Indiana Michigan Power Company's 2024 Indiana Integrated Resource Plan

Technical Stakeholders Meeting Summary

September 9, 2024

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Welcome & Introductions

Dylan Drugan covered slides 1-3

Dylan Drugan, Indiana Michigan Power (I&M) Manager, Resource Planning, called the meeting to order at 1:00 EST on September 9, 2024.

Dylan welcomed stakeholders to the 2024 Indiana Integrated Resource Plan (IRP) Technical Conference. Dylan introduced I&M IRP, Infrastructure Development, and Load Forecast team members. Dylan also introduced I&M Leadership including Andrew Williamson, Director, Regulatory Services.

Andrew provided an overview of the meeting's purpose; this is a collaborative workshop to discuss modeling software, methodology, and assumptions that will drive I&M's decision-making process for the Indiana IRP. I&M values stakeholder collaboration, and Andrew encouraged stakeholders to ask questions and provide feedback throughout the conference. Finally, Andrew announced the scheduling of Indiana IRP Stakeholder Conference #2 on September 24th.

Dylan concluded introductions with Brian Despard, Senior Project Manager with 1898 & Co. (a part of Burns & McDonnell), who is assisting with the stakeholder process for the Indiana IRP.

Dylan presented the meeting agenda, briefly covering each topic of discussion that follows herein. Dylan reiterated that although there is a time set aside for open discussion as per the agenda, stakeholders are encouraged to provide input and ask questions at any time during the meeting.

Going-In Capacity Position Review

Dylan Drugan covered slides 4-5

Dylan presented preliminary PJM Electric Load Carrying Capability (ELCC) and Forecast Pool Requirements (FPR) metrics.

Dylan described ELCC as a measure of accredited capacity by resource class that I&M must provide for when analyzing resources for load obligation purposes. He noted that within PJM, renewable resources decrease over time to account for increasing future penetration, lowering the accredited capacity for these resources over time.

FPR denotes to what percentage of peak load PJM members, including I&M, must plan to meet reserve margins. Like ELCC, these values decline over time, which offsets the declining accreditation figures for other resources, such as intermittent resources.

Dylan then presented the capacity needs assessment, also known as the preliminary "going-in position". These values, adjusted from previous Indiana IRP meetings, reflect new insights on load growth due to timing fluctuations in planned Hyperscaler Load (HSL). Overall demand is shown to increase drastically, primarily in 2029-2030 and 2034.

Capacity totals assume no action on many decisions that the IRP process will be investigating, such as the relicensing of Cook Nuclear Plant. Shortfall values are not indicative of the goal I&M holds in acquiring year-over-year capacity and I&M has incorporated a contingency that exceeds annual PJM obligation by roughly 5% to avoid overreliance on PJM under extreme conditions and other potential risks.

Q&A Related to Going-In Capacity Position

1. The demand resource accreditation, is that just demand response or does that include energy efficiency as well?
    a. The demand resource just includes demand response and does not include energy efficiency. PJM defines demand response as a supply-side resource and, in turn, PJM gives demand response an associated ELCC value for accreditation in the same way that it does for other supply-side resources. Energy efficiency, however, is treated as a demand-side resource.
2. I&M has traditionally been an FRR (Fixed Resource Requirement) utility. Do you anticipate that you will be going forward and if so, can you talk a little bit about how that interacts with the capacity auctions or your ability to participate in those?
    a. I&M is currently an FRR entity, which means that we self-supply our capacity into PJM. At this time, our expectation is that I&M will continue to be an FRR entity, but that election is something I&M evaluates each year prior to making our annual election.
3. I know there's been a lot of changes in PJM's rules, but we don't follow those as closely as we do in MISO. So, can you talk about how, if at all, FRR entities can interact with BRA auctions?

   a. An FRR entity such as I&M is required to self-supply which means that entity cannot purchase capacity through the base residual auction. If an FRR entity has excess capacity, a certain amount can be sold into PJM's auctions. As an FRR entity, I&M is required to acquire any capacity needs through ownership of resources, through long term contracts such as PPAs, or short-term bilateral purchases from other generation owners in PJM ahead of the base residual auction.

4. For the contingency, the target reserve margin that you guys were building in there, could you maybe just give me a sense of how large that contingency is?

   a. The target reserve margin is tied to the projected load and reaches about 450 megawatts by 2034 when the hyperscaler loads are projected to ramp up to their highest level.

5. And is that for your planning purposes, something that you guys have done in other IRPs or is that new for this one?

   a. The 2024 Indiana IRP will be the first time we include contingency capacity in an Indiana IRP.

6. If the megawatts that represent the contingency were not needed, would that excess capacity be sold into the auctions? Also, everything underneath the black line, includes things like your forced outage rate and other things, right? You're not planning a perfect resource below that, right?"

   a. The 5% contingency is intended to be a physical hedge against increased load requirements or a decline in resource values leading up to the delivery year to ensure I&M has sufficient capacity. If I&M had excess capacity because of the contingency, then the Company could potentially sell it into PJM. The reality is that when you sell it, it's no longer available as a hedge. If I&M were to require any of that capacity back due to higher load requirements or lower capacity values, then I&M would have to buy back capacity.

7. It seems all the stated needs for a contingency were true before you applied the 5% contingency and with all your past planning and your last IRP, all those risks were still true and you planned to the black line rather than include a contingency. So, you planned to your reserve margin requirement rather than to rather than to the

reserve margin requirement plus a surplus. And the only thing that really changed is perhaps more risk because of the performance penalties exposure that has to do with some of the changes that are going on in the PJM market. But all those things that you just described in terms of the incremental auctions and the risk of performance, all of those existed in your prior planning, correct?

a. Yes. While that is true it is also important to recognize that the consideration of a contingency is important when a utility is short generation. Prior to the last IRP, I&M historically had sufficient length in excess of our obligation to mitigate these risks. In addition, PJM's rules have changed in recent years with respect to capacity performance requirements and potential financial penalties. In a scenario where a utility is short capacity, it is prudent to ensure that you have some buffer there to manage the uncertainties that could happen along the way that are largely outside your control. Thus, some of the capacity risk is a relatively new issue or challenge for I&M just given the capacity position relative to load versus what it has historically been.

Dylan introduced Trenton Feasel, I&M Manager, Economic Planning.

Load Forecast Assumptions and Methodology

Trenton Feasel covered slides 6-11

Trenton provided stakeholders with an overview of I&M's latest peak demand forecast assumptions. Significant forecasted changes in peak demand are demonstrated, accounting for a peak demand increase of roughly ~8.3% each year over the next decade within I&M. Trenton noted that HSL addition within Indiana is the primary driver for this increase; commercial load is expected to grow much faster than industrial and residential load, from 31% of I&M's total load obligation in 2015 to 79% by 2030.

Trenton presented stakeholders with the load forecast scenarios that inform the overall energy requirements I&M must meet, noting the drivers of high and low economic growth. These scenarios form the band in which the base energy forecast falls. Also noted is an "extreme weather" scenario using data from Purdue University that shows a subtle increase over base energy projections.

Trenton informed stakeholders that there has been a change in methodology as to how I&M accounts for control of Demand Side Management (DSM) and Energy Efficiency (EE) projects in their load forecasts. These have historically been studied and provided as a post-model adjustment to load. Following the Rockport Coal Plant Unit 2 declination of jurisdictional settlement, I&M committed to making EE and DSM assumptions an independent variable in econometric models. This has caused a sharp increase in the value of DSM/EE in load forecasts.

Finally, Trenton discussed Distributed Energy Resources (DERs), with emphasis on electric vehicles and rooftop solar. Electric vehicle growth within I&M's Indiana territory tends to be less aggressive than USA-wide figures and does not contribute to load growth as much as may be seen in IRP filings from different entities. Similarly, a growing, albeit small portion of I&M's customer base is adopting the use of rooftop solar, leading to only a 0.4% decrease in I&M Indiana energy retail needs by 2040.

Q&A Related to Load Forecast Assumptions and Methodology

8. What are you using to model the low economic forecast impact on data centers?
    a. For our data center forecast, we include load from customers that have a letter of agreement (LOA), or an electric service agreement signed. If prospective load does not meet those criteria, we do not include it. Because of our requirement for including data center load, we have not explicitly done a low scenario for data centers.
9. So, you aren't considering that low economic impact or that change is efficiencies for data centers or anything like that could impact the data center loads?
    a. We are certainly monitoring those potential issues, but there is no explicit assumption that comes through in the low economic scenario for the data center efficiencies.
10. For the numbers behind the data center load forecasts, we can really provide the best feedback when we can look at data that you're using. It would be really helpful to see the data behind your load forecast; I'm not talking about just like the drivers of the other regression analysis but the assumptions that you're making around the data center load particular because that's obviously the biggest driver of the load here. Is there anything you can provide us about what type of data center you're assuming, whether it is all data centers or whether there are other types of

customers included, what the ramp rate is for those data centers. We don't need to know the names of any of these customers, but just like the quantity, that information and the numbers that are going into the load forecast is what we're looking for. Is that the sort of thing that you can provide to it to stakeholders? I would presume the hourly load forecast to be part of PLEXOS database. But I'm talking about the all the things that go into creating that load forecast before you even put it into PLEXOS. We're not asking for anything that you haven't done already. We're asking for the information that you're using to develop the load forecast, so the only question here is whether you will provide it or not it. We're not asking you to do anything extra.

   a. The hourly load forecast and the total amounts can be provided, but as far as it being broken out by residential industrial or hyper scalers won't be segmented in that fashion. It will be down to the hourly granular level. If you could send a request to the IRP website of exactly what you are asking for we can provide a response to that.

11. Just looking (on slide 8) at the spread of the lines between low and base and high and it just visually looks like the low economic forecasts scenario is materially pretty similar to the base case. And I'm wondering if it would be appropriate to consider the potential for these data centers to maybe not materialize. In the volume that's currently being anticipated under such a scenario, if there was an economic recession, I would expect some of these data center developments could be scaled back, could be delayed, could not go forward. Similarly, if there's efficiency developments in the GPU chips that are used. Just because there's a letter signed doesn't mean that an energy service agreement is signed, right? It doesn't mean that they are actually committing to moving forward with these, so I just comment that I'm a little worried that these scenarios look like they're a pretty narrow, a very narrow band, so we're not going to be able to really test a broad variety of future economic situations if the load forecast is pretty similar in all the cases.

   a. I appreciate that feedback. We will certainly take that back. You raise a number of valid points that we will take into consideration. If you're familiar with the pending Industrial Power (IP) Tariff filing in Cause No. 46097, I&M has proposed to establish a 90% minimum demand based on the contract capacity for customers with contract capacity greater than 150 MW. From an operational perspective, we are not going out and acquiring generation until we have a signed electric service agreement with a contracted capacity requiring the need for additional capacity. If we are successful in getting that minimum demand provision approved and part of our tariffs going forward, it would address a lot of the potential financial impact due to variability in actual load, which I think is one of your concerns. Also, it's worth pointing out that this is not a new line of business. This business has been around for quite some time. We have experience with data centers across AEP and the industry, and these loads have actually been pretty stable and operate with very high load factors. We are hearing from these customers that there is a desire for more availability, but there are limitations based on what can be served from the energy delivery system. It is important to point out that that the majority of our forecasted load between 2024 and 2030 is associated with two data centers that have been publicly announced and have significant construction activities underway. These companies are investing billions of dollars. That is a positive signal regarding the reality of these loads. To your point, there is always risk and we are taking every reasonable step we can to work to manage that risk.

12. I think I heard you say that you don't include these new large loads in your load forecast until they have assigned entity services agreement it. Can you help us understand what your load interconnection process looks like at the time that they sign that agreement? What are they obligated to financially?

    a. New large load customers have to sign an interconnection agreement first which establishes the cost to interconnect, the timeline and the parties' respective responsibilities including any cost responsibilities that they would have for the interconnection.

       The next step, getting closer to establishing service, would be signing an electric service agreement according to our terms and conditions of service and our tariffs. Then the main provision within that contract is establishing the contract capacity. This establishes the amount of capacity that the customer will be obligated to according to terms and conditions of service, and the amount of capacity that the company is expected to be able to serve at that location for that customer.

13. Are there any costs that data centers are going to pay that they would have to repay irrespective of whether they have an account number or not?

    a. Customers have the responsibility to pay for the cost of interconnection according to the terms of their respective interconnection agreement.

14. While the interconnection and transmission costs seem like they will be significant, they're actually dwarfed by the generation costs needed to serve these loads and there's no mechanism to guarantee that those costs will be recovered from these new customers. This is a huge risk to the remaining customers and how this will be addressed seems like a really important question for this IRP.

    a. We encourage review of the IP Tariff filing. Amongst the provisions proposed, I&M has proposed a minimum 20-year contract term for large load customers, a 5-year minimum bill, Contract Termination Fee should the customer permanently close its operations, and revised credit requirements. I&M will serve these customers as part of its integrated system serving its Indiana retail customers. The transmission and generation costs of the integrated system must necessarily be reflected in the Company's rates for service. I&M is and will be addressing the risk associated with load growth and new generation investment outside the scope of the IRP.

15. I certainly agree that the IRP should be looking at expected load, but I think it should also be looking at risks related to serving customers too. What we're saying here is that there is a huge risk related to acquiring this capacity for load that may appear or may not. That sort of question is fundamentally within that IRP and I'm not heavily involved in this, this tariff case you're talking about, but my understanding based on a first read of that tariff is that it's addressing transmission related costs and not generation related costs. So, I guess I would push back on the notion that this isn't a question that relates to that IRP, because I think it definitely does. The question of how much capacity you build to serve customers, which is really the fundamental output of the IRP, relates a lot to what that load looks like. And so, looking at different load outcomes is a really important thing to address within the IRP.

    a. I would encourage you to take a closer look at that IP Tariff filing. The proposed tariff modifications are focused on establishing a reasonable terms and conditions of service that recognize and address the different needs and unique risks that large load customers present differently from

I&M's other Tariff IP customers. The proposed Tariff IP modifications are necessary to memorialize a reciprocal commitment from large load customers that reasonably recognizes and aligns with the financial commitments that will be required by I&M. The proposed Tariff IP refinements are important to reasonably balance not only the interest of new large load customers but also I&M's existing customers and other large load customers. An important difference here versus other jurisdictions is that this IRP does not provide us resource approvals; the IRP itself is not committing the Company or customers to any particular resource costs. These commitments are coming through subsequent filings to seek approval of new generation resources which are litigated and subject to the Commission's review and approval. The questions that you raise can be thoroughly evaluated through those subsequent generation resource approval filings. I&M appreciates the feedback on this and can certainly continue to consider it.

16. It is the case that while including a resource in an IRP in Michigan may constitute a pre-approval it does not in Indiana and I totally understand that. But I would be surprised if when you come to the point of filing for certificate of need, for example, that you don't point back to the results of your IRP and so I don't think we can pretend that there's not a connection between the IRP and those subsequent filings. This IRP is really the opportunity to thoroughly investigate those types of risks because once you file that certificate of need, we have a very short time frame in which all these things need to be adjudicated and evaluated. We have more time to do that in the IRP. So, that's where the request comes from and I will certainly go back and look at that tariff again and see if I've missed something about how it addresses generation versus transmission costs or both. But I just want to be clear about where that request is coming from.
    a. We appreciate the feedback.
17. The last slide that you had up there about solar, I don't see anything that suggests that the new substantial customers are going to provide any distributed solar from themselves, the data centers if you will. That's not the expectation in your forecast?
    a. I&M is currently not aware of any plans for behind-the-meter solar at data centers.

DSM Modeling Inputs

Dylan Drugan covered slides 12-15

Dylan briefly reviewed market potential study savings and the DSM inputs being used in the Indiana IRP, previously shared by GDS. Modeling will utilize different EE and Demand Response (DR) bundles as shown on slide 12.

Dylan shared graphical overviews of energy savings being offered by these EE and DR bundles by sector.

Q&A Related to DSM Modeling Inputs

18. Just trying to understand the impact of the data centers, there's no DR expected or help expected from their on-site diesel generators? I think Wyoming had done some of that in the past and created some constructs that allowed that. It's not assumed or embedded in your forecast for DR, correct?
    a. That's correct. I&M will continue to talk with the data center customers about if there is a potential to look at DR in the future. But for these current inputs, DER or DR at data centers is not assumed. Our understanding is that the generation configuration used in this industry (diesel backup) that air permits do not allow for demand response participation, but I&M is working with each of these customers to evaluate the potential for opportunities. Our plan would be that if those opportunities would materialize, they would have to be unique to each of the customers and probably be subject to a commission filing and approval. Once approved, they would then be reflected in our IRP at that point going forward.
19. I'm a little confused by that because CVR was not included in the GDS Potential Study. So, I just wanted to understand if CVR is being treated as an energy efficiency resource.
    a. Slide 15 shows the potential and associated costs that I&M is planning to model with CVR. Through 2030, it's around 90 projects and you can see the associated energy savings. We did develop an updated model for cost benefit for CVR and used that to pre-screen for what will be fed into the IRP. The reason we did that is because CVR savings are going to be forced into the IRP modeling. I&M has developed a total CVR revised forecast that

essentially reflects what's existing on our system currently and no incremental new CVR installations beyond what's existing today or planned to go into service within the next few years. That's what the slide 15 CVR reflects, currently planned CVR from the prior IRP that is not in-service as of 2023 and it will be forced into the IRP modeling.

20. So, the first column (slide 15) says the first full year in service. I guess I find that confusing. If it's reflecting this (future years), is it supposed to reflect existing CVR, not new CVR?
    a. It reflects currently planned projects that will go into service from the prior IRP CVR Plan. These have not changed since the last IRP.
21. Why wouldn't the existing CVR be reflected in the load forecast? Why is an adjustment necessary?
    a. All the bundles that we received were marked as already existing regardless of when they will be implemented, where existing means from the prior IRP CVR Plan. We did not include CVR from that prior IRP CVR Plan that is already installed, or in-service, as an additional resource in the model because it's already in the load forecast.
22. Thoroughly confused because I thought I heard you say that these are all representing existing CVR and not new incremental CVR, but now it sounds a lot like new incremental CVR.
    a. There's no new incremental CVR included in this IRP from what was contained in the prior IRP CVR Plan. I clarified earlier that all existing projects from the 2021 IRP got approved. It is installed circuits from that plan plus anything that's in process of installation, because we are not going to halt the installation of those in process circuits and some of those circuits that are not in service yet. We looked at categories for installed in 2025, installed in 2026, and installed in 2027 from that original plan and that is shown on this slide and those would not be in the existing load forecast.
23. My recollection from the 2021 IRP was that it did not select any new CVR.
    a. Yes, the CVR Plan was not optimized in the previous IRP.

24. We can see IQW has separate bundles by time vintages. Can you confirm that IQW is being forced in?"
    a. Yes, on slide 13. IQW will be forced in.
25. Due to data centers, any energy efficiency or demand response opportunities from those new loads are not entirely reflected here. So, there is a disconnect or a mismatch in the analysis and part of that is timing from the market potential study, which has been underway for pretty close to a year now, some of those loads weren't known.
    a. Agreed. Thanks for that feedback. We will continue to adjust as things change.

Dylan introduced Tim Gaul, Director, Regulated Infrastructure Development for I&M.

Market Assessment of Existing and New Resources

Tim Gaul covered slide 16

Tim presented availability in PJM's Interconnection Queue for resources eligible to serve load and contribute to capacity requirements in I&M's Indiana territory. Resources being considered are geographically and technologically diverse, with a variety of projects in Indiana, Michigan, Illinois, Ohio, and Kentucky being presented. Projects are sorted based on queue cluster and potential COD: "Fast Lane" projects, Transition Cycles #1 and #2, and Cycle #1 projects under PJM's new queue methodology are all being considered.

Tim walked stakeholders through the graph, talking through splits by both project number, Megawatts available, and technology type. Solar projects constitute much of the available queue capacity and volume of projects through the presented queue cycles, especially within Indiana. Wind is in very limited supply, and most projects reflected are additional capacity for existing projects. Storage projects increase in both volume and capacity in later queue cycles, making them more viable in the future. Finally, gas is limited to a small number of existing gas projects eligible for RFP inclusion.

Key Modeling Inputs

Dylan Drugan covered slide 17

Dylan presented an overview of key resource modeling parameters that will be shared with stakeholders, using a generic solar unit as a reference. Examples of parameters include capacity, availability and lifespan, financial assumptions, energy production, and more. Dylan reminds stakeholders that final inputs are still under development.

Dylan introduced Mohamed Abukaram, I&M Director, Resource Planning.

Mohamed Abukaram covered slide 18-22

Mohamed presented an overview of Inflation Reduction Act of 2022 (IRA) tax credit assumptions being applied to the Indiana IRP analysis. Investment Tax Credits (ITCs) will be applied to capital costs for solar, storage, and small modular nuclear reactor projects at 30% through 2036 before a "phase out" period through 2039.

Production Tax Credits (PTCs) will be applied to wind projects in place of ITCs. These $40/MWh-$58/MWh credits are applied through the first 10 years of asset life for projects completed in the 2025-2036 window. Like ITCs, these credits will decrease gradually for projects completed in 2037 and 2038, before being phased out entirely in 2039.

Finally, Carbon Capture Storage (CCS) credits are applied on a dollar per Megawatt-hour basis for the first 12 years of asset life for new combined cycle plants completed between 2025-2036. These credits do not "phase out" and instead end in 2037.

Mohamed also discussed the Cook Subsequent License Renewal (SLR) analysis being conducted as part of this IRP. He shared model input assumptions such as current license expiration dates and assumed costs for relicensing the Cook Nuclear Plant. Similarly, Mohamed discussed relicensing cost assumptions for the Elkhart and Mottville Hydro Plants.

Finally, Mohamed discussed storage modeling inputs and methodology for utility scale and distribution-sited resources. For utility scale resources, storage is dispatched against fundamental market prices within a production cost model with hourly generation and charge costs then used as inputs in expansion planning (PLEXOS). Storage options considered are lithium-ion batteries of durations from 4-10 hours, and iron-air storage.

Distribution-sited storage will be modeled under two cases: the Thermal Use Case, where storage is sited at stations nearing thermal overload conditions, and the Reliability Use Case. Where storage is placed at stations with historic reliability need. The intent with both cases is to improve capacity for existing resources.

Q&A Related to Key Modeling Inputs

26. So, did you decide the ITC made more sense for solar as opposed to the PTC based on where the price points are for solar these days?
    a. Yes, especially in the PJM region. We looked at the operation of solar and the benefit of ITC versus PTC and ITC was the better option. We also consulted with our internal Tax Department and the consensus was that ITC is the better option for solar in the PJM region.
27. And then what about the consideration of potential bonus tax credits, for instance, things like energy storage, where you might have an ability to make sure they're cited in an energy community. You could take advantage of the 10% tax credit bonus. Is that factored in this analysis somehow?
    a. I&M has taken this feedback into consideration and is planning to model a subset of our renewable resources that will have capital costs with deductions to reflect the energy community tax credit bonus in addition to the Investment Tax Credit (ITC)
28. I agree with that, I think it's important to include the energy bonus credits and I think especially that's true for storage because you have a lot more ability to capture the areas where those credits are available, including at the locations of retiring plants. So, if you don't do that, then you'll never know whether it makes sense for I&M itself to construct those resources at the sites of retiring plants. So, I think it's very important to include that credit and we've seen that credit actually being material to the selection of those resources in other IRPs.
    a. Thank you for that feedback.
29. On slide 20, are these new or have those decommissioning costs been accounted for in previous decommissioning studies?
    a. These values are based on a new decommissioning study recently conducted for our hydroelectric generation assets. The number shown on

the slide reflects the midpoint between a range of estimates and takes into account the potential for environmental remediation and sediment removal which is one of the most significant components of the cost estimate. When I&M files its next depreciation study and revise depreciation rates, it expects to include and address the results of the new decommission study for its hydroelectric generating assets.

30. You're including these hydro decommissioning costs in IRP cost because it hasn't been accounted for in the past? Are these costs incorporated into your IRP as a decision for whether or not these facilities should be relicensed? It's just a little bit unusual because I know for existing resources a lot of the times in the past you didn't consider costs like that because it was seen as something that you would already have to do. I understand that this is a decision point whether or not it's a point in time in which you would incur it versus where you were required to get it cleaned up by a date certain, whether or not you were you had intended to continue operating the plant.

    a. Going into this IRP, I&M had a commitment to evaluate relicensing associated with any of our hydroelectric dams that had a license ending within 10 years. To assist in the evaluation of our hydros, we did a comprehensive review and engaged WSP, a third-party consulting firm. The comprehensive analysis included a new decommissioning study. With respect to this IRP, we will be looking at relicensing or decommissioning for the two facilities identified. You are correct that for purposes of the IRP modeling, the cost of decommissioning is a timing consideration because it will be incurred at some point in the future, but that timing is impacted by relicensing decisions.

       The model will utilize these costs to determine whether the facilities should be relicensed or retired. It will evaluate the generation value of these resources and compare the ongoing capital and O&M costs associated with renewing the license. It is a pure optimization problem that the model is looking to solve; retire or relicense.

31. I just wanted to ask if you could provide more information about how you are deriving the benefit from reduction in cost that you're modeling by estimated CMI value? Is that just some sort of volume value or is that something else? And then

could you also provide information on how you define the deferred cost of the distribution upgrade?

   a. For the CMI (Customer Minutes Interrupted) value we are using the ICE (Interruption Cost Estimate) report. The ICE report provides metric on how much can be saved per CMI. We take that total dollar savings amount and deduct it from the direct capital cost. For a few of the resources that are available to address thermal overloading at distribution stations, there is a deferred savings that is netted against the capital costs. This deferred amount and the deferred timeframe is assumed in the modeling. Therefore, to account for the time value of money we take the net present value (NPV) of the deferred amount and deduct it from the capital costs of the resource.

32. What is the ICE report?

    a. The ICE report calculates the interruption cost estimate.

33. Is that something specific to I&M or is that a literature review of other estimates?

    a. There's an online calculator that will estimate the interruption cost by putting in different key reliability inputs. Here is the link to the online calculator tool. https://icecalculator.com/home. State is one of the data inputs.

34. Are your distribution folks identifying the pool of potential upgrades that this measure can be used for? Is that how you're developing the limits on the resource?

    a. Yes, we worked heavily with our distribution planning team to come up with the costs and the metrics.

35. I presume this is a simplified table, or are we assuming a onetime capital cost and no degradation in the battery's efficiency over 20 years?

    a. Yes, it is a simplified table. There are other projections and metrics associated with these.

Release of Modeling Data

Dylan Drugan Covered Slides 23-24

Dylan discussed the schedule and composition of modeling data to be released to stakeholders. Additional stakeholder input will be gathered at the September 24th meeting and further inform data that I&M aims to release by October 1st. Data shared will include information discussed during this conference such as load forecasts, DSM inputs, and more. Also to be shared are modeling constraints, import/export data, and other information necessary for transparent stakeholder evaluation.

Dylan informed stakeholders that I&M will be holding “Office Hours” in which modeling questions can be answered. These will occur monthly and last around 60-90 minutes; stakeholders are encouraged to submit their questions at least three days in advance to allow I&M time to prepare responses.

Dylan walked stakeholders through the process to install and utilize PLEXOS and I&M data. This information is on Slide 24 of the presentation material. Finally, Dylan provided stakeholders with guidelines for contacting Energy Exemplar customer support. Stakeholders provided context to I&M regarding their PLEXOS licenses and interactions with Energy Exemplar to date.

Q&A Related to Release of Modeling Data

36. In terms of the data that we're going to be receiving, will you be giving us the spreadsheet that you used to calculate the carrying charges for the new resources?
    a. We can provide a table that displays all of the components of the carrying charge along with the calculation that yields the carry Levelized Charge rate.

Open Discussion

Dylan Covers Slide 25

Dylan asked stakeholders one final time for any unanswered questions. All questions and answers asked during the presentation are located under their appropriate segments.

Andrew makes closing remarks, thanking stakeholders for their time and contributions to the Indiana IRP Technical Conference and overall process. Any unanswered questions, requests, or follow-up feedback is encouraged to be submitted to I&MIRP@aep.com.