Report on Indiana Michigan Power Company 2018-19 Integrated Resource Plan

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Authors:
Anna Sommer, Energy Futures Group
Chelsea Hotaling, Energy Futures Group
Chris Neme, Energy Futures Group
Elizabeth A. Stanton, PhD, Applied Economics Clinic

On behalf of CAC, Carmel Green Initiative, Earthjustice, IndianaDG, Sierra Club, and Valley Watch

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Overview

The following comments on the 2018-2019 Integrated Resource Plan submitted by Indiana Michigan Power Company ("I&M" or the "Company") were prepared by Anna Sommer, Chelsea Hotaling, and Chris Neme of Energy Futures Group, and Elizabeth A. Stanton, PhD, of the Applied Economics Clinic. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Carmel Green Initiative, Earthjustice, Indiana Distributed Energy Alliance ("IndianaDG"), Sierra Club, and Valley Watch pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.

Our review of I&M's 2018-2019 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule.

Table 1 summarizes the Indiana IRP rule sections and provides the section in which our findings will be addressed in detail. Our review raised the following main categories of concerns with I&M's 2018-2019 IRP:

- Energy efficiency was so distorted by multiple, flawed assumptions that there can be no meaningful preferred demand side management ("DSM") plan derived from I&M's modeling (Sections 4.2, 5.1, and 5.2);
- Energy efficiency potential was unreasonably constrained even below the levels currently implemented by I&M (Sections 6.1 and 6.2);
- Significant build constraints were placed on renewables without reasonable support for those assumptions (Section 3.1);
- Wind costs were modeled at higher prices than I&M intended and higher than is justifiable (Section 3.1);
- Solar costs were modeled at higher prices than I&M intended and higher than is justifiable (Section 3.1);
- I&M used an unrealistically low capital cost for gas combined cycled units (Section 3.2);
- I&M explored very limited to no retirement options for its coal units (Section 3.4);
- Three 18 MW reciprocating internal combustion engine ("RICE") units were forced into the model as "Mini-grid" resources without any basis for this assumption and likely contributed to depressed selection of energy efficiency (Section 3.3);
- Scenarios and portfolios were conflated in ways that missed important areas for analysis (Sections 7.1 and 7.2); and
- I&M's stochastic analysis is fatally flawed and cannot be relied upon for risk assessment (Section 7.3).

Table 1. Summary of I&M's Compliance with Indiana IRP Requirements

IRP Rule Section	Description	Findings	Section
Integrated Resource Plan Submission	The IRP submission should include a non-technical appendix and an IRP summary that communicates core IRP concepts and results to a nontechnical audience.	**Partial**	**1**
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Partial**	**2**
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Not Met**	**3**
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Partial**	**4**
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Partial**	**5**
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Not Met**	**6**
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Partial**	**7**
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Partial**	**8**

1 Integrated Resource Plan Submission

Section 1 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-2 of the Indiana IRP Rule. Please see Table 2 below for our findings.

Table 2. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Findings
4-7-2 (c)	Utility must submit electronically to the director or through an electronic filing system if requested by the director or through an electronic filing system if requested by the director, the following documents: (1) The IRP	**Met**
4-7-2 (c)	(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts; (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models (in electronic format); (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file.	**Not Met**
4-7-2 (c)	(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director and (B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	**Partial**

We appreciate the steps that I&M took to help increase transparency in this IRP by providing us access to a read-only license for Plexos. Using the read-only license, we were able to access the Plexos model inputs and outputs along with the model manual which aided greatly in our review of I&M's modeling as well as our understanding of how Plexos works. I&M staff also held multiple meetings to help us become more familiar with the Plexos interface and readily answered questions about the model. While we received significant transparency from I&M, our experience does prompt some questions about how to ensure all parties get this same level of transparency. Because Plexos cannot export input files, there is not a good workaround to using a read-only license. I&M could have, as it did in its last IRP filing, include the so-called "2-pagers" in spreadsheet, rather than pdf, format in its IRP's Technical Appendix to help address that issue. However, there are many other additional input files we found on AEP's Plexos server that were important to shaping our understanding of I&M's IRP. Without those files, any other stakeholder would not be able to understand the full scope of the IRP. In addition, the model manual would be critical to have and it may be possible, if Energy Exemplar allowed it, to export the Plexos manual so that non-licensees under the proper nondisclosure agreement (NDA) can review it. We found the manual very helpful, not just in understanding the model settings and terminology, but also in understanding the model's logic.

To help make these comments as transparent and readable as possible, we have attached confidential screenshots of information in Plexos as part of an appendix to this report that only those who have a nondisclosure agreement with Plexos can view. This is not a long-term workable solution to full transparency because a) it is cumbersome to do this across a big dataset; b) there is no way for the parties to ensure that the screenshots are properly attributed to the correct modeling run without having access to Plexos themselves; and, c) it requires parties to sign a nondisclosure agreement with both I&M and Energy Exemplar. Nonetheless, we offer this information to the Commission to aid in their understanding of our comments.

2 Public Advisory Process

Section 2 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-2.6 of the Indiana IRP Rule. Please see Table 3 below for our findings.

Table 3. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Findings
4-7-2.6 (b)	The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	Mostly
4-7-2.6 (c)	The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) the interested parties; (2) the OUCC; (3) the commission staff.	Partial
4-7-2.6 (e)	The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process, (B) The utility's load forecast, (C) Evaluation of existing resources, (D) Evaluation of supply-side and demand-side resource alternatives, (E) Modeling methods, (F) Modeling inputs, (G) Treatment of risk and uncertainty, (H) Discussion seeking input on its candidate resource portfolios, (I) The utility's scenarios and sensitivities, (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	Partial
4-7-2.6 (e)	(2) The utility may hold additional meetings.	Met
4-7-2.6 (e)	(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	Met
4-7-2.6 (e)	(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting.	Met
4-7-2.6 (e)	(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	Met
4-7-2.6 (e)	(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC.	Met

In its IRP, I&M stated that its "goal throughout the process was to improve its resource planning process by conducting a meaningful, transparent and comprehensive stakeholder outreach effort to explore a wide-range of assumptions and resource options as I&M anticipates substantial changes in its resource mix over the IRP planning period."[1] CAC acknowledges the steps I&M has taken to make this IRP more transparent than past IRPs, especially allowing stakeholders to have access to a read-only version of Plexos. However, there is still room for improvement in its engagement with stakeholders and utilizing stakeholder feedback in the IRP.

[1] I&M 2018-2019 IRP, p. 3.

During I&M's third stakeholder meeting, it presented results from its modeling of our proposed decrement approach to evaluating energy efficiency.[2] The decrement approach tests increasing levels of savings at zero cost to derive an avoided cost estimate associated with each decrement level. While we appreciate that I&M took the time to engage us and CAC on this issue, the manner in which the decrements were modeled is entirely inconsistent with our proposal. First, the decrements were unrealistically constrained to 0.25% incremental savings in each of the residential and industrial classes and 0.5% in the commercial sector. This greatly understates the potential for savings on I&M's system and truncates the value of doing a decrement analysis. Second, the savings in each decrement were inappropriately "degraded" in the same way that I&M's bundles were (see Sections 4.2, 5.1, and 5.2 for an explanation of degradation and how I&M applied it). This renders the derived avoided costs meaningless for any purpose. As we have stated many times throughout Indiana IRP stakeholder meetings, it is incumbent on the utilities to engage stakeholders in a back and forth, iterative process that will ensure their suggested scenarios, sensitivities, and portfolios are modeled in the manner they intended. It does no one any good to perform runs that no party can stand behind. In fact, it does harm in the sense that meaningless data is contained in the IRP, and trust is lost in the IRP stakeholder process.

I&M invited stakeholders to submit questions that it would respond to throughout the stakeholder process. CAC and Sierra Club both submitted questions in January 2019 regarding the costs of solar and wind resources.[3] In response to the Sierra Club's request for I&M to correct the costs of solar and wind resources, I&M stated:

> *The Company believes the renewable estimates provided are reasonable for this IRP analysis and expects to update the values before the final report based on new information from BNEF; however, an initial review of the new BNEF data has not revealed any significant differences from the company's current estimates. Additionally, the Company is open to considering a stakeholder portfolio that includes discounts to the Company estimated renewables installed costs.*[4]

CAC and Sierra Club both recommended early on in the stakeholder process that I&M use the bid results from NIPSCO's 2018 request for proposal ("RFP") as the reference point for its solar and wind costs, but I&M resisted that suggestion. I&M stated:

> *The solar installed cost range from ~5% less or up to 15% higher, this is without knowing many key design considerations that impact this price; such as, expected*

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[2]Slide 58 from I&M's 3rd IRP Stakeholder Meeting held February 21, 2019. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/IM_IRPStakeholderPresentation3-02192019-R2.pdf

[3] 2018-2019 IRP Stakeholder Process, I&M Response to CAC Question 88 and Sierra Club Question 76. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/2019StakeholderCommentsandResponses7-23-19.pdf

[4] 2018-2019 IRP Stakeholder Process, I&M Response to Sierra Club Question 76. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/2019StakeholderCommentsandResponses7-23-19.pdf

> *capacity factor and DC to AC ratio, etc. For the wind resource our estimate is ~1% higher, again without knowing any key design characteristics of the NIPSCO resource.*
>
> *The major differences identified are between a 'PPA' resource cost and an owned resource cost. The Company's current assumption is to own generating resources.*[5]

I&M seems to be saying that ownership is more expensive than a power purchase agreement ("PPA"). If so, there is no justification for assuming all resources would be owned. That simply serves to inflate the costs of resources that I&M could actually contract for and does not provide the resources that would be least cost to customers. Even setting this issue aside, we could not reconcile I&M's description of the differences in wind and solar cost assumptions with the NIPSCO RFP bid information as we discuss in Section 3.1 of this report.

I&M announced at its last stakeholder workshop held on May 23, 2019 that it had modified its solar and wind costs. It provided updates on revisions to the wind and solar prices used for its modeling due to "slight price declines"[6] from the values previously included in its presentations. However, we could not reconcile the wind prices given in I&M's IRP with the prices that were actually input into Plexos as discussed in Section 3.1 of this report.

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[5] 2018-2019 I&M IRP Stakeholder Process, I&M Response to Sierra Club Question 76. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/2019StakeholderCommentsandResponses7-23-19.pdf

[6] Slide 9 from I&M's 4th IRP Stakeholder Meeting held on May 23, 2019. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/IM_IRPStakeholderPresentation4.pdf

3 Integrated Resource Plan Contents

Section 3 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-4 of the Indiana IRP Rule. Please see Table 4 below for our findings.

Table 4. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Findings
4-7-4 (1)	At least a twenty (20) year future period for predicted or forecasted analyses.	**Met**
4-7-4 (2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	**Met**
4-7-4 (3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	**Met**
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	**Met**
4-7-4 (5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed	**Met**
4-7-4 (6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	**Partial**
4-7-4 (7)	The resource screening analysis and resource summary table required by section 7 of this rule.	**Met**
4-7-4 (8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	**Not Met**
4-7-4 (9)	(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	**Partial**
4-7-4 (10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	**Met**
4-7-4 (11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions	**Not Met**
4-7-4 (12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	**Partial**
4-7-4 (13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	**Not Met**
4-7-4 (14)	The database in subdivision(13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility; (B) Load research developed in conjunction with another utility; (C) Load research developed by another utility and modified to meet the characteristics of that utility' (D) Engineering estimates; and (E) Load data developed by a non-utility source.	**Not Met**
4-7-4 (15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	**Partial**
4-7-4 (16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	**Partial**
4-7-4 (17)	A discussion of the designated contemporary issues, if required by section 2.7(e).	**N/A**
4-7-4 (18)	A discussion of distributed generation within the service territory and the potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting	**Partial**

4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	**Partial**
4-7-4 (20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development	**Met**
4-7-4 (21)	A discussion of how the utility's emission allowance inventory and procurement practices for air emission have been considered and influenced the IRP development.	**Not Met**
4-7-4 (22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	**Partial**
4-7-4 (23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	**Mostly**
4-7-4 (24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	**Partial**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	**Partial**
4-7-4 (26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	**Partial**
4-7-4 (27)	A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis; (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC); and (C) Reliability criteria for transmission planning as well as the assessment practice used.	**Not Met**
4-7-4 (28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use and (B)The utility's effort to develop and improve the methodology and inputs.	**Mostly**
4-7-4 (29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement; (B) The avoided transmission capacity cost; (C) The avoided distribution capacity cost; and (D) The avoided operating cost.	**Mostly**
4-7-4 (30)	A summary of the utility's most recent public advisory process, including: (A) Key issues discussed and (B) How the utility responded to the issues.	**Met**
4-7-4 (31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	**Partial**

3.1 Renewable Constraints and Cost

I&M placed annual and cumulative constraints on the amount of solar and wind that could be selected in Plexos. The limits on solar additions are described by I&M as follows:

> *A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources, a nonsensical result. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by I&M in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually.*
>
> *Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of I&M's load obligation or 1,700MW. 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).*[7]

I&M describes its limits on wind as follows:

> *The amount of wind resources available beginning in 2022 was limited to 300MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 2,100MW nameplate over the planning period. The annual limit on wind additions is based on I&M's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as I&M gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for I&M allows the model to select up to 30% of generation energy resources as wind-powered by 2038.*[8]

Neither the annual nor the overall limit on solar are justifiable. The annual limit of 300 MW is not based on any technical or operational limitation nor on any comparable experience of another utility. Indeed, the only rationale for it is that I&M believes it and it alone can build and operate solar facilities on behalf of its customers. But as NIPSCO demonstrated in its recent all-source RFP solicitation, when ownership is not a constraint on resource selection, many more MWs become available to the utility. NIPSCO received bids for 2,580 MW of solar and 1,220 MW of

[7] I&M 2018-2019 IRP, p. 104.
[8] *Id.*, 107.

solar + storage hybrid projects (Figure 1) in its 2018 IRP—far more than I&M is even allowing Plexos to select over the entirety of the planning period.

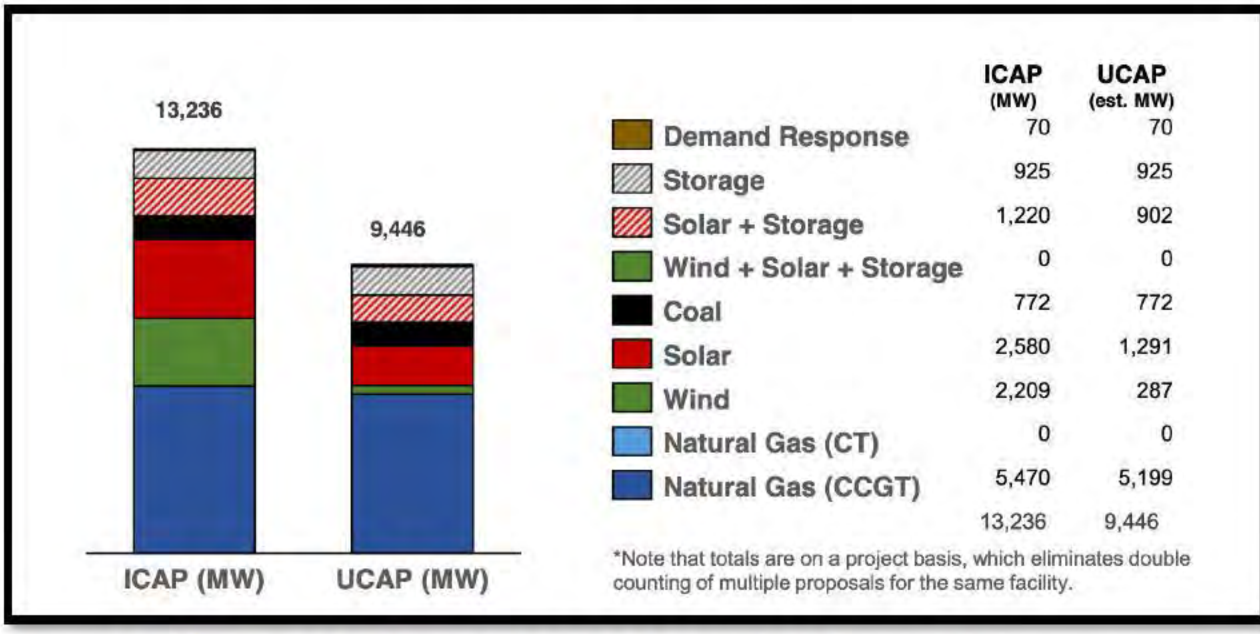

Figure 1. Bids Received in Response to NIPSCO's 2018 All-Source RFP[9]

Indeed, in addition to the cumulative limit of 1,700 MW of solar, I&M placed an annual limit on solar so that Plexos could not even select a full 300 MW of solar in each year of the planning period. Solar is first available in Plexos in 2022 and the last year of I&M's planning period in 2049, that is a 29-year period over which only 1,700 MW[10] of solar can be picked, i.e., an average of 59 MW per year. The limits are arbitrary and not reasonably supported by I&M.

Similarly, I&M's wind limits are unsubstantiated. The annual limit of 300 MW is well below what can be implemented without constraining ownership to I&M. For example, just one of NIPSCO's wind farms is 400 MW alone. And I&M's 2,100 MW[11] limit over the planning period is less than the 2,209 MW of wind NIPSCO received in response to its 2018 all-source RFP. Given the 29-year planning period, the 2,100 MW planning period limit amounts to an average of only 74 MW of wind per year. Nor is I&M's reliance on Department of Energy's Wind Vision Report appropriate for setting this limit. The intent of the report was to explore a scenario of 10% wind energy throughout the entire nation in 2020, 20% in 2030, and 35% in 2050. It is not a cap on the amount of wind nor would it be reasonable to think that the level of

[9] NIPSCO 2018 IRP, p. 55.
[10] Please see Figure A.1 in Confidential Attachment 1 for the total build constraint on solar resources in Plexos. I&M set up a constraint to limit the amount of Tier 1 and Tier 2 solar resources that can be added in the planning period to 34 units in order to set the 1,700 MW limit.
[11] Please see Figure A.2 in Confidential Attachment 1 for the total build constraint on Tier 1 and Tier 2 wind resources in Plexos. I&M set up a constraint to limit the amount of Tier 1 and Tier 2 wind resources that can be added in the planning period to 14 units in order to set the 2,100 MW limit.

wind would be the same for all utilities. In short, the constraints placed on wind in I&M's Plexos modeling are arbitrary and not reasonably supported.

The solar and wind limits are further divided between two tiers each. The solar tiers[12] were based on cost differences, while the wind tiers were distinguished by both cost and capacity factor differences.[13]

I&M describes one of the solar tiers as based on the Bloomberg New Energy Finance ("BNEF") utility price forecasts, while the other is 10% lower than the base BNEF forecast.[14] I&M chose to model two different costs "based on the concept that during an RFP process the 'Best Bids' would be approximately 10% less than the average bids."[15] While a well-run, all-source RFP would likely reveal price separation between bids, the problem with this logic goes back to the overall constraint on solar selection that I&M imposes. As demonstrated by the responses to NIPSCO's all-source 2018 RFP solicitation, it is very unlikely that I&M would receive only 150 MW worth of bids for the best in class solar resource and only 150 MW for the next best. Again, I&M's rationale for limiting solar to these tiers falls flat.

Confidential Table 5 shows the capital cost projections I&M assumed for both tiers of solar resources, along with the percentage changes in cost between each year of the forecast. The cost projections for both tiers decline until 2024 when there is then a significant jump – presumably because the safe harbor period for the higher level of the Investment Tax Credit ("ITC") has come to a close. It is unlikely to be a coincidence that 2024 is the only year during the period from 2022 – 2033 that Plexos does not add the maximum 150 MW of Tier 1 solar possible.[16] These solar additions would help defer or eliminate the gas combustion cycles ("CCs") that are built in 2028. The fact that Plexos is maximizing Tier 1 solar builds in all other years in this period would be yet another reason to relax the constraint on solar.

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[12] Solar costs are contained in the confidential I&M workbook 'Solar Bundles R10 redo', tab 'IM Solar Costs'. See also Slide 32 from I&M's 4th IRP Stakeholder Meeting held on May 23, 2019. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/IM_IRPStakeholderPresentation4.pdf

[13] I&M modeled two "tiers" or "tranches" of wind resources with tranche A having a capacity factor of 40.5% and tranche B having a capacity factor of 35%. Wind costs are contained in the confidential I&M workbook 'I&M_2018 Wind Build Costs R8', tab 'Wind Prices'.

[14] I&M 2018-2019 IRP, p. 104.

[15] *Id.*

[16] Based on "Copy of CASE 9_Base Band Pricing_ 2-Pager Summary_061019.xlsx" taken from AEP's Plexos server.

Confidential Table 5. I&M's Solar Cost Projections[17]

	I&M			
	Tier 1	Tier 2	Tier 1	Tier 2
Year	($/kW)	($/kW)	% Change	% Change
2019	[redacted]	[redacted]		
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]

During the I&M 2018-2019 IRP stakeholder process, CAC suggested that I&M use NIPSCO's all-source RFP bid information to characterize wind and solar. NIPSCO's average 2018 RFP bid for solar resources was 1,180 $/kW,[18] which is [redacted]% lower than I&M's Tier 2 solar resource and [redacted]% lower than I&M's Tier 1 resource. As we have stated previously, limiting each tier to just 150 MW at a price that is materially higher than NIPSCO's all-source 2018 RFP bid responses does not mimic what I&M would likely get in response to a well-run and well-written all-source solicitation. If I&M wanted to explore the impact of different solar capital costs, it would have been far more appropriate to run the higher solar cost as a sensitivity.

As with solar, I&M also modeled different capital costs for the two tiers of the wind resources modeled. Again, these costs do not make sense and are materially different than the cost

[17] Solar costs from confidential I&M workbook 'Solar Bundles R10 redo', tab 'IM Solar Costs'. Please see Figure A.3 and Figure A.4 in Confidential Attachment 1 for the solar build costs modeled in Plexos.
[18] NIPSCO's 2018 IRP, Figure 4-11 Summary of Proposals by Price, p. 56 (reported in 2018 dollars).

NIPSCO realized in its all-source 2018 RFP. In the IRP, I&M says the wind cost for the first tier, Tranche A, is $31.05 per MWh in 2022 including the Production Tax Credit ("PTC"), and the second tier, Tranche B, is $38.55 per MWh in 2022 including the PTC.[19] We were unable to reconcile this cost with the workpapers located on the AEP Plexos server or with the inputs modeled in Plexos.[20] Rather than $31.05 per MWh, the actual Tranche A modeled cost is based on a levelized cost of energy ("LCOE") of $[redacted] per MWh in 2022.[21] And the actual modeled cost of Tranche B is based on a LCOE of $[redacted] per MWh instead of $38.55 per MWh.[22] And the 2023 and 2024 prices of the Tranches increase at a rate many times inflation. None of these costs compares favorably to the average PPA price realized by NIPSCO of $27.64 per MWh.[23] I&M's Tranche A is about [redacted]% higher and Tranche B is about [redacted]% higher than NIPSCO's average PPA price. I&M only relaxed its constraints on renewable resources in two cases that we have access to, 12 and 12A, the so-called "High Renewables" cases. In these two cases, I&M allowed two times the level of renewable resources to be selected by the model on a cumulative and annual basis. Confidential Table 6 provides the annual and planning period total constraints I&M imposed on the wind and solar resources modeled for this IRP for the Preferred Plan and a High Renewables (Case 12A) case.

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[19] I&M 2018-2019 IRP, p. 115.
[20] Please see Figure A.5 and Figure A.6 in Confidential Attachment 1 for the wind tier build costs modeled in Plexos.
[21] From confidential I&M workbook 'I&M_2018 Wind Build Costs R8', tab 'Wind Prices' available on AEP's Plexos server.
[22] *Id.*
[23] NIPSCO's 2018 IRP, Figure 4-11 Summary of Proposals by Price, p. 56 (reported in 2018 dollars).

Confidential Table 6. Comparison of Constraints on New Resources for Preferred Plan and Case 12A (High Renewables)

	Preferred Plan		Case 12A (High Renewables)	
Resource	**Max Units Built in Year**[24]	**Max Units Built**	**Max Units Built in Year**[25]	**Max Units Built**[26]
Solar Tier 1 (50MW unit)	[redacted]	[redacted]	[redacted]	[redacted]
Solar Tier 2 (50MW unit)	[redacted]		[redacted]	
Wind Tier 1 (150MW unit)	[redacted]	[redacted]	[redacted]	[redacted]
Wind Tier 2 (150MW unit)	[redacted]		[redacted]	
M501 JAC (325MW unit)	[redacted]	[redacted]	[redacted]	[redacted]
GE 7F.05SC (110MW unit)	[redacted]	[redacted]	[redacted]	[redacted]

Table 7 shows the cumulative present worth of the base case, preferred plan, and the two high renewable plans modeled by I&M.

Table 7. Cumulative Present Worth Comparison

Portfolio	**Cumulative Present Worth ($000)**
Base (Case 1)	11,957,668
Preferred Plan (Case 9)	11,991,955
High Renewables and Peaking (Case 12)	11,484,729
High Renewables and Peaking + CC (Case 12A)	11,058,098

Both cases with higher levels of renewables, Case 12 and Case 12A, have a lower cumulative present worth than the base case and preferred plan selected by I&M. However, in its IRP, I&M stated:

> *While the High Renewable plan begins to show a favorable cost position after 2040, it is more costly to I&M customers over the 20 year IRP planning period and is based on assumptions that the Company considers to be impractical at this time.*[27]

[24] Please see Figure A.7 and Figure A.8 in Confidential Attachment 1 for the annual constraint on solar and wind resources for the Preferred Plan in Plexos. Please see Figure 9 and Figure 10 in Confidential Attachment 1 for the annual constraint on the combined cycle ("CC") and combustion turbine ("CT") resources in Plexos.
[25] Please see Figure A.11 and Figure A.12 in Confidential Attachment 1 for the annual build constraint on solar resources for Case 12A in Plexos.
[26] Please see Figure A.13 and A. 14 in Confidential Attachment 1 for the planning period total build constraint on solar and wind resources for Case 12A in Plexos.
[27] I&M 2018-2019 IRP, p. 133.

I&M argues that the so called High Renewables plan would have a larger rate impact in the near term in comparison to the other plans shown in Figure 2.

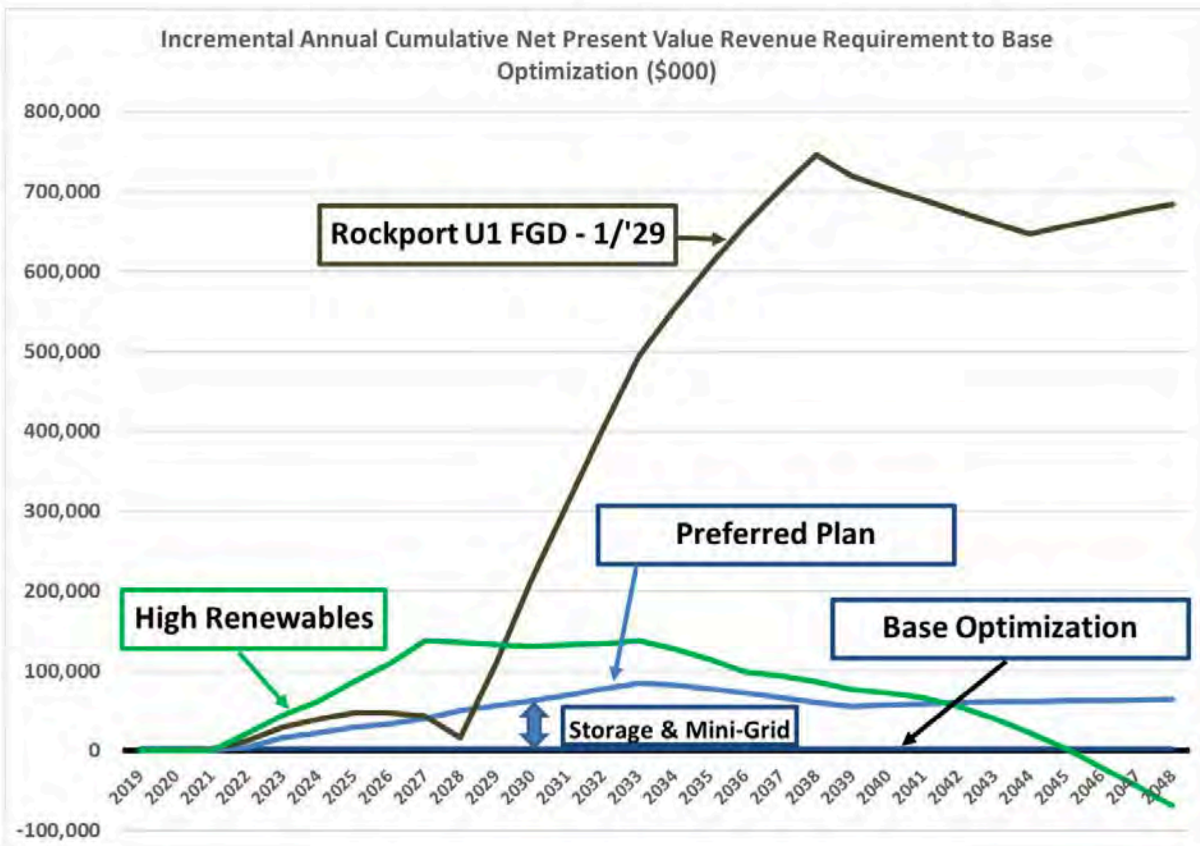


Figure 2. Incremental Annual Cumulative Net Present Value Revenue Requirement to Base Optimization[28]

But this differential in revenue requirements is likely to be distorted by I&M's incorrect modeling of wind and solar prices and the unreasonably low cost it assumed for gas combined cycle units ("CCs") as discussed in Section 3.2, below.

I&M further tested its constraints on renewables by running Cases 18 and 19.[29] I&M shielded those runs from review by stakeholders so virtually no information is given about those runs in the IRP or in I&M's fourth stakeholder presentation. And the Plexos files from those runs are missing from AEP's Plexos server. This is the only descriptive information I&M has given about those runs:

- *When large amounts of wind and solar are available they are selected, in this sensitivity 300GW of wind was selected in 2022, 50GW of solar was selected in 2023 and 50GW of tier 2 solar was selected in 2030*

[28] I&M IRP Stakeholder Presentation #4, Slide 19.
[29] I&M's 2018-2019 IRP, p. 150 and I&M IRP Stakeholder Presentation #4, Slide 25.

- *With the reserve margin constraint of 20%, only tier 1 wind was added, 46GW by 2028*[30]

Throughout the stakeholder process, we recommended to I&M that, rather than use restrictive, resource specific limits, it should instead limit the amount of total capacity that could be built using a global constraint such as "maximum reserve margin" so that the model can choose between the least cost options rather than I&M choosing which resource to discriminate against. We understand the first bullet point in the quote above to correspond to a scenario without such a global constraint, and we agree that these purported results appear to be unreasonable, but we have no way to verify this without reviewing the underlying modeling files. This is another example of I&M running a scenario that no party would stand behind. It violates the trust in the IRP stakeholder process and only serves to muddy the waters of the IRP.

The second bullet point of the quote above refers to a run that I&M performed that did employ a maximum reserve margin constraint. This run apparently added 4,600 MW of wind by 2028, approximately the same amount as I&M's peak load. Even if this were an unreasonable amount of wind to add to I&M's system by that date, it still would have been useful to see that run in order to see the cost impact of relaxing the resource specific constraints in favor of a global constraint (the cost must be lower because Plexos chose that level of wind rather than the level in, say, Case 9 – Preferred Plan) and the effect on the rest of I&M's portfolio. And we would need to review the Plexos files associated with this run to understand why Plexos tended to maximize solar additions in the first 12 years of the planning period in Case 9 (see Section 3.1), but chose wind in this run. Either way, there is substantial evidence that higher limits on wind and solar build constraints than what I&M imposed would have been a far more reasonable assumption, because it would have allowed the model to choose a still reasonable but likely lower cost portfolio.

3.2 Combined Cycle Capital Cost

I&M describes the modeled combined cycle resource as a "25% share of a NGCC (2x1 "J" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,600MW at summer conditions. The 25% interest assumes that I&M coordinates the addition of this resource with other parties."[31]

The constraints of the model allow [redacted] units of this resource to be built in any year during the planning period, starting in 2023. The firm capacity (what is counted toward the reserve margin requirement) is set to [redacted] MW. We were initially puzzled as to why Plexos would choose the CCs at all because they [redacted]. Their annual net profit[32] is [redacted] in [redacted] year of the planning period .[33] The general pattern we observed in I&M's Plexos files is that all gas

[30] I&M IRP Stakeholder Presentation #4, Slide 25.
[31] I&M 2018-2019 IRP, p. 115.
[32] In Plexos, net profit = net revenue – start & shutdown cost – fixed costs. Capacity revenue is not modeled, however, because I&M is a Fixed Resource Requirement utility and does not participate in PJM's capacity auctions.
[33] Please Figure A.16 in Confidential Attachment 1 for the net profit calculation in Plexos for the CC.

resources generate [redacted] net profit throughout their lives while the renewable resources start out [redacted] but eventually [redacted]. We realized that the key to selection of the CCs in Case 9 is very likely to be in the size assumed. Plexos is a market model, which means that it adds all profitable resources it can subject to constraints on that optimization, such as minimum reserve margin and maximum reserve margin. Where all resource choices are unprofitable, it will add the least amount of unprofitable capacity it can to meet the minimum reserve margin requirement. Two blocks of [redacted] MW CCs or [redacted] MW total are *exactly what is needed to reach the minimum reserve margin of 8.87%*.

However, I&M's ability to acquire this resource is predicated on an unrealistic assumption that it can hold a minority share in multiple combined cycle units, a total of 3,200 MW of capacity, coming online in exactly the year it needs them. We initially assumed that the size was a function of gas selected in resource plans from other AEP subsidiary utilities. However, as AEP's website shows, no other AEP utility intends to add gas capacity between 2028 and 2030.[34] The only AEP utility that plans to add gas before that time is Public Service Company of Oklahoma which is in an entirely different regional transmission organization ("RTO") than I&M.

If it had to build a smaller plant, we think it is likely that the cost of the plant would be significantly more. I&M's capital cost assumption is about $[redacted] per kW,[35] this figure is inclusive of allowance for funds used during construction ("AFUDC"), transmission interconnections, and pipeline costs. Combined cycle projects currently under development, construction, or recently completed in the U.S. for which data was available from S&P Global are shown in Table 8, below.

[34] See https://www.aepsustainability.com/energy/sustainable-electricity/planning/.
[35] Based on Confidential I&M workbook "2019 M 501 JAC CC Annualized Build Cost Calculation," tab "LFCR Method Generic CC Cost" Cost includes Allowance for Funds Used During Construction ("AFUDC").

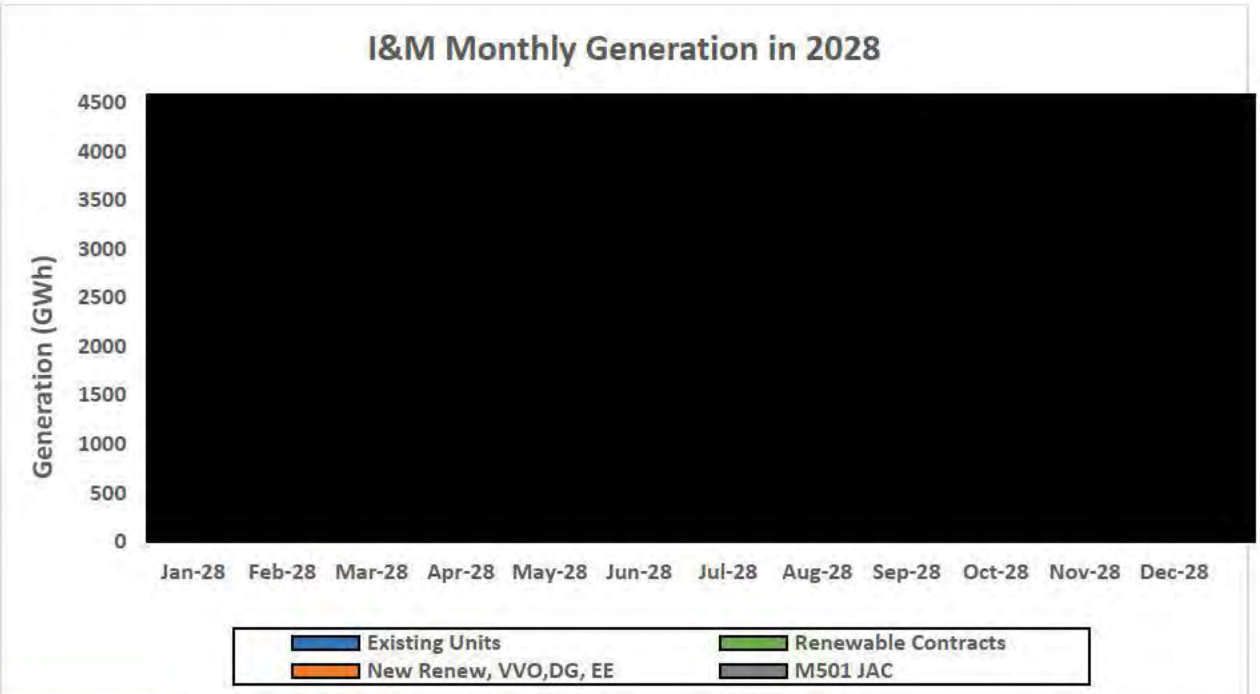
Table 8. Capital Costs of CC Projects Completed, Under Development and Construction in the U.S.

Project Name	New Capacity (MW)	State, Province, or Admin Region	Year in Service	Current Development Status	Estimated Construction Cost ($000)	Capital Cost ($ per kW)
Big Bend CC Project	1090	FL	2023	Construction Begun	853000	783
Birdsboro Combined Cycle Plant	488	PA	2019	Completed	600000	1230
Blue Water Energy Center (Belle River Combined Cycle Plant)	1146	MI	2022	Construction Begun	1000000	873
Cadiz Combined Cycle Plant (Harrison County Industrial Park)	1050	OH	2021	Early Development	900000	857
Clear River Energy Center (Burrillville Power Plant)	1080	RI	NA	Early Development	1000000	926
CPV Three Rivers Energy Center	1250	IL	2021	Early Development	1312500	1050
Danskammer Energy Center (Repowering)	636.4	NY	2023	Early Development	649128	1020
ESC Brooke County Power I	830	WV	2022	Advanced Development	884000	1065
Guernsey Power Station	1875	OH	2022	Advanced Development	1600000	853
Harrison County Project	578.9	WV	2022	Advanced Development	615000	1062
HenderSun Energy Center (Cash Creek)	790	KY	2021	Early Development	816900	1034
Indeck Niles Energy Center	1171.4	MI	2022	Advanced Development	1000000	854
Killingly Energy Center	647	CT	2022	Early Development	537000	830
La Paloma Energy Center	735	TX	2021	Advanced Development	650000	884
Lincoln Land Energy Center (Pawnee Natural Gas Plant)	1100	IL	2023	Early Development	1000000	909
Long Ridge Energy Generation Project (Hannibal CC Project)	485	OH	2021	Advanced Development	600000	1237
Mankato Power Plant	200	MN	2019	Completed	300000	1500
Moundsville Power Project	673	WV	2022	Advanced Development	700000	1040
Nemadji Trail Energy Center	625	WI	2024	Early Development	700000	1120
North Bergen Liberty Generating Project	1200	NJ	2022	Early Development	1500000	1250
R.D. Morrow Repower Project	550	MS	2023	Advanced Development	442000	804
Reidsville Energy Center	475	NC	2022	Advanced Development	500000	1053
South Field Energy	1132	OH	2021	Construction Begun	1300000	1148
Trumbull Energy Center	940	OH	2023	Advanced Development	900000	957
West Riverside Energy Center	732	WI	2020	Construction Begun	700000	956
Projects <700 MW						1053
Projects <700 and >1000 MW						981
Projects >1000 MW						956

Combined cycle projects under 700 MW in size currently under development, construction, or recently completed in the U.S. for which data was available from S&P Global, are shown to have a weighted average cost of $1053 per kW, [redacted]% higher than I&M's assumption. Projects between 700 and 1,000 MW in size have a weighted average cost of $981 per kW, [redacted]% higher than I&M's assumption. And projects greater than 1,000 MW in size have a weighted average cost of $956 per kW, [redacted]% higher than I&M's assumption.

It seems likely the overly optimistic CC cost, sizing I&M's share to [redacted] to meet the minimum reserve margin requirement, the limitations on solar and wind selection, the overestimation of solar and wind costs, and the contortions applied to the energy efficiency bundles have all have helped lead to what is a counterintuitive result: 3,200 MW of combined cycle capacity that would have to come online in 2028.

Indeed, from an energy perspective, I&M's system does not need new combined cycles in 2028. As Confidential Figure 3 shows, there is only one month in which the absence of the CCs might cause a deficit of on-system energy relative to load – the month of [redacted] And this is merely an artifact of the way in which maintenance outages were scheduled by I&M, the actual schedule of those outages may well be different in practice. We recognize that Plexos is not matching I&M's generation to load, again, because it is a market model. This is a question, however, of whether it is prudent for I&M to maintain such an energy surplus particularly when that energy comes at a [redacted] to customers.



Confidential Figure 3. Monthly Energy Generation and Load in 2028[36]

[36] Monthly energy generation for existing units and renewable contracts from Plexos solution file 'Model 2018-48 IM IRP Base 053119 Solution.' Monthly energy generation for new units and I&M's load from Plexos solution file for the Preferred Plan (Case 9).

3.3 Modeling of Fixed Resources

During I&M's final IRP stakeholder workshop held on May 23, 2019, I&M described its Preferred Plan as containing fixed resources including three 18 MW RICE units (in 2022, 2025, and 2028) and 50 MW of battery storage. I&M said that the three RICE units were stand-ins for a "Micro/Mini-grid." These resources are significant enough in size that they are likely to depress the selection of energy efficiency. Particularly in the near term, it is very important that the combination of constrained and unconstrained optimizations is presented so that stakeholders can evaluate the tradeoffs of resource choices in the same way I&M has likely done.

In Informal CAC Data Request 3.16,[37] I&M was asked to explain how it will own and operate the microgrids/mini-grids and how this would be distinguished from the RICE units serving as peaking resources. In response, I&M stated:

> *I&M intends to own and operate the micro grid resources. Each micro-grid will include uniquely configured generation resource(s) and distribution investments to allow the sectionalizing of the distribution system. In addition, the IRP micro grid generation resources are different in its proposed size in MWs than the traditional RICE plant the Company models. Although not modeled in the IRP, there may likely be different cost and performance characteristics based on the final location and design of each Mini-grid deployment (for example, location-specific, interconnection requirements).*

Further, RICE units in and of themselves do not make a micro-grid. If I&M actually plans to install these units, I&M needs to perform significant stakeholder engagement and undertake careful planning to ensure that these units provide cost-effective resiliency. Indeed, as I&M acknowledges, the cost and performance characteristics of an actual micro-grid will likely be different. Either way, these resources were not optimized nor justified on other grounds.

3.4 Retirement Scenarios

In the Director's Draft Report on NIPSCO's 2018 IRP, the Director stated at page 27,

> *Despite the reasonableness of the two-stage [retirement] analysis, both its rationale and the implementation, the Director would have liked to have seen a resource optimization with the timing of retirements and replacement options minimally constrained. We recognize that there are good reasons why the resulting portfolio might be unreasonable, but it still would have been a useful point of comparison.*

The same sentiment very clearly applies here. In no scenario were the retirements of both Rockport Units 1 and 2 optimized. And in no scenario could the model choose to exit from the Ohio Valley Electric Corporation ("OVEC") contracts for Clifty Creek and Kyger Creek coal units.

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[37] Included as Public Attachment 1.

3.5 Description of Optimization and Dispatch Models

Section 4-7-4 (19) of the IRP rule requires a description of the model structure and its applicability. In the IRP, I&M focuses its discussion of the Plexos model on its use of the long-term optimization model, which is known as "LT Plan."[38] While I&M focused on LT Plan, there is another feature within Plexos that I&M used for its modeling called "ST Schedule." I&M did not discuss in its IRP how it used ST Schedule, though it was material to the IRP. Our understanding is that I&M used ST Schedule to create a dummy unit for its existing thermal resources. The dummy unit is a representation of the collective shape of the existing thermal units and is fixed in LT Plan. This was characterized to us as necessary to allow LT Plan to perform simplified dispatch using load duration curves and therefore reach a result within a reasonable run time. We do not have a problem with this conceptually, but it does raise concerns about the accuracy of dispatch within LT Plan, particularly because I&M did not rerun any of the new resources through ST Schedule to allow comparison between the ST Schedule and LT Plan outputs.

[38] Indiana and Michigan Power 2018-2019 IRP, pp. 112-113.

4 Energy and Demand Forecasts

Section 4 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-5 of the Indiana IRP Rule. Please see Table 9 below for our findings.

Table 9. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-5

IRP Rule	IRP Rule Description	Findings
4-7-5 (a)	The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes; (B) Seasonal load shapes; (C) Monthly load shapes; (D) Selected weekly load shapes; and (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Met
4-7-5 (a)	(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	Met
4-7-5 (a)	(3) Actual and weather normalized energy and demand levels.	Met
4-7-5 (a)	(4) A discussion of methods and processes used to weather normalize.	Met
4-7-5 (a)	(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Met
4-7-5 (a)	(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system; (B) Customer classes, rate classes, or both; and (C) Firm wholesale power sales.	Partial
4-7-5 (a)	(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Not Met
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	Partial
4-7-5 (a)	(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Partial
4-7-5 (a)	(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	Met
4-7-5 (b)	To establish plausible risk boundaries, the utility shall provide In providing at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable peak demand and energy use forecasts.	Met
4-7-5 (c)	In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as (1) Rate of change in population; (2) Economic activity; (3) Fuel prices, including competition; (4) Price elasticity; (5) Penetration of new technology; (6) Demographic changes in population; (7) Customer usage; (8) Changes in technology; (9) Behavioral factors affecting customer consumption; (10) State and federal energy policies; and (11) State and federal environmental policies.	Mostly

4.1 Load Forecast and Energy Requirements

Due to slower growth of sales in some of the customer classes and the loss of certain wholesale customers, I&M's forecasted sales have a lower average growth rate than the historical. Figure 4 shows the comparison between historical and forecasted sales across each of I&M's customer classes. I&M is forecasting a drop in wholesale customers which results in a large dip in sales.

I&M also projects that Company wholesale customer sales will decrease from 4,509 GWh in 2019 to 3,586 GWh in 2020 and then 2,988 GWh in 2021.[39]

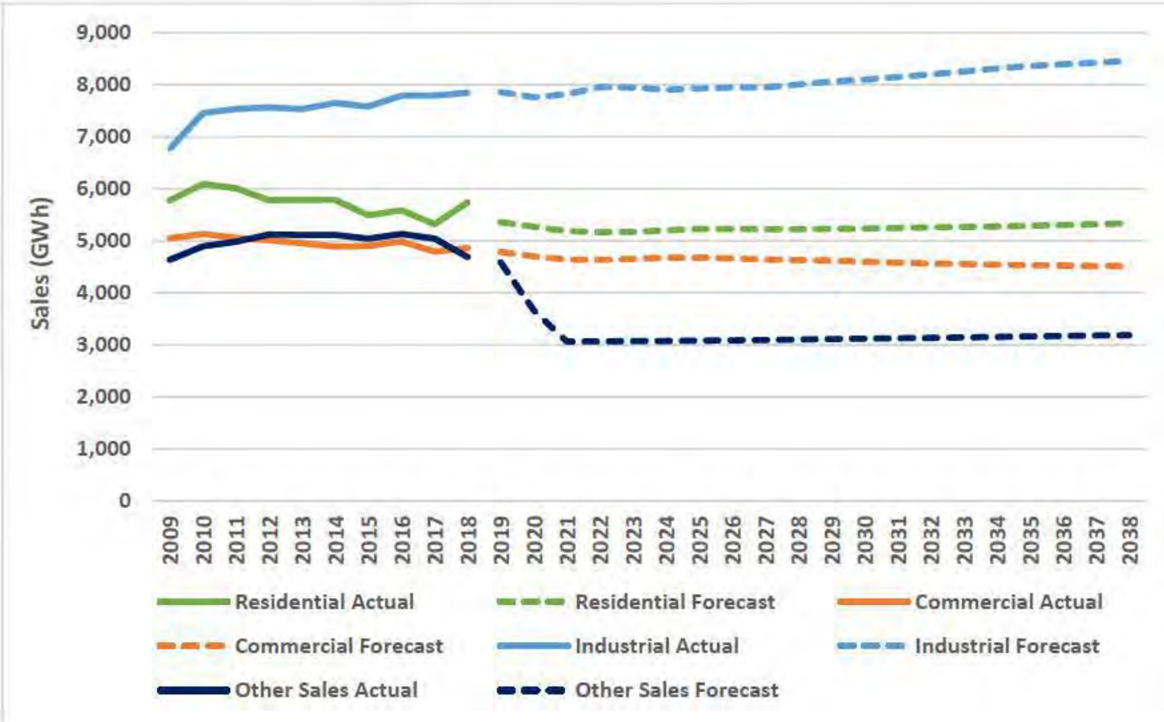

Figure 4. I&M Historical and Forecasted Sales by Customer Class[40]

Table 10, below, shows the comparison of average annual growth rates across each customer class and for total sales. The drop in wholesale customers, "Other Sales", results in a forecasted average annual growth rate of -0.77% compared to the historical average annual growth rate of 0.18%.

Table 10. Historical and Forecasted Average Annual Growth for Customer Class Sales

	Historical	Forecast
Residential	0.02%	-0.02%
Commercial	-0.40%	-0.31%
Industrial	1.70%	0.39%
Other Sales	0.18%	-0.77%
Total	0.56%	0.09%

Not surprisingly, this translates into a decline in projected energy requirements and peak demand. Figure 5, below, shows the historical and forecasted energy requirements with the average annual growth rate of each.

[39] I&M 2018-2019 IRP, Exhibit A-3.
[40] I&M 2018-2019 IRP, Exhibit A-1.

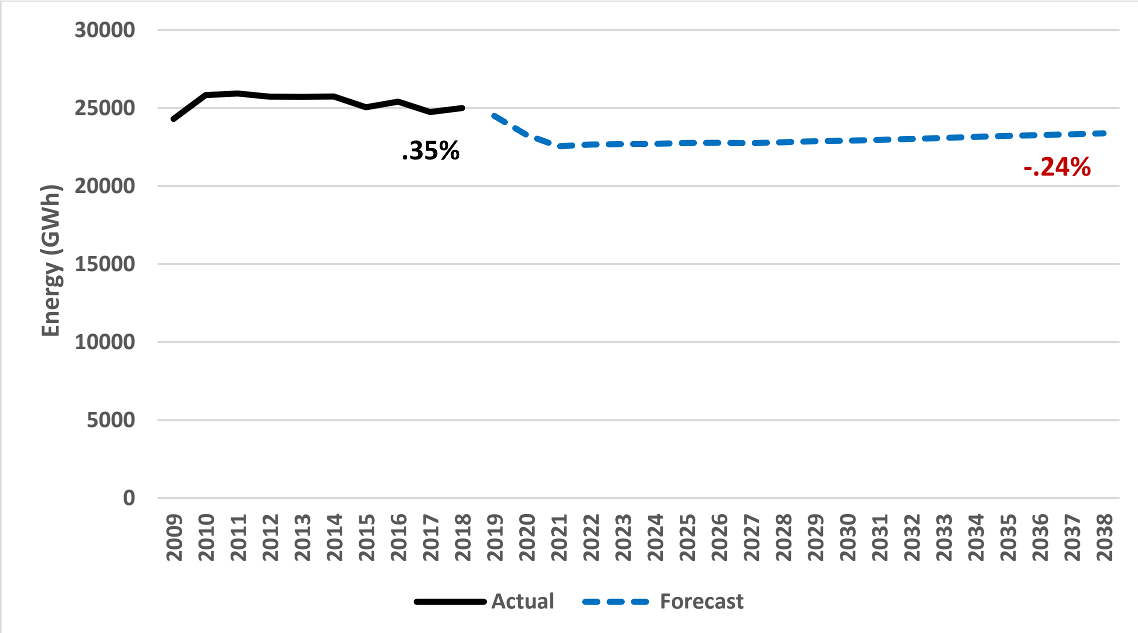

Figure 5. Comparison of Historical and Forecasted Energy Requirements[41]

Figure 6, below, shows the historical and forecasted peak demand. I&M's average annual growth rate declines from .38% to -.23%.

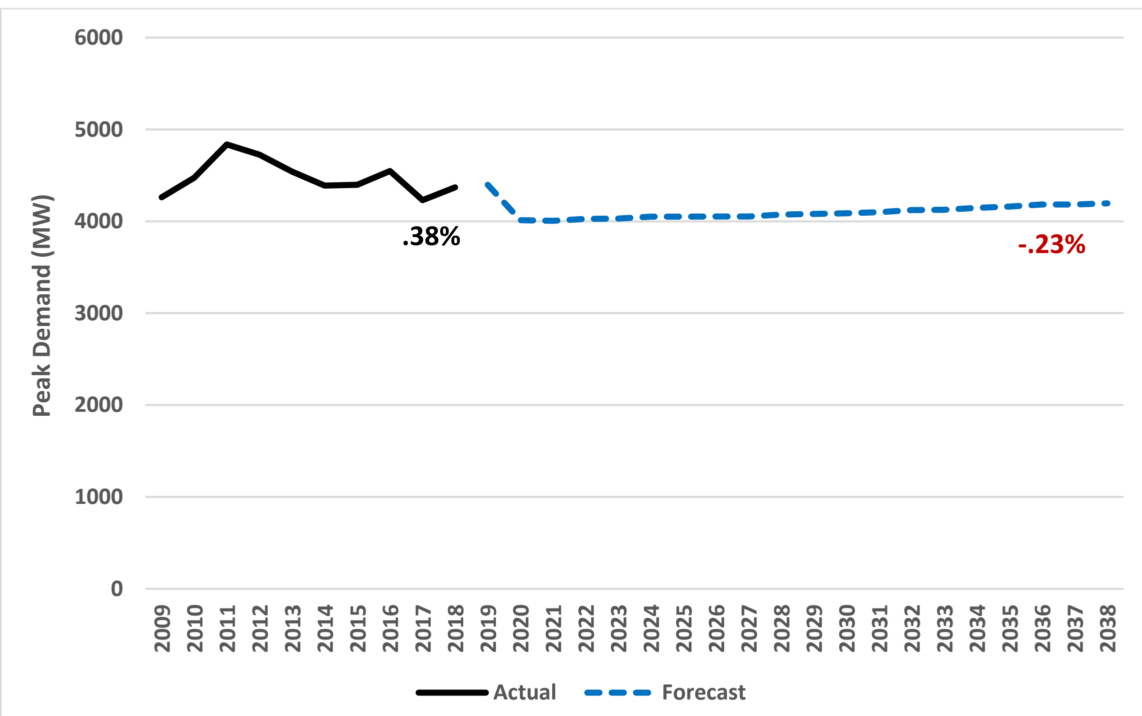

Figure 6. Comparison of Historical and Forecasted Peak Demand

[41] I&M 2018-2019 IRP, Exhibit A-4.

4.2 Degradation Factors in I&M's Load Forecast

I&M makes an out-of-model adjustment to its load forecast that it terms "degradation". This term and its methodology are non-standard. We are unaware of any other utility that uses Itron's statistically adjusted end-use ("SAE") load forecast methodology, e.g., Duke, Vectren, and NIPSCO, that then apply a "degradation" adjustment to their load forecast. The basic presumption behind I&M's use of degradation is that energy efficiency savings decline almost linearly to zero by the end of their measure lives and that measure lives are either 5, 10, or 15 years only. The rationale for this is convoluted but I&M has characterized degradation as adjustments to its load forecast to account for energy efficiency and as necessary to make the forecast more accurate following a period of over-forecasting load.[42] I&M also applies these adjustments to its energy efficiency bundles which we discuss later in Sections 5.1 and 5.2.

During its second IRP stakeholder workshop, I&M described the degradation methodology as it applies to the load forecast as follows:

- *Start with SAE load forecast before DSM adjustments. Set aside for later.*
- *Map the specific EE/DSM programs to class and end-use (i.e. Residential Light, Commercial Cooling) to match up with the respective load shapes.*
- *Assign a measurement [sic] life for each EE/DSM that will be used to the degradation matrix (10 year, 15, year, etc.)*
- *Shift the annual savings by ½ year to account for the fact that not all program savings reported in a specific year will be installed and functioning for the entire calendar year.*
- *Insert each year's annual EE/DSM program savings impact into Degradation Matrix and sum output by end-use.*
- *Subtract the cumulative degraded DSM impacts by end-use from the original SAE forecast.*[43]

We received the spreadsheet showing this methodology in response to CAC Data Request 2-2 in I&M's 2020-2022 DSM Case, Cause No. 45285. The spreadsheet regroups savings coming from I&M's DSM programs from the historic period 2008-2018 and forward looking savings through 2021 largely in the manner described above with a couple of exceptions. First, if the difference in so-called degraded savings is negative, i.e., fewer degraded savings exist in the current year than in the prior, then a zero is inserted instead of summing "output by end-use". Second, the spreadsheet does not show I&M subtracting "the cumulative degraded DSM impacts by end-use from the original SAE forecast." So we do not know exactly how the results were applied to the

[42] See for example, slides 14 - 16 from I&M's 2nd IRP Stakeholder Meeting held April 11, 2018.
[43] Slide 18 from I&M's 2nd IRP Stakeholder Meeting held April 11, 2018.

load forecast but can guess because there is a table of numbers in the spreadsheet entitled "Inputs to the Forecast in GWh", replicated here as Table 11.

Table 11. Degradation Inputs to I&M's Load Forecast

MATRIX METHOD	Incremental Change starting current real-time year and cumulating going forward Inputs to the Forecast in GWh										
Year	Residential Total	Residential Heat	Residential Cool	Residential Lighting	Residential Other	Commercial Total	Commercial Heat	Commercial Cool	Commercial Other	Industrial	Total
2008	1.14	0.14	0.09	0.90	0.01	-	-	-	-	-	1.14
2009	2.33	0.71	0.47	1.13	0.01	0.82	0.50	0.33	-	-	3.15
2010	7.75	0.93	0.61	5.30	0.90	2.23	0.72	0.48	1.02	1.02	11.00
2011	26.69	0.39	0.26	24.02	2.03	7.83	0.24	0.16	7.43	7.17	41.70
2012	32.69	4.14	2.73	23.32	2.51	21.04	1.24	0.82	18.98	15.35	69.09
2013	33.00	9.36	6.21	14.49	2.95	64.06	4.39	6.65	53.02	31.83	128.89
2014	33.05	13.73	9.11	7.53	2.67	68.87	7.60	12.63	48.64	26.59	128.51
2015	30.29	17.17	11.00	-	2.12	37.27	11.70	18.48	7.09	7.08	74.64
2016	31.24	18.07	11.61	-	1.56	32.01	12.93	19.09	-	5.50	68.75
2017	28.76	16.61	11.03	-	1.12	28.20	11.53	16.66	-	7.21	64.17
2018	27.18	13.50	9.00	3.69	1.00	24.52	9.78	14.75	-	10.96	62.66
2019	40.33	19.08	12.54	7.98	0.73	22.50	10.08	12.42	-	3.98	66.80
2020	47.42	25.01	16.37	6.04	-	25.41	12.08	13.34	-	-	72.83
2021	18.20	11.01	7.19	-	-	4.68	3.58	1.11	-	-	22.88

Because this matrix is characterized as being created after the production of I&M's load forecast, we would presume, but again do not know for sure, that the values in Table 11 after 2018 are added to the load forecast results and that the values prior to 2019 in Table 11 are not used. This would lead to a near-term overstating of I&M's load forecast because savings are not being reflected consistently with how they are actually realized on I&M's system. If the values from 2008 – 2018 are used to adjust historic sales, which are an input into the regression analysis that is the basis for I&M's load forecast, then the forecast would still be overstated, because only about 50% of actual savings are added back to the years 2008 – 2018. Either way, the adjustment is non-sensical.

To avoid under-forecasting sales, it would have been far more accurate to assume an average measure life by year and extrapolate savings forward for the length of that measure life, sum the result, and add it back into the historical sales. Then I&M could use the historical sales adjusted for EE savings to forecast load without future EE. It would, however, then have to make a post-estimation adjustment and subtract savings associated with 2008 – 2018 programs that persist past 2018 to ensure they are accounted for.

5 Description of Available Resources

Section 5 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule. Please see Table 12 below for our findings.

Table 12. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-6

IRP Rule	IRP Rule Description	Findings
4-7-6 (a)	In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	Met
4-7-6 (a)	(2) The expected changes to existing generating capacity, including the following: (A) Retirements; (B) Deratings; (C) Plant life extensions; (D) Repowering; and (E) Refurbishment.	Partial
4-7-6 (a)	(3) A fuel price forecast by generating unit.	Met
4-7-6 (a)	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge at each existing fossil fueled generating unit.	Met
4-7-6 (a)	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Partial
4-7-6 (a)	(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Partial
4-7-6 (b)	In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	Partial
4-7-6 (b)	(2) For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters; (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined; (C) The customer class or end-use, or both, affected by the demand-side resource; (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings; (E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements; (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Partial
4-7-6 (b)	(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered; (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost; (C) A description of significant environmental effects.	Mostly
4-7-6 (b)	(4) In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource; (B) A description of the timing, types of expansion, and alternative options considered; (C) The approximate cost of expected expansion and alteration of the transmission network; (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources; (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Not Met

5.1 Modeling of Energy Efficiency

5.1.1 I&M's Degradation Curves

CAC had several discussions with I&M in the I&M IRP stakeholder workshops and in individual meetings with I&M to try to understand what so-called "degradation" is intended to capture and why I&M would apply it to its energy efficiency ("EE") bundles. The most frequent explanation given by I&M is summed up in the meeting minutes from the third stakeholder workshop:

> *Much of it has to do with market. For example, consider lighting. When programs began, lighting was based on cfl [sic] bulbs. Now the market has caught up with that since some choices of lighting are already energy efficient. Therefore, the SAE model already has that market condition baked into it. We do not want to double count it. Over time, older inefficient appliances will be replaced. When a customer goes to a store, they cannot buy old inefficient appliances. They will buy new appliances with already improved energy efficiency, even if the customer buys appliances outside of our EE programs. That is the reason for the degradation.*[44]

In response to a stakeholder question from CAC, I&M also offered the following explanation:

> *There is no double counting of the degradation factors. The baseline projection from the market potential study does include some estimate for the impact of existing and approved changes to building codes and appliance standards but does not account for free ridership and spillover that result from I&M programs. The market potential study does, however, apply a net-to-gross ratio (similar in concept to the degradation factor) when translating from a measure-level to a program level. The IRP inputs are at the measure level which have not been adjusted for free riders and spillover. Therefore the measure level inputs from the MPS are degraded in the IRP modeling so that the output from the IRP can be consistent with the program level outputs, both at a net savings level.*[45]

The application of degradation to energy efficiency bundles is wholly inappropriate and serves to make EE potential look much smaller than it actually is in practice. Both of I&M's explanations above can be boiled down to pointing to naturally occurring EE as the reason for degradation. However, naturally occurring EE can occur for one of four reasons:

1. Customers with old, inefficient equipment replace such equipment over time, often (but not only) when it dies or becomes too expensive to maintain;

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[44] Meeting Minutes from I&M IRP Stakeholder Workshop #3, p. 5. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/IMStakeholderMtg3Notes3-8-2019.pdf

[45] I&M's Response to CAC Data Request 1.5(D) in the 2019 Stakeholder Questions Submitted to I&M, p. 43. Retrieved from https://indianamichiganpower.com/global/utilities/lib/docs/info/projects/IMIntegratedResourcePlan/2019StakeholderCommentsandResponses7-23-19.pdf

2. Customers replacing old equipment buy something more efficient than they might have had they replaced it a year or two earlier because of a new federal product efficiency standard;
3. Some customers who buy new equipment buy something more efficient than required by federal standards (if they did so and took an I&M EE program rebate, these would be free riders); and
4. Some customers who add something to their building – like insulation to an attic – would do so without an efficiency program (if they participate in an I&M EE program, they would also be free riders).

It is our understanding that all four of these forms of natural savings were already netted out of the market potential study ("MPS") estimate of savings potential. Indeed, Applied Energy Group's MPS for I&M states, "the energy efficiency potential estimates represent net savings"[46] and that "'Net' savings mean that the baseline forecast includes naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option."[47] Thus, because the EE bundles from which I&M allowed its IRP model to choose were largely based on the MPS, any application of degradation factors double-adjusts for naturally-occurring EE.

Moreover – and this addresses the first rationale offered by I&M for the degradation factors – when I&M estimates savings for an efficiency program rebating appliances, for example, it estimates them relative to the standard new, less-efficient appliance the customer would otherwise have purchased – *not* the old appliance the customer is replacing and *not* a new appliance with efficiency lower than the minimum federal standard. In other words, the first two forms of naturally occurring savings are always already accounted for when efficiency program savings are estimated.

That leaves the issue of free ridership. Again, we believe it is clear that the MPS estimates of savings potential are already net of free riders for several reasons. First, because AEG has said that they are and second because, in its 2020-2022 DSM filing, I&M adjusted the selected bundle savings in its preferred plan for a 91% net-to-gross factor,[48] which is a much smaller adjustment than impact of I&M's degradation factor would account for.

However, even if the bundles did not already account for free riders, the degradation factors would still be problematic for at least three reasons.

First, they assume that savings acquired from, for example, a rebate for an efficient water heater, decline almost linearly to zero over the life of that water heater. That is entirely inconsistent with how free ridership would affect savings for most EE programs. Most EE programs are designed to influence the decision of a customer already in the market to buy an electricity-consuming product (or a builder already deciding to build a new home or office building). If a customer participates in a program and takes a rebate for a new water heater, they are either a

[46] Excerpt from AEG MPS Indiana Report included as Public Attachment 2.
[47] *Id.*
[48] Direct Testimony of Jon Walter in Cause No. 45285, Attachment JCW-3.

free rider or they are not. Their savings either persist – unchanged – for the entirety of the water heater life, or they are zero for the entirety of the water heater life. To assume that they decline linearly over the water heater life provides a distorted view of savings over time. Mathematically, it implies that, for measures with a ten year life, about 10% of customers who were not free riders when they purchased the efficient water heater would have become a free rider in the second year, which implicitly assumes that 10% of customers who would have bought a standard water heater would have ripped it out and replaced it – at significant expense – just one year later; and another 10% would have replaced their water heaters after just two years of operation – again at great expense. And so on. That implicit characterization of how customers invest in efficiency is just not believable. Again, for efficiency programs promoting the purchase of efficient new equipment or efficient new construction, customers are either a free rider at the time of the equipment purchase or they are not. Thus, if adjustments to EE measure bundle savings was necessary to account for free ridership, I&M should make a one-time adjustment in the first year and that adjusted first year savings should persist for the life of the measures.

Second, because the degradation factors decline almost to zero, almost linearly, over the assumed life of the efficiency measure bundles, the impact on lifetime savings is roughly equivalent to about a 50% free rider rate (and no spillover) – much more than I&M's portfolio level, non-behavior 91% net-to-gross ratio.

Third, free ridership is (in large part) a function of program design and should vary considerably from one program type to another. It is probably 0% for low income customers, relatively low for many HVAC and appliance rebates and probably higher for residential lighting. But even for each of those program types, free ridership can be changed by changing the program design (e.g. the free ridership for a program offering a $50 rebate on a $500 measure would typically be higher than if the program offered a $400 rebate for the same $500 measure). However, the degradation factors used by I&M imply it is the same for every type of program. No matter what it is intended to account for, degradation applied to energy efficiency is hugely problematic.

5.1.2 Application of the Degradation Rate

I&M ignored the actual estimated useful lives of its energy efficiency bundles in Plexos (except for behavioral savings which have only a 1-year life) and instead assigned each EE bundle either a 10 or 15-year life. Confidential Table 13 below gives the actual measure life of each EE bundle, the degradation life applied to the bundle, and the difference between the applied degradation life and the actual life of the bundle. Although six of the bundles do not have a difference between the applied degradation life and the actual life of the EE bundle, nine do. Thus, for nine bundles, the savings are being degraded over a different life than their actual measure life and are moving savings through time in a way that is not consistent with how those savings are actually achieved. Confidential Table 13 shows the actual measure life of the bundles, the degradation measure life applied to the bundle, and the difference between the two.

Confidential Table 13. Measure life of Bundles Modeled by I&M

Bundle	Measure Life	Degradation Measure Life	Difference
R - HVAC Equipment - AP	[redacted]	[redacted]	[redacted]
R - Building Shell - AP	[redacted]	[redacted]	[redacted]
R - Appliances - AP	[redacted]	[redacted]	[redacted]
R - Water Heating - AP	[redacted]	[redacted]	[redacted]
R - Lighting - AP	[redacted]	[redacted]	[redacted]
R - Behavioral - AP	[redacted]	[redacted]	[redacted]
R - Miscellaneous - AP	[redacted]	[redacted]	[redacted]
C - VFD – AP	[redacted]	[redacted]	[redacted]
C - INDUSTRIAL MEASURES - AP	[redacted]	[redacted]	[redacted]
C - HVAC & REFRIGERATION - AP	[redacted]	[redacted]	[redacted]
C - COMMERCIAL OUTDOOR LIGHTING – AP	[redacted]	[redacted]	[redacted]
C - COMMERCIAL INDOOR LIGHTING – AP	[redacted]	[redacted]	[redacted]
C - BUILDING MANAGEMENT SYSTEM - AP	[redacted]	[redacted]	[redacted]
C - COM MISCELLANEOUS - AP	[redacted]	[redacted]	[redacted]
C - IND MISCELLANEOUS - AP	[redacted]	[redacted]	[redacted]

Confidential Table 14, below, shows the 10 and 15-year degradation curves I&M developed and applied to the energy efficiency bundles it modeled in Plexos. Since there is a difference in the actual measure life for some of the bundles and the degradation life applied by I&M, modeled savings are either spread out over a fewer or greater number of years than actual measure savings would occur.

Confidential Table 14. 10 and 15-Year Degradation Curves

Year	10-Year Degradation	15-Year Degradation
0	[redacted]	[redacted]
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]
9	[redacted]	[redacted]
10	[redacted]	[redacted]
11		[redacted]
12		[redacted]
13		[redacted]
14		[redacted]
15		[redacted]

I&M says that it adjusts for this by increasing the allowed number of "units built" so that the total degraded GWh are roughly the same regardless of when the bundle comes online. But this flawed rationale assumes EE savings can simply be moved in time as necessary. This is completely at odds with how the yearly impact of those EE measure savings would actually manifest, assuming that degradation is even appropriate to begin with.

5.2 Illustration of How EE Bundles Are Modeled by I&M

The problem with condensing and expanding savings through time in a way that is not consistent with reality is compounded by the manner in which Plexos interprets the shape of the savings in each bundle. One might expect that if a 1 GWh bundle with a 10-year degradation life were selected in Year 0 and again in Year 1 that the degraded shape of that bundle would merely shift downward so that the Year 1 bundle also starts out at 1 GWh. This is not the case, instead it begins at [redacted] GWh and ends at 0 GWh in the exact same year that the Year 0 bundle ends. In other words, 1 GWh in Year 0 is not equal to 1 GWh in Year 1, solely because Plexos cannot even model the degradation factor as I&M intended to apply it. I&M told us that it attempted to adjust for this problem by making sure the total savings over the now truncated measure life are roughly equal to the total of the Year 0 savings even if those savings occur in a now shorter number of years. I&M's adjustment does not actually do this, however, and further understates energy efficiency potential. For example, as shown in Confidential Table 15 below, the total number of available "1 GWh" achievable potential ("AP") bundles for industrial measures increases in order to make approximately the same savings available to the model in year 2021 as in year 2020, etc. through 2024, though not because the potential is actually increasing.

Confidential Table 15. Bundle Inputs for 'I&M_C_AP_Ind_25'

Year	Bundles
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]

Compare Confidential Tables 16 and 17, below. Confidential Table 16 shows the cumulative savings from this bundle with the degradation curve applied, but shifted downward every year so that each bundle started at 1 GWh of savings and not something less than that. Confidential Table 17 shows how those savings are actually modeled in Plexos. While the near term differences are relatively small, over the life of the bundles, I&M's methodology results in 25% fewer savings actually modeled.

Confidential Table 16. Industrial Measure Savings Available to Plexos If Bundle Shape Shifted with Each Bundle Picked (GWh)

	2020	2021	2022	2023	2024	Total
2020	[redacted]					[redacted]
2021	[redacted]	[redacted]				[redacted]
2022	[redacted]	[redacted]	[redacted]			[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total						[redacted]

Confidential Table 17. "Industrial Measures" AP Bundle as Actually Modeled in Plexos (GWh)[49]

	2020	2021	2022	2023	2024	Total
2020	[redacted]					[redacted]
2021	[redacted]	[redacted]				[redacted]
2022	[redacted]	[redacted]	[redacted]			[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030						
2031						
2032						
2033						
Total						[redacted]

[49] From Plexos generation output for 'I&M_C_AP_Ind_25' energy efficiency bundle.

6 Selection of Resources

Section 6 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule. Please see Table 18 below for our findings.

Table 18. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Findings
4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	**Not Met**

A market potential study by Applied Energy Group is the purported basis for the energy efficiency bundles modeled by I&M. However, there are inconsistencies between the MPS and the IRP bundles and major issues with the MPS itself that lead to inappropriate over-screening of energy efficiency.

6.1 I&M Does Not Model Residential Lighting until 2030

While residential lighting is a measure with significant savings in contemporary MPSs performed on behalf of Vectren[50] and Indianapolis Power and Light,[51] it was not included as a bundle for potential selection until 2030 in I&M's modeling. I&M's MPS does show significant cumulative savings from residential lighting, as shown in Figure 7, below, but the MPS only reports cumulative savings by end-use from 2017 onwards, not incremental savings. So it is impossible to accurately separate the incremental potential for lighting savings from the savings from prior measure installations that may or may not be rolling off.

[50] Vectren Energy Delivery's 2020-2025 Market Potential Study by GDS Associates, Inc. Please see Cumulative Annual MWh in Table 4-5 on p. 27.

[51] Indianapolis Power & Light's 2021-2039 Market Potential Study by GDS Associates, Inc. Please see Cumulative Annual MWh in Table 5-5 on p. 37.

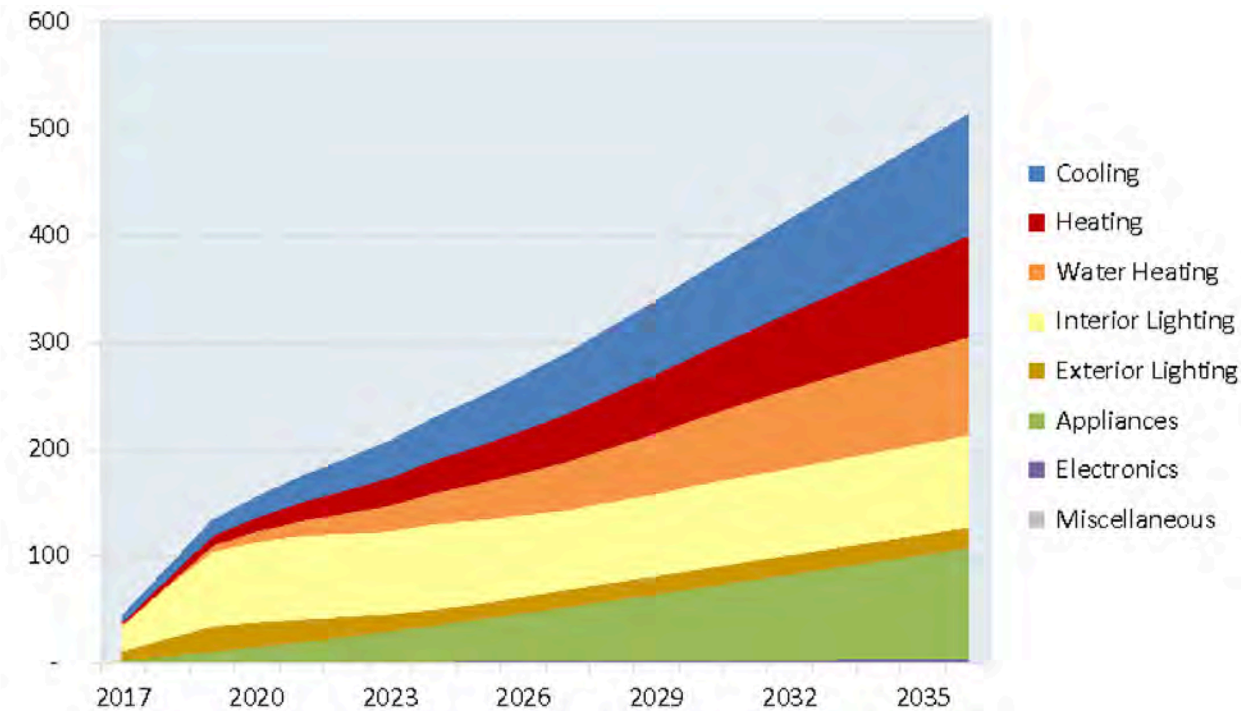

Figure 7. I&M Residential "Realistic Achievable" Cumulative Savings from AEG MPS (GWh)

Nevertheless, this figure from I&M's AEG MPS certainly does not support an assumption of zero incremental residential lighting savings through 2030. Indeed, I&M does not even believe that is a reasonable assumption in the near term since I&M Witness Jon Walter testified in his direct testimony filed in Cause No. 45285 that I&M's upcoming three-year DSM plan includes a program with a residential lighting component.[52]

6.2 IRP Modeled and MPS Savings Are Lower than Recent I&M Goals

Initially, I&M planned to base its EE bundles only on the Top 20 measures in terms of cumulative annual savings in the MPS. After input from stakeholders, "potential was added from measures outside of the top 20 measures into a 'miscellaneous' bundle for each sector."[53] Yet, incremental savings either in the MPS – which are theoretically supposed to be based on maximum achievable cost-effective savings - do not even reach the modest levels in I&M's historic combined goals across Indiana and Michigan service territories as shown in Figure 8 below.

[52] Cause No. 45285, Direct Testimony of Jon Walter, Attachment JCW-4.
[53] I&M 2018-2019 IRP, p. 87.

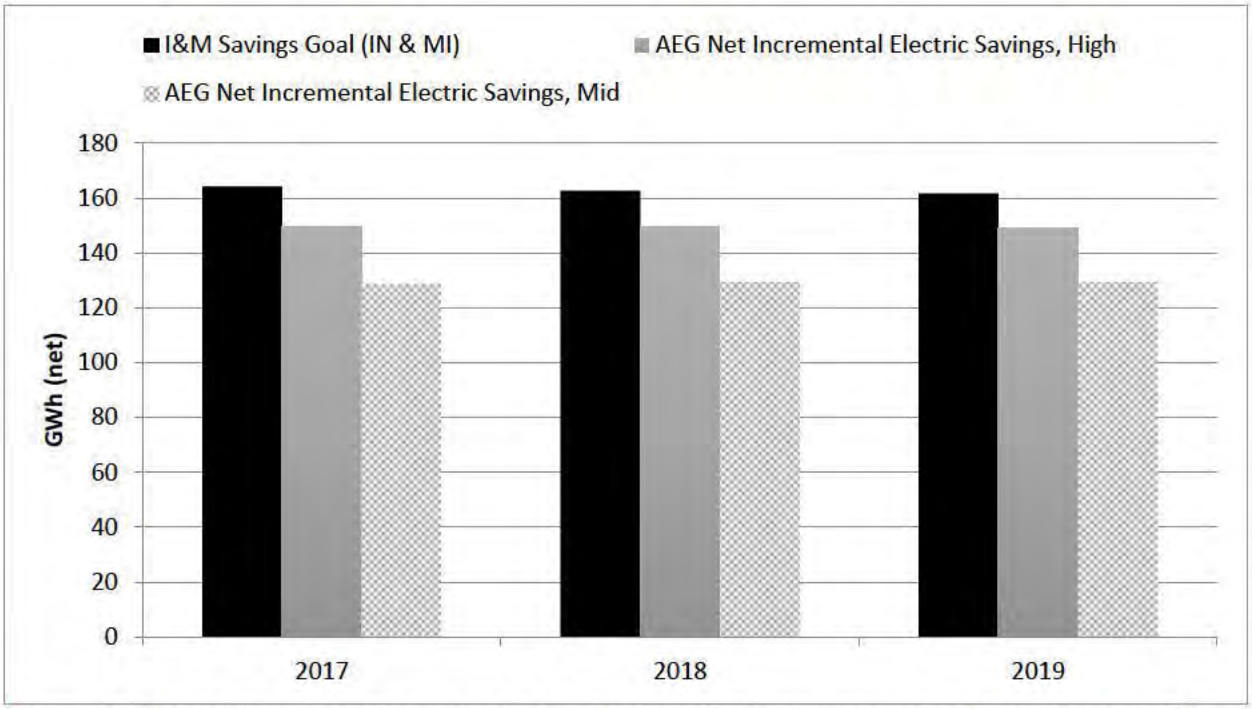

Figure 8. I&M Historic Savings Goals Are Materially Higher than Net Potential in MPS

The black bars show I&M's combined savings goals across its two-state territory and are significantly higher than I&M's AEG MPS savings.

The IRP bundle savings also do not match up with I&M's most recent goals as show in Figure 9. Note that the 2020 goals are based on this IRP and are a function of the very low potential modeled in I&M's bundles as well as the elevated cost of those bundles.

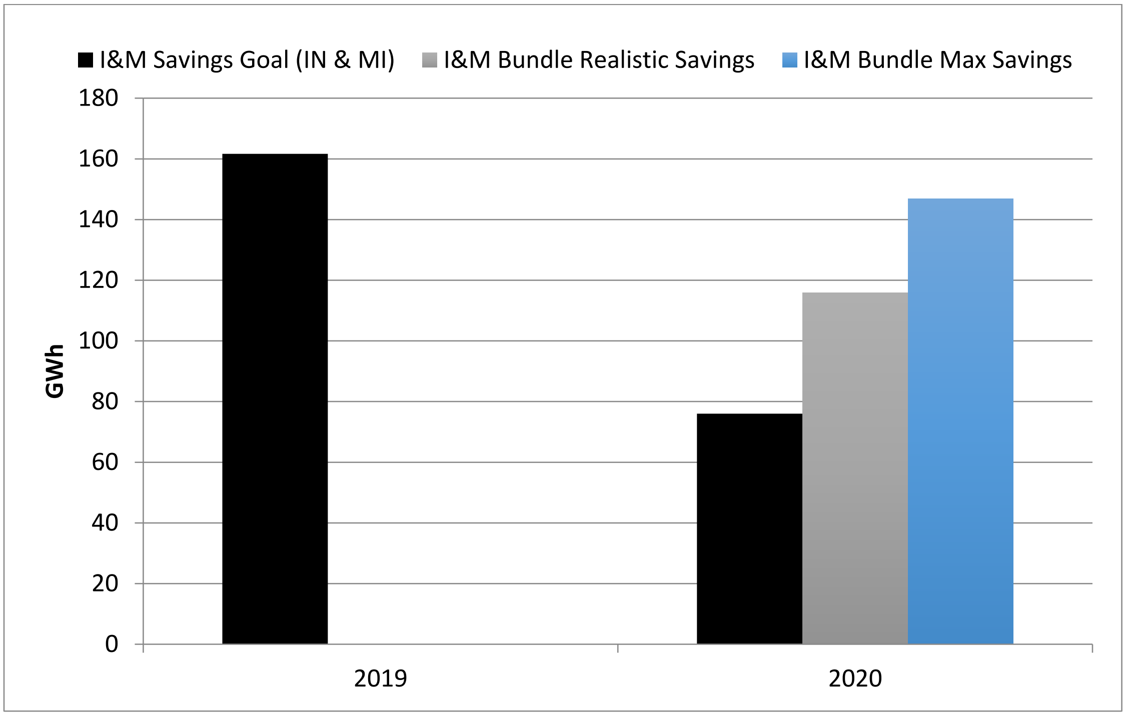

Figure 9. IRP Cannot Result in Level of Savings Equal to I&M's Current Goals

The cost of the IRP bundles may be different than the MPS costs - we are not clear on that point because savings are grouped in the bundles differently than they are in the MPS. But whatever the source of the bundle costs, they are dramatically higher than I&M's two-state EE budget for 2019 (Figure 10 below) which is forecasted to achieve much higher savings as shown in Figure 9 above. In other words, I&M's customers are getting more savings for less money in 2019 than what I&M has modeled for 2020 and beyond.

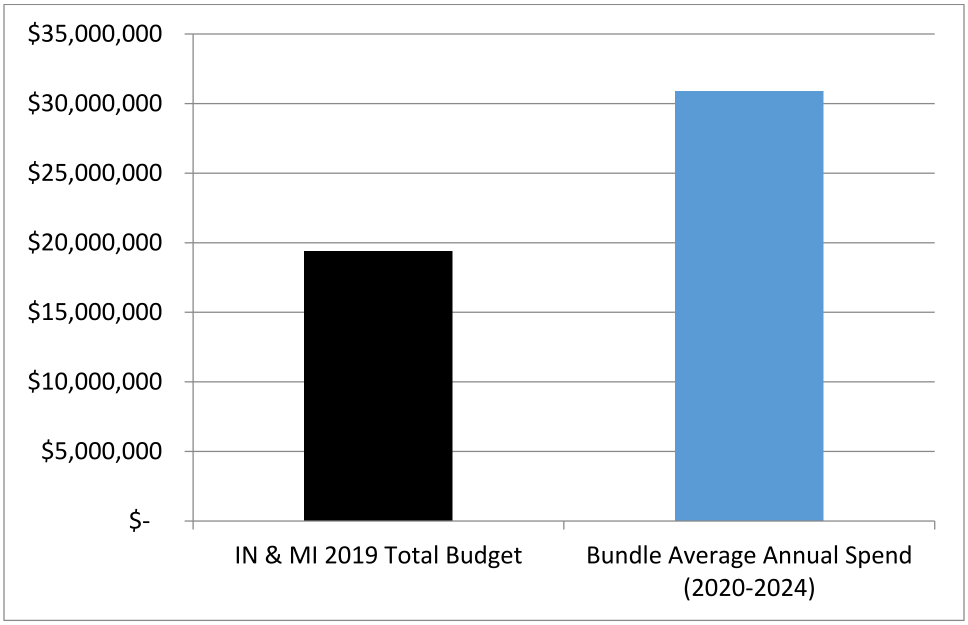

Figure 10. 2019 EE Budget Achieved More Savings at Lower Cost than IRP Bundles Would

I&M has utterly failed to model EE savings in any way that represents a) the manner in which those savings are actually achieved, b) a level consistent with its own MPS, or that represents c) the likely maximum achievable level of savings. These errors compounded upon other errors explained above create fatal, irredeemable flaws in I&M's 2018-2019 IRP.

7 Resource Portfolios

Section 7 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule. Please see Table 19 below for our findings.

Table 19. Summary of I&M's Compliance with Indiana IRP Rule 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Findings
4-7-8 (a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Partial
4-7-8 (b)	With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	Not Met
4-7-8 (b)	(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Not Met
4-7-8 (b)	(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Not Met
4-7-8 (c)	Considering the analyses of its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Met
4-7-8 (c)	(2) Identification of the standards of reliability.	Met
4-7-8 (c)	(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Not Met
4-7-8 (c)	(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Not Met
4-7-8 (c)	(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Not Met
4-7-8 (c)	(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Not Met
4-7-8 (c)	(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio; (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule; (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio; and (D) The utility's ability to finance the preferred resource portfolio.	Partial
4-7-8 (c)	(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties and (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Not Met

4-7-8 (c)	(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	**Partial**
4-7-8 (c)	(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following: (A) Demand for electric service; (B) Cost of a new supply-side resources or demand-side resources; (C) Regulatory compliance requirements and costs; (D) Wholesale market conditions; (E) Changes in Fuel costs; (F) Changes in Environmental compliance costs; (G) Technology and associated costs and penetration; (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	**Not Met**

7.1 Candidate Portfolio Assessment

I&M uses a non-traditional approach to IRP modeling, combining portfolios and scenarios together rather than designing scenario-neutral portfolios that are then tested under each scenario. In effect, this approach limits modeling to Company-selected portfolio-scenario combinations instead of investigating modeling results' sensitivity to all portfolio-scenario combinations. In essence, certain potential futures do not get modeled. Gaps in I&M's 2018-2019 IRP modeling include the effects of lower load under the "high band" pricing conditions, effects of higher load under the "low band" pricing conditions, as well as variations in load in portfolios with storage, minigrids, unconstrained renewables, and using the EE Decrement method. I&M has not constructed scenario "storylines" but rather tests an ad hoc set of one-off scenario characteristics, creating gaps of untested portfolio/scenario combinations. (Note that I&M tests a wider range of parameter values in its stochastic modeling, discussed below.) For example, the "no carbon" pricing conditions are only tested under base load. In addition, what I&M refers to as "optimized portfolios" appear to often have constrained either retirements, lease lengths or resource additions.

As a consequence of this practice, the Preferred Portfolio (Case 9 Transitional) does not appear to be tested under all scenario characteristics including high and low band pricing conditions, no carbon price, high and low load conditions, and combinations of these characteristics. Thorough evaluation of the Preferred Portfolio requires that it be tested under a full range of likely future scenarios. I&M's 2018-2019 IRP does not include this information. The scenarios modeled by I&M are given in Figure 11.

Figure 11. Reproduction of Table 17 from I&M's IRP[54]

	Type	Name	Commodity Pricing Conditions	Load Conditions
Group 1	Group 1 Commodity Pricing Scenarios	1. Base - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Base	Base
		2. High Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	High Band	Base
		3. Low Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Low Band	Base
		4. No Carbon - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	No Carbon	Base
Group 2	**Group 2 & 2A** Rockport Scenarios Includes Storage & MiniGrid	5. Case 5 & 5A (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		6. Case 6 & 6A (RP1 FGD 1/2026 & Retires 12/2044; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		7. Case 7 & 7A (RP1 FGD 1/2029 & Retires 12/2044; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		8. Case 8 &8A (RP1 Retires 1/2025; RP2 Lease Extended, FGD 1/2029, & Retires 12/2048)	Base/No Carbon (A)	Base
Group 3	Group 3 IRP Scenarios Includes Storage & MiniGrid	**9. Transitional** (RP2 Lease End 2022, RP1 Retire 12/2028)	Base	Base
		10. 12 - Year Peaking (Post RP2 Lease End)	Base	Base
		11. 15 - Year Peaking (Post RP2 Lease End)	Base	Base
		12. Case 12 & 12a 12 - High Renewables - Peaking 12a - High Renewables - Peaking and CC	Base	Base
Group 4	Group 4 Load Scenarios	**13. Low Load**	Base	Low
		14. High Load	Base	High
		15. Low Load	Low Band	Low
		16. High Load	High Band	High
Group 5	Group 5 Other Scenarios	**17. EE Decrement Method**	Base	Base
		18. Unconstrained Wind and Solar Additions	Base	Base
		19. Reserve Margin Constraint with unconstrained Renewables	Base	Base

7.2 Approach to Selecting a Preferred Portfolio

I&M's description of how it selected its Preferred Portfolio is much less detailed than that of other Indiana utilities, providing a selected comparison to other cases rather than a comprehensive comparison across all modeling runs. I&M's selection of the Case 9 Transitional portfolio as preferred is under-explained and appears largely to be a choice made on the basis of the Company's judgment rather than on the basis of modeling designed to openly explore and assess possible future capacity mixes.

54 I&M 2018-2019 IRP, p. 117.

The two high and unconstrained renewables cases are both dismissed by I&M because of purported cost issues. Even though the High Renewables case, Case 12, receives the lowest "Revenue Requirement at Risk" (called "RRaR" in the IRP) score of those cases highlighted by I&M, I&M dismisses this finding stating, "While the lower RRaR of the High Renewables plan indicates that the addition of renewable resources reduces revenue requirement risks, the analysis does not take into account, the aggressive build-out of these resources which may not be practical."[55] As we have described in Section 3.1, even in the High Renewables Case, the addition of wind and solar are unduly constrained. But more importantly, wind is modeled at a higher cost than I&M intended, EE savings and costs are distorted in a way that dilutes its value, and the cost of the CC in Case 9 is too low.

7.3 Stochastics

I&M's risk assessment is performed using a Monte Carlo analysis—multiple iterations of modeling runs based on random selection of certain variable values, within a given distribution. I&M varies its gas, coal, CO_2 and electric prices, selecting 100 combinations of these prices to test its modeling results' sensitivity to unexpected future price conditions. From this, the Company reports, for each case, the difference in modeled system costs between the 95 most expensive runs and the median run (I&M's RRaR).

I&M's Monte Carlo analysis is deeply flawed and unlikely to result in useful information about risks. One hundred iterations is in no way sufficient to sample and make conclusions regarding a four-variable space like the one used by I&M (that is, gas, coal, CO_2 and electric prices are varied). Imagine, for example, a two-variable space: gas and coal prices. To fully sample this space in 100 iterations, a possible value of each variable would be selected from its lowest 10 percent, next 10 percent, next 10 percent, and so on, taking 10 well-distributed (that is, well spread out) values from each variable. If each variable is divided into 10 bins, a two-variable space has 100 possible bin combinations. Taking one pair of gas and coal prices from each of these 100 bins gives the best sampling across the entire space.

With three variables, 100 bins (iterations) sample these values not 10, but 4 to 5, times; and with four variables (as in I&M's risk analysis), 100 bins samples these values just 3 to 4 times. Put another way, getting values from each 10 percent bin in a four-variable space would require 10,000 iterations. I&M mentions correlative relationships that may mitigate this concern, essentially limiting the combinations of variables to bins that represent more plausible combinations (see I&M's 2018-2019 IRP, Tables 30 and 31) but it is very unlikely that, even employing these correlations in selecting variable values, could result in a complete or useful sampling of risk in these modeling runs.

[55] I&M 2018-2019 IRP, p. 140.

8 Short Term Action Plan

Section 9 describes our assessment of I&M's performance in meeting the requirements of 170 IAC 4-7-9 of the Indiana IRP Rule. Please see Table 20 below for our findings.

Table 20. Summary of I&M's Achievement of Indiana IRP Rule 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Findings
4-7-9 (a)	A utility shall prepare a short term action plan as part of its IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Partial
4-7-9 (b)	The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule	Not Met
4-7-9 (c)	The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio and (B) The criteria for measuring progress toward the objective.	Not Met
4-7-9 (c)	(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	Not Met
4-7-9 (c)	(3) The implementation schedule for the preferred resource portfolio.	Not Met
4-7-9 (c)	(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	Not Met
4-7-9 (c)	(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	Not Met

I&M's short-term action plan is a product of the many flaws contained in its IRP. I&M's biases against energy efficiency, wind, and solar in favor of thermal resources, result in a plan that underutilizes the first category and over utilizes the second. The result is a plan that goes from being very heavily dependent on thermal resources, specifically coal and nuclear power, to one that is still dominated by thermal resources that now includes gas, as shown in Figure 12 and Figure 13.

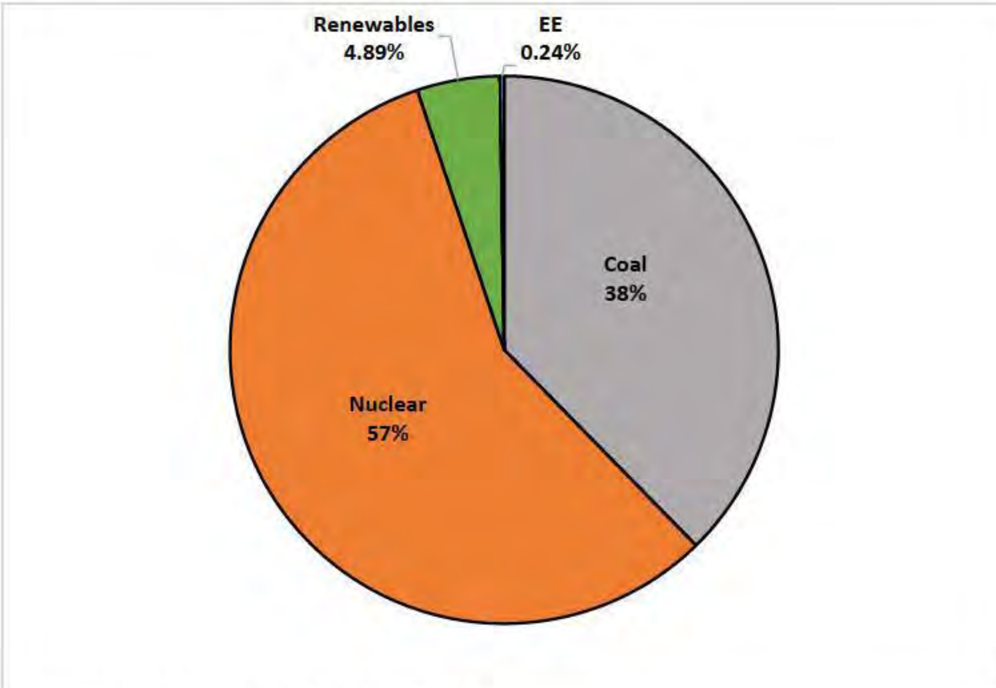

Figure 12. I&M's 2020 Energy Mix

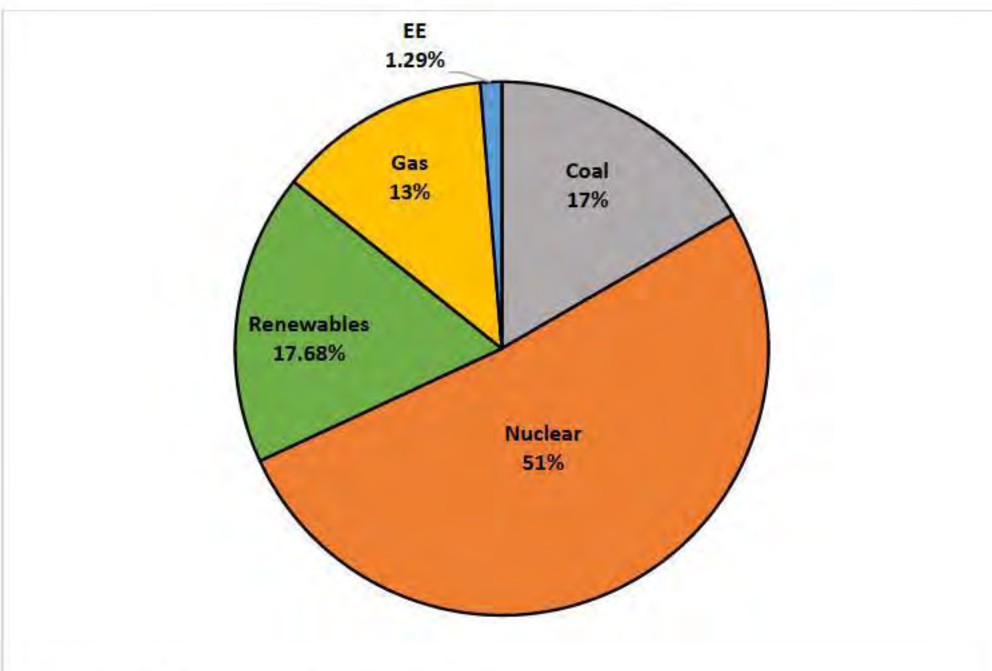

Figure 13. I&M's 2028 Energy Mix

PUBLIC ATTACHMENT 1

3.1 Please identify and provide instructions on where in Plexos reduced costs can be found. If reduced costs cannot be accessed with the read-only license, please provide the reduced costs for Case 9, Case 12, and Case 12A.

Response: This information is available in the respective "2-pager" files for each case located on the Citrix server in the PLEX IN OUT folder. Please see the summary tab for the major cost components for each case.

3.2 Please provide, in spreadsheet format with all formulas and links intact, I&M's demand and energy forecasts.

Response: The material available in spreadsheet format is located on the Citrix server in IRP Appendix Vol. 1, Exhibit A.

3.3 Please provide, in spreadsheet format, the economic, weather, and other forecast variables used to develop I&M's load forecast.

Response: The Company does not use spreadsheets to prepare its load forecasts. Please refer to IRP Appendix Vol. 2 and Vol. 3, Exhibits H, K, L and M for load forecast model inputs, assumptions and output.

3.4 Please provide, in spreadsheet format, the input and output files produced in the development of I&M's load forecast.

Response: Please refer to the Company's response to Q 3.3.

3.5 Please provide definitions for all variables included in the regression models to determine the load forecast across all customer classes and/or end-uses.

Response: Please refer to the Company's response to Q 3.3.

3.6 Please specify which variables were in the regression model for determining load forecasts across each customer class.

Response: Please refer to the Company's response to Q 3.3.

3.7 Please provide the variable coefficients and model statistics for each regression model used to determine the load forecast for each customer class.

Response: Please refer to the Company's response to Q 3.3.

3.8 Please provide a spreadsheet showing the specific post estimation adjustments, if any, made to I&M's load forecast.

Response: Please refer to the Company's response to Q 3.3.

3.9 Please provide any economic datasets purchased (from Moody's, IHS Markit, etc.) by I&M since April 1, 2018.

Response: Please see IRP Appendix Vol. 1, Exhibit A -11 and the Company's response to Q 3.3.

3.10 Please break out the specific Effluent Limitation Guideline (ELG) and Coal Combustion Residuals (CCR) compliance costs assumed in the fixed operations and maintenance (O&M) costs for each of I&M's coal units, if applicable. If those costs are not embedded in the fixed O&M field, please indicate where they can be found and break them out from other capitalized maintenance, etc.

Response: This information is available in the respective "2-pager" files for each case. The CCR and ELG costs for Rockport are included in the on-going capital costs of the units. The OGC costs can be found in the RP Costs tab of the 2 pagers. The specific CCR and ELG costs for Rockport can be found in the Citrix server PLEX IN OUT/Inputs/Existing System fixed costs/2018 I&M IRP Existing Unit Fixed Costs.xlsx, in the OGC Data tab, rows 160 and 161.

3.11 Please provide, in spreadsheet format, all forecasts used for commodity prices.

Response: This is available in the PLEX_IN_OUT>Inputs>Commodity Prices folder on the Citrix server.

3.12 Please provide, in spreadsheet format, the costs and operating characteristics for potential supply-side resources.

Response: This is available in the Appendix Vol. 1, Exhibit D and IRP Section 4. The information is also available in the Citrix server PLEX_IN_OUT>Inputs>Generic Units.

3.13 Please provide, in spreadsheet format, the hourly production profile for solar and wind.

Response: This is available in the PLEX_IN_OUT>Inputs>Solar> Solar Bundles R10 Redo.xlsx file and PLEX_IN_OUT>Inputs>Wind> Headwaters 35.0% (40.5) Forecast For 2018 I&M IRP 09-12-2018_xz.xlsx and on the Citrix server.

3.14 Please provide I&M's two most recent MISO-OMS survey responses.

Response: I&M is in the PJM RTO and doesn't prepare MISO-OMS survey responses.

3.15 Please provide any identified benefits from the addition of the RICE units as a microgrid/mini-grid.

Response: See IRP Section 4.7.4.3, page 100, for the discussion of RICE units. The specific economic benefits are shown in each "2-pager" file. Please also refer to the Company's response to Q 3.1.

3.16 Please explain how I&M will own and operate the microgrids/mini-grids and how this is different from the RICE units serving as peaking resources.

Response: I&M intends to own and operate the micro grid resources. Each micro-grid will include uniquely configured generation resource(s) and distribution investments to allow the sectionalizing of the distribution system. In addition, the IRP micro grid generation resources are different in its proposed size in MWs than the traditional RICE plant the Company models. Although not modeled in the IRP, there may likely be different cost and performance characteristics based on the final location and design of each Mini-grid deployment (for example, location-specific, interconnection requirements).

PUBLIC ATTACHMENT 2

Indiana Michigan Power Company

Energy Efficiency Market Potential Study - Indiana

Final Report

Applied Energy Group, Inc.
211 Broad Street, Suite 206
Red Bank, NJ 07701
732.945.9940
www.appliedenergygroup.com

Prepared for:
Indiana Michigan Power Company

June 2, 2016

Definitions of Potential

In this study, the energy efficiency potential estimates represent net savings[1] developed into several levels of potential. At the measure-level, before delivery mechanisms and program costs are considered, there are four levels: technical potential, economic potential, maximum achievable potential, and realistic achievable potential. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential**, represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.
- **Maximum Achievable Potential (MAP)** estimates customer adoption of economic measures when delivered through DSM programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Maximum Achievable Potential establishes a maximum target for the savings that an administrator can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Realistic Achievable Potential (RAP)** reflects expected program participation given barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets.

At the program-level, there are three levels of potential: high, mid and low.

- **High Scenario** reflects expected program participation given ideal market implementation and few barriers to customer adoption. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with dealers and delivery partners. Under this scenario, incentives represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Mid Scenario** reflects expected program participation given barriers to customer acceptance and non-ideal implementation conditions. These measures are delivered under less than ideal market conditions, however, there are less barriers and less limitations on budgets than there would be under the low scenario.
- **Low Scenario** reflects low program participation given high barriers to customer acceptance, non-ideal implementation conditions, limited program budgets and limited access to support for implementation as well as education and outreach.

[1] "Net" savings mean that the baseline forecast includes naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option.

CONFIDENTIAL ATTACHMENT 1

Confidential Attachment 1 to

CAC et al.'s Report on

Indiana Michigan Power 2018-19 IRP

Submitted to the IURC on December 2, 2019

Confidential Attachment 1 to Report on Indiana Michigan Power Company 2018-2019 IRP Submitted to the IURC on December 2, 2019

Confidential Figure A.1. Plexos Total Build Constraint on Tier 1 and 2 Solar Resources

[redacted]

Confidential Figure A.2. Plexos Total Build Constraint on Tier 1 and 2 Wind Resources

[redacted]

Confidential Figure A.3. Plexos Build Cost Input for Tier 1 Solar Resources

[redacted]

Confidential Figure A.4. Plexos Build Cost Input for Tier 2 Solar Resources

[redacted]

Confidential Attachment 1 to Report on Indiana Michigan Power Company 2018-2019 IRP Submitted to the IURC on December 2, 2019

Confidential Figure A.5. Plexos Build Cost Input for Tier 1 Wind Resources

[redacted]

Confidential Figure A.6. Plexos Build Cost Input for Tier 2 Wind Resources

[redacted]

Confidential Figure A.7. Plexos Annual Build Constraint on Tier 1 and 2 Solar Resources

[redacted]

Confidential Figure A.8. Plexos Annual Build Constraint on Tier 1 and 2 Wind Resources

[redacted]

Confidential Figure A.9. Plexos Build Constraints for CC Resource M501 JAC

[redacted]

Confidential Figure A.10. Plexos Build Constraints for CT Resource GE 7F.05 SC

[redacted]

Confidential Figure A.11. Plexos Case 12A Annual Build Constraint on Tier 1 and 2 Solar Resources

[redacted]

Confidential Figure A.12. Plexos Case 12A Annual Build Constraint on Tier 1 and 2 Wind Resources

[redacted]

Confidential Figure A.13. Plexos Case 12A Total Build Constraint on Tier 1 and 2 Solar Resources

[redacted]

Confidential Figure A.14. Plexos Case 12A Total Build Constraint on Tier 1 and 2 Wind Resources

[redacted]

Confidential Figure A.15. Plexos Firm Capacity Input for M501 JAC Combined Cycle Unit

[redacted]

Confidential Attachment 1 to Report on Indiana Michigan Power Company 2018-2019 IRP Submitted to the IURC on December 2, 2019

Confidential Figure A.16. Plexos Net Profit Calculation for M501 JAC Combined Cycle Unit

[redacted]