-3. I&M's Base, High Carbon, High, Low, and No Carbon AEP Gen Price Forecasts and OTC On-Peak Forward Prices[132] [133]



[132] I&M Commodity Price Forecast spreadsheet provided through informal discovery to Joint Commenters.
[133] OTC forward prices are from SNL for the AEP-Dayton Hub since no forwards were available for the AEP Gen hub. The two hubs have historically tracked very closely in price.

OTC Global Holdings uses a combination of actual and historical price data to develop its forward price curve. To be conservative, we used OTC's on-peak price curve. Even so, I&M's base case price forecast is often higher after 2018 and really begins to diverge as I&M's $15 per ton CO_2 price is incorporated in the trajectory. Of course, this does not explain why the No Carbon forecast would also be above the forwards prices. All of I&M's market price trajectories seem to be focused on the high side of the spectrum, as is I&M's risk analysis of market prices (*see* Figure 32 of the IRP). This raises the question of: what if market prices were lower, much lower than I&M projects? Or what if the CO_2 prices were higher and had the effect of placing coal on the margin more than I&M predicts? Or what if the requirements of CPP necessitate reductions above and beyond those in the Preferred Plan?[134] It is not clear which of these futures is most possible, but that is exactly the point. There is great uncertainty in market prices and, therefore, great uncertainty in market revenue.

V. Even under I&M's Assumptions, Rockport Units 1 and 2 are Not Profitable

Let's say, for the sake of analysis, that I&M's PJM price forecast turns out to be fairly close to reality. It would still not be enough to say that such large volumes of sales should be made simply because they may have been made in the past. It is essential to examine what benefit arises to customers from such sales given the costs they will have to bear. In the case of Rockport Units 1 and 2, for example, if the units provided a net positive benefit to customers in the longer-term, not just hour to hour or month to month, they should be able to recover their future costs through revenue from PJM. Future costs would *not* include the remaining plant balance for the units, which is considered "sunk," but *would* include variable O&M,[135] fuel, fixed O&M, and even capital expenditures. Confidential Figure 5-4 shows the present value of the market revenue to the Rockport units under its Preferred Plan with base band pricing, as well as the present value of variable O&M, fuel, and fixed O&M costs for each unit.

[134] *See* Figure 29 on page 123 of the I&M 2015 IRP. Note that emissions increase from the 2022 – 2024 average when CPP requirements would have them decrease. Also, these totals do not include emissions from the purchase of power by contract from Clifty Creek and Kyger Creek (both coal plants).

[135] For simplicity, we count what I&M terms "emission" costs in variable O&M since they seem to vary with the amount of MWh generated.

Confidential Figure 5-4. Present Value of Operational Costs and Revenue to Rockport Units, 2016 - 2045[136]

[redacted]

Using I&M's own assumptions, the Rockport units cannot cover their variable O&M, fuel, and fixed O&M costs through revenue from PJM. This is true every year of the planning period. Even looking just 5 years out, Rockport Unit 1 would have a net loss of $[redacted] million and Rockport Unit 2 a net loss of $[redacted] million. None of these facts or Confidential Figure 5-4 include any capital expenditures related to future flue gas desulfurization (FGDs) technology or selective catalytic reduction (SCRs) technology or other capital expenditures. Including those costs simply worsens the economic picture for the units (Confidential Figure 5-5).

Confidential Figure 5-5. Present Value of Future Costs and Revenue to Rockport Units, 2016 - 2045[137]

[redacted]

[136] Based on Preferred Plan – Base Band "two pager." Excludes costs and revenues after 2045 (end effects).
[137] Based on Preferred Plan – Base Band "two pager." Excludes costs and revenues after 2045 (end effects).

It is not enough for the Rockport units to cover their variable costs (fuel and variable O&M) through revenue from PJM. If that same narrow calculus that governs dispatch guided resource planning decisions is used, then the Company should choose to build or continue to operate any resource whose variable O&M and fuel costs were less than the market price for power. In such a case, it should build unlimited amounts of nuclear, wind, solar, and hydro power. Clearly, that is not a rational or least cost way to plan for a utility system.

Beyond the concerns raised above about relying on market revenue to reduce customers' costs, there is also good reason to believe the market revenue is overstated. I&M has a mechanism in place by which its shareholders receive a portion of surplus or off-system sales (OSS) margins. This mechanism was put into place in Indiana as a result of the IURC Order in Cause No. 43306 and modified in IURC Cause No. 44075.[138] OSS margins are not a separate revenue stream, but rather a calculation of "the net profit that results after taking the total revenue from all sales made to non-affiliated counterparties, and subtracting out the variable costs of making those sales."[139] Variable costs "may include the cost of fuel, variable O&M, purchased power, emissions credits, or cost associated with entering into a financial product."[140] One of the ways in which OSS margins are made is through the sale of excess generation.[141] Notably, fixed O&M (and likely capital expenditures) are not counted as variable costs so margins would not be calculated in the manner illustrated in Confidential Figures 5-4 and 5-5 above. Rather, they are more akin to how PJM determines whether or not to dispatch a unit.

If Indiana jurisdictional OSS margins are above $26.9 million, then I&M shareholders keep 50 percent of OSS margins.[142] This is a simplified and hypothetical example of how the calculation of OSS margins might work:

Rockport Unit 2 Annual Net Generation: 8,000,000 MWh
Fuel and Variable O&M Costs per MWh: $27 per MWh
Revenue per MWh: $32 per MWh
OSS Margins: $(\$32 - \$27) \times 8{,}000{,}000 = \$40\text{ million}$
I&M Shareholder Portion of OSS Margins: $50\% \times \$40\text{ million} = \$20\text{ million}$
Customer Portion of OSS Margins: $\$40\text{ million} - \$20\text{ million} = \$20\text{ million}$

Fuel and variable costs are clearly covered in this situation, but only $20 million remains to cover Rockport Unit 2's fixed costs. In 2014, Rockport as a whole had $195 million in fixed production expenses.[143] If 50 percent of those were allocated to Rockport Unit 2, then only $20 million would be available to cover the additional $97.5 million in plant expenses. I&M's modeling team confirmed that the modeling does not

[138] Testimony of Matthew Horeled in Cause No. 43775 OSS-6 at page 4.
[139] Testimony of Brian Tierney in Cause No. 43306 at page 3, lines 18-20.
[140] *Ibid*, page 4, lines 1 – 3.
[141] *Ibid*, page 4, lines 5 – 6.
[142] IURC Order in Cause No. 44075
[143] From SNL Financial.

account for the sharing of OSS margins with shareholders.[144] Therefore, not only are the revenues in Confidential Figures 5-4 and 5-5 above very probably overstated, but so is the Market Revenue from Surplus in Figure 5-2, meaning that the net cost to customers is underestimated.

VI. Surplus Sales from Rockport Units 1 and 2 are Highly Likely to Occur

The above example does indeed assume that all MWhs generated by Rockport Unit 2 are surplus. But should the volume of surplus sales revenue projected by I&M materialize, it seems very likely that sufficient OSS margins will exist, resulting in continued margins going to shareholders. The Rockport units are very likely to contribute to this total.

As Confidential Figure 5-6 demonstrates, energy produced from I&M's baseload units (not including its contract with OVEC for power from Kyger Creek and Clifty Creek, since we did not have the information necessary to include it) will exceed native load in [redacted] hours of the year 2017 or [redacted] percent of the time.

Confidential Figure 5-6. Generation from Rockport 1 and 2 and Cook 1 and 2 will Frequently Exceed Load in 2017.

[redacted]

Much of this surplus will likely come from one or both Rockport units since nuclear units are often designated as entirely must run and will be at the bottom of the dispatch stack.

[144] Call with I&M on January 29, 2016.

Confidential Figure 5-7. Generation from Rockport 1 and Cook 1 and 2 is a Better Match for Load in 2017.

[redacted]

If Rockport Unit 2's projected generation is removed, the remaining units provide power closer to the needs of I&M's customers. This particular year was chosen because we expected that it would include an extended outage at Rockport Unit 1 to accommodate installation of the SCR on that unit, which would add conservatism to this analysis. There is [redacted].

If Rockport Unit 2 were retired before 2017, however, I&M would have a capacity deficit of 1,023 MW in 2017 under its Preferred Plan. But this does not mean that a baseload unit is best suited to meet that deficit; since the shortfall in capacity is greater than the shortfall in energy, the most economic replacement would likely be resources that provide more capacity than energy rather than something akin to another baseload unit.

VII. Rockport's Heat Rates May Be Too Low

Revenues resulting from Rockport surplus generation may also be overstated due to I&M's assumptions about those units' future heat rates. Unless it is retired, Rockport Unit 1 is under a consent decree to install selective catalytic reduction (SCR) by December 31, 2017 and a flue gas desulfurization (FGD) unit by the end of 2025. Similarly, Rockport Unit 2 must install an SCR by December 31, 2019 and an FGD unit by end of 2028. These pollution controls will add to what is known as "parasitic" load or the level of energy needed to operate the plant which decreases the amount of energy put onto the grid. Despite this fact, both Rockport units have effectively improving heat rates going forward.

Confidential Figure 5-8. Rockport Projected Annual Heat Rates under Preferred Plan

[redacted]

Confidential Figure 5-8 shows the annual average heat rate, meaning that these values are not controlled for the level of generation produced. Higher production levels tend to improve the overall heat rate of a power plant, so this fact might help to partially explain why heat rates decrease after [redacted]. In addition, at the same time that the SCRs are installed, I&M plans to upgrade the turbines at Rockport Units 1 and 2, which would also improve their efficiency.[145]

Even so, it is not clear how I&M's heat rate assumptions square with the installation of new pollution controls. The Steady State Plan [redacted] in heat rate with the addition of the SCRs, but there is [redacted] when the FGDs come online. During our conversations with I&M, the IRP team indicated that they believed this to be a result of the FGDs allowing Rockport to burn higher sulfur, higher heat content coal. In their Comments on the Draft Report, we would encourage I&M to explain the technical assumptions that influence its heat rate projections, particularly those factors that decrease and increase heat rates through 2028 when the FGDs would come online in the Preferred Plan.

[145] I&M IRP Public Summary at page 8.

VIII. Renewables are Likely Overconstrained in I&M's Modeling

I&M states that solar resources were made available in quantities up to 50 MW each year starting in 2016 (IRP at pg. 106-107). I&M picked this limit because:

> [t]his 50MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted and constructed by I&M in a given year. Certainly, as I&M gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Id. at p. 107. This limit is inappropriate and should concern the Commission for four reasons. First, I&M should acquire new resources through a request for proposal ("RFP") process that allows suppliers outside of I&M to compete.[146] As discussed in Section 3 of this Report, I&M's solar construction costs may be higher than that of outside companies in part due to its financing assumptions. Second, it is good practice to allow competition through RFPs to ensure the least cost resource is acquired. Third, allowing other suppliers to compete to build new solar would also create the potential for I&M's "practical" limit to be exceeded cost-effectively. Finally, most of I&M's portfolios did not include an extension of the Investment Tax Credit. All are factors that could unnecessarily result in a plan that does not leverage cheaper solar resources.

The limit on wind was 300 MW (nameplate) for a total of 1,400 MW. This "cap is based on the DOE's Wind Vision Report chart on page 12 of the report which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in 2020 to 2030 timeframe."[147] In the inputs for the one plan we were able to review (the Steady State Plan), the limit was set at only [redacted] MW annually for each of the two tranches of wind and [redacted] MW total, again for each tranche. But as we discussed in Section 3 of this Report, much of this wind is too expensive because it does not include the Production Tax Credit. Both the annual and maximum caps are likely to be overly limiting even once the cost is properly represented.

One of the spreadsheets[148] provided to us in support of I&M's wind assumptions included the following statement:

> The expected magnitude of wind resources available per year will be limited to 300 MW with a total Wind cap of 1,400 MW over the planning period. This is based on management's view for I&M to have 30% of the resources available be wind by 2040. I&M's Total Capability is 4,700 MW (ICAP) in 2040, assume that I&M targets 30% wind resources by 2040. That equates to a total of ~1,400MW of wind over the planning

[146] It should also be fuel neutral in recognition that costs and need can be different from those identified in the IRP.
[148] Wind Bundles spreadsheet provided on January 22, 2016.
[148] Wind Bundles spreadsheet provided on January 22, 2016.

period." So rather than the 2020 to 2030 timeframe, the limit is actually over the whole planning period (through 2045).

Finally, while I&M claims to rely on the DOE Wind Vision Report as the basis for the total limit on wind, it is not clear why renewable integration studies covering areas outside of PJM should have much of an influence when PJM has done its own integration study. PJM's 2014 Wind Integration Study found that:

- The cost of transmission upgrades necessary to support 30% renewables by 2026 across the entire PJM system would range from $5 to $13.7 billion.[149]
- "Although the values varied based on total penetration and the type of renewable generation added, on average, 36% of the delivered renewable energy displaced PJM coal fired generation, 39% displaced PJM gas fired generation, and the rest displaced PJM imports (or increased exports).
- No insurmountable operating issues were uncovered over the many simulated scenarios of system-wide hourly operation and this was supported by hundreds of hours of sub-hourly operation using actual PJM ramping capability.
- There was minimal curtailment of the renewable generation and this tended to result from localized congestion rather than broader system constraints.
- Every scenario examined resulted in lower PJM fuel and variable Operations and Maintenance (O&M) costs as well as lower average Locational Marginal Prices (LMPs). The lower LMPs, when combined with the reduced capacity factors, resulted in lower gross and net revenues for the conventional generation resources. No examination was made to see if this might result in some of the less viable generation advancing their retirement dates.
- Additional regulation was required to compensate for the increased variability introduced by the renewable generation. The 30% scenarios, which added over 100,000 MW of renewable capacity, required an annual average of only 1,000 to 1,500 MW of additional regulation compared to the roughly 1,200 MW of regulation modeled for load alone. No additional operating (spinning) reserves were required.
- In addition to the reduced capacity factors on the thermal generation, some of the higher penetration scenarios showed new patterns of usage. High penetrations of solar generation significantly reduced the net loads during the day and resulted in economic operation which required the peaking turbines to run for a few hours prior to sun up and after sun set rather than committing larger intermediate and base load generation to run throughout the day.
- The renewable generation increased the amount of cycling (start up, shut down and ramping) on the existing fleet of generators, which imply increased variable O&M costs on these units. These increased costs were small relative to the value of the fuel

[149] PJM Renewable Integration Study Executive Summary, page 18 available at http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx.

> displacement and did not significantly affect the overall economic impact of the renewable generation…"[150]

Of course, none of this would support the annual limit on wind resources either. As with solar, the annual limit on wind builds may prevent customers from accessing cost-effective wind resources before the wind production tax credit (PTC) begins to sunset.

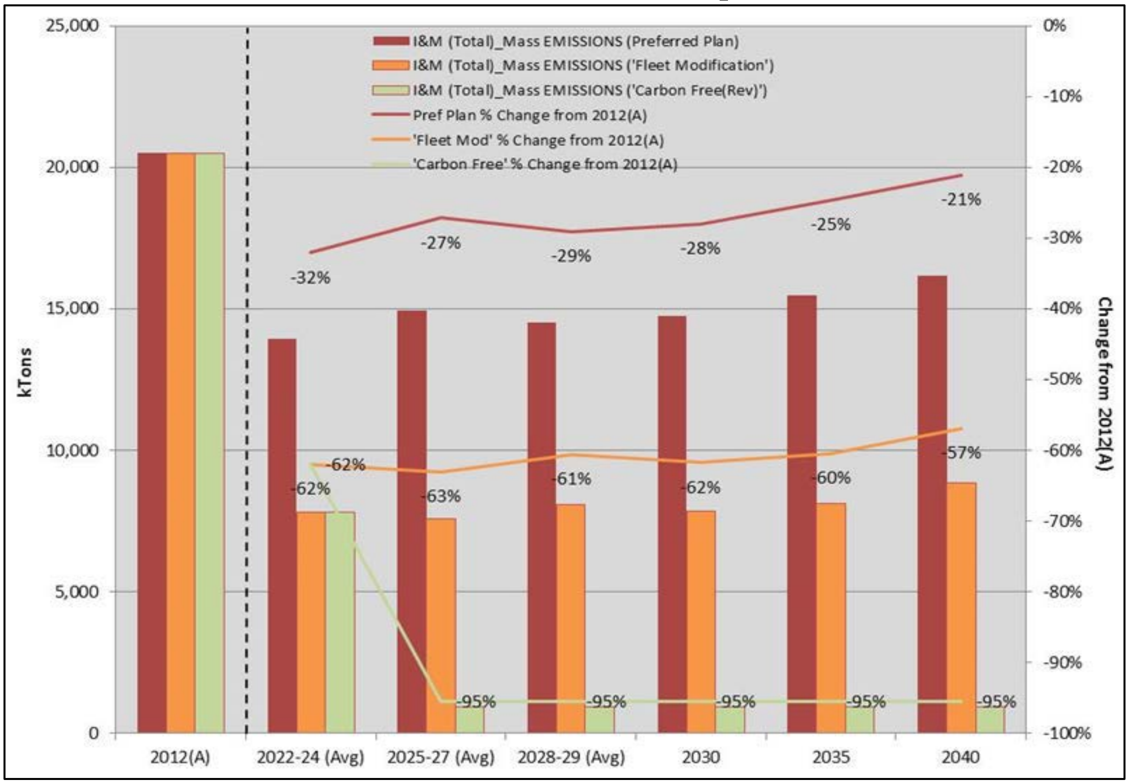
When reviewing the expansion plan results for any given portfolio, it is not clear to what extent these limits ended up being binding. During our conversations with I&M, they indicated to us that they often specified when resources should be built and in what quantity. Since those constraints would not be contained in the Steady State Plan inputs, it is impossible to critique those constraints with any specificity.

[150] PJM Renewable Integration Study Executive Summary, pages 7 – 8 available http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx.

IX. I&M's Modeling Does Not Reflect the Impact of the Clean Power Plan

I&M's modeling does not include any scenarios looking at the requirements of the Clean Power Plan (CPP), whether in draft or final form. It does believe that its preferred plan offers a significant drop in CO_2 emissions compared to 2012,[151] though.

Figure 5-9. I&M Projection of CO_2 Emissions for Preferred Plan, Fleet Modification, New Carbon Free Portfolios Compared to 2012 Emissions[152]



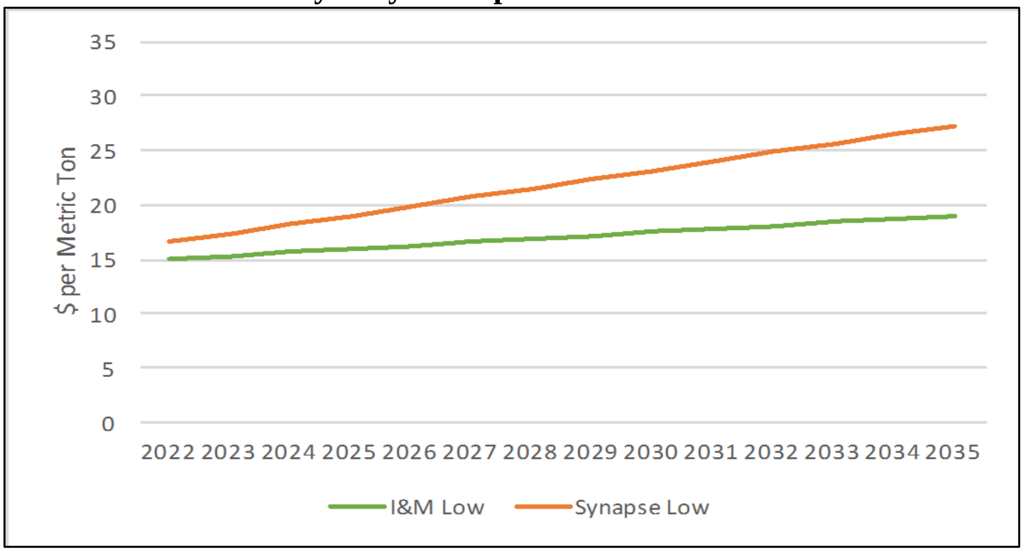
From 2022 to 2024, I&M believes that its Preferred Plan will offer an average reduction of 32 percent from 2012 emissions. I&M's projection of emissions only includes owned units, i.e. Rockport plus any fossil fuel based units that are added to its system. Emissions associated with the Clifty Creek and Kyger Creek units, from which I&M purchases power, are not included. Even without accounting for those units, emissions go up from there, which is not in line with the CPP requirements for declining emissions through 2030. I&M does model "high" and "low" carbon prices, but to the extent they would be a proxy for CPP requirements, both support the selection of the Fleet Modification portfolio, which is 0.6 to 1.7 percent cheaper, over I&M's preferred portfolio—without any modifications for the many biases toward the preferred plan discussed previously (revenues too high and too uncertain, renewables prices too high and too constrained, etc.).

[151] The CPP baseline year is also 2012.
[152] I&M 2015 IRP Figure 29.

In its just released 2016 CO_2 Price Forecast, Synapse Energy Economics' low case forecast, which is above I&M's low forecast, is described as:

> [A] scenario in which Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030. Low case prices are also representative of the incremental cost to produce electricity with natural gas as compared to coal, as indicated in the Energy Information Administration's 2015 Annual Energy Outlook.[153]

Figure 5-10. I&M Low CO_2 Price Forecast is Lower than Synapse's Estimate of Cost for "Relatively Easy" Compliance with the Clean Power Plan



The low nature of I&M's low CO_2 price forecast, which serves as its base assumption, combined with the many other factors described in this section, should make clear that the Fleet Modification plan, including early retirement of Rockport Unit 2, is obviously superior to I&M's Preferred Plan. If replacement capacity for Rockport Unit 2 is built more in line with native load requirements and with less emphasis on selling surplus power, this plan would also place even less market price risk on customers. This would make compliance with environmental regulations easier, and open to the door to leveraging low-cost renewable and energy efficiency resources.

[153] Available at: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast_0.pdf.

SECTION 6. MODELING BY DUKE IN SUPPORT OF ITS IRP

I. Introduction

Duke uses two models, System Optimizer (SO) and Planning and Risk (PaR), to conduct its resource planning. SO is a capacity expansion model, meaning that it can choose to build or retire units on a least cost basis subject to the constraints imposed by the modeler. These constraints could be anything from a requirement to meet the load and energy needs of customers to restrictions on when and how many units can be built or retired. Capacity expansion models like SO simulate dispatch of units in order to derive an estimate of operating costs in addition to capital costs. However, most capacity expansion models, including SO, do not simulate all 8760 hours of the year. Their results are simply scaled up to estimate annual totals (or whatever time-scale is being reported in the output, i.e., monthly, etc.). This is where PaR comes into play. It is a dispatch model, meaning that its only function is to simulate the dispatch of units. It can do so on an 8760 hour-basis, but the modeler must specify the units that will be dispatched. It cannot choose to build or retire units. In developing the PVRRs of each run, Duke combines a portion of the capital cost output from SO with the operating cost output from PaR.

Our review of Duke's modeling revealed the following:

1. While Duke recognizes that its Clean Power Plan (CPP) scenarios are not consistent with the final rule, the runs intended to test how portfolios fare under the draft version of the rule and model a requirement to reduce CO_2 emissions that is not binding.
2. The modeled heat rates of the Gallagher and Edwardsport units are too low.
3. Several units would not be profitable to operate under Duke's own assumptions including Gallagher Units 2 and 4 and Gibson Unit 5.
4. Duke forced in many resource choices within the portfolios it modeled, which heightens the possibility that there is likely a more cost-effective portfolio than that preferred by Duke.

II. Modeling the Clean Power Plan

During the time horizon when both I&M and Duke were conducting their IRP modeling, there was broad expectation that the Environmental Protection Agency (EPA) would finalize its Clean Power Plan (CPP) at the end of the Summer of 2016. CPP is EPA's rule regarding carbon dioxide (CO_2) emissions from existing thermal generators, primarily coal and natural gas combined cycle power plants.

Given this reality, we applaud Duke for at least making an attempt at modeling CPP requirements, and we welcome its plans "to perform updated modeling to better reflect the now-final CPP rule."[154] Of course, the more stringent CO_2 emissions constraints included in the final CPP rule essentially render these scenarios outdated.

Even so, we felt it was worth commenting on the modeling assumptions under this scenario in case a similar approach is taken with modeling the requirements of the final rule. Duke's runs mimicking CPP requirements were described by Duke's IRP modeling team as setting a cap on CO_2 emissions equal to a 20% reduction from 2012 emissions by 2020.[155] However, the cap being modeled does not seem to be binding. Confidential Figure 6-1 shows the cap imposed in System Optimizer compared to the annual emissions under each CPP (Scenario 3) plan.[156]

Confidential Figure 6-1. Modeled CPP Cap on CO_2 compared to CPP Scenarios in System Optimizer[157]

[redacted]

With the exception of the [redacted], [redacted], and [redacted] plans, the CPP scenario plans would emit at least [redacted] tons per year above the "cap" supposedly imposed in the modeling. Since so many plans exceed the cap, it is not clear what CO_2 reduction requirements are actually being simulated in these runs and whether they are really comparable to CPP requirements.

[154] The U.S. Supreme Court granted requests on February 9, 2016, to temporarily stay the Environmental Protection Agency's Clean Power Plan, while the court case is being litigated.
[155] Call with Duke on January 22, 2016.
[156] The run S3P7 is not shown here because it seemed to have a different (lower) CO_2 cap for unknown reasons.
[157] Taken from data in the spreadsheet "SO Summary Tool Indiana IRP 09-16-2015."

Duke told us that because PaR cannot simulate a system wide cap on emissions, the CO_2 cap had to be instituted indirectly by iterating a CO_2 price that would produce the correct level of emissions. Since PaR is the source of operating costs, we again compared the projected CO_2 emissions with each of the S3 portfolios and Duke's modeled "cap."

Confidential Figure 6-2. Modeled CPP Cap on CO_2 Compared to CPP Scenarios in Planning and Risk[158]

[redacted]

As with the SO modeling, the CPP portfolios generally exceed the cap by significant margins, which again leads to the question of what emission reduction requirements exactly are being modeled. It is definitely not clear.

[158] Taken from Confidential CAC 1.1 a.2 PROSYM output files.

III. Modeled Heat Rates for Edwardsport and Gallagher are Likely Too Low

While accurately modeling the requirements of environmental regulations is certainly a vital component of a good IRP, the assumptions regarding the units affected by these regulations are also critical. In that regard, we have some further concerns about Duke's modeling approach. Namely, some of its coal units are modeled at optimistically low heat rates, which in turn would cause CO_2 emissions to be understated with all else equal.

Confidential Figure 6-3. Gallagher and Edwardsport Heat Rates are Optimistically High[159]

[redacted]

The years 2013 and 2014 reflect actual heat rate data whereas 2015 – 2018 are based on Duke's modeling. Gallagher Unit 2's projected annual heat rate is the closest of the three to recent actuals. Gallagher Unit 4 is about [redacted] btu per kWh lower or about a [redacted] percent improvement. Edwardsport clearly stands out with a huge drop in heat rate from the 2014 actual data. Rather than the [redacted] Btu per kWh projected by PaR, Edwardsport had a heat rate in 2015 of about [redacted] Btu per kWh, which is about [redacted] percent higher. Part of the explanation for these heat rates undoubtedly has to do with higher than normal levels of generation projected by PaR. In general, as generation goes up, the efficiency of a power plant improves. However, in Edwardsport's case, these results also reflect an assumption that the plant will finally emerge from its history of frequent outages and technical problems. Indeed, Duke's preferred plan puts 2015 generation from Edwardsport at [redacted] GWh. Through November 2015, Edwardsport has

[159] Based on historical data provided by SNL (2013-2014) and EIA and projected data (2015-onward) provided in response to CAC 1.1.

produced just 2,766 GWh. Edwardsport has a long way to go before it produces power at the level and cost modeled by Duke.

IV. Duke Should Have Modeled Earlier Retirement of Unprofitable Units

At the same time that a better than actual heat rate probably results in lower than actual CO_2 emissions, it would also result in lower than actual costs per kWh generated. This is because as the heat rate declines, less fuel is necessary to produce the same number of kilowatt-hours. So it is telling indeed that even under Duke's assumptions several coal units will lose millions of dollars in the coming years.

PaR projects something called "net profit" for each unit in the model.[160] The net profit of thermal units is very informative since it is a projection of the revenue accruing to those units through dispatch into the wholesale market, in this case MISO, less the avoidable costs[161] of operating those units. The basic equation is:

[redacted]

Confidential Figure 6-4. Annual Net Profit by Unit, 2015 – 2019.[162]

[redacted]

[160] For a few resources, i.e., energy efficiency, annual net profit is not meaningful because it calculates net profit on the basis of whether energy efficiency's costs are recovered in the first year even though energy efficiency continues to provide energy savings and therefore "profit" for many years afterwards.
[161] Recall that avoidable operational costs include fixed O&M because, in the long-run, those costs can be avoided by shutting down a unit.
[162] From Duke's Preferred Plan run. There is no CO_2 cost embedded in these figures.

Confidential Figure 6-4 does not show all the units that produce negative net profit during this period, just those that produce particularly high levels of negative net profit. The Gibson units are of particular concern here. Gibson Units 1 – 5 would lose a total of $[redacted] million during this period with Gibson 3 losing the most ($[redacted] million), followed by Gibson 5 ($[redacted] million). During our conference call with Duke's IRP modeling team, we were told that the costs of complying with the coal ash rule and effluent limitation guidelines (ELG) were likely contained in the fixed O&M costs of existing units. If true, this might explain why fixed O&M varies so much from year to year and therefore why net profit also varies so much. However, as a general matter, a unit should be able to cover its going forward cost through MISO market revenue in order to be viewed as profitable. Thus, we would invite Duke in its Comments to the Draft Report to clarify what fixed O&M costs for the Gibson units are intended to represent, including whether and how expenditures to comply with environmental regulations are reflected in these numbers.

At the time that the 2013 IRP was filed, Duke characterized installation of a new flue-gas desulfurization (FGD) on Gibson Unit 5 as "cost prohibitive."[163] The 2015 analysis would suggest that this situation has not changed. As a net loser in the energy market, it would not make sense for Duke to invest tens, if not hundreds, of millions of dollars in Gibson Unit 5 in order to extend its operating life. In this IRP, Duke now seems to have changed course and assumed that an upgrade to the Gibson Unit 5 scrubber is not required. Its modeling inputs would not seem to reflect an increase in costs sufficient to cover such an upgrade, nor is the upgrade shown in the column "Notable, Near-Term Environmental Control Upgrades" in Table 8-K of the IRP. In its Comments on the Draft Report, we would also invite Duke to clarify the environmental compliance requirements that it believes would apply to Gibson Unit 5, the dates by which they would apply, and the incremental costs of meeting those requirements.

As Synapse Energy Economics discussed in its report on the 2013 IRP, the Gallagher units are not profitable to operate and should be retired as quickly as possible,[164] rather than waiting until 2019, particularly if additional investment will be necessary to keep them operating through 2019. If these units continue to operate through 2019, the present value of their losses is estimated at $[redacted] million. These losses are a continuation of the current reality for the Gallagher units. Over at least the past five years, Gallagher has typically lost millions of dollars each year.

[163] Synapse report on 2013 Duke IRP at page 7.
[164] Synapse report on 2013 Duke IRP at pages 4 – 7.

Figure 6-5. Gallagher 2 and 4 Net Profit, 2009 – 2014.[165] [166]

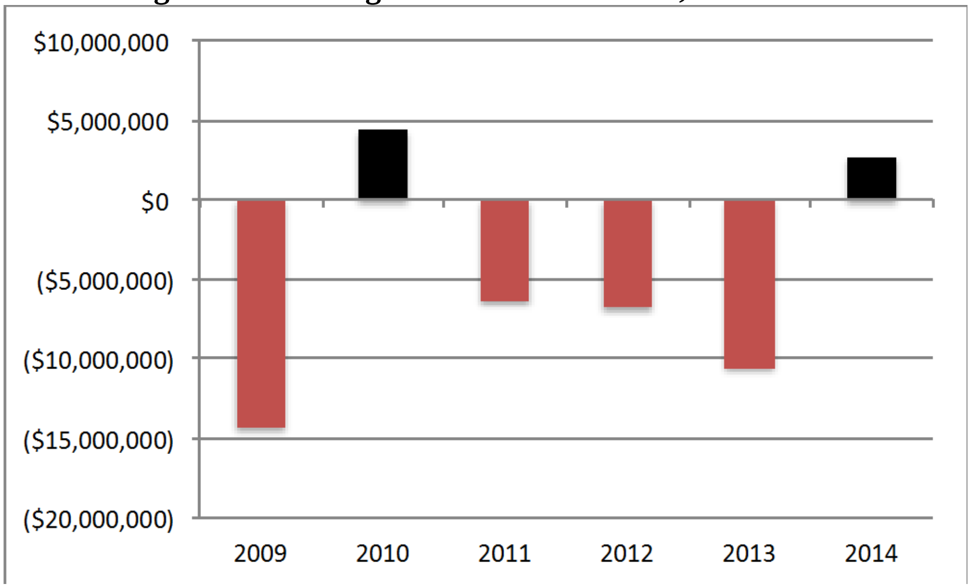


Figure 6-5 can be viewed as a more conservative analysis of profitability for Gallagher than Figure 6-4, above. While Figure 6-4 includes all fixed O&M, Figure 6-5 includes operational but not maintenance costs. This was done to account for the possibility that even if one was, for example, considering Gallagher's economics in 2011 for the coming year 2012, some maintenance costs could be considered sunk. Despite the current uneconomic status of Gallagher and Duke's own projections about the units' future profitability, it appears that Duke considered no scenarios in which the retirement of Gallagher was advanced to a date earlier than 2019.

Similarly, the retirement of Gibson Unit 5 also seems to have been hardcoded in every run to the extent it occurred during the planning period and no earlier than 2020.

165 Based on EIA Form 923, FERC Form 1, and MISO data. Does not include potential capacity revenue. If the units had received revenue in the three MISO capacity auctions held so far, total revenue would have been no more than $109,000 in PY13/14, $1.74 million in PY14/15 and $362,000 in PR15/16. The MISO Planning Year runs from June to May 31 of the following year.

166 For many marginal coal units in MISO, the very high prices associated with severe winter weather in 2014 turned around what would otherwise have been another year of net loss. Net positive profits in 2010 seem likely to be the result of higher power prices throughout that year and therefore more generation from the units.

V. Duke Likely Forced Many of the Resource Additions in Each Portfolio

We were surprised to see retirements seemingly forced in partly because at page 9 of the IRP, Duke claims that "The model optimizes retirement decisions and resource additions simultaneously." Also, Volume 2 of the IRP includes the following Q&A from Stakeholder Meeting #3:

> Gallagher 2 and 4 would retire in all cases. Why does Gibson 5 retirement move around to different timeframes in the various portfolios?
>
> - The cost of keeping the plant running becomes uneconomical faster in the CPP scenario, whereas in other options it won't happen until the cost of coal makes it uneconomical. The model makes these selections based on economics.[167]

These would seem to be unequivocal statements that SO selects the retirement dates, when in fact it does not.

Furthermore, there is other evidence of Duke forcing in resource choices. One of our informal discovery requests asked for a report showing any build constraints imposed on the modeling. This would be, for example, requirements that a minimum number of new units must be built or that capital expenditures could not exceed certain levels in any year, etc. Duke refused to provide this report and instead simply gave us the following table.

Table 6-1. Duke's Purported Build Constraints on its Modeling[168]

	Max Cumulative Units	Max Annual Units	Unit Capacity (MW)
BioMass DEI	20	2	25
Biomass Digester	10	1	10
BioMethPPA DEI	14	2	2
Coal DEI	30	10	361
Cogen CT	3	1	14.5
New CC 1 DEI	40	20	325
New CC Duct 1 DEI	40	20	48
New CC G DEI	40	20	393
New CC G Duct DEI	40	20	55
New CT 1 DEI	80	15	208
New CT LM DEI	80		43
New CT LMS DEI	80	4	100
Nuclear DEI 280	6	3	280
PPA CT 1 DEI	100	25	50
SolarPPA 2 DEI	60	20	10
SolarPPA 3 DEI	60	20	10
SolarPPA 4 DEI	50	20	10
SolarPPA DEI	30	20	10
Wind 1 DEI	6	2	50
Wind 2 DEI	100	4	50
WR 6 NG	1	1	318
DEI Battery	100	10	10

[167] Page 114 of Volume 2 of the 2015 IRP.
[168] DEI Response to CAC 1.2.

During the one phone call our experts were afforded with Duke's IRP team, we requested that a report exported from System Optimizer be provided since it was not clear how the numbers in this table squared with, for example, page 138 of the IRP. Page 138 of the IRP suggests that a number of portfolios, such as the "Stakeholder Inspired" portfolios, were created based on the desires of process participants, as opposed to optimization arrived at through modeling. Duke's IRP team said that build constraints were not used, but instead they used techniques such as inserting new resources as if they were existing. Depending on what that means in practice, this may be a distinction with no difference since the build constraints would seemingly have the same net effect. At any rate, if the response to CAC 1.2 is accurate, this implies that no minimum number of units were specified in any run and that the model could build up to the maximum number of units listed here as it saw fit.

Once the System Optimizer input files were delivered, we discovered many examples of Duke hardcoding in resources through minimum build constraints. For example, its preferred plan, S2P5, adds a 448 MW combined cycle plant in 2020. Duke set the constraint "[redacted]" for that resource to [redacted], meaning that System Optimizer had to add it to the portfolio. It was not possible for us to analyze the inputs of all 63 SO runs provided, so we can only assume that constraints placed on the modeling runs we reviewed would also be employed in other runs.

Even with these constraints in place, the alternative plan S2P3 or what Duke calls the "Proposed Clean Power Plan Portfolio" is cheaper than Duke's preferred plan by about [redacted] percent. Table 6-2 below shows the resources that constitute this plan.

Table 6-2. S2P3 Load, Capacity, and Reserves

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast																					
Duke System Peak	6,259	6,401	6,535	6,613	6,662	6,705	6,732	6,769	6,805	6,836	6,881	6,916	6,960	6,992	7,035	7,075	7,137	7,193	7,246	7,288	7,330
Cumulative DSM Capacity	641	708	752	803	845	885	915	923	949	967	987	1,005	1,015	1,020	1,029	1,037	1,046	1,054	1,062	1,071	1,078
Net System Peak	5,618	5,693	5,783	5,810	5,817	5,820	5,818	5,846	5,857	5,869	5,894	5,911	5,945	5,972	6,007	6,038	6,092	6,140	6,184	6,218	6,252
Cumulative System Capacity		-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generating Capacity	7,396	7,396	6,728	6,728	6,562	6,282	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966
Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Derates	0	0	0	0	0	-6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Retirements	0	-668	0	-166	-280	-310	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Generating Capacity	7,396	6,728	6,728	6,562	6,282	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966	5,966
Existing BTMG	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Cumulative Purchase Contracts	13	21	21	21	21	21	21	19	19	19	19	19	19	6	6	6	6	6	6	6	6
Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Future Resource Additions																					
Peaking/Intermediate	0	0	0	0	208	656	656	656	656	656	656	656	656	656	656	864	864	864	864	1,072	1,072
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	10	21	30	47	68	89	99	108	125	142	142	142	142	142	148	148
PPA & Cogen	0	0	0	0	115	29	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Cumulative Production Capacity	7,427	6,767	6,767	6,601	6,644	6,700	6,725	6,732	6,749	6,769	6,791	6,801	6,810	6,813	6,830	7,038	7,038	7,038	7,038	7,253	7,253
Reserves w/DSM																					
Equivalent Reserves	1,809	1,074	984	791	827	880	908	886	892	901	897	890	864	841	824	1,000	947	899	855	1,035	1,001
% Reserve Margin	32.2%	18.9%	17.0%	13.6%	14.2%	15.1%	15.6%	15.2%	15.2%	15.3%	15.2%	15.1%	14.5%	14.1%	13.7%	16.6%	15.5%	14.6%	13.8%	16.7%	16.0%
% Capacity Margin	24.4%	15.9%	14.5%	12.0%	12.4%	13.1%	13.5%	13.2%	13.2%	13.3%	13.2%	13.1%	12.7%	12.3%	12.1%	14.2%	13.5%	12.8%	12.1%	14.3%	13.8%

S2P3 is substantially similar to Duke's preferred plan (shown on page 159 of the IRP in Table 8-M) except that Gibson Unit 5 is retired earlier (in[redacted]), a [redacted] MW CT is added in [redacted], and renewables and PPA/cogen resources are added in somewhat greater quantities. Of course, because Gibson retires earlier in the S2P3 plan, one important way in which these two portfolios are different is in CO_2 emissions.

Confidential Figure 6-6. CO_2 Emissions from Duke's Preferred Plan (S2P5) vs. S2P3

[redacted]

The retirement of Gibson Unit 5 eliminates about [redacted] million tons of CO_2[169]; if a [redacted] replaces the 310 MW of Gibson Unit 5 capacity, then the plant for plant reduction is about half of that, or [redacted] million tons of CO_2. Clearly, this level of reduction will not satisfy CPP requirements; but given that it comes at essentially the same cost as the continued operation of Gibson Unit 5, it is hard to see why S2P3 would not be preferable to S2P5, particularly given the fact that both portfolios perform comparably under Duke's sensitivity analyses.

A very different portfolio of resources, S2P7 or the "Stakeholder Distributed Generation Portfolio," provides another expansion plan pathway with greater CO_2 reductions. Table 6-3, below, shows the resources that constitute this plan.

[169] S2P5_Solar2017 PaR outputs.

Table 6-3. S2P7 Load, Capacity, and Reserves

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecast																
Duke System Peak	6,259	6,401	6,535	6,613	6,662	6,705	6,732	6,769	6,805	6,836	6,881	6,916	6,960	6,992	7,035	7,075
Cumulative DSM Capacity	643	713	760	839	885	928	986	995	1,048	1,095	1,141	1,158	1,191	1,219	1,250	1,281
Net System Peak	5,617	5,689	5,775	5,774	5,777	5,777	5,746	5,775	5,757	5,741	5,740	5,758	5,769	5,773	5,785	5,794
Cumulative System Capacity		-	-	0	-	-	-	(0)	-	-	-	-	-	-	-	-
Generating Capacity	7,396	7,396	6,728	6,728	6,562	6,282	6,276	5,966	4,997	4,997	4,367	4,367	4,367	4,367	4,367	4,367
Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Derates	0	0	0	0	0	-6	0	0	0	0	0	0	0	0	0	0
Capacity Retirements	0	-668	0	-166	-280	0	-310	-969	0	-630	0	0	0	0	0	0
Cumulative Generating Capacity	7,396	6,728	6,728	6,562	6,282	6,276	5,966	4,997	4,997	4,367	4,367	4,367	4,367	4,367	4,367	4,367
Existing BTMG	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Cumulative Purchase Contracts	13	21	21	21	21	21	21	19	19	19	19	19	19	6	6	6
Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Future Resource Additions																
Peaking/Intermediate	0	0	0	0	0	0	40	966	1,006	1,244	1,284	1,304	1,324	1,344	1,354	1,374
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	134	229	310	394	495	535	618	700	759	787	790	818	827	903
PPA & Cogen	0	0	0	44	102	160	218	276	334	392	450	464	464	464	464	464
Cumulative Production Capacity	7,427	6,767	6,901	6,874	6,733	6,869	6,757	6,810	6,990	6,739	6,896	6,958	6,981	7,017	7,036	7,131
Reserves w/DSM																
Equivalent Reserves	1,810	1,079	1,125	1,100	955	1,091	1,011	1,035	1,233	998	1,156	1,200	1,212	1,243	1,251	1,337
% Reserve Margin	32.2%	19.0%	19.5%	19.0%	16.5%	18.9%	17.6%	17.9%	21.4%	17.4%	20.1%	20.8%	21.0%	21.5%	21.6%	23.1%
% Capacity Margin	24.4%	15.9%	16.3%	16.0%	14.2%	15.9%	15.0%	15.2%	17.6%	14.8%	16.8%	17.2%	17.4%	17.7%	17.8%	18.7%

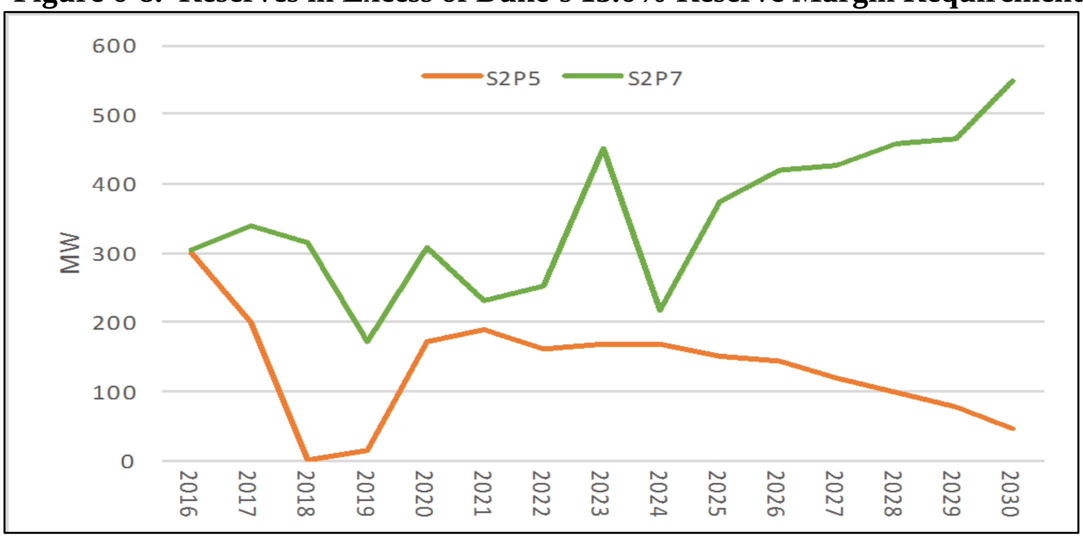
S2P7 includes not only the retirement of Gibson Unit 5 in [redacted], but the retirement of both Cayuga units in [redacted] and Gibson Unit 1 in [redacted]. It does rely on two new combined cycle units of [redacted] MW and a new CT ([redacted] MW) to help replace that capacity, but it also includes much larger quantities of renewables and cogeneration than the other portfolios. Notably, it also has higher levels of energy efficiency – "Cumulative DSM Capacity" is the sum of capacity provided by both demand response and energy efficiency. Not surprisingly, this portfolio has much lower projected CO_2 emissions.

Confidential Figure 6-7. CO_2 Emissions from Duke's Preferred Plan (S2P5) vs. S2P3 vs. S2P7

[redacted]

According to Duke's analysis, these reductions come at a significant premium compared to its preferred plan, costing $[redacted] or about [redacted] percent more than Duke's preferred plan. However, there are some significant flaws in Duke's modeling of this portfolio in that the costs of this alternative portfolio are greatly overstated. It is entirely possible that proper modeling of the portfolio would result in a cost that is much more similar, perhaps even at a lower cost than Duke's preferred plan, S2P5. First, S2P7 includes more resources than are necessary to meet reserve margin requirements.

Figure 6-8. Reserves in Excess of Duke's 13.6% Reserve Margin Requirement.



In virtually all years between 2016 and 2030, more than 200 MW of excess capacity is included in S2P7. This figure is based on Duke's modeled reserve margin of 13.6 percent and does not account for any of the issues that we identified with its load forecast or reserve margin requirement, as discussed in Section 4 of this Report. The modeling files that Duke provided cannot substantiate this level of capacity as the least cost, given the requirements of Scenario 2 and the unit retirements (which are forced in) because all of the renewable, natural gas, and energy efficiency resource additions are also forced in.

The present value of expenditures on renewables in S2P7 is approximately $[redacted], whereas it is $[redacted] in S2P5. As explained in Section 3 of this Report, the modeled cost of renewables is much too high. Even if accounting for the identified flaws in renewable costs reduced the present value of expenditures on renewables by just 20 percent, that would cause a $[redacted] reduction in the cost of the S2P7 portfolio.

Duke also forced S2P7 to take an eleventh bundle of energy efficiency (labeled "[redacted]") that does not seem to be discussed anywhere in the IRP. It is unclear what this bundle represents. It may be Duke's My Home Energy Report program, which sends reports to customers regarding their energy usage and shares tips to reduce said usage, although that would be a very high amount of savings for such a program. [redacted] In addition, the measure life of this bundle seems to be just [redacted] in length, which is [redacted] as the My Home Energy Report program. As modeled, this bundle is extremely expensive, costing $[redacted] in present value while the ten "base" and "incremental" bundles have a present value of $[redacted] Despite its much higher cost, it provides far fewer savings than the other ten bundles of efficiency.

Confidential Figure 6-9. Though Much Higher Cost, Duke's 11th EE Bundle, "[redacted]" Provides Much Fewer Savings than its Other Bundles.

[redacted]

Between overstated renewables costs and the forced addition of this eleventh bundle of energy efficiency, at least some $[redacted] of unnecessary costs are included in S2P7. This amount cannot be subtracted directly from the present value of the portfolio since removing the eleventh bundle of energy efficiency may change other costs in the plan. But, it also does not account for the fact that S2P7 is overbuilt as shown in Figure 6-8 above, nor does it account for the presence of additional, low cost energy efficiency as described in Section 2 of this Report nor the likelihood that Duke's load forecast and reserve margin requirements are overstated as described in Section 4 of this Report. These are all major flaws in Duke's analysis that undermine its selection of S2P5 as its preferred plan.