Report on Indiana Michigan Power Company's 2021 Integrated Resource Plan

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Authors:

Chelsea Hotaling, Energy Futures Group
Anna Sommer, Energy Futures Group
Dan Mellinger, Energy Futures Group

On behalf of CAC, Earthjustice, and Vote Solar

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Overview

The following comments on the 2021 Integrated Resource Plan ("IRP") submitted by Indiana Michigan Power Company ("I&M" or the "Company") were prepared by Chelsea Hotaling, Anna Sommer, and Dan Mellinger of Energy Futures Group. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Earthjustice, and Vote Solar ("Joint Commenters") 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 2021 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule.

We look forward to continuing to work with I&M to address the issues identified here to improve I&M's next IRP and prior to I&M making any resource decisions relying on this 2021 IRP before the IURC.

Our major concerns relate to the heart of I&M's economic analysis of new resources. The way in which I&M conducted this analysis undermines the notion that it could have led to the selection of this Preferred Portfolio.

Table 1 gives the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of I&M's 2021 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- Section 1. I&M's provision of information during the stakeholder process did not allow stakeholders to weigh in on key details before the IRP modeling was finalized. In addition, I&M did not timely comply with the requirements of Indiana IRP rules to turn over its modeling inputs with the filing of its IRP. This timing constraint prevented stakeholders from utilizing a key portion of those inputs.
- Section 2. It was frequently unclear whether I&M would incorporate stakeholder feedback or not, and whether it actually considered the feedback it received.
- Section 3. I&M made a number of mistakes in calculating the costs of new resources which resulted in overestimates of costs, particularly for solar hybrids and standalone batteries.
- Sections 4 and 5.1.3. It is unclear whether I&M will fully cease use of the Supplemental Efficiency Adjustment or any similar mechanism despite a commitment to do so.
- Section 5. Energy efficiency modeled in the IRP was based only on the Program Potential level identified in the Market Potential Study, meaning that program offerings were largely based on current offerings and budgets. The Realistic Achievable Potential and Maximum Achievable Potential levels were entirely excluded from the modeling.
- Section 7. The Preferred Portfolio was derived from an optimized portfolio based on poorly formed rationale.

Table 1. Summary of I&M's Achievement of Indiana IRP Rule Requirements

IRP Rule Section	Description	Findings	Citation
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**	See Section 1
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Partial**	See Section 2
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Partial**	See Section 3
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Mostly**	See Section 4
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Partial**	See Section 5
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Mostly**	See Section 6
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Partial**	See Section 7
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Partial**	See Section 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 Achievement of Indiana IRP Rule at 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Finding
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	**Partial**
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**

I&M and its IRP consultant, Siemens Power Technologies International ("Siemens PTI"), used Energy Exemplar's AuroraXMP ("Aurora") software for capacity expansion and production cost modeling for this IRP. One of the objectives stated in the IRP for Stage 3 of the modeling process was:

> *To provide the ability to verify model inputs and assumptions, re-produce the dispatch simulation results for the Reference Scenario and provide the ability for the Technical Stakeholder to analyze alternative dispatch simulation scenarios and sensitivities.*[1]

While we appreciate the opportunity that was provided to technical stakeholders to receive access to an Aurora license, we do have several recommendations that we believe will increase transparency and facilitate the exchange of information between I&M and stakeholders and meet the modeling objectives. These recommendations include:

[1] I&M 2021 IRP, page 32.

1. I&M should provide all modeling input and output files for capacity expansion and production cost modeling runs[2] at the time of the IRP filing, including the workbooks used to produce the Present Value of Revenue Requirement ("PVRR") calculations.

2. I&M and Siemens PTI should work with stakeholders who receive a license prior to the filing of the IRP to ensure that all software can be downloaded and is functioning. For our license, we ran into an issue with being able to execute the Gurobi solver within Aurora and that took additional time to work through correcting with Siemens PTI and Energy Exemplar.

3. I&M should also provide its modeling files during the stakeholder process as AES Indiana did during its last IRP so that stakeholders may provide comments on the full set of input assumptions *prior* to the IRP being finalized. This is truly important, given the spirit of the IRP stakeholder process should be to work through our issues prior to the finalization of the IRP.

4. I&M and Siemens PTI should hold the technical training with Energy Exemplar in closer proximity to the release of the modeling files. For this IRP, the technical training with Energy Exemplar was held on June 24, 2021.[3] We appreciate the training being held for stakeholders, but it is challenging when there was such a large gap in time between the training and when all modeling files were ultimately provided to stakeholders over ten months later.

The timing of the provision of capacity expansion and production cost modeling files to stakeholders is crucial for the evaluation of any IRP. All of the steps necessary to perform modeling, from setting up the model, reviewing the modeling inputs and how settings are configured, to running the model and processing the results, are all extremely important and take time. I&M submitted its IRP to the IURC on January 31, 2022, and then provided an updated report on February 11, 2022. Within the IRP narrative, I&M stated that, "Siemens anticipates posting the I&M AURORA model on the secure website in late February 2022." On March 3, 2022,[4] the production cost modeling files were made available to stakeholders, however, these modeling files did not include the files from the capacity expansion plan modeling step. On April 26, 2022, the capacity expansion files were made available to the Indiana stakeholders, after several data requests were submitted by intervenors in the Michigan case. The timing of the provision of modeling files to stakeholders is especially critical because of the way that the

[2] Within Aurora, modeling runs are saved to a project file. The setup for Aurora is that capacity expansion and production cost modeling runs are in separate project files, and stakeholders would need access to both project files.

[3] There was approximately seven months between the training and the release of the production cost modeling files, or ten months between the training and the release of the capacity expansion files.

[4] An updated version of the production cost modeling files was made available on April 25, 2022, in response to MPSC Staff's Data Request Staff 2-01 submitted in Michigan Public Service Commission Case No. U-21189. This updated production cost file provided the specific name of the I&M resources contained within the National Resources Table in the Aurora database. Siemens PTI had labeled all resources in the National Resources Table with generic names to protect confidential information which meant stakeholders could not discern which units were I&M specific.

stochastic modeling step was set up for I&M's IRP. Siemens PTI set up the stochastic modeling process to do 200 deterministic production cost runs or "iterations" where each iteration contains a unique combination of each of the stochastic variables modeled, including coal prices, natural gas prices, carbon emission price, load, and capital costs for new resources modeled in areas outside of I&M. We tested a few of these deterministic runs, and each one took about three to three and a half hours to complete. If each of these iterations were run sequentially, or one after the other, it would take approximately 700 hours or close to 30 days to perform all of the iterations for the stochastic modeling of one candidate portfolio, and that is if all went perfectly, and each run was close to the average run time. We attempted to leverage other features within Aurora to be able to perform more than one iteration at a time, but this resulted in less efficient run times, meaning it was not possible to utilize this functionality.

With regard to ensuring that the modeling software is configured and set up for stakeholders to use, we encountered some delays with setting up the Aurora model due to an issue with installing the Gurobi solver. This solver is crucial for allowing Aurora to execute the modeling runs and, without it being installed, the model will not run. We worked with Siemens PTI and Energy Exemplar to be able to work around the error we were encountering with installing the Gurobi solver, but this process also took a few weeks to complete and added some delays in being able to start modeling runs.

CAC appreciated I&M and Siemens PTI's willingness to hold technical meetings with interested stakeholders to discuss the configuration of the Aurora model and answer questions on modeling inputs (although feedback from CAC and others was never incorporated or substantively addressed). I&M and Siemens PTI did provide a data release in November 2021 that provided some information on modeling inputs (although some of the data had to be transformed into different cost inputs to model in Aurora, effectively making us unable to see this information until we ultimately received the modeling files), but I&M and Siemens PTI were too far along in the modeling to incorporate any feedback provided. We would recommend that I&M consider a process of releasing and sharing information like the process that AES Indiana used for its 2019 IRP and is currently using for its 2022 IRP. AES Indiana is using a file sharing site to share information at several points of time throughout the IRP process, according to a predetermined schedule, where information related to the topics being discussed at the public stakeholder meetings is provided to interested stakeholders. Information is only shared with those stakeholders with an executed nondisclosure agreement ("NDA") with AES Indiana. AES Indiana has a schedule of release dates for when they provide stakeholders with key modeling inputs such as capital cost information, resource constraints, resource accreditation, modeling of demand side management ("DSM") resources, and then modeling results. We believe that this data sharing approach helps to facilitate stakeholder involvement, expectations, and input throughout the process and ultimately increase stakeholder engagement.

AES Indiana's approach is much closer to satisfying 170 IAC 4-7-2(c), which requires each utility to provide input and output files in electronic format, as well as include "documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP".[5] This also is much more in the spirit of the IRP stakeholder process, allowing a better opportunity for resolution or narrowing of concerns prior to the finalization of the IRP.

[5] 170 IAC 4-7-2.6 also requires a utility to discuss modeling methods and modeling inputs as part of the public advisory process. *See also* Order, I/M/O Submission by Hoosier Energy Rural Elec. Coop., Inc. of Its 2017 Integrated Res. Plan, Cause No. 45058, 2018 WL 2329333, at *2 (May 16, 2018) (acknowledging that 170 IAC 4-7-2(c)(2) requires disclosure of market price assumptions, production statistics for generating assets, and model data).

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 Achievement of Indiana IRP Rule at 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Finding
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**

2.1 STAKEHOLDER ENGAGEMENT

One of our major concerns with the stakeholder process for this IRP was the lack of dialogue between I&M and the participating stakeholders. Once comments were provided to I&M, responses would be posted back through the IRP comment website, but it was rarely clear whether I&M would incorporate the feedback or how it would be used for the IRP analysis. I&M never notified parties when its responses were posted. In several instances, the Company's responses did not directly relate to the comment or concern made. For example, when it was pointed out that, for a given portfolio, reporting a single cumulative scorecard value for, e.g., carbon reduction, was arbitrary, the Company's partial response was, "A principle [sic] benefit of the Balanced Scorecard is that it can be used to communicate the balanced nature of the ultimate preferred portfolio."[6] Nowhere in its response did the Company directly address the use of a single combined value aggregated over many years for each area of interest.

While written responses to comments are always appreciated, if there is no further dialogue on the topic or explanation of how the feedback will be incorporated, it undermines the point of engaging in a stakeholder process and instead becomes a one-way street in which the utility merely transmits information to stakeholders. In the IRP narrative, I&M said, "The goal was a Stakeholder engagement process that focused on promoting transparency in the IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions to incorporate into the IRP process."[7] CAC and Earthjustice submitted comments after the IRP stakeholder workshops and made several requests to be able to see written feedback from I&M that explained whether the recommendations would be incorporated or an explanation of why the recommendation would not be incorporated into the IRP analysis. This lack of feedback from I&M made the process frustrating to participate in.

One of the stated objectives from I&M related to stakeholder engagement was to listen, inform, and consider[8] with "consider" being defined as, "Review all Stakeholder input and carefully consider this feedback at key points in the Integrated Resource Plan process to inform I&M's decision making."[9] The excerpt below, from the IRP narrative, explains how I&M claims stakeholders were able to provide feedback:

> *As a result, Stakeholders had the opportunity to provide feedback on virtually all areas of the IRP, including but not limited to the following:*
>
> - *Establishing objectives of the IRP.*
> - *Identification of metrics to be used in evaluating objectives.*
> - *Review of inputs and key assumptions.*
> - *Identification of alternative scenarios and sensitivities to generate a diverse range of potential Candidate Portfolios.*
> - *Analysis of the Candidate Portfolios through the Stochastic Modeling process.*
> - *Creation of the Preferred Portfolio.*[10]

We hold a very different view of how the process played out. For example, as a stakeholder participating in the IRP workshops, we did not feel like stakeholders had any hand in determining the Preferred Portfolio. I&M presented modeling results and outlined the Preferred Plan to stakeholders as something for stakeholders to react to, but it never sought nor incorporated feedback from stakeholders on the contents of its Preferred Plan. Furthermore, stakeholders did not have access to the Aurora modeling files at the time of the determination of the Preferred Plan.

For example, CAC and Earthjustice submitted the following comment on the application of renewable constraints in the modeling:

> *We would also request that I&M work with stakeholders to define the limits on renewables that it will model consistent with Section 6(d) of the settlement regarding I&M's 2019 IRP that was filed with the Michigan Public Service Commission, which states, "I&M will work with stakeholders to define the modeling inputs for the IRP, including scenarios for […] renewable generation resources.*[11]

I&M's response to this comment was, "The Company has invited all Stakeholders to be part of the process that includes an open and transparent discussion on modeling inputs and scenarios."[12] And yet there was never any feedback solicited during the workshops on the constraints I&M would use or further engagement with CAC and Earthjustice regarding our request.

2.2 SHARING MODELING INPUTS WITH STAKEHOLDERS

CAC and Earthjustice alerted I&M, in response to the stakeholder workshop held on October 14th, that, "I&M is not sharing information with stakeholders in a timely manner that permits feedback on key details before the modeling is finalized." [13] In order for a utility to be able to incorporate stakeholder feedback into the IRP modeling, it is imperative for there to be timely exchange of information related to modeling inputs and assumptions. For this IRP, I&M and Siemens PTI did share some modeling assumption workbooks with stakeholders, but by the time stakeholders received this information, it was too late in the modeling process for the feedback to be able to be incorporated into the modeling given where I&M and Siemens PTI were in the modeling process.

One of the frustrating aspects of the data release to stakeholders was the constantly changing target dates for when information would be provided. While we understand that the Rockport acquisition settlement in IURC Cause No. 45546 played a role in the delays of providing data to stakeholders, the technical stakeholders were not able to get the Aurora modeling files and have

[11] 2021 I&M IRP Website Stakeholder Comment Summary, page 9. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/StakeholderWebsiteComments_6-07-22.pdf
[12] 2021 I&M IRP Website Stakeholder Comment Summary, page 9. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/StakeholderWebsiteComments_6-07-22.pdf
[13] 2021 I&M IRP Website Stakeholder Comment Summary, page 22. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/StakeholderWebsiteComments_6-07-22.pdf

the model set up for review until after the IRP was filed. Being able to see how the inputs are set up in the model is extremely important, given that often the modeling assumptions provided to stakeholders have to be transformed into different terms. For example, Aurora looks at new resource costs on a $/MW-week basis, so more information is required to see how this input will be calculated and set up in the model than just looking at the $/kW cost provided in the modeling assumptions workbook.

2.3 RESPONSES TO DISCOVERY QUESTIONS

A frustrating aspect of the informal discovery process for this IRP is that I&M posted responses to discovery questions as part of the IRP Website Stakeholder Comment Summary, never engaging directly with us about our comments. Normally, with other utilities, CAC receives notice of responses to any discovery questions and an opportunity for further dialogue, but no message was sent alerting the parties that this material was posted. In this case, the responses were submitted to the website and, if any workbooks were referenced as attachments, we had to follow up with I&M again to ask for those workbooks. While it is positive that all stakeholders can view the comments submitted for the IRP workshops in addition to the discovery questions, I&M should facilitate use of the site and be respectful of parties' time by notifying all parties when material is posted and by sending attachments to the parties (or at least those who have signed the NDA) simultaneously with the posting of the responses. I&M should also set up meetings and have further engagement and dialogue with parties regarding the comments submitted.

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 Achievement of Indiana IRP Rule at 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Finding
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.	**Partial**
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.	**Partial**
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.	**Mostly**
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.	**Partial**
4-7-4 (9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	**Met**
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.	**Partial**
4-7-4 (11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions.	**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.	**Met**
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.	**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.	**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.	**Met**
4-7-4 (17)	A discussion of the designated contemporary issues designated, 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.	**Met**
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 an air emission have been considered and influenced the IRP development.	**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.	**Met**
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.	**Partial**
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.	**Partial**
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	**Partial**

	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.	
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.	**Partial**
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 NEW RESOURCES

The following sections address several concerns we noted related to how new supply-side resources were modeled, the costs of new resources, the constraints modeled in Aurora, and the natural gas price forecast.

3.1.1 Cost of New Resources

I&M made several problematic modeling assumptions related to new renewable, thermal, and battery storage resources including:

- Use of a nominal capital charge rate in the development of the new resource costs modeled in Aurora when cost inputs were modeled in Aurora in real terms,
- Double counting certain costs of solar hybrid resources,
- Application of variable O&M for new wind and solar resources, and
- Normalizing the Investment Tax Credit ("ITC").

We recognize that supply-side constraints and inflationary pressures have changed since I&M and Siemens PTI performed this modeling for the IRP. Given the changes that the entire electric system faces, it is imperative that I&M update its database to reflect the current realities of its electric system and influencing factors, which will entail changing inputs across several categories (*i.e*. power, fuel, and market price forecasts; all supply-side resource costs; demand-side resource costs).

3.1.1.1 Capital Charge Rate ("CCR") Applied to New Resources

New resource costs are modeled in Aurora on a $/MW-week basis, which means that there is a translation of the projected $/kW capital costs along with a CCR applied to create a levelized cost stream that can be modeled in Aurora. For this translation, Aurora will take the $/kW capital cost multiplied by the CCR and then divided by 52 weeks to arrive at the levelized $/MW-week cost input. This is the approach I&M and Siemens PTI took to model all new supply-side resources including thermal, renewable, and battery storage resources.

For this IRP, Siemens PTI input all values into Aurora in real 2019 dollars. When Aurora outputs modeling results, it applies an inflation vector to translate results on a nominal basis regardless of whether the inputs were real or not. I&M and Siemens PTI then decided to convert the outputs back into real 2019 dollars.[14]

This detail is important for how the new resource costs were modeled, because there was a misapplication of a nominal CCR to real $/kW capital costs in Aurora. Table 5 shows the comparison of the reported nominal CCR for new resources that we calculated by using the formulas for the real and nominal CCR for each new resource compared to the CCR values that were input into Aurora.[15]

Table 5. Comparison of Capital Charge Rate ("CCR") for New Resources

Resource	Real	Nominal	Modeled[16] in Aurora
Wind	6.32%	8.21%	11.40%
CT	6.32%	8.21%	11.40%
Battery Storage	6.32%	8.21%	17.60%
Solar	5.92%	7.88%	11.10%
Solar Hybrids	5.92%	7.88%	11.10%

If capital costs are modeled in real dollars, then the real CCR should be applied; and if the costs are modeled in nominal dollars, then the nominal CCR should be applied. It was incorrect to mix and match a real 2019 $/kW capital cost with a nominal CCR in Aurora. This error leads to an overstating of the cost of new resources.

There is a second problem with the modeled CCRs, but the origin of it is unclear. The "Modeled in Aurora" CCR values (last column) do not match the nominal values shown in Table 5 so it appears that there was an additional error in the Company's cost calculations. The book life information from I&M indicated that battery storage resources had the same book life as CT and wind resources so the CCR for battery storage resources modeled in Aurora should be the same as those resources. As shown in Table 5, the CCR for battery storage resources is much higher than what was modeled for wind and CTs. This means that the $/MW-week cost modeled in Aurora would appear much higher than it should be for battery storage resources and potentially bias the model from selecting them in the capacity expansion step.

3.1.1.2 Overapplication of Costs to the Battery Portion of Hybrid Resources

One of the other modeling issues is that I&M and Siemens PTI overapplied the $/MW-cost for the solar hybrid systems, which made them look more expensive. The $/kW capital cost and fixed O&M assumptions for the solar and battery hybrid resources were developed as multipliers

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[14] 2021 I&M IRP Website Stakeholder Comment Summary, page 34. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/StakeholderWebsiteComments_6-07-22.pdf

[15] The following equations were used to calculate the nominal and real CCR for 30- and 35-year book lives for the new resources modeled:

$$Nominal\ CCR = Nominal\ WACC * (1 + Nominal\ WACC)^{Book\ Life} \div ((1 + Nominal\ WACC)^{Book\ Life} - 1)$$

$$Real\ CCR = Real\ WACC^{15} * (1 + Real\ WACC)^{Book\ Life} \div ((1 + Real\ WACC)^{Book\ Life} - 1)$$

[16] CCR values from the Aurora database.

of the size of the solar portion of the project and should have only been multiplied by those megawatts. However, I&M and Siemens PTI applied both the $/MW-week capital and fixed O&M costs to both the solar and battery portions of the hybrid resources. The result is that this leads the model to see solar hybrid resources as more expensive than what I&M intended to have been modeled.

3.1.1.3 Application of Variable O&M to New Wind, Solar, and Solar Hybrid Resources

The assumptions provided to stakeholders in November did not indicate that a variable O&M cost would be modeled for new wind, solar, or solar hybrid resources. Furthermore, the IRP did not provide any indication of a variable O&M cost in the information presented on new resource cost parameters.[17] However, when reviewing the Aurora database and the modeling outputs, we discovered that a $1.75/MWh variable O&M cost was assessed on new solar, wind, and the solar portion of solar hybrid resources. It would have been helpful if I&M had provided this information to stakeholders instead of indicating that renewable resources would not see a variable O&M cost in the capacity expansion and production cost modeling.

3.1.1.4 Investment Tax Credit ("ITC")

I&M's modeling of the costs for solar[18] and solar hybrid[19] resources assumed that the ITC would be normalized, or spread across the entire life of a project, versus assuming monetization, i.e., that the ITC value would be credited to the first year of the project. By normalizing the ITC, the value of the ITC is reduced due to discounting. This can have important implications for whether the IRP model picks solar or not and ignores the opportunities I&M has to leverage the ITC through PPAs, tax equity partnerships, etc. Assuming normalization over monetization overstates the costs of solar and solar hybrid resources and may potentially bias the model against selecting more of these resources.

The IRP confused this important point, saying, for example, in Section 7 in the discussion of new supply side resources modeled in Aurora that:

> *The IRP modeling considered generic resource cost and performance characteristics and did not attempt to model resource differences based on ownership structure for example (owned, power purchase agreement, tax equity, etc.).* ***This approach allows the IRP modeling and process to focus on resource type and the underlying performance and installed and operating cost that are common regardless of ownership structure****. This also avoids potentially inaccurate treatment when modeling federal and state policies and other ownership structure characteristics that are examined in more detail when specific resources are being acquired.*

[17] I&M 2021 IRP, Table 8, page 95.
[18] I&M 2021 IRP, page 101 for standalone solar and page 104 for solar hybrid resources.
[19] I&M 2021 IRP, page 104.

> *Furthermore, as discussed in the Short-Term Action Plan the Company has committed to using an all-source RFP to solicit resources needed in the Near-Term. This will ensure the timely recognition of federal tax policies and allows for the consideration of project specific accurate and relevant information needed to evaluate the best resources for I&M. This includes the consideration of items such as: tax efficiency and utilization, terminal value of owned projects, impacts to financing costs and availability of financing, etc*. [emphasis added][20]

However, when I&M discusses the capital costs of individual resources, the IRP narrative said that, "[t]he large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC"[21] and "[t]he hybrid solar + storage cost used in this IRP reflects a normalized treatment of the ITC" which would mean that only owned hybrid resources were considered.[22]

3.2 NEW RESOURCE BUILD CONSTRAINTS

For the capacity expansion planning step in Aurora, I&M and Siemens PTI applied build constraints to renewable, battery storage, and thermal resources. The following sections discuss the build constraints applied to new solar and wind resources, along with the binding constraints from the modeling results.

3.2.1 Solar and Wind Build Constraints

Table 6 shows the annual and cumulative build constraints that were applied in Aurora for new solar and wind resources. In the IRP, I&M stated that, "renewable and hybrid resource limits were informed by responses received from the Company's RFP's."[23] I&M and Siemens PTI broke out new solar resources into two categories – Tier 1 and Tier 2. Tier 1 solar is supposed to represent the "Best-In-Class solar resource and is based on the lowest bid received for solar resources from the All Source and Renewable RFP" while Tier 2 is "the average of higher bids received as part of the All Source and Renewable RFP."[24] I&M stated that constraints are needed because "there will come a point where the optimization model will theoretically pick an unlimited number of solar resources, a nonsensical result."[25]

[20] I&M 2021 IRP, page 94.
[21] I&M 2021 IRP, page 101.
[22] I&M 2021 IRP, page 104.
[23] I&M 2021 IRP, page 105.
[24] I&M 2021 IRP, page 101.
[25] I&M 2021 IRP, page 101.

Table 6. Solar and Wind Constraints Modeled in Aurora[26] (MW)

	Annual	Cumulative 2025-2034	Cumulative 2035-2037	Cumulative 2038 +
Solar Tier 1	250	1,800	2,400	3,500
Solar Tier 2	250	1,800	2,400	3,500
Wind	800	1,600	3,200	5,800

We acknowledge that some constraints are necessary and that those used in this IRP are an improvement from I&M's last IRP, which applied annual limits of 300 MW for solar and wind respectively, a 2,100 MW cumulative limit for wind, and a 1,700 MW cumulative limit for solar. However, we are still skeptical about the need to model the Tier 1 and Tier 2 solar tranches separately. An all-source RFP process that is well run will likely result in price separation between bids, but it is extremely unlikely that I&M would only receive 250 MW of bids for the best-in-class solar resource and 250 MW for the next best, nor is it likely that the results of this RFP are indicative of the numbers of bids that I&M would see if it conducted RFPs periodically throughout the study period. As I&M acquires renewable and storage resources, it will likely see development of additional projects in its service territory. Moreover, despite the fact that solar and solar hybrid costs were modeled as if such projects had to be utility owned, I&M does not appear to have included the possibility that it would construct such projects itself.

3.2.2 Binding Constraints

Table 7 below shows the capacity expansion for the Reference candidate portfolio, which is the optimized portfolio that was used to derive the Preferred Plan. All of the cells colored in orange indicate that the annual constraint, or the annual and cumulative constraint in the case of new wind, have been met.

Table 7. Reference Case Expansion Builds 2025 - 2028

	2025	2026	2027	2028
Solar Tier 1	250	250	250	0
Solar Tier 2	250	250	250	0
Wind	800	800	0	0
Solar Hybrid	0	0	300	0
Hybrid Battery	0	0	60	0
CT[27]	0	0	250	500

I&M did explore a few scenarios that could impact the buildout of new renewable and CT resources. I&M modeled the Rapid Technology Advancement scenario which applied a 35% reduction in the cost of renewables, battery storage, and energy efficiency. I&M also looked at the Expanded Build Limits and the Reference with No Renewable Limits candidate portfolios, which relaxed the constraints applied to new renewable and battery storage resources in varying

[26] I&M 2021 IRP, page 105.
[27] I&M 2021 IRP, Table 9, page 106.

degrees. Table 8 shows the new resource additions between 2025 to 2028 across the Reference, Rapid Technology Advancement, Expanded Build Limits, and Reference with No Renewable Limits candidate portfolios. The 35% cost reduction under the Rapid Technology Advancement scenario does not have a significant impact on the expansion plan results since the annual constraints have already been met for solar and wind, and wind has met the first cumulative constraint applied for 2025 to 2034. However, as the limits placed on renewable builds are relaxed under both the Expanded Build Limits and the Reference with No Renewable Limits, the expansion plan build shifts away from the addition of new gas and towards more solar, wind, and battery storage resources.

Table 8. 2025 - 2028 Capacity Additions for Select Candidate Portfolios[28]

	2022 - 2028 Additions			
	Wind	**Solar***	**Storage***	**Gas CT**
Reference'	1,600	1,800	60	750
Rapid Technology Advancement	1,600	1,800	160	750
Expanded Build Limits	2,400	2,700	240	250
Reference with No Renewable Limits	6,000	6,000	600	0

**I&M combined hybrid and stand-alone solar and battery storage resources for reporting*

3.3 NATURAL GAS PRICE FORECAST

Given the spike in natural gas prices since I&M developed the fuel forecast inputs for its IRP modeling and the large natural gas buildout in I&M's Preferred Portfolio, we request that I&M continue to re-evaluate this resource decision and engage with stakeholders prior to any resource filings. Figure 1 shows the comparison of the natural gas price forecast that I&M modeled for the new thermal resources against the CME/NYMEX futures for gas at the Henry Hub as of June 21, 2022. We assume that the prices I&M modeled are commodity-only prices, but if they also include any transportation costs, then the gap would be larger. The futures are higher than I&M's forecast, but this is not to say that I&M should have or could have used natural gas futures that coincide with or post-date its IRP filing date. As I&M moves forward with any certificate of public convenience and necessity filings or similar approvals, its resource decisions must be reevaluated in light of a myriad of changed circumstances, including natural gas pricing. The recent increases in natural gas prices illustrate the volatility of natural gas pricing, which would be an important consideration to explore as I&M moves forward with the 1,000 MW of CTs in its Preferred Plan.

[28] I&M 2021 IRP, Table 20, page 131.

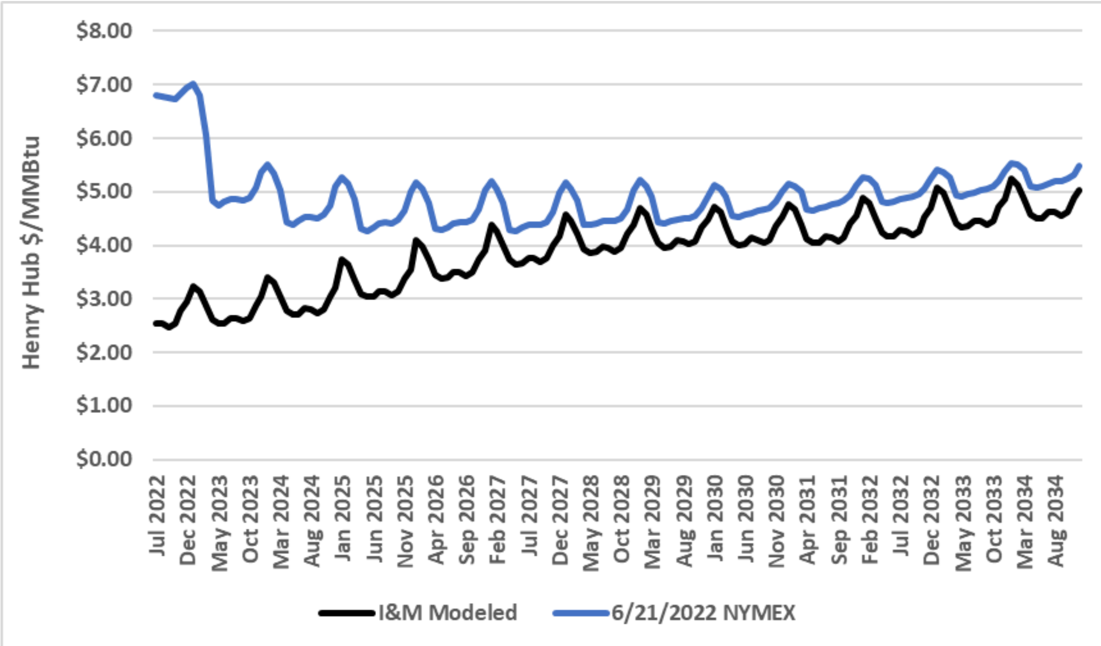

Figure 1. Natural Gas Price Forecast Comparison ($/MMBtu)

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 Achievement of Indiana IRP Rule at 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.	**Met**
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.	**Partial**
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.	**Met**
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 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.	**Met**

4.1 LOAD FORECAST

I&M's energy and peak demand forecasts are both expected to decrease over the course of the IRP planning horizon. Figure 2 shows the comparison of I&M's historical and forecasted energy requirements and Table 10 shows the historical and forecasted average annual growth by customer class.

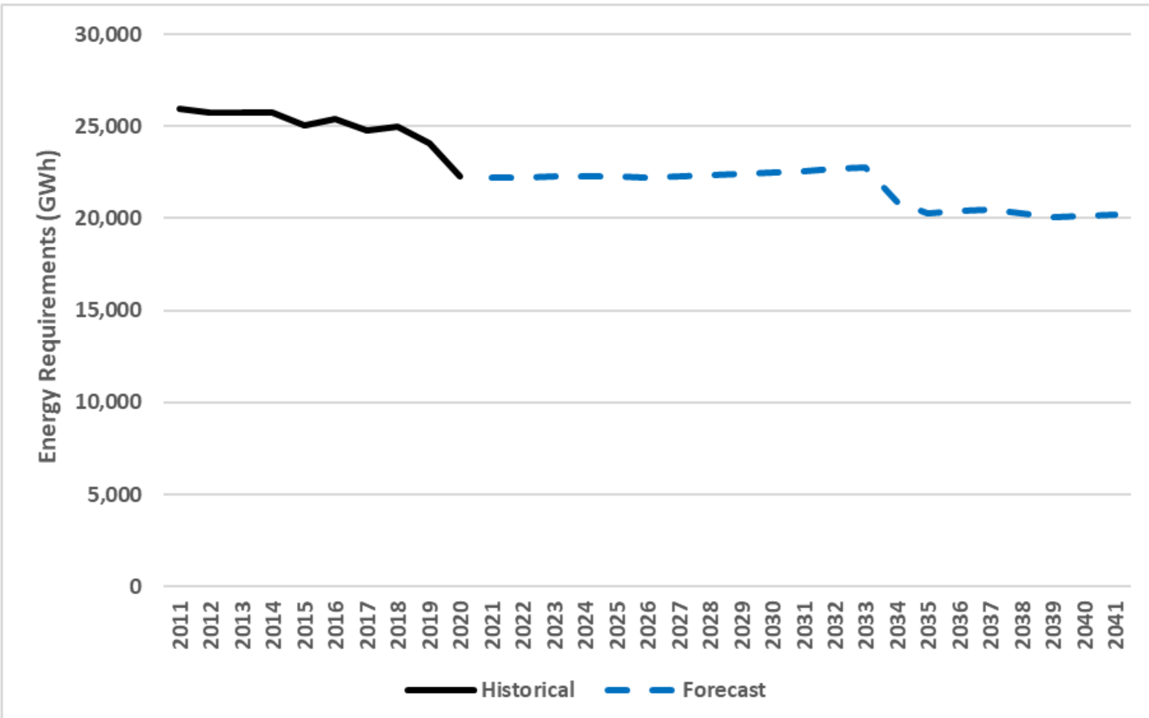

Figure 2. I&M Historical and Forecasted Energy Requirements (GWh)[29]

Table 10. Average Annual Growth by Customer Class (%)[30]

	Residential	Commercial	Industrial	Internal	Total Energy
Historical	-0.94%	-1.30%	-0.42%	-3.58%	-1.63%
Forecast	0.28%	-0.03%	0.54%	-12.07%	-0.51%

While there is some increase in growth from the residential and industrial customer classes, the Internal customer class, which includes wholesale and street lighting customers, is expected to see a significant decrease in average annual growth due to the loss of some of the wholesale customers. Figure 3 shows the forecasted load from the Internal Sales customer class. The Internal Sales forecast remains relatively steady until 2034 when there is a significant decrease in the forecast due to the anticipated loss of some wholesale customers.

[29] I&M 2021 IRP, Volume 1, Exhibit A-1.
[30] I&M 2021 IRP, Volume 1, Exhibit A-1.

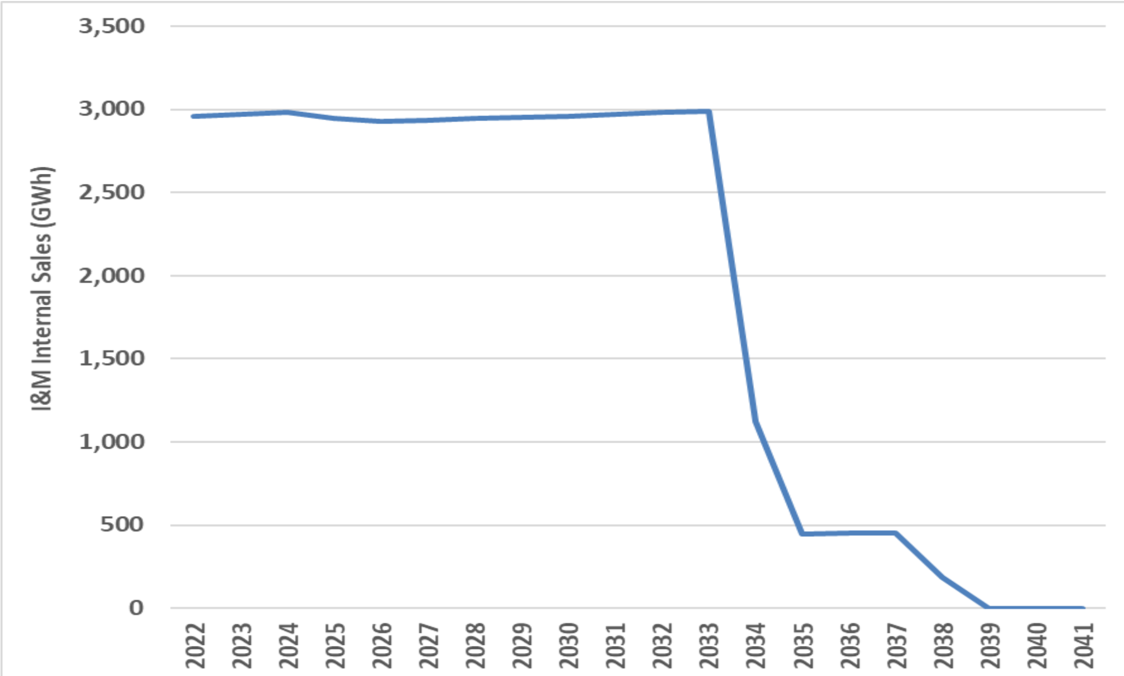

Figure 3. I&M Internal Sales (GWh)[31]

I&M's peak demand average annual growth rate is also projected to have a negative average annual growth rate over the forecast period. Figure 4 shows the historical and forecasted peak demand over the forecast period, and Table 11 shows the historical and forecast average annual growth for the peak demand. I&M predicts that the negative peak demand rate of change will slow and *not* mirror the recent historical decline in demand.

[31] I&M 2021 IRP, Volume 1, Exhibit A-3.

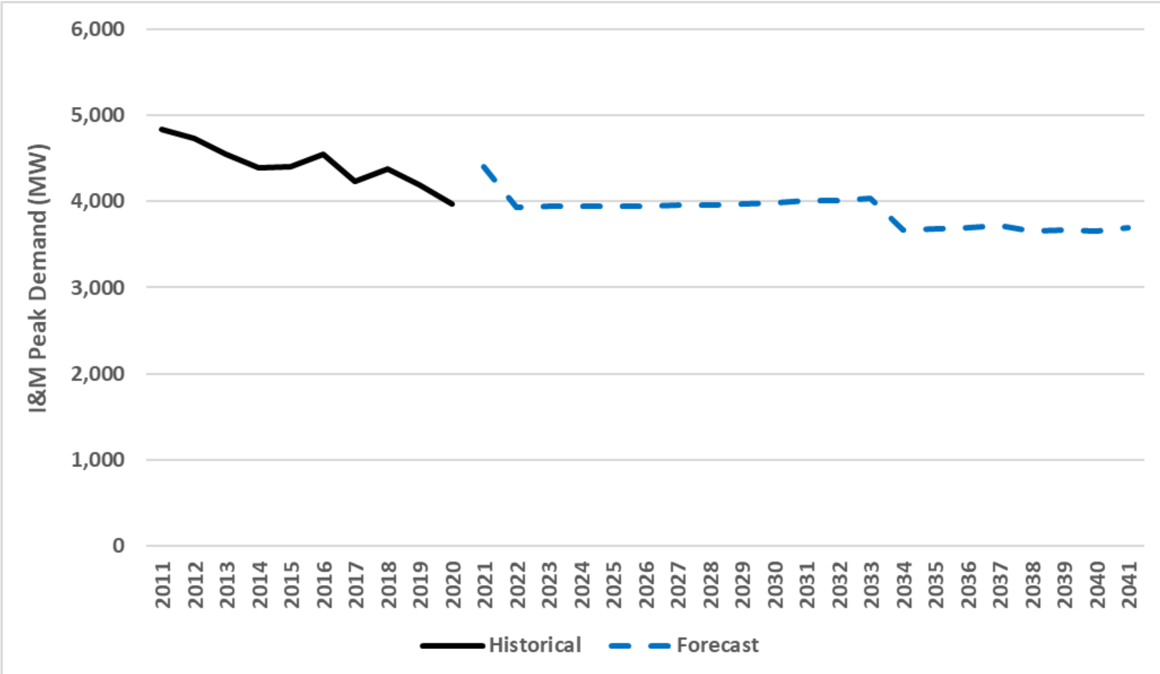

Figure 4. I&M Historical and Forecasted Peak Demand (GWh)[32]

Table 11. Average Annual Growth (%) for I&M Peak Demand[33]

	Peak Demand
Historical	-2.11%
Forecast	-0.82%

4.2 FORECAST BLENDING

The IRP includes a discussion of the short-term and long-term forecasts that are evaluated for use in the IRP analysis. Based on the IRP, it is our understanding that I&M develops a short-term monthly model that could be used for the first 24 months of the IRP planning period, and then the long-term monthly models are developed for 30 years. It seems that the difference is that the short-term models are derived from the most recent sales and weather data whereas the long-term model is based on a statistically adjusted end-use ("SAE") model. I&M describes creating both forecasts in the IRP with the rationale for developing both forecasts and then the reason for choosing only one to include in the IRP as follows:

[32] I&M 2021 IRP, Volume 1, Exhibit A-4.
[33] I&M 2021 IRP, Volume 1, Exhibit A-4.

> *The blending process is an integral part of the Company's forecast process. It entails not only evaluating the annual load growth, but also the monthly variation within each year's forecast. The Company's forecast process evaluates the pros and cons of both the short- and long-term forecasts before determining what they believe is the optimal forecast for the Company for each sector. While the Company has selected the long-term forecast in most instances, the forecast was enriched with the evaluation process and the consideration of the short-term forecast.*[34]

Figure 5 shows the blending illustration that I&M included in the IRP to provide an example of how a weighting assignment could be used to blend the two forecasts together for modeling purposes. Based on the information provided in Exhibit A-13[35] to the IRP, it appears that I&M did not choose to pursue the blending approach and used the long-term model to develop the forecasts for each customer class. We believe this approach would be preferable over a blended forecast, given the challenge of trying to find the right weighting assignment to develop a blended forecast.

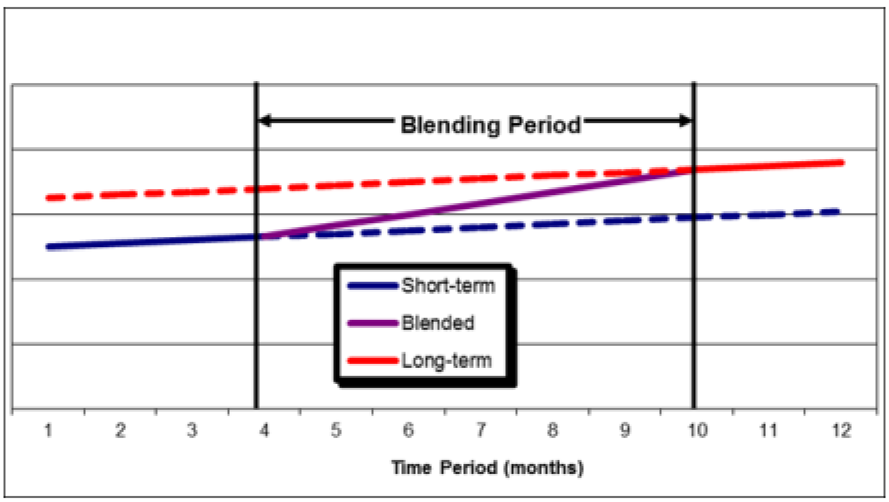

Figure 5. I&M Forecast Blending Illustration[36]

[34] I&M 2021 IRP, page 55.
[35] I&M 2021 IRP, Volume 1, Exhibit A-13.
[36] I&M 2021 IRP, Figure 17, page 49.

4.3 ACCOUNTING FOR DSM IN THE LOAD FORECAST

We had hoped that the CAC's prior settlement agreement with I&M in which it agreed not to use what it calls the Supplemental Efficiency Adjustment ("SEA") in future IRP filings had put to rest the issue of how it models DSM. However, we are deeply troubled by I&M's language in its IRP to the contrary. For example, I&M states that, "EIA AEO documentation specifically states its forecast data (used by Itron in the SAE) 'accounts for the effects of utility-level energy efficiency programs designed to stimulate investment in more efficient equipment for space heating, air conditioning, lighting, and other select appliances.'" As we have stated to I&M numerous times, Itron has developed and uses a version of this AEO information that removes utility sponsored energy efficiency. Several other Indiana utilities use this data and understand that those effects are removed and yet I&M seems totally unwilling to internalize this information. Should I&M do what it has committed for the next IRP, then it can cease use of the SEA or any other similar mechanism and take a typical approach to the problem of removing DSM impacts from the load forecast:

> *While the Company did not have any significant changes in load forecast methodology since the last IRP, the Company has explored and plans to implement changes in future IRPs to the residential and commercial sales model to have DSM as an explanatory variable to incorporate DSM effects in the load forecast*.[37]

Incorporating the impact of DSM into the load forecast as an explanatory variable in the Itron SAE model has been something we have suggested to I&M and other utilities. We are hopeful that I&M will utilize this approach in the development of the load forecast for future IRP filings which would put DSM on a more level playing field with other resources and improve the accuracy of its load forecast, as well as be consistent with the term I&M agreed to in the settlement approved in IURC Cause No. 45546.

[37] I&M 2021 IRP, page 55.

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 Achievement of Indiana IRP Rule at 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.	**Met**
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.	**Not 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.	**Not Met**
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.	**Partial**

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.	**Partial**

5.1 ENERGY EFFICIENCY

5.1.1 Market Potential Study ("MPS")

I&M engaged GDS Associates, Inc. ("GDS"), in December 2020 to determine the potential energy and demand savings that could be achieved by demand-side management ("DSM") programs. I&M and GDS sought input from members of the I&M DSM Oversight Board ("OSB") during the development of the market potential study ("MPS") through four stakeholder meetings held between December 2020 and May 2021. The final MPS report was published in September 2021. CAC found the development process to be generally open and collaborative. GDS was responsive to comments and incorporated many of the recommendations provided by CAC.

The market potential study quantified the technical, economic, maximum achievable, realistic achievable, and program potential savings for the years 2022 through 2041. Each of these scenarios is described within the MPS as follows:

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.
- **Achievable Potential** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:

  - **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
  - **Realistic Achievable Potential** ("RAP") estimates achievable potential with I&M paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- **Program Potential** simulates the expected program outcomes in forecasted years by including the following updated factors informed by best practice research:
  - Program Net-to-Gross values ("NTG"): Existing program offerings utilize 2019/2020 program NTG estimates. New program offerings are defaulted to 0.8 unless research dictates otherwise.
  - Incentive levels and structures: Measures within existing I&M programs were modeled within their current framework unless research dictates otherwise.
  - Program non-incentive costs (admin)
  - Measure Assignments: In some cases, achievable potential cost-effective measures were reassigned to new program types.

5.1.2 MPS Cost-effectiveness Screening

The MPS economic potential cost-effectiveness screening was performed as described below in the MPS:

> *In the I&M territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness. Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential.*

Utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP and Program Potential scenarios. Non-incentive costs were calibrated to recent I&M Indiana levels by sector and program and applied on a per-first year kWh basis.

A notable inconsistency with the IRP is that the MPS did not consider the avoided cost of carbon regulation. The IRP Reference Scenario included the assumption that, "Carbon regulations limiting CO_2 emissions will commence in 2028 and remain in effect throughout the forecast horizon." Had the MPS included a similar assumption for future carbon regulation, the UCT scores for all measures would have improved, thereby enabling additional measures (or programs, in the case of program potential) to be considered cost-effective. This inconsistency resulted in a smaller amount of savings being available for selection within the IRP.

5.1.3 MPS Scenarios Modeled in IRP

Based on discussions with I&M and GDS during stakeholder workshops, CAC was under the impression that I&M would be modeling bundles of savings from the MPS RAP scenario, consistent with IRP modeling performed by other Indiana utilities. Instead, EE bundles were constructed from the MPS *Program Potential* scenario. RAP (and MAP) savings were excluded from the IRP model entirely, and therefore were not a selectable resource within Aurora and were never allowed to compete with other resource options. This approach is problematic since it imposes limits on future EE potential based on existing program design, budget, and incentive levels. As a result, the MPS forecast is no longer independent of existing program constraints. Dozens of measures were excluded from the IRP modeling and were unable to compete for selection, despite being economically attractive. In fact, the residential cumulative annual savings under the Program Potential represents **less than half** of the savings identified by the RAP scenario, as shown in Table 13 below.

Table 13. MPS RAP and Program RAP Potential (MWh)[38]

TABLE 7-1 PROGRAM POTENTIAL (MWH)

Program	RAP (gross)	Program RAP (gross)
Residential	654,240	319,404
C&I	973,046	979,544
Total	1,627,285	1,298,947

The loss of savings within residential is primarily due to the complete elimination of entire programs under the Program Potential scenario:

- Home Appliance Recycling
- Home Energy Management
- Home Weatherproofing
- School Education

These programs were removed from the Program Potential scenario on the basis that they were not cost-effective. Yet the MPS model provided by GDS lacks any quantification of program-level cost-effectiveness. Instead, the measures associated with the programs listed above were eliminated from the Program Potential scenario through a hard-coded 0% applicability factor.

Had the RAP scenario been modeled within the IRP, the savings shown in Table 14 would have been available for selection from measures with passing cost-effectiveness scores within the eliminated programs. Each program is shown with incremental annual savings in 2023, and cumulative annual savings in 2041, by end-use.

[38] I&M 2021 MPS, Table 7-1.

Table 14. RAP Scenario Savings

Program	End Use	Incremental Annual MWh (2023)	Cumulative Annual MWh (2041)
Home Appliance Recycling	Appliances	2,452	19,617
Home Appliance Recycling	HVAC Equipment	490	2,147
Home Energy Management	HVAC Equipment	682	10,241
Home Weatherproofing	Behavioral	0	0
Home Weatherproofing	HVAC Equipment	296	1,481
Home Weatherproofing	Lighting	59	117
Home Weatherproofing	Shell	7,094	100,904
Home Weatherproofing	Water Heating	3,305	29,807
School Education	HVAC Equipment	151	2,116
School Education	Lighting	95	206
School Education	Water Heating	2,404	15,187
Total		**17,027**	**181,824**

5.1.4 Income Qualified Weatherproofing

I&M modeled a very conservative amount of savings from the Income Qualified Weatherproofing ("IQW") program within the IRP as shown in Table 15. While IQW measures are not subject to cost-effectiveness testing within the MPS, the savings within the Program Potential scenario were drastically reduced due to artificially imposed budget limitations. The incremental annual savings for every single measure within IQW was reduced, by an average of 92%, within the Program Potential scenario. As a result, only 8% of the incremental annual savings and 7% of the cumulative annual savings, compared to the RAP scenario, were modeled within the IRP. Constraining the potential from these measures outside of the IRP undermines the modeling process. In fact, many of the IQW measures are cost-effective on their own and may have performed well within the IRP.

Table 15. Income Qualified Weatherproofing Savings (MWh)

Income Qualified Weatherproofing Scenario	Incremental Annual MWh (2023)	Cumulative Annual MWh (2041)
RAP	6,195	119,354
Program Potential	517	8,097
Difference	**5,678**	**111,257**

5.1.5 Emerging Technology

The MPS analysis included 32 measures (18 residential, 14 commercial & industrial) that were designated by GDS as emerging technology. These measures were identified using a variety of resources including the American Council for an Energy-Efficient Economy ("ACEEE"), the U.S. Department of Energy, and the Northwest Energy Efficiency Alliance ("NEEA"). CAC commends the inclusion of emerging technologies in the MPS, however, the relatively small number of measures resulted in a very limited impact. Many of the emerging technology measures included in the study failed to pass the economic screen and therefore did not contribute to the achievable potential. Ultimately, the RAP scenario only included 22 emerging technology measures (8 residential, 14 commercial & industrial). In the residential sector, emerging tech measures accounted for only 3-5% of incremental annual savings in the RAP scenario.[39] In the commercial & industrial sectors, emerging technology measures accounted for only 1-3% of incremental annual savings in the RAP scenario.[40]

The nature of new emerging technology is such that high initial costs tend to fall as production volume and market adoption increase. The MPS analysis made no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost-effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in a conservative and unrealistic view of the potential savings.

As a point of comparison, the Consumers Energy 2021 Electric Energy Waste Reduction Potential Study, completed by Cadmus, evaluated over 200 emerging technology measures

[39] Excluding the following measures, which are rarely considered to be emerging technologies: AMI Data Portal, Smart Thermostat.
[40] Excluding the following measures, which are rarely considered to be emerging technologies: Behavioral, Central Lighting Monitoring & Controls (non-networked), Network Lighting Controls - Wireless (WiFi), Energy Recovery Ventilator, Smart Thermostat.

which were characterized and included in the model.[41] Ultimately, 170 unique measures were included in what Consumers Energy refers to as the "Transformational Scenario." The impact of this scenario was significant on the estimate of future achievable potential, as shown in Figure 6 below.[42] In years 3 through 9, emerging technologies account for roughly 20% of the achievable potential. In the later years of the Consumers Energy study, emerging technologies account for roughly two-thirds of the achievable potential. These results plainly demonstrate the significance of emerging technologies and highlight the importance of adequately accounting for them in a market potential study.

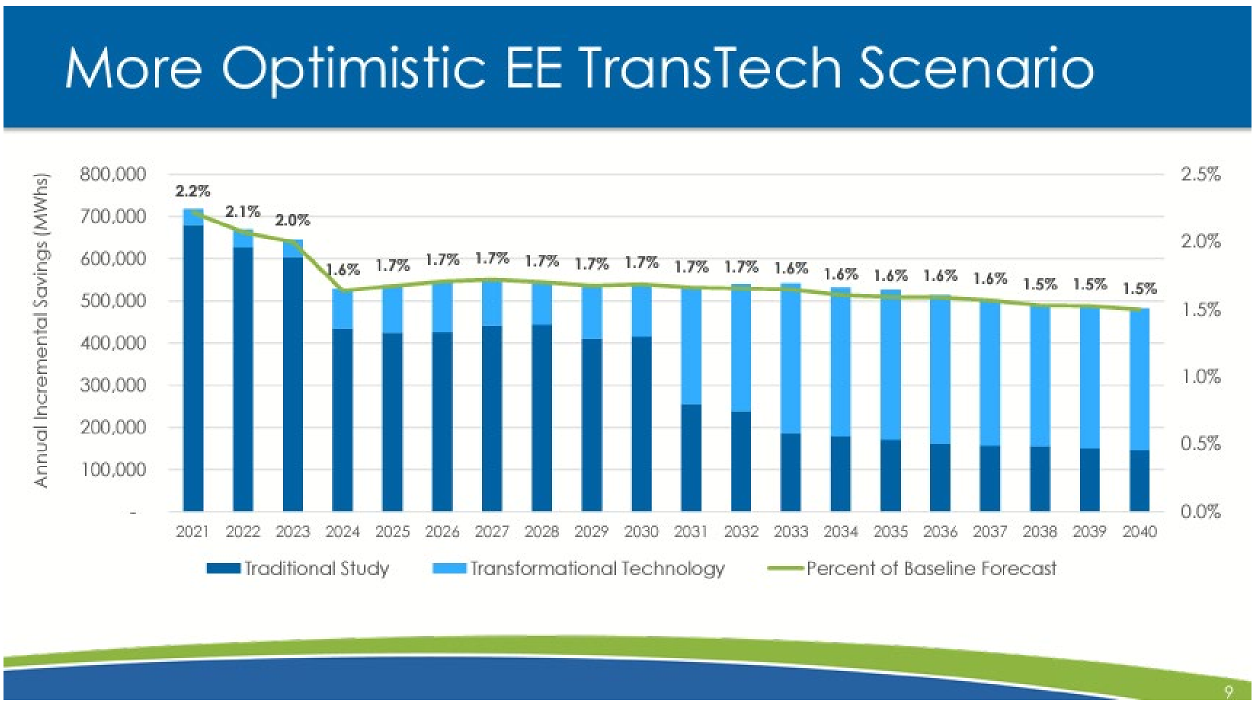

Figure 6. Consumers Energy Transformational Scenario

5.1.6 Energy Efficiency Modeled in Aurora

Based on the MPS, I&M and Siemens PTI modeled one income-qualified bundle, five residential bundles, and eight C&I bundles that were available across the time horizons of 2023 – 2025, 2026 – 2028, and 2029 – 2040. Notably, I&M did not model energy efficiency beyond 2040 even though its capacity expansion study period extended through 2050. This is a less than ideal

[41] MPSC Case No. U-21090, Consumers Energy Co. Witness Garth, Exhibit A-81 available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf

[42] Presentation by Consumers Energy, "Creating a Transformational Path to the Future of Energy Efficiency, Together!," available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Transformational-EWR-Together_CE_20220719-final.pdf

approach because energy efficiency will not have the same opportunity to defer or eliminate capacity additions that it did in during the first 27 years of the planning period.[43]

Three of the best practices we recommend for modeling DSM resources on a comparable basis to supply side resources is to adjust the costs modeled to capture the benefit from avoided T&D, to adjust the savings to the generator level by using marginal line losses, and to levelize the costs across the lifetime of the DSM resources. Levelizing costs is preferable since this ensures that the model can capture the lifetime costs and benefits of energy savings in the same manner it does for supply-side resources.

In its modeling of DSM, I&M did include an avoided T&D benefit for DSM resources that was applied as a reduction to the cost of the resources. We support I&M's modeling of an avoided T&D benefit. However, I&M did not model the costs associated with DSM resources on a levelized cost basis. As I&M stated in the IRP:

> *The energy efficiency MWh and MW impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because energy efficiency program costs are only incurred during the year of measure installation, budgets are only reflected during the identified years in each vintage block.*[44]

We disagree with the approach that I&M took to model the costs of DSM in Aurora, because it creates an end-effects problem in which the full costs of DSM are accounted for, but the savings are truncated, or undercounted. We welcome the opportunity to have a dialogue with I&M about this modeling approach for the next IRP filing and well in advance of the next DSM filing.

We also have concerns with the approach used to translate the MPS results into bundles modeled in Aurora. For this IRP, I&M used a k-means clustering approach to bundle measures, which resulted in bundles as small as a single measure and other bundles with a span of measures across different end-uses – an approach that means I&M cannot say that the selected measures would actually conform with a coherent program design that I&M will actually implement.[45] We would recommend that I&M take a different approach to bundling measures for the next IRP, focusing instead on grouping at the sector level. We welcome the opportunity to collaborate with I&M on a bundling approach for the next IRP.

5.1.7 Net to Gross Sensitivity and Supplemental Efficiency Adjustment ("SEA")

I&M had historically applied what it calls a Supplemental Efficiency Adjustment ("SEA") to its energy efficiency potential to remove what it believes are naturally occurring savings included in that potential. As we have stated many times in the past to I&M, this approach incorrectly double counts naturally occurring savings and artificially reduces energy efficiency potential. The very

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[43] Note that while resource selection was performed out to 2050, the portfolio PVRRs were only calculated using data through 2041.
[44] I&M 2021 IRP, pages 115-116.
[45] I&M 2020 IRP, page 115.

purpose of an MPS is to understate participation in programs that incentivize energy efficiency. To the extent there are free riders in those programs, adjustments are needed, but the scale of the SEA reduces savings by 45% over their lifetime, a free-rider rate that is unheard of.

As part of the IURC Cause 45546 settlement, I&M agreed to model portfolios that utilized a Net-to-Gross ("NTG") factor in place of the Supplemental Efficiency Adjustment ("SEA"). It is our understanding that I&M is going to discontinue the application of the SEA or any kind of factor that degrades energy efficiency savings for future IRP filings, however, in several places I&M seems to ignore its commitment to ceasing this flawed practice. We have argued against the use of the SEA and ask for the discontinuation of this methodology in favor of one that models the full lifetime savings of DSM resources pursuant to the 45546 settlement. To the extent that free riders are not accounted for in the MPS, it is appropriate to apply a reasonable net to gross factor to the MPS potential, but this is different than the purpose and scope of SEA that I&M has historically used.

I&M appears to have used a nearly 20% net to gross factor on all its savings to develop portfolios with a different set of bundles. This factor does not seem to have any analytical basis. In the IRP narrative, I&M described the approach:

> *The measure/bundle assignment was not altered for the NTG factor bundles and in both the SEA and NTG bundles, the gross program savings were the same. In addition, the first adjustment (noted in 7.8.1.2) to the Market Potential Study's program energy efficiency potential was also carried forward in the NTG Factor IRP inputs to adjust to savings at the generator level.*
>
> *In the NTG factor IRP bundles, a second adjustment converted the projected gross program savings estimates to net savings using I&M's most recent program evaluation results but does not assume that customers will adopt more efficient technologies outside of a utility sponsored program. This is in contrast to the SEA factor approach, which utilized gross program savings but assumes a weighted average effective useful life (EUL) for all measures in each bundle and adjusts the same projected gross program savings to account for the future customer adoption of efficient technologies already considered in the load forecast.*[46]

I&M included the application of the NTG factor in three of the original Candidate Portfolios, including the Rockport 1 2024, Rockport 1 2025, and Rapid Technology Advancement portfolios. Table 23 in I&M's IRP indicates that the NTG application to energy efficiency was used to inform and "Evaluate Alternative Treatment of Energy Efficiency Resources."[47]

Ultimately, the three NTG portfolios were screened out by I&M:

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[46] I&M 2021 IRP, page 116.
[47] I&M 2021 IRP, Table 23, page 140.

> *The three Net-to-Gross portfolios, Rockport 1 2024 N2G, Rockport 1 2026 N2G, and Rapid Technology Advancement N2G, were screened out as they were used to evaluate an alternative method of modeling new energy efficiency resources related to the Settlement Agreement in IURC Cause No. 45546. While the Company plans to study and test potential modifications needed to model NTG EE bundles savings in the IRP modeling construct in future IRP's, this approach includes and monetizes energy efficiency savings that already are included in the Company's load forecast described in Section 5.6.2 and further discussed in section 7.8.1 used for this IRP.*[48]

We are concerned that I&M continues to misunderstand how naturally occurring savings are accounted for – those savings are excluded from the MPS. Only free-riders are included in the MPS potential. To the extent that the load forecast includes some amount of new DSM because the data upon which it is based also include DSM, that is an issue that is unique to the load forecast and has nothing to do with the MPS. It must be resolved through adjustments to the load forecast, and Itron, I&M's load forecast model vendor, has offered several ways to do this. By I&M's own admission during its 2021 IRP Contemporary Issues presentation, it could identify no utility that uses a mechanism similar to its SEA. And as we have stated numerous times over multiple years, the problem I&M seeks to resolve of DSM embedded in its load forecast is not unique to I&M and can be appropriately resolved using the methodologies that numerous other utilities use, rather than the flawed SEA approach.

[48] I&M 2021 IRP, page 141.

5.2 DEMAND RESPONSE

The following sections discuss I&M's modeling of existing and new demand response resources. For existing demand response, there was conflicting information on how the resource was reflected in the modeling. For the next IRP, it will be helpful for I&M to be clearer in the discussion and explanation of how existing demand response is captured in the modeling.

5.2.1 Existing Demand Response

We typically see utilities choose to model existing demand response as either a reduction to the load forecast or set up explicitly as a supply-side resource that can be selected within the capacity expansion model. However, it was not clear how or if I&M accounted for its existing demand response resources in the modeling performed for this IRP.

In the section of the IRP discussing existing Demand-Side Programs, I&M stated that:

> *DR[49] programs* ***are accounted for as a load shape reduction from the load forecast*** *used in the IRP. For the year 2023, I&M anticipates 204 MW of DR reduction. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control*. [emphasis added][50]

The IRP's load forecast section contradicts this, where I&M stated:

> *The Company has two customers with interruptible provisions in their contracts. These customers have a combined interruptible contract capacity of 15MW. However, these customers are expected to have only 14MW available for interruption for winter and summer peaks. An additional 135 customers have 248MW available for interruption in emergency situations in DR agreements.* ***The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking.*** *As such, estimates for DR resource impacts are reflected by I&M in determination of PJM-required resource adequacy (i.e., I&M's projected capacity position).* [emphasis added][51]

This suggests that existing demand response was not modeled on the supply-side, and indeed I&M's Aurora database contained nothing that would represent these resources explicitly. We were not able to determine whether existing DR was somehow accounted for in this load forecast and, given that the language in the IRP was confusing and unclear, it may even be that these resources were not included at all. I&M's existing demand response is not an immaterial

[49] I&M uses DR to refer to Demand Reduction.
[50] I&M 2021 IRP, page 74.
[51] I&M 2021 IRP, page 48.

resource and ought to be modeled explicitly with the ability to economically dispatch the resource, as appropriate, so that its full value can be simulated.

5.2.2 New Demand Response

I&M and Siemens PTI modeled new demand response that is assumed to come online starting in 2023 with a nameplate capacity that grows incrementally until it reaches 121 MW by 2041. This demand response resource was assigned a specific hourly shape within Aurora, which tells the model which days and hours the demand response is available to be dispatched. In any given year, the demand response resource is only available for a total of 16 hours across the months of April, June, July, and August. If there is a need in any of those "available" hours, then Aurora will dispatch the resource.

When we were reviewing the modeling outputs, we realized that the accredited capacity value[52] of this new demand response resource was treated by the model as 0 MW in many years of the planning period. When we reviewed the Aurora model manual, it appears that Aurora only recognizes the capacity value for a resource if it is available during the peak hour in any given year. Since the demand response resource was assigned a specific hourly shape, if the hours in which it was available happened to not include the peak hour for a given year, then zero capacity value was given. Table 16 shows the comparison of the nameplate capacity of the demand response resource compared to the accredited capacity reported from Aurora between 2023 and 2041. Since the capacity expansion modeling step is primarily focused on meeting the peak demand plus reserve margin, in those years where the demand response resource receives no capacity value, the model may choose to build otherwise unneeded capacity to meet its obligation. When we reviewed the capacity position workbooks[53] that I&M and Siemens PTI created for each candidate portfolio in the capacity expansion modeling step, it was clear that I&M intended to account for the full capacity value of the demand response resource. It is not clear, therefore, why Aurora was not set up to do so through the use of a dummy unit or not specifying a specific hourly shape for the dispatch of the resource. The effect of undervaluing this resource is that the model would see a lower capacity position for I&M than actually exists, and therefore the model could choose to build new resources to fill what it perceives as a gap in I&M's capacity position.

[52] In the Aurora modeling outputs, this is reported as "Peak Capacity".
[53] Step 3 modeling outputs provided in Indiana Michigan Power Company response to Staff data request 1-01. MPSC Case No. U-21189.

Table 16. Demand Response Aurora Input and Output

Year	Nameplate Capacity[54] (MW)	Peak Capacity[55] (MW)
2023	8	8
2024	12	12
2025	20	20
2026	33	0
2027	52	0
2028	71	0
2029	86	0
2030	97	0
2031	104	0
2032	108	0
2033	112	112
2034	113	113
2035	115	115
2036	117	0
2037	118	0
2038	119	0
2039	120	120
2040	120	120
2041	121	121

One of the comments submitted by the Office of Utility Consumer Counselor ("OUCC") on I&M's 2021 IRP was in regard to how I&M modeled the new demand response resource. The OUCC said: "The OUCC is concerned that I&M did not allow these programs to compete on a level playing field with supply-side resources. This would seem to be at odds with some basic IRP principles, as well as comments in previous IURC Directors' reports about not 'hard-wiring' DSM into IRPs."[56] We agree with OUCC in as much as there ought to be a rationale for hard-wiring resources, e.g., previous runs have demonstrated that a particular resource is cost-effective. We would note that, while not conclusive, on the subject, the UCT ratios of the new DR in the MPS was often well above 1.0. In addition, OUCC's concern ought to extend to the supply-side as well in that several new generators were hard wired on the basis of poorly supported rationale, which is discussed in Section 7.

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[54] Modeling files provided in Indiana Michigan Power Company response to Staff data request 1-01. MPSC Case No. U-21189.
[55] Step 3 modeling outputs provided in Indiana Michigan Power Company response to Staff data request 1-01. MPSC Case No. U-21189.
[56] OUCC Comments on I&M's 2021 IRP. Retrieved from https://www.in.gov/iurc/files/OUCC-Comments-on-IM-2021-IRP-05-12-2022.pdf

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 17 below for our findings.

Table 17. Summary of I&M's Achievement of Indiana IRP Rule at 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Finding
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.	**Mostly**

6.1 RESOURCE SCREENING TABLE

For this IRP, I&M and Siemens PTI considered new supply side resources consisting of natural gas base and peaking technologies, solar, wind, solar hybrid, and standalone battery storage resources. Exhibit D to the IRP contains a table that shows the new supply side resources capital and operational costs. The IRP narrative reported that several technologies, including Coal and Coal with Carbon Capture Utilization and Storage ("CCUS") options were removed from the Aurora model because they were not selected by Aurora. I&M said in the IRP:

> *To improve the robustness of model results, a number of alternative resources explicitly modeled were reduced through an economic screening process focused on observed penetration in AURORA LTCE runs. The Siemens PTI team identified a set of forecasted expensive resources that the LTCE process routinely did not select as a reasonable option. Specifically, Coal and Coal with Carbon Capture Utilization and Storage (CCUS) base-load options were considered but were ultimately removed from the AURORA resource optimization modeling analyses. For coal generation resources, environmental regulation (see Section 6) makes the construction of new coal plants economically impractical.*[57]

Given the rapid technological advancements in battery storage technology, we recommend that I&M explore longer duration and multiday storage options for the next IRP.

[57] I&M 2021 IRP, page 94.

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 18 below for our findings.

Table 18. Summary of I&M's Achievement of Indiana IRP Rule at 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Finding
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.	Partial
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.	Partial
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.	Partial
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.	Partial
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.	Partial
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.	Partial

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.	Met
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.	Partial

7.1 I&M's PREFERRED PORTFOLIO

I&M's Preferred Plan was not a pure optimized plan from Aurora. I&M reported that it looked at the expansion plan from the Reference Candidate Portfolio and then moved around some of the wind, solar, and CT resource additions. In the IRP, I&M stated:

> *The Preferred Portfolio was derived from the Reference Candidate Portfolio with adjustments to resource selections to reduce risks around near-term capital requirements, project execution, reserve margin and energy position surplus influence on portfolio costs in order to best align with the Company's overall objective and metrics.*[58]

Table 19 below shows the comparison of the optimized Reference capacity expansion plan between 2025 and 2028 compared to those resources in I&M's Preferred Plan. Over this four-year time period, I&M's Preferred Plan cuts the amount of new wind additions in half and lowers the solar additions by 500 MW while increasing the gas CT capacity by 250 MW. The 800 MW of wind from the Reference Candidate Portfolio was shifted out to 2035 and 2038 from 2025 and 2026 while the 500 MW of solar moved from 2025 and 2026 to 2034, 2035, 2036, and 2039.[59] The 250 MW of gas CT capacity added in each 2027 and 2033 under the Reference' Candidate Portfolio were combined with the 500 MW of gas CT selected for 2028 under the Reference' Candidate Portfolio to arrive at the 1,000 MW total gas CT capacity in 2028 under the Preferred Portfolio. These are radical changes to the plan, not just adjustments by a year or small changes in capacity.

I&M discussed the Company's rationale for moving the 2025 and 2026 wind and solar resources in the IRP:

[58] 2021 IRP, pages 142-143.

[59] The 500 MW of 2025 and 2026 solar was spread across later years in the following amounts: 200 MW in 2034, 100 MW in 2035, 200 MW in 2036, and 250 MW in 2039. I&M added another 250 MW of solar in 2039.

> *The Reference' Portfolio included a high amount of renewable resources in the near term to take advantage of Federal renewable tax credits, in particular wind resources, however that impacted the Company's energy position, imposing additional market risk through forecasted energy margins, as reflected in the Sales as a Percentage of Load metric in the Balanced Scorecard and Exhibit C-21. This sales length begins to grow in 2025 as the model adds low-cost wind and solar resources up to the Company constraints, discussed in Section 7.6.5.1. Due to this and other considerations, the Company reduced the solar and wind resource additions in 2025 and 2026 by 50%, which reduced the forecasted energy length in 2027 by approximately a third, down to 29% and is reflected in the Preferred Portfolio, while meeting its PJM capacity obligation.*
>
> *Additionally, this modification reduces the Preferred Portfolio's Capital Investment through 2028 to $3.83 B, whereas the Reference' Portfolio has a $5.52 B capital investment need through the same time period.*[60]

Table 19. Expansion Plan Build Comparison

	2025 – 2028 Additions			
Candidate Portfolio	**Wind**	**Solar**	**Storage**[61]	**Gas CT**
Reference'	1,600	1,800	60	750
Preferred	800	1,300	60	1,000

While there are some instances when it makes sense to make out-of-model changes to an optimized portfolio, the changes made to I&M's Preferred Portfolio in the Short-Term Action Plan period radically change the near-term resource mix in particular. I&M's Preferred Plan pushes 1,300 MW of wind and solar selected by the model in 2025 and 2026 out to the later portion of the planning period while it also slides forward additional gas capacity by five years. **I&M is essentially doing the opposite of what its modeling says is optimal – substituting new, more gas for lower-cost renewables**.

All the portfolios passed to the scorecard stage were long on energy and many were similarly long on capacity. If I&M was concerned about this, it should have used the optimization modeling as a jumping off point to test additional portfolios including earlier retirement of units to explore the nature of a portfolio with fewer sales. It could also have set limits on sales in its modeling to understand how that would affect the preferred plan. Instead, it created a radically different plan biased toward expensive gas buildout.

I&M also contends that this reduces capital investment, but capital is just one of several categories of costs ratepayers will bear. A fair comparison would have included variable costs such as fuel as well as fixed costs which will arise disproportionately from the gas units that I&M intends to add.

[60] I&M 2021 IRP, page 145.
[61] Battery storage portion of a solar hybrid resource.

7.1.1 MICHIGAN COMMISSION RECOMMENDATIONS ON I&M's PREFEERED PLAN

In the testimony filed by Zachary Heidemann of the Michigan Public Service Commission ("MPSC") Staff, Mr. Heidemann put forward an alternate resource addition of 255 MW[62] of battery storage in 2028 in place of the 250 MW of CT capacity that I&M brought forward from 2033 to 2028. In his testimony, Mr. Heidemann said:

> *Shifting one 250 MW CT peaking plant back a year does not cause issues, as both are in the Short-Term Action Plan and both are added by the model to replace capacity currently provided by Rockport. However, shifting the 250 MW CT from 2033 to 2028 creates a problem. The LTCE optimization added this resource under the assumption that Cook Unit 1 would be retiring in 2034. Looking at Exhibit C-5 in Company Exhibit IM-2, no more peaking plants are added past 2028 if the Cook license is assumed to be renewed. This means that the addition of the last 250 MW of CT capacity conflicts with the idea that the Company endeavors to maintain optionality around the Cook relicensing. In addition, the model did not select the fourth 250 MW CT for this time period, while it did select the other three. The Company did not allow the model to optimize the build plan around any capacity need in this year, and instead selected this resource outside of an LTCE optimization that included all other components of the Short-Term Action Plan.*[63]

In place of the 250 MW of CT capacity, Mr. Heidemann put forward the recommendation to replace it with 255 MW of battery storage resources. Mr. Heidemann made this recommendation based on the results of the additional resources added in the Candidate Portfolios where renewable build limits were relaxed in the modeling. Mr. Heidemann said:

> *Based upon the increase in hybrid storage selected by the model when constraints were relaxed, Staff recommends the Company replace 250 MW of CT with 255 MW of additional storage. The model selected approximately this amount of storage for the Short-Term Action Plan 6 in the Expanded Build Limit portfolio. In addition, storage is a capacity resource, and it does not increase the renewable generation in the Company's short-term portfolio, while also providing increased resource diversity in the Company's overall resource portfolio.*[64]

[62] Witness Zachary Heidemann recommends a build of 85 MW increments over 2026, 2027, and 2028 to replace the 250 MW of CT capacity.
[63] Direct Testimony Witness Zachary Heidemann. MPSC Case No. U-21189. Page 15.
[64] Direct Testimony of Witness Zachary Heidemann. MPSC Case No. U-21189. Pages 16 – 17.

7.2 PORTFOLIO EVALUATION

Figure 7 shows the objectives and metrics I&M developed for its balanced scorecard approach that was used to evaluate the Candidate Portfolios. We reiterate the comments that we provided during the stakeholder workshop that a weakness of this approach is that many of the metrics are reported based on a single year. It appears that some of the metrics like the purchases and sales as a percentage of load are an average over the IRP period, however, there are still other single-year metrics, like the CO_2 emissions and the surplus reserve margin above the PJM Forecast Pool Requirement ("FPR"). For these two metrics, only the 2041 value is reported, but the impact from CO_2 emissions and the reserve margin requirement are germane for every year of the study period. Merely looking at 2041 does not yield meaningful information for comparing Candidate Portfolios. As Witness Tyler Comings pointed out about in his testimony in MPSC Case No. U-21189:

> *The Company scores portfolios for 'sustainability' based on CO_2 emissions reductions from 2005 to 2041, looking only at the first and last years of that span. But this calculation ignores the emissions in the interim years. When using the more reasonable metric of cumulative emissions, the preferred plan—including continued reliance on OVEC until 2040—is the worst of the 16 plans presented by I&M.*[65]

While we appreciate some of the visualizations provided with the IRP that show how the emissions change throughout the planning period, ultimately a single value is being reported in the scorecard, and that is the only methodology to demonstrate "balance" in I&M's preferred plan.

Objective Category	Objective	Metric
Affordability	Affordability	20-Year NPV Cost to Serve Load
		10-Year NPV Cost to Serve Load
	Rate Stability	95th percentile value of NPV Cost to Serve Load
		Difference Between Mean and 95th Percentile
		5 Year Net Rate Increase CAGR (2025-2029)
		Capital Investment Through 2028
	Market Risk Minimization	Avg. Purchases as a % of Load (2022-2041)
		Avg. Sales as a % of Load (2022-2041)
Sustainability	Sustainability	% Reduction of CO_2 (2005-2041)
Reliability and Resource Diversification	Reliability	Surplus Reserve Margin above FPR Requirement
	Resource Diversity	Average # of Unique Generators
		Average # of Unique Fuel Types

Figure 7. I&M Balanced Scorecard Objectives and Metrics[66]

[65] Direct Testimony of Witness Comings. MPSC Case No. U-21189. Page 9.
[66] I&M 2021 IRP, Table 21, page 138.

7.2.1 PORTFOLIOS SCREENED OUT

Table 23 of the IRP provides an overview of which Candidate Portfolios were eliminated by I&M. I&M stated that the Expanded Build Limits portfolio were eliminated because of energy exports and market risk:

> *The Expanded Build Limits portfolio and the No Build Limits portfolio, used to evaluate the cost and performance implications of portfolio limitations on new capacity additions, were screened out due to their high energy exports, exposure to market risk, and costs. Energy exports that exceed acceptable thresholds can produce greater economic risks due to the uncertainty of future energy spot market prices and also did not meet I&M's objectives around managing capacity and energy length above its projected load requirements. Annual build limits were removed for the Reference with No Renewable Limits Candidate Portfolio, which as shown in Table 22, results in Sales as a Percent of Load averaging 96.3% over the analysis period.* [67]

It is not clear how the Expanded Build Limits portfolio was used to inform the limits modeled in the Reference or Reference' portfolios, and, ultimately, I&M's Preferred Portfolio includes the movement of the 2025 and 2026 wind and solar resources to the second half of the planning period. Regarding the concern about high energy exports and market risk, it is not clear why I&M did not apply constraints within the capacity expansion model to limit sales. Applying a constraint would have helped to address I&M's concern about high exports.

7.3 RISK ANALYSIS

I&M's risk analysis relied on the stochastic modeling approach that Siemens PTI utilizes for modeling in Aurora. I&M's stochastic modeling included performing 200 deterministic production cost runs or "iterations" where the average of the 200 iterations was calculated to report out the NPV for each portfolio. Each of the 200 iterations contained a unique combination of each of the variables modeled, which included coal prices, natural gas prices, carbon emission prices, load, and capital costs for new resources in modeled areas outside of I&M. I&M assumed that the portfolio of resources within the I&M service territory is held constant, but the buildout in the other modeled areas outside of I&M are allowed to change under each set iteration.

Table 20 shows the timespan of historical data that was used to develop the stochastic gas prices modeled over the three different time periods between 2021 to 2041. I&M said in the IRP that, "This allows gas price volatility to be low in the short-term, moderate in the medium term and higher in the long-term in alignment with observed historical volatility."[68] Looking back at the natural gas price forwards discussed in Section 3.3, this stochastic modeling approach fails to capture the recent shift in natural gas prices which are higher than what was modeled in I&M's

[67] I&M 2021 IRP, page 141.
[68] I&M 2021 IRP, page 123.

stochastic modeling. This is not to say that I&M should have or could have used natural gas futures that coincide with or post-date its IRP filing, but it does point to a downside of using this stochastic modeling approach that assumes higher volatility which only manifests later in the planning period.

Table 20. Natural Gas Stochastic Variable Distribution Development[69]

Time Frame	Historical Natural Gas Price Data
2021 – 2024	Past Three Years
2025 – 2027	Past Five Years
2028 – 2041	Past Ten Years

The creation of a probability distribution to use for modeling CO_2 costs is challenging for stochastic modeling since there are no historical datasets to leverage to assist in the development of a distribution, which means that any distribution created is entirely subjective. I&M acknowledges this in the IRP when it said, "The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historic data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions."[70]

We believe that sensitivity testing is a more informative way to test uncertainty in place of stochastic testing of variables that are not truly volatile or lack the data in order to be properly characterized for stochastic testing.

7.4 EARLY TERMINATION OF THE OVEC CONTRACT

I&M and Siemens PTI modeled a 2030 termination date for the power purchase agreement with the Ohio Valley Electric Corporation ("OVEC"), also known as the Inter-Company Power Agreement ("ICPA"). There are two problems with the manner in which I&M and Siemens modeled the contract energy costs and its CO_2 emission costs. Each of these concerns are discussed in the following sections.

7.4.1 OVEC Energy Costs Modeled in Aurora

Figure 8 shows an illustration of how I&M and Siemens PTI modeled the OVEC units within Aurora. In order to model the OVEC units, I&M and Siemens PTI used a combination of three major inputs. One was a dummy unit, [71] which represented the contribution of the contract's capacity to I&M's capacity obligation. The second was a set of units intended to represent I&M's ICPA costs; the third was outside the I&M system and was modeled to capture the

[69] I&M 2021 IRP, page 123.
[70] I&M 2021 IRP, page 128.
[71] A dummy unit is used to capture information that cannot be included in the principal representation of a generating unit.

dispatch[72] of the units. The right-hand side of the figure shows the total capacity of the OVEC units. The generation from these resources sets the generation that flows into the units modeled for I&M's share of OVEC, which are shown on the left-hand side of the figure. Those units are the contract units that capture the generation[73] and energy costs of the contracts, and the dummy units that account for the capacity of the contracts.

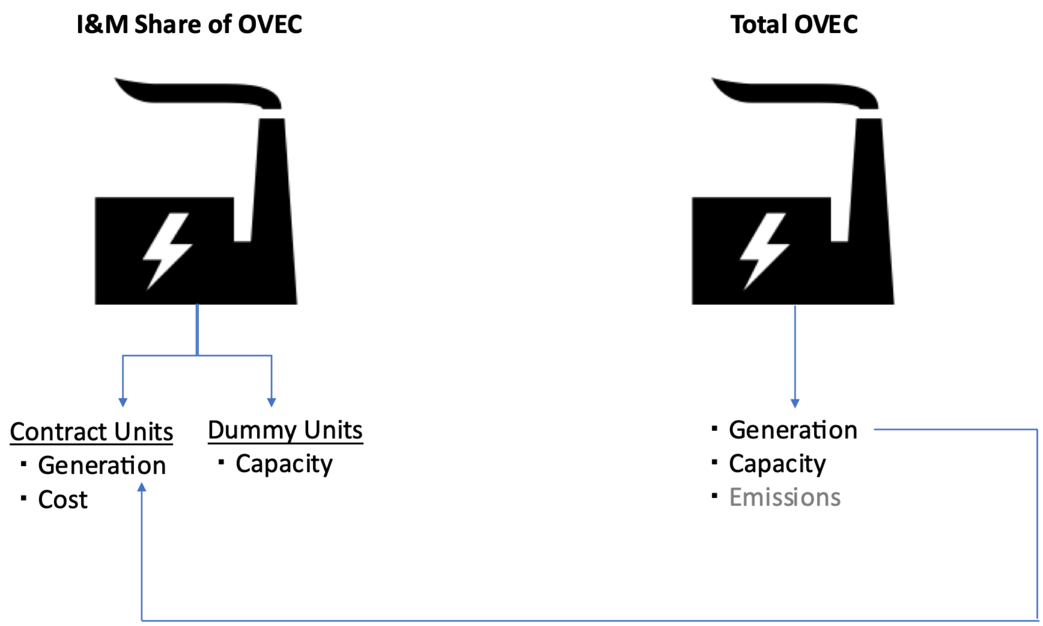

Figure 8. Modeling of OVEC in Aurora[74]

One of the problems with the modeling approach for I&M's share of the OVEC contract costs is that I&M and Siemens PTI input all Aurora modeling input costs in real 2019 dollars.[75] Aurora then translates the cost *inputs* into nominal modeling *outputs*. In the spreadsheet used to calculate the PVRR of each candidate portfolio, I&M and Siemens PTI then deflated the nominal Aurora outputs back to 2019 real dollars. While this approach of switching between nominal and real dollars is unusual, there is nothing wrong with this approach *per se*. The issue is that Aurora does not permit the use of real dollars in all of the input tables. Aurora's manual specifically says that the table containing the OVEC contract costs treats all costs as nominal. Even though the OVEC contract costs were seemingly entered in terms of real dollars, they were being treated as nominal inputs by Aurora. As a result, Aurora did not translate the costs into nominal dollars for the reporting of the modeling outputs; it presumed they were already in nominal terms. This creates

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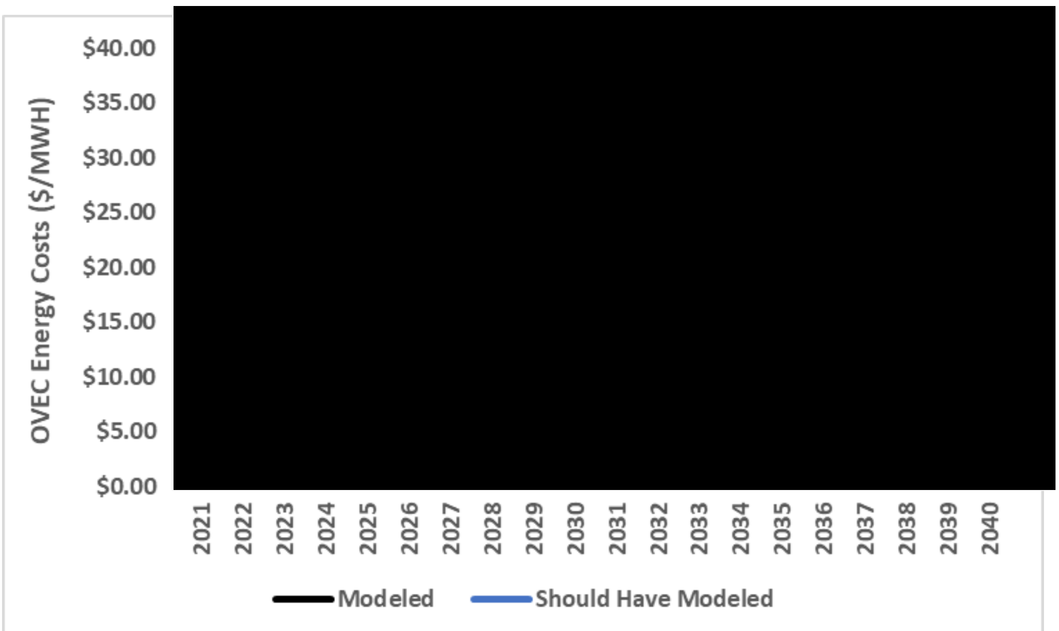
[72] Aurora assigned the generation from each of the OVEC units to I&M proportional to I&M's ownership share.
[73] The generation for the contract is equal to the generation of the total OVEC unit multiplied by I&M's ownership share.
[74] Testimony of Witness Hotaling, page 5. MSPC Case No. U-21189.
[75] Indiana Michigan Power Company response to Sierra Club data request 1-18. MSPC Case No. U-21189.

a problem for the PVRR calculation since I&M and Siemens PTI treated the ICPA cost outputs as nominal, when in fact they were real. Since the PVRR calculation was premised on the assumption that all outputs were in nominal dollars and I&M and Siemens PTI calculated the PVRR in real 2019 dollars, all outputs including the OVEC energy costs were further deflated for the PVRR calculation. Effectively, it was assumed that OVEC contract costs would decline over time, rather than remaining flat in real terms. Confidential Figure 9 below shows the comparison of the OVEC energy costs ($/MWh) as they were modeled in Aurora[76] and the costs that should have been modeled[77] in Aurora.



Confidential Figure 9. Comparison of OVEC Energy Costs ($/MWH)[78]

7.4.2 OVEC CO_2 Costs Not Included in the Present Value of Revenue Requirements ("PVRR")

One of the other issues with the way that I&M and Siemens PTI modeled the OVEC units is that the energy from the contract did not have any CO_2 emissions assigned to it, and, therefore, no CO_2 emission costs were calculated for the PVRR calculation when all the other thermal units in the portfolio had CO_2 emission costs assigned to them starting in 2028. For the calculation of the PVRR for each candidate resource portfolio, I&M and Siemens PTI included the CO_2 emission

[76] OVEC energy costs were modeled in real 2019 dollars.
[77] The particular input table in Aurora for the OVEC contract expected energy costs to be in nominal terms and not real dollars.
[78] Energy costs provided in workbook "Staff 8-02 Corrected Calculation CONFIDENTIAL" in MPSC Case No. U-21189.

cost for each thermal resource in the generation fleet starting in 2028,[79] except for the OVEC units. Looking back at Figure 8, the PVRR calculation pulled the emission cost information from the dummy OVEC units. Since those dummy units captured capacity only, there was no generation and therefore no CO_2 emissions associated with them. This means that the PVRR calculation was not picking up the CO_2 emission cost for the OVEC units, since the calculation was not recognizing that generation and, therefore, emissions would be coming from the contract units and not the dummy units. In order for the CO_2 emissions from the OVEC units to be included in the calculation, I&M and Siemens PTI needed to make a post-modeling adjustment to calculate the CO_2 emission cost associated with the generation from the OVEC contract, which I&M and Siemens PTI did not do.

7.5 EARLY TERMINATION OF THE OVEC CONTRACT

I&M included two additional candidate portfolios to evaluate an early termination of the OVEC contract in 2022 and 2030. I&M's modeling found that the Preferred Plan was lower cost than terminating the OVEC contract in 2030. However, I&M's approach was to evaluate a resource replacement that could only happen in 2030 and includes the constraints and resource switching that I&M assumed for its Preferred Plan. That, in combination with the concerns about the inflated new supply-side resource costs and the issues we identified with how the OVEC energy and CO_2 costs were modeled, leads us to question whether a 2030 OVEC termination would be lower cost than the Preferred Plan. As Witness Comings points out in his testimony:

> *The costs of I&M's share in the OVEC units have outweighed the value of energy and capacity that the units have provided since at least 2016. In the 2018-2019 I&M IRP case (U-20591), I compared I&M's OVEC costs to the combined energy and capacity value, showing a net cost of $39 million over a three-year period of 2016 through 2018. More recently, Sierra Club Witness Devi Glick presented a similar analysis in the most recent I&M PSCR case (U-21052) which showed roughly $61 million in net costs from 2019 through 2021. In sum, from 2016 through 2021, the net cost of I&M's share of the OVEC units was $100 million.*[80]

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[79] The CO_2 emission cost is assessed on each thermal resource starting in 2028 since that is the first year when a CO_2 price is applied in the modeling.

[80] Direct Testimony of Witness Comings. MPSC Case No. U-21189. Pages 21 – 22.

7.6 DISCOUNT RATE USED FOR THE PVRR CALCULATIONS

All the Aurora modeling inputs were based on real 2019 dollars. For purposes of creating outputs, Aurora applies an inflation vector to translate the inputs into nominal dollars. In a spreadsheet, I&M and Siemens PTI then translated the nominal Aurora outputs back into real 2019 dollars to determine the PVRR calculation of each portfolio. However, like the issue of mixing and matching nominal CCRs with real $/kW capital cost numbers for new supply side resources, I&M and Siemens PTI used a nominal discount rate to develop a PVRR that was based on real 2019 dollars. Since I&M and Siemens PTI took the extra step to translate the nominal Aurora modeling outputs back to real 2019 dollars, they should have used a real discount rate in the calculation of the PVRR for each Candidate Portfolio.

Since all the Candidate Portfolios used the nominal discount rate, this means that the relative rankings of the portfolios based on their PVRR would not change. Rather, it means that the overall PVRR dollar amounts presented in the IRP are not accurate since the nominal discount rate was applied to numbers reported in real 2019 dollars.

7.7 DISCOUNT RATE USED FOR THE OVEC TERMINATION ANALYSIS

For the analysis of the termination of the OVEC contract in 2022 and 2030, I&M calculated the termination costs outside of Aurora and then added those to the portfolio costs from Aurora. In this step, however, I&M combined the Aurora portfolio costs, which they translated into 2019 real dollars, with the OVEC termination costs, which were calculated in nominal dollars. Witness Comings discussed this issue in his testimony:

> *The Company presented an analysis of terminating the OVEC contract in 2022 and 2030, using a low and high range of termination costs along with Aurora modeling results. But, again, there is a mix up of nominal and real dollars. The Company is reporting the portfolio costs, which are in 2019 dollars, but combining that with OVEC termination costs that are in nominal dollars. The Company's exhibit IM-30 (JMS-2) states that all costs are "nominal" but this is not true for the "utility cost" values, which come from the Aurora modeling. The Company then calculated the net present value of all costs using the nominal discount rate. The Company should have either: 1) translated the Aurora model outputs (the "Utility Cost" values) to nominal terms or 2) translated the OVEC termination costs to real 2019 dollars and then applied the real discount rate to those costs and the real 2019 dollar Aurora outputs. Instead, the Company made an error by combining real and nominal dollars costs together and then, in a repeat of an aforementioned error, discounted the model outputs using the wrong discount rate.*[81]

[81] Direct Testimony of Witness Comings. MPSC Case No. U-21189. Page 15.

8 Short Term Action Plan

Section 8 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 21 below for our findings.

Table 21. Summary of I&M's Achievement of Indiana IRP Rule at 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Finding
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.	**Mostly**
4-7-9 (b)	The short term action plan is a summary of the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule	**Partial**
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.	**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.	**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.	**Partial**

I&M's Preferred Plan is a combination of an optimized capacity expansion build with some near term fixed resource decisions, which include pushing out to later years some solar and wind that were optimally selected by the model, and moving forward to earlier years some of the CT capacity for a total of 1,000 MW built in 2028. In the Short-Term Action Plan section of the IRP, I&M stated that they will:

> *Issue an All-Source RFP in 2023 or 2024 to satisfy identified needs, targeting 2027 and 2028 renewables, storage, and gas additions (in-service by the end of 2026 and 2027), totaling 800MW of solar, 60MW of storage as a hybrid resource, and 1,000 MW of gas peaking.*[82]

In response to a Sierra Club inquiry about when a CPCN might be filed for the 1,000 MW of gas capacity in 2028, I&M said:

[82] I&M 2021 IRP, page 156.

> *I&M does not have any definite plans at this time regarding the 1,000MW of CT's in 2028. I&M's focus up to this point has been to complete the IRP modeling and develop its preferred plan. With the preferred plan now established, I&M's immediate focus is on initiating the RFP for the 2025 and 2026 capacity needs. I&M expects to convene a project team in 2022 to begin formulating a high level timeline associated with the potential gas capacity identified in the preferred plan in 2028. Ultimately, the decisions regarding 2028 capacity will be made based on the results of an all-source RFP and the best information I&M has available at the time.*[83]

Since I&M filed its IRP and put forward its Preferred Plan, there have been several dynamics that could impact the cost of resource additions, including supply chain constraints and higher natural gas prices. We recommend that all of these impacts be considered across the board for all technology types and not solely one technology and request that I&M convene a meeting with stakeholders to discuss next steps for addressing the concerns laid out in these comments. As I&M moves forward with any certificate of need filings or similar approvals, its resource decisions must be reevaluated with stakeholder input, especially when considering these changed circumstances.

[83] 2021 I&M IRP Website Stakeholder Comment Summary, page 25. Retrieved from https://www.indianamichiganpower.com/lib/docs/community/projects/StakeholderWebsiteComments_6-07-22.pdf