BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 121
Witmeier 2025 ERAS Testimony

TAB C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

June 6, 2025

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position where I have remained for the past five years.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony in a number of proceedings before the Commission. The most recent testimonies are as follows:

- In March 2025, I provided testimony in Docket No. ER25-1674-000 to support MISO's original Expedited Resource Addition Study ("ERAS") proposal.
- In November 2024, I provided testimony in Docket No. ER25-507-000 to support MISO's generator interconnection cap proposal.

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

- In August 2024, I provided testimonies supporting the JOA and MISO Tariff revisions implementing the JTIQ initiative in Docket No. ER24-2797-000 and ER24-2871-000.
- In November 2023, I sponsored testimony in Docket Nos. ER24-340-000 and ER24-341-000 supporting a package of reforms of MISO's generator interconnection process.
- In December 2021, I submitted testimony in Docket No. ER22-661-000 on issues relating to MISO's generator queue reform and resource utilization.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to file certain urgent improvements to the GIP. MISO is proposing the creation of a new process—the Expedited Resource Addition Study ("ERAS")—to facilitate the addition of projects to address certain near-term resource adequacy and reliability needs. This process will be separate from MISO's generator interconnection queue process, which is referred to as the Definitive Planning Phase ("DPP") process. As further discussed below, while MISO has been actively improving the efficiency of its generator interconnection queue with recent reforms, it will take several years for the impact of these changes to be fully realized and for MISO to reduce queue processing time to an approximately one-year timeframe. MISO has refined its original ERAS process, which will be more fully explained and addressed in my testimony.

Q. CAN YOU BRIEFLY EXPLAIN THE REFINEMENTS THAT WERE MADE TO MISO'S ORIGINAL ERAS PROPOSAL?

A. Yes. At a high level, MISO is now implementing a cap on ERAS projects to 68 total with carve outs for a maximum of 8 projects to serve retail choice load and a maximum of 10 projects from Independent Power Producers ("IPPs"). MISO is also implementing a requirement to only study 10 projects per ERAS Quarterly Study cycle.[2] In addition to the cap, MISO is changing the Relevant Electric Retail Rate Authority ("RERRA") notification requirement to a RERRA verification so that the ERAS project will be more closely targeted to a resource adequacy and/or reliability need in the RERRA's footprint. MISO is also limiting proposed ERAS project's interconnection service to 150% of the identified MW need, is requiring the project to be in the same Local Resource Zone ("LRZ") as the load need it is addressing (unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA), and is now requiring additional information in the ERAS Interconnection Request application. Finally, MISO has proposed tariff language to incorporate the retail states into the ERAS process. In the rest of my testimony, I go into further detail and background on these refinements.

Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?

A. At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order Nos.

[2] MISO is requiring that projects proposed by IPPs must be with entities other than Load Serving Entities ("LSEs").

2003 and 2023.[3] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff.

Q. IS MISO REQUESTING AN INDIVIDUAL ENTITY VARIATION?

A. Yes. ERAS is a new and temporary process that is intended to exist separately from MISO's DPP cluster-based queue process. Unlike the DPP, ERAS will not employ a 3-phase process, cluster studies, use the same withdrawal penalties, or employ many of the other mechanisms associated with the DPP process. Given the unique nature of ERAS, the limited timeframe for which it will be in effect, and the comparatively small number of projects that MISO expects to process through ERAS, MISO submits ERAS as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

Because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach. This said, I briefly describe some of the more salient differences below and explain why these are appropriate.

- Serial study: Studying ERAS Interconnection Requests individually in serial fashion will increase the speed of analysis, remove uncertainty caused by other requests being included in those analyses, and allows Interconnection Customers to better replicate study results prior to submission. Cluster studies are more complex with increased uncertainty due to

[3] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008), *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023), order on reh'g, Order No. 2023-A, 186 FERC ¶ 61,199 (2024).

withdrawal concerns since projects are reliant on those in front of them or within their cluster in the review process.

- Different timelines: Individual analysis of ERAS Interconnection Requests allows for a significantly reduced timeline to complete the process and allows for an Expedited Generator Interconnection Agreement ("EGIA") to be executed in months rather than years.
- Higher deposits: ERAS requires higher non-refundable fees and higher milestone payments that must be made at application submission. The financial commitment required for ERAS ensures the level of certainty that the project is ready to move forward and the higher non-refundable fee is necessary to support the additional overhead MISO needs to facilitate the ERAS process.
- Financial commitment to fund Network Upgrades at EGIA: To further validate the certainty of ERAS Interconnection Requests and prevent impact on Interconnection Requests in the DPP that are relying on Network Upgrades identified in the ERAS process, ERAS Interconnection Requests will be required to fund all Network Upgrades once the EGIA is executed, even if that EGIA is later terminated.
- Enhanced Site Control: ERAS Interconnection Requests must present evidence of all necessary Site Control to ensure the project can be built on the generator site as well reach its Point of Interconnection ("POI") on the transmission system.
- RERRA Verification: Interconnection Requests eligible to utilize ERAS must have a written verification from a RERRA, who is ultimately responsible for resource adequacy as noted in the Federal Power Act, that (i) the new, incremental load addition is valid and

is not currently included in a plan or other procedure under the RERRA's purview or (ii) the Generating Facility will address an identified resource adequacy deficiency.

- Off-taker agreement: ERAS Interconnection Requests are required to show that the generation has an agreement with a specific load or is a Load Serving Entity ("LSE") to ensure that generation will be utilized for known load.

Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE ERAS FILING?

A. Yes. The transition provisions are included in proposed section 5.13 of the GIP. Generally, the proposed reforms will apply only to ERAS Interconnection Requests submitted after the requested effective date of the reforms, which is August 6, 2025.

III. THE CURRENT MISO QUEUE AND THE ERAS PROCESS

A. ERAS is Necessary to Address Resource Adequacy and Reliability Needs

Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.

A. As of June 5, 2025, MISO's generator interconnection queue contains 1,573 active Interconnection Requests comprising 291 GW of proposed new generator interconnection capacity. This considerable backlog of applications is spread over all five of MISO's study regions and includes queue cycles going back to 2019. The queue size continues to be extraordinary and unprecedented—the 2023 queue cycle, the last to close in 2024, alone is 123 GW. Notably, almost 70% of the total generation capacity that entered the 2017 and 2018 queue cycles was eventually withdrawn. The remaining 30% obtained GIAs, but the actual amount of generating capacity that will be completed and energized will be less than

30% due to financial and construction challenges. Similar withdrawal rates are occurring in the later cycles as well.

Q. DO YOU EXPECT THE CURRENT QUEUE DELAY TRENDS TO CONTINUE?

A. Yes, as I noted in my previous ERAS testimony, I expect the delays to continue in the short-term, as the bulk of the recent proposed generating resources from the unprecedented queue sizes (e.g., the 2022 study cycle included over 956 application submittals totaling approximately 171 GW) continue through the MISO interconnection queue process, and only the 2023 study cycle takes advantage of the queue reforms approved in January 2024 under Docket No. ER24-341-000. Queue delays caused by restudies due to late-stage withdrawals are one of the latest issues negatively impacting Interconnection Customers' ability to timely execute a GIA. Additionally, ongoing delays to resource additions with signed interconnection agreements are caused by supply chain bottlenecks, permitting delays and commercial challenges. To further demonstrate this unprecedented backlog, MISO recently published a COD dashboard to help stakeholders determine when resources might attain commercial operation.[4] These resulting delays are currently interfering with the ability to plan for meeting growing resource adequacy needs and ultimately creates a major reliability concern. The ERAS proposal will help address some of these needs in the short term.

While MISO has taken targeted actions to help manage a highly active generator interconnection queue with process improvements and leveraging technology to speed up processing and studying of new interconnections requests, a temporary solution is required

[4] MISO Generator Interconnection, *COD Report: Overview*, https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

in the short-term to address the immediate and urgent capacity needs until the queue backlog and study timelines are reduced.

Q. IS ERAS A SEPARATE PROCESS FROM MISO'S QUEUE?

A. Yes. ERAS is not a part of MISO's Definitive Planning Phase ("DPP") process. ERAS is also not another interconnection queue that will supplant the generator interconnection process. MISO understands the concerns that ERAS is enabling queue jumping but ERAS is a unique and separate process from the DPP process that is limited in size and scope. The process has extremely stringent eligibility requirements that will limit the projects that can participate in it to those with commercial viability, RERRA verification, and the ability to come online in the next few years. MISO sees ERAS as a complementary process to the generator interconnection queue and a solution that will assist in addressing resource adequacy and reliability needs in the next few years.

Q. PLEASE DESCRIBE WHY ERAS IS NECESSARY.

A. There is a growing critical reliability challenge facing the industry, which has been documented and highlighted in various MISO and non-MISO reports. Examples of such reports include:

1. MISO Futures Report Series 1A: posted in November 2023 and utilized for Long Range Transmission Planning Tranche 2.1 portfolio.[5]
2. MISO's Reliability Imperative Report: 2024 MISO Regional Resource Assessment (RRA).[6]

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[5] *MISO Futures Report, Series 1A* (November 1, 2023), available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

[6] *2024 Regional Resource Assessment*, A Reliability Imperative Report (January 2025), available at: https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf.

3. The 2024 NERC Long-Term Reliability Assessment (LTRA).[7]
4. The 2024 OMS-MISO Survey: As in previous years, MISO and the Organization of MISO States (OMS) completed a volunteer survey on resource adequacy to identify potential future resource adequacy needs in the MISO region.[8] The 2025 OMS-MISO Survey will be published on the same day as this refined ERAS filing and indicates a similar resource adequacy and/or reliability need trajectory.[9]
5. NERC's 2025 Summer Reliability Assessment.[10]
6. Comments from FERC's Technical Conference on Resource Adequacy.[11]

The reports all include the following elements:

- The increasingly significant challenges facing the MISO footprint in meeting state energy goals and expectations.
  - The RRA report noted that the MISO members and states may need to add capacity at 17 GW/year for 20 years.

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[7] *NERC 2024 Long-Term Reliability Assessment* (December 2024), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[8] *2024 OMS-MISO Survey Results* (June 20, 2024), available at: https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[9] *See 2025 OMS-MISO Survey Results* (Updated June 2025), available at: https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[10] 2025 Summer Reliability Assessment, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[11] Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments"); Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

- The critical timeframe and urgent need for resources on the horizon as demand growth continues to accelerate.
  - The 2024 OMS-MISO Survey found that additional actions would be needed as soon as possible to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
  - The 2025 OMS-MISO Survey indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficiency, with greater needs in future years."[12] The survey also states that survey responses show "increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[13]
- Indications that MISO is at "high risk" for meeting upcoming resource adequacy requirements.
  - The NERC LTRA report highlights that based on potential delays to generator construction, there is a potential in MISO's footprint to see a 2.7 GW shortfall by 2029 if not earlier.

In further recognition of this issue, the Department of Energy recently introduced the GRID Modernization Initiative, which "envisions a fully integrated electric system from generation to transmission to load consumption … with an emphasis on maintaining the

[12] 2025 OMS-MISO Resource Adequacy Survey Results, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

[13] *2025 OMS-MISO Survey Results* (June 6, 2025) at 10.

reliability and resilience of the grid."[14] Concerns about resource adequacy in the MISO footprint have only increased since the publication of these reports. For instance, MISO initiated the process to redesign the Futures, last finalized in November 2023, as MISO and stakeholders have determined that the load forecasts represented in those Futures are too low. On February 28, 2025, MISO held the first of several workshops to redesign the assumptions within the Futures.[15]

In light of these industry-wide challenges, MISO realized it needed a more responsive process to work with the states to address these resource adequacy needs. The refined ERAS is intended to help maintain resource adequacy integrity within this short timeframe until it sunsets on August 31, 2027, or the completion of sixty-eight ERAS Interconnection Request studies, whichever occurs first. Ultimately, the purpose of ERAS is to provide a mechanism for addressing these resource adequacy and/or reliability needs within this short timeframe, rather than waiting until it is too late.

Q. DOES MISO HAVE ADDITIONAL EVIDENCE TO SUPPORT ITS CLAIM FOR IMMEDIATE RESOURCE ADEQUACY NEEDS?

A. Yes. MISO's internal data supports the general claims about resource adequacy needs. The need for generation to serve load additions through the Expedited Project Review ("EPR") illustrates this challenge and is addressed later in my testimony. MISO has been very vocal about communicating and presenting this impending concern. Simply glossing over this inevitable emerging need for generation only confuses the issue. Additionally,

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[14] *Grid Modernization Initiative*, U.S. Department of Energy (July 2024), available at: https://www.energy.gov/sites/default/files/2024-12/Grid%20Modernization%20Strategy%202024.pdf.

[15] MISO, *Futures Redesign Workshop* (Feb. 28, 2025), available at: https://www.misoenergy.org/events/2025/futures-redesign-workshop---february-28-2025/.

this issue of resource adequacy concerns has been the subject of numerous discussions throughout the MISO stakeholder process for some time now with considerable stakeholder support. MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, noting that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[16] MISO also recently published material from its System Planning Committee, which included updates to the Reliability Imperative.[17] The update noted that "[t]here is no single type of investment that will support all system needs; the necessity for near-term but large-scale transmission to support these large load additions recently came to the forefront."[18] The 2025 OMS-MISO Survey will be published on the same day as this filing and its projection are in alignment with the resource adequacy and reliability needs that MISO has referenced in this filing.[19] The survey identifies ERAS as an in-progress initiative and one that will help address resource adequacy challenges.[20]

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[16] *Id.*

[17] *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Directors, Jun. 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

[18] *Id.* at 5.

[19] *See 2025 OMS-MISO Survey Results* (June 6, 2025).

[20] *Id.* at 16.

Q. WHY WON'T ERAS PROJECTS BENEFIT FROM THE DPP QUEUE?

A. As detailed in the following testimony and substantiated by multiple examples, a need exists in the near term to accelerate the interconnection process for resource adequacy and/or reliability projects that are unable to benefit from the impact of the recent MISO GIP improvements or Order No. 2023. These resource adequacy concerns are driven by the following: 1) significant growth in spot load; 2) the inability to study new necessary resources immediately upon entering the queue; 3) the accelerated retirement of generation resources; 4) the ongoing delays to resource additions with signed interconnection agreements due to supply chain bottlenecks, permitting delays, and commercial challenges; and 5) the continued large volumes of Generator Interconnection Queue requests and accumulating backlog. The increasing impact of these factors requires urgent improvements to the current GIP to ensure that MISO can meet the challenge. Accepting the proposed ERAS revisions will contribute to ensuring that MISO has sufficient new resources to meet these impending challenges in the coming years.

Q. WHY ISN'T THE CURRENT QUEUE SUFFICIENT TO ADDRESS THESE RESOURCE ADEQUACY NEEDS?

A. MISO successfully implemented several queue reforms improving various aspects of the generator interconnection queue or DPP process. Despite these efficiency updates, MISO's interconnection queue continues to experience significant delays. Due to the aforementioned delays in bringing resources online, the current interconnection queue jeopardizes the short-term availability of resource adequacy projects that are stuck in the queue or are yet to be submitted into the queue. The current DPP queue process will not ensure a timely executed GIA with known Network Upgrades until the backlog is cleared

and a new cycle can be processed with a yearly cadence. MISO is proposing the ERAS process to fill the gap in the short-term by expediting the approval of new generation needed to address resource adequacy and reliability needs.

B. ERAS Projects Will Not Harm DPP Queue Projects

Q. WILL ACTIVE DPP PROJECTS STILL BE ABLE TO TRANSFER TO THE ERAS PROCESS?

A. Yes. If the projects meet the eligibility requirements to enter the ERAS interconnection process, DPP projects in active DPP cycles at or before Decision Point 2 (anticipated only 2022 and 2023 cycles) may transfer to the ERAS process. MISO will not allow Interconnection Requests to transfer from the existing interconnection queue after Decision Point 2 to avoid the Phase 3 restudies due to late withdrawals, which contribute to ongoing queue delays. If an Interconnection Request is beyond Decision Point 2, then it can still drop out of the DPP process; however, it cannot enter ERAS until a year has passed since the withdrawal. This limitation was implemented to maintain the integrity of the DPP process. Allowing active projects in the current queue to transfer to ERAS process also enables the faster completion of studies for projects that can address resource adequacy and/or reliability needs in the short term.

Q. DOES MISO KNOW OF ANY EXISTING PROJECTS IN THE QUEUE THAT PLAN TO TRANSFER TO ERAS?

A. Yes. MISO is aware of several projects that are interested in participating in ERAS and can meet the eligibility requirements. Upon transferring from the DPP process to ERAS, the projects will be subject to all existing withdrawal penalties and/or harm calculations stated in the Tariff. Based on stakeholder feedback, MISO determined that projects

withdrawing from the DPP to enter ERAS should not provide undue impact on Interconnection Requests remaining in the DPP process. That is why withdrawals can only occur at the existing off ramps (i.e. Decision Point 1 and/or Decision Point 2) and that they should be subject to any Automatic Withdrawal Penalty or harm calculation.

Q. WHY ISN'T MISO EVALUATING PROJECTS IN THE DPP QUEUE TO DETERMINE WHETHER THEY CAN ADDRESS RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. MISO does not believe it is appropriate for it to decide which generation projects address an identified need. MISO is not the resource planner. Ultimately it is the states/RERRAs processes that determine which generation is utilized to meet a resource adequacy and/or reliability need. ERAS provides a means to determine Network Upgrades necessary to aid the states/RERRAs in their determination processes by providing a timely process to study certain Interconnection Requests that the RERRA has acknowledged. Without ERAS, the states/RERRAs need to make their determination after an Interconnection Request is out of the DPP process, which may be too late, or with unknown or incomplete transmission upgrade costs.

Q. WILL ERAS TAKE NECESSARY RESOURCES AWAY FROM THE DPP QUEUE?

A. No. ERAS will not take away resources from the DPP Queue as MISO is requiring significantly increased financial commitments from ERAS participants. First, the D1 payment is $100,000 and is non-refundable. The funds from this payment will provide the additional financial resources needed to help MISO manage the ERAS process. These resources may include additional software tools and enhancements to process ERAS.

Second, MISO has committed to hiring additional personnel or contractors as needed to help manage the ERAS requests. MISO is actively monitoring the workload and need for additional support to effectively process both ERAS and the DPP queue. The cap on 10 projects per ERAS cycle will also make MISO's workload and resource needs easier to forecast and manage. While MISO believes that it has sufficient resources to manage ERAS even without the project cap, MISO recognizes that the project cap will further assist it in efficiently managing both the ERAS and DPP processes. No resources or staff time will be diverted from the DPP queue to ERAS or vice versa.

Q. DO YOU AGREE WITH CLAIMS THAT ERAS WILL REDUCE THE TRANSMISSION CAPACITY HEADROOM AVAILABLE TO PROJECTS IN THE DPP QUEUE?

A. No. As I previously explained in my testimony, ERAS projects will ultimately be studied on a different MTEP base case than projects currently in the MISO queue. An ERAS project that is studied in September 2025 will use the MTEP 2024 base case that is supplemented with changes since that base case was built with both approved EPR projects and new generators with signed GIAs. The 2022 DPP cycle that kicked off in March 2023 used the 2022 base case from when the projects joined the queue. Those DPP projects will have access to the headroom existing in the 2022 base case, which is not impacted at all by the ERAS process.

Q. WILL ERAS PROJECTS SHIFT OR INCREASE UPGRADE COSTS TO CUSTOMERS CURRENTLY IN THE DPP QUEUE?

A. No. This speaks to a misunderstanding of how MISO will create the model for the serially studied ERAS projects. In building the model for new ERAS interconnection projects,

MISO will rely on the latest MTEP base case, including any recently approved EPR projects. In the normal DPP process, the base case is never updated once the study process is kicked off except for changes due to projects withdrawing at the Decision Points or generator retirements, which limits the Network Upgrades to only those introduced as part of the ERAS project.

Q. WHY ARE PHASE 3 PROJECTS NOT INCLUDED IN THE BASE CASE FOR ERAS?

A. MISO does not include Phase 3 projects in the base case for any study process because doing so would require it to deviate from its standard practice. MISO only includes projects that have obtained a GIA in the subsequent base model. MISO does not want to assume that these Phase 3 projects will obtain a GIA, then include them in the model, only to be proven wrong and negatively impact the base model. MISO does not consider projects to be "real" until they have obtained a GIA, at which point they are included in the next base case model.

Q. WHY ARE LATE-STAGE DPP PROJECTS PROHIBITED FROM PARTICIPATING IN ERAS?

A. Late-stage DPP projects are prohibited from participating in ERAS to prevent negative impacts on the DPP queue. To maintain the integrity of the queue, MISO must protect the projects already in the DPP process. Allowing late-stage DPP projects to transfer into ERAS would require their removal from the DPP queue, triggering re-studies. These re-studies would cause delays and adversely affect the remaining projects in the queue.

Q. IN LIGHT OF THE RECENT QUEUE REFORMS, WHY IS IT NECESSARY TO IMPLEMENT ERAS NOW?

A. The recent queue reforms are essential and will result in beneficial changes to the DPP queue, but on a longer time frame than is needed to address current resource adequacy and reliability needs. MISO views the refined ERAS process as complementary to the recent queue reforms but argues that it addresses a more imminent problem. ERAS is not redundant to the existing DPP queue as its purpose and structure is completely different. Several protestors to the original ERAS filing suggested that the SUGAR Software that MISO has been working to implement will solve the problem. However, these claims fail to consider that MISO is currently implementing the SUGAR software only for increasing the speed of the Phase 1 Study of the MISO DPP process, not for the more in-depth Phases 2 and Phase 3, portions. MISO anticipates that it will utilize SUGAR for the later phases, but the software as currently developed is not designed to run the Phase 2 or Phase 3 studies.

Q WHY SHOULDN'T MISO UTILIZE PROVISIONAL GIAs TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. A Provisional Generator Interconnection Agreement or PGIA is another tool for Interconnection Customers to achieve a timely interconnection agreement; however, it is insufficient to address the problem on the scale or in the time frame that is needed. Provisional interconnection service, while available for interconnection projects to request as soon as they enter the DPP process, only provides for limited operation, and is conditional on DPP studies for full deliverability that 1) may not be available to recognize the new capacity and 2) can still take several years to finalize. Having a PGIA poses a

substantial risk on generator projects depending on the projects in the queue that may never go commercial or may not be built due to not having an off-taker or a load to serve. Some of the benefits of PGIAs such as increased financial commitments and an expedited timeframe to getting an EGIA were incorporated into the ERAS process. Ultimately, only the ERAS process will ensure that all the Network Upgrades on the MISO transmission system that are necessary to provide deliverability across the system are identified by the time the EGIA is executed.

V. THE REFINED ERAS PROPOSAL

Q. WHY IS MISO REFINING THE ERAS PROCESS?

A. Following the Commission's review of MISO's original ERAS process, it rejected MISO's proposal and made several recommendations for how to ameliorate the issues it identified in the original ERAS proposal. Thanks to this guidance from the Commission, MISO has changed several aspects of its original proposal and is now seeking Commission approval of its refined ERAS process. As explained earlier in my testimony, ERAS is MISO's solution to the near-term resource adequacy and reliability needs within its footprint. Due to unforeseen circumstances related to unexpected and dramatic load growth, MISO needs to implement a process that can enable the completion of projects addressing resource adequacy and/or reliability needs in the next few years. ERAS is not another interconnection queue; rather, it is a separate process that the states may utilize to address short-term resource adequacy and/or reliability needs.

Q. HOW WAS THIS NEW ERAS PROPOSAL DEVELOPED?

A. Following the Commission's Order on MISO's original ERAS filing and other stakeholder feedback, MISO worked quickly to refine its Expedited Resource Addition Study to

address the concerns identified by the Commission and to propose a framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term. With the Commission's guidance, MISO made critical changes to its original ERAS proposal including adding a total project cap with carve outs for retail states and independent power producers. MISO has also added several requirements to establish a stronger connection between the proposed ERAS projects, and the resource adequacy needs that the projects will be addressing.

MISO developed this process and the accompanying Tariff language based on its resolve to address its urgent short-term resource adequacy needs and has provided extensive opportunities for all interested parties to comment during the stakeholder process. It should be noted though that these issues are complex and there is no set of reforms that will flawlessly meet the needs of every stakeholder affected by these updates, but the final ERAS proposal that MISO is submitting today incorporates many of the comments and recommendations we received through this process.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.

A. MISO engaged in an extensive stakeholder process throughout the development of the original ERAS proposal. MISO obtained feedback through the Planning Advisory Committee (PAC), conducted dozens of calls with stakeholders across the MISO sectors, and received multiple rounds of both formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with

stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the original ERAS proposal stakeholder process were as follows:

- November 13, 2024: MISO presented an initial ERAS proposal to the PAC and requested written formal feedback from stakeholders from this meeting be included with feedback from the November 18th workshop.
- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.
- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought written formal feedback on the updated proposal.
- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.
- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought written formal feedback at the PAC.
- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the final details of the ERAS proposal.

The key milestones for the refined ERAS proposal stakeholder process were as follows:

- May 28, 2025: MISO presented its refined ERAS proposal at the PAC.[21] MISO received feedback from this presentation through its informal feedback tool.[22]
- MISO conducted dozens of calls with stakeholders across the MISO sectors.

Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS ON MISO'S ORIGINAL ERAS PROPOSAL?

A. MISO supported many of the concerns and objectives identified by the stakeholders while crafting the original ERAS proposal and was committed to working with stakeholders to incorporate elements of their proposals to meet those objectives. MISO also considered the concerns and recommendations of stakeholders following the Commission's rejection of its original ERAS proposal. The figure below demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance.

[21] *See Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.

[22] *Informal Feedback (2025)*, MISO, available at: https://www.misoenergy.org/engage/stakeholder-feedback/2025/informal-feedback-2025/.

Figure 1: ERAS Proposal Changes from First Iteration

	Where we began	Original ERAS filing	Refined ERAS filing
Cap	N/A	N/A	No more than 10 projects studied per quarter and no more than 68 projects studied overall with an 8 project carve out for restructured states and a 10 project carve out for IPPs with agreements with entities other than LSEs
Applicants	Load Serving Entities	LSEs, IPPs, and DPP transfer projects meeting all requirements	No change
Process timeline	Project studied and GIA issued in 60 days	Quarterly cadence following established MISO timelines, receiving GIA in ~90 days	No change
Required documentation	RERRA acknowledgement	RERRA acknowledgement and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need	RERRA verification and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need
Identification of need	N/A	Description of need in ERAS application	IC must identify specific load addition and/or RA deficiency the project will address (MW value band, approximate location, etc.) and this information will be made public
Locational requirement	N/A	N/A	Project and RA and/or reliability need must be within the same Local Resource Zone
Size requirement	N/A	N/A	Interconnection Service must not exceed 150% of the identified MW need
Commercial Operation Date	Expected COD with 2-5 years	2025/26 applicants: 3 years from submission plus 3-year grace period; 2027/28 applicants: 12/31/2028 COD plus 3-year grace period	All applicants must have a COD within 3 years of submission plus a 3-year grace period
Penalties	Requested feedback after first PAC	Projects transferring from DPP process will be subject existing tariff language (e.g. AWP and Harm Calculations)	No change
Sunset	2028 / 2029	12/31/2028 or on the completion date of the 2027 DPP queue cycle, whichever first	ERAS will sunset at the earlier of the completion of the sixty-eighth ERAS study or on August 31, 2027

Q. DID MISO CONSIDER ANY ALTERNATIVE ERAS PROPOSALS?

A. Yes. During the stakeholder process in January and February of 2025, two parties submitted alternative ERAS proposals in the PAC meetings. Those proposals focused on improvements to the existing queue process and many suggestions were not relevant to the serial approach of ERAS as MISO has envisioned it. MISO believes the feedback was extremely beneficial but focused on improvements that MISO can make to its current cluster process and not the ERAS process. The refined ERAS proposal does align with a number of items from the Developer Coalition Counterproposal (February 12, 2025),

including limiting the number of ERAS projects allowed to participate and ensuring those projects are tied to a specific need.[23]

The proposals also recommended that MISO utilize a scoring system to evaluate ERAS Interconnection Requests. MISO has not adopted this recommendation because the states have authority over resource adequacy needs and MISO should not be ranking or selecting ERAS Interconnection Requests. It is not appropriate for MISO to be second guessing a RERRA determination that a project should be studied in ERAS.

Q. PLEASE DESCRIBE THE CONCERNS RAISED BY THE COMMISSION'S ORDER AND HOW MISO IS RESPONDING TO THEM.

A. The Commission raised numerous concerns when addressing MISO's original ERAS proposal. The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[24] The Commission identified two main concerns with ERAS: (1) there was "no limit on the number of projects that could be entered into the ERAS process,"[25] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[26] The Commission also recognized that it was "appropriate for RERRAs to communicate to

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[23] *See Developer Coalition: ERAS Counter Proposal (February 12, 2025)* https://cdn.misoenergy.org/20250219%20PAC%20Item%2008%20ERAS%20Alternative%20from%20Developer%20Coalition679607.pdf.

[24] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 197 (2025) ("ERAS Order").

[25] *Id.* at P 199.

[26] *Id.* at P 201.

MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[27] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[28]

MISO is extremely grateful for the Commission's guidance on how to better craft its ERAS proposal and has worked swiftly to develop a refined ERAS process that addressed the Commission's concerns. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025, to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

A. Implementing an ERAS Cap

Q. WHY IS MISO IMPLEMENTING A CAP ON ERAS PROJECTS?

A. After receiving feedback from stakeholders and guidance from the Commission in its ERAS order, MISO is implementing a cap on the total number of projects that can participate in ERAS. The Commission was concerned that MISO's original ERAS proposal was unlimited in size and asked that MISO place additional guardrails around ERAS.[29] MISO is now proposing to cap the total number of ERAS projects studied to 68 Interconnection Requests. In addition, MISO is creating a carve out of a maximum of 8 Interconnection Requests (of the total 68) that may be submitted to serve retail choice load and a carve out of a maximum of 10 Interconnection Requests (of the total 68) that may be

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[27] *Id.* at P 203.

[28] ERAS Order at P 3 (Christie, Comm'r, dissenting); P 6 (Rosner, Comm'r, concurring); P 8 (See, Comm'r, concurring).

[29] ERAS Order at P 203.

submitted by IPPs with agreements with entities other than LSEs. The remaining 50 Interconnection Requests may be utilized by the remaining states and developers for non-retail states. MISO recognizes that PJM's Reliability Resource Initiative similarly capped its program at 50 projects and MISO is providing additional carve outs for certain groups that would otherwise have difficulty participating in ERAS. The Commission has previously recognized that an appropriately structured cap used in the interconnection processes can be consistent with open access principles.[30]

Q. IS THERE A LIMIT ON THE NUMBER OF ERAS PROJECTS STUDIED PER CYCLE?

A. Yes. MISO is also going to limit the number of projects studied *per* ERAS quarterly study cycle to 10 projects no matter who submits them. MISO believes that 10 projects per study cycle is a manageable number of projects for its team to study on a quarterly basis. This will allow MISO to spread the number of projects over a longer period of time, which will also help with the expedited review and management of MISO's internal resources to serve ERAS.

Q. HOW WILL THE 10 PROJECTS BE SELECTED FOR THE STUDY?

A. Once the ERAS process is approved, MISO will process the ERAS Interconnection Requests using a serial "first-come, first-served" approach based on the date and time the application was submitted. The first ten projects to submit applications to be studied in ERAS will be tentatively selected until MISO has finalized its screening process of all ten projects to ensure that they (1) meet the ERAS eligibility requirements, and (2) are not

[30] *Id.*

geographically located near another project in the group or impacting the same constraints. After the ten projects in a cycle are finalized, the remaining projects that applied in the cycle will be deferred to the next available ERAS cycle in order of submission time. Since only ten projects will be studied at a time, serial review of the applications will expedite the review process. MISO expects the ERAS Interconnection Requests to apply when they are ready and meet all the necessary eligibility requirements to participate. All application deadlines and ERAS Interconnection Requests will be posted on the MISO public website in a timely fashion.

Q. WHY WILL MISO CREATE A WAITLIST OF ERAS PROJECTS?

A. Projects that apply in a certain cycle but are not the first ten projects that are submitted will be studied in a future ERAS Quarterly Study Period and will remain on an ERAS "waitlist" until MISO has completed a screening process of the first ten projects. After the first ten projects are validated, the remaining projects on the waitlist will be deferred to the next available study quarter in order of when each project was submitted. As soon as the remaining ERAS applicants have gone through the screening process and are accepted into ERAS, MISO will publish the projects and their assigned quarters on the ERAS webpage.

Q. WHAT DOES THE ERAS SCREENING PROCESS INVOLVE?

A. MISO will complete a screening analysis to verify that the projects in a single ERAS study cycle are not in the same geographic area or do not impact the same constraints. If they are in the same area or do impact the same constraints, then the projects will be placed in different quarterly study cycles as separate serial studies. The first submitted project will be processed first, and the next highest priority project (based on submission time) will be processed in a future quarter study cycle.

Q. WHAT IF MULTIPLE ERAS REQUESTS HAVE CONTRACTS TO SERVE THE SAME LOAD?

A. There is a possibility that a very large load will need multiple generators to serve it and would potentially sign agreements with more than one generator. It is incumbent upon the load to determine whether it has negotiated for a sufficient amount of generation and to not rely upon the RERRA to match exact load amounts with generation amounts. It is important to note that these projects cannot be studied together in the ERAS serial process. Thus, the projects would be split over multiple ERAS quarterly study periods in order of submission time even if they are submitted within the same quarter and will serve the same load. MISO recognizes that this is less than ideal from a load need perspective, but in order to ensure that ERAS remains an expedited process that enables the efficient study of ERAS Interconnection Requests in serial order, it must spread out proposed requests that impact the same constraints or serve the same load. This also means that MISO could process a lower queued project ahead of one of these projects if it is a later submitted project that is not similarly situated geographically or if it does not impact any of the same constraints as a higher queued project.

Q. WILL DEFERRED ERAS PROJECTS LOSE THEIR NON-REFUNDABLE D1 PAYMENT?

A. No. MISO will hold their D1, D2, and M2 in order for them to continue to be active requests that are not deficient. But proposed projects that do not meet the ERAS eligibility requirements and are rejected from the ERAS process will lose their D1 payment, but MISO will refund the remaining study and milestone deposits if they withdrawal. Otherwise, they will be automatically transferred into the DPP process. The ERAS projects

will be studied serially in order of submission time. MISO conducts a similar process for the queue cap and will be able to efficiently study the ten projects submitted per ERAS cycle.

B. Updating the RERRA Notification Requirement

Q. WHY DID MISO CHANGE THE RERRA NOTIFICATION REQUIREMENT?

A. Following the guidance provided in the Commission's rejection of MISO's original filing, MISO drafted updated language to better tailor and connect the resource adequacy needs with the ERAS projects as verified by the relevant RERRA. The Commissioners indicated that the previously proposed RERRA notification was insufficient to establish a true connection to the resource adequacy and/or reliability need. MISO is also now requiring that the load being addressed by the ERAS project be in the same LRZ region as the RERRA providing the verification, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. An example of a resource filing that was submitted to a RERRA is an Integrated Resource Plan. This is another way to more closely tie the ERAS project to the identified resource adequacy and/or reliability need.

Q. HOW DID THE RERRA NOTIFICATION REQUIREMENT CHANGE?

A. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language in the tariff. The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource

adequacy or reliability needs are eligible for expedited study through the ERAS process."[31] Under the new language, the ERAS Interconnection Request must be accompanied by a written verification from a RERRA that either the new, incremental load addition is valid and not otherwise included in a resource plan, or the Generating Facility proposed will address a resource adequacy deficiency as determined by the RERRA.[32] MISO changed the language to better tailor the RERRA notification requirement to a new resource adequacy and/or reliability need. The verification may only come from the RERRA where the load to be served is located and the Generating Facility must be in the same LRZ as the load needed as described above.

Q. WHY IS IT REASONABLE TO REQUIRE A RERRA TO VERIFY TO MISO THAT A PROJECT SHOULD BE CONSIDERED FOR THE ERAS PROCESS?

A. First and foremost, MISO is not a resource planner. It is the reliability and market operator for 15 states and one Canadian province. It is the state or RERRA that has jurisdiction over and determines the resource adequacy needs and/or policies that governs the retail electric service to end-customers. Rather, as noted in the Federal Power Act, the states are the ultimate authority for resource adequacy, hence their necessary inclusion in the ERAS process to address the need for these critical projects to maintain resource adequacy. In order to ensure that the proposed ERAS projects will address a resource adequacy and/or reliability need claimed by an Interconnection Customer, MISO needs the RERRA (or its documented representative) where the load is located to provide a written verification as described above for MISO to study the generation expected to serve that need.

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[31] ERAS Order at P 202.

[32] *See* Tab A Redlines, GIP Section 3.3.1.

This requirement will prohibit the submission of projects that have no connection to a verified load need thereby increasing the certainty that the project will reach completion and prevent speculative projects from using the ERAS process.

Q. WHY IS MISO REQUIRING THE ERAS PROJECT AND THE IDENTIFIED RESOURCE ADEQUACY AND/OR RELIABILITY NEED BE LOCATED IN THE SAME LOCAL RESOURCE ZONE?

A. MISO is requiring the load being addressed by the ERAS project be in the same LRZ as the Generating Facility unless the project applicant can demonstrate that the use of the Generating Facility was included in a resource filing made to the relevant RERRA. Requiring the proposed ERAS project to be located in the same LRZ as the RERRA-verified new, incremental load or resource adequacy deficiency ensures that the generation is going to support the load need in that area. This requirement also ensures that the proposed ERAS project is closely tied to a specific spot load or resource adequacy need. This requirement strengthens the nexus between the new load and the ERAS generation project and will serve as MISO's location criterion, which other RTOs have utilized in their similar proposals.[33]

Q. DOES THE RERRA VERIFICATION CONSTITUTE EVIDENCE OF A DESIGNATION OF NEED OR A FINDING OF APPROPRIATENESS BY THE RERRA?

A. No. The following language was included in the proposed tariff redlines as part of the RERRA verification requirement:

> A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for

[33] ERAS Order at P 202.

any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.[34]

The purpose of the verification requirement is to confirm to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency. After lengthy conversations with the states during the development of MISO's first ERAS filing, MISO understands that each RERRA has its own process and timeline for formally determining needs and approval processes and that part of these processes by necessity occur after the project has been studied by MISO.

It is important that the RERRA verification not prejudice the ability of the RERRA to make later determinations in accordance with applicable laws and regulations. The purpose of ERAS is to enable the states to meet their resource adequacy needs, while not acting as an impediment to their approval processes. For MISO's purposes, what is important is that it knows which projects to study on an expedited basis and to ensure any Network Upgrades identified in the study, and listed in an EGIA are constructed to provide certainty to later planning processes. The Tariff language meets this need while protecting the rights of the RERRA to make determinations in accordance with its own processes. This language was included to ensure that the RERRA's written verification to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency could not be used by the Interconnection Customer in a subsequent state or RERRA regulatory process as proof or evidence that the project must be approved.

[34] Section 3.9.1.

The RERRAs reserve the right to make a judgement on the need for a project after MISO has studied the project through ERAS as applicable state regulatory processes and approvals still apply. This ensures that MISO's acceptance of the project into ERAS cannot be interpreted as MISO *directing* the state or RERRA to approve the project through their independent regulatory review process. The intention of the language noted above was also to ensure the notification does not pre-determine the outcome of any applicable state process.

In addition, any Network Upgrades identified in the ERAS process and included in an executed EGIA, or filed unexecuted EGIA, will be constructed regardless of whether that EGIA is later terminated due to the ERAS Interconnection Request not being constructed. This adds an additional layer of responsibility to the ERAS Interconnection Request to ensure its certainty and ensures that MISO can utilize that Network Upgrade(s) in later planning processes. For instance, projects within the DPP process can rely on approved MTEP projects, including Network Upgrades approved through the ERAS process, to mitigate constraints identified with the DPP process.[35]

Q. HOW DOES THE ERAS REVIEW PROCESS ALIGN WITH STATE REGULATORY REVIEW PROCESSES?

A. State processes are expected to commence during the ERAS submission window and then work in parallel to ERAS, as presented in Figure 2. These processes may be completed after MISO has finalized the study and issued the EGIA, or potentially complete before the execution of an EGIA. If the state processes and ERAS are done in parallel it may allow

[35] Generator Interconnection Business Practices Manual (BPM-015), Section 6.1.1.1.

for even distribution of work and ensures these critical, time-sensitive projects can proceed efficiently and come online as necessary.

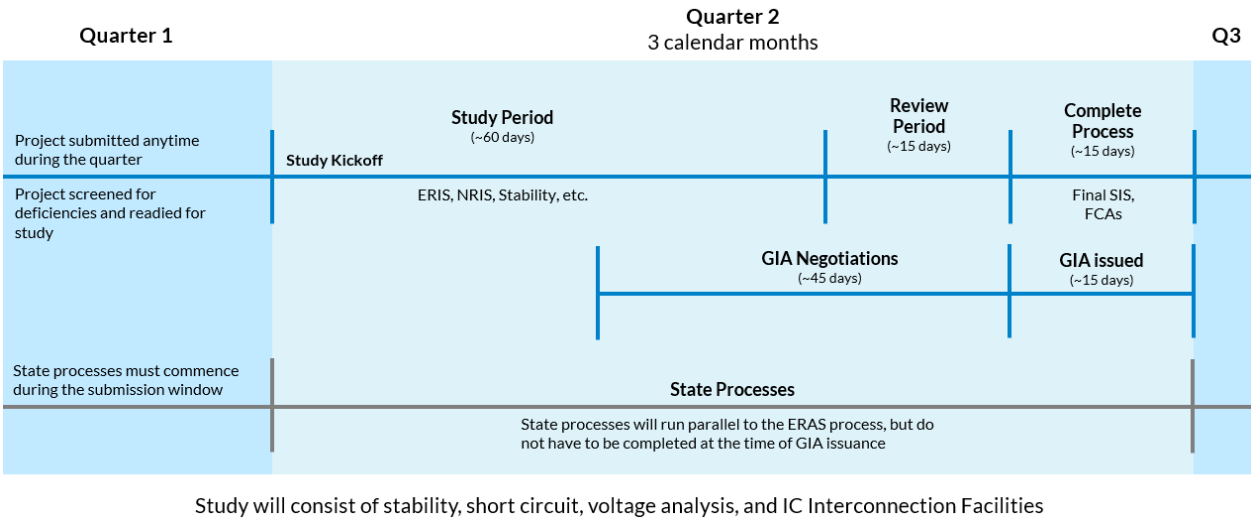


Figure 2: ERAS Quarterly Study Period Example

Q. WILL MORE THAN ONE RERRA NEED TO PROVIDE A VERIFICATION FOR A SINGLE PROJECT?

A. No. MISO is only requiring verification from one RERRA for ERAS participation. The RERRA providing the written verification for the project must be the RERRA responsible for the load that the project is proposed to serve. Per the resource adequacy definition of a RERRA, an identified load can only be regulated by one RERRA.

C. <u>ERAS for Illinois and Part of Michigan</u>

Q. WILL THE REFINED ERAS PROCESS INCLUDE ILLINOIS AND THE RESTRUCTURED PARTS OF MICHIGAN?

A. Yes. MISO has drafted proposed language to incorporate the restructured states into the ERAS process. If an Interconnection Customer's new Generating Facility will address resource adequacy and will either: "(1) serve retail choice load located in a state that limits

the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or (2) serve retail choice load and/or be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales", the Generating Facility may qualify to participate in ERAS, given it meets all other ERAS requirements.[36] In these instances, the Interconnection Customer will indicate the specific retail choice load on the Interconnection Request and provide evidence of the determination of need, but will not be required to include a verification from a RERRA. MISO is proposing these changes to include Illinois and a small part of Michigan in the ERAS process.

Q. WILL MISO'S PROPOSED LANGUAGE FOR ILLINOIS AND MICHIGAN GIVE PROJECTS AN ADVANTAGE OVER OTHER PROJECTS HOPING TO PARTICIPATE IN ERAS?

A. No. Due to the way that Illinois is structured, it does not have a RERRA that could verify the resource adequacy and/or reliability need like the other states. At first glance, removing the RERRA verification requirement for retail states would seem to give these areas an advantage over other states in the MISO footprint. But MISO has crafted other limitations in the ERAS process that will limit the number of projects that can be proposed from developers in Illinois and Michigan that serve retail choice load. First, only 8 ERAS projects will be accepted to serve retail choice load and only 10 ERAS projects will be studied per cycle. Additionally, those studied within the same quarter cannot be geographically located near other projects or impact the same constraint. Second, the

[36] *See* Tab A Redlines, GIP Section 3.9.1.

ERAS projects will be limited to LRZ regions where the need is located, which will further reduce the number of projects that can be proposed from retail choice states. Interconnection Customers will also still have to provide evidence of determination of need as outlined in the Tariff. MISO is working to level the playing field between the states in its footprint and also wants to ensure that the projects are spread out among the states to better address the resource adequacy and/or reliability needs that they may have.

Q. DO ERAS PROJECTS IN RETAIL CHOICE STATES HAVE A DIFFERENT CAP?

A. Yes. ERAS projects submitted in accordance with Section 3.9.1(1) will be separately limited to a maximum of 8 projects for resource adequacy deficiencies until the sunset of the ERAS process. Retail choice states are a small subset of the MISO footprint and require an ERAS process that is not bound by a RERRA verification due to the need to host an open auction process within those states. Since a RERRA will not be involved in providing a verification for projects proposed in restructured states, MISO needed to ensure that this restructured ERAS process was limited in scope. After an internal analysis and discussion with retail choice states, MISO determined that a cap of eight projects strikes the proper balance between the portion of MISO that the retail choice states represent and the number of projects that will be accepted into the ERAS process. These eight projects will be studied in addition to the 10 accepted by IPPs to serve non-LSE load and the 50 projects allocated for the remaining needs in the MISO footprint, but they will still be limited by the 10 project per quarterly study cycle cap. A member of the IPP sector proposed that MISO set aside a specific number of projects for IPPs to submit with agreements with non-

LSE load and MISO believes that 10 projects is an appropriate balance similar to the retail choice cap above.

D. Changes to the Interconnection Application

Q. HOW HAS THE INTERCONNECTION REQUEST APPLICATION CHANGED FOR ERAS?

A. MISO is requiring additional information from ERAS applicants as compared to other generation Interconnection Requests in order to better tie the ERAS project to the load need and the associated RERRA in the relevant LRZ. As part of the ERAS application process, project applicants will be required to supply a non-confidential summary of the following information: the developer of the ERAS project, the MW range of need the ERAS project is addressing, what LRZ region the project is located in, and a general description of what the load is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). This information will provide MISO will the full picture of the proposed project including fuel source and MW size, details about the load it is serving, and what RERRA is involved in the project's proposal to ERAS. MISO is also planning to publish what cycles the ERAS projects will be studied in and which carve out they are requesting, if applicable. This information will be published on MISO's ERAS webpage as well.

Q. WHY IS MISO IMPLEMENTING THESE CHANGES TO THE APPLICATION FOR ERAS?

A. To further create a tight nexus between the load need and the Generating Facility addressing the need, MISO is requiring additional information be submitted with the ERAS application. MISO is aiming to closely tailor the proposed ERAS project to the verified resource adequacy and/or reliability need and in a more transparent manner. These changes

aim to better connect the ERAS project with the need and the generator addressing that need. With the Interconnection Request application, along with the RERRA verification and the executed agreement, MISO will have a full picture of the ERAS project, the resource adequacy or reliability need it is proposing to address, and all the relevant parties involved with the project. MISO is making the ERAS process more transparent and believes that the additional information required on the Interconnection Request application will serve this purpose.

Q. WHAT DOCUMENTS ARE REQUIRED WITH THE ERAS APPLICATION?

A. Each ERAS applicant will need to submit the following: (1) the Interconnection Request application with detailed information regarding the project, the developer, and the load that will be served; (2) the RERRA verification validating the specific driver (new, incremental load or resource adequacy deficiency) in its footprint; and (3) an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need. As explained above, the ERAS applicants are also required to submit a non-confidential summary of the proposed project that will be published on MISO's webpage.

V. THE ERAS ELIGIBILITY REQUIREMENTS

Q. WHAT ENTITIES CAN SUBMIT PROJECTS TO PARTICIPATE IN ERAS PROCESS?

A. Initially, MISO proposed that only LSEs could apply to participate in ERAS due to their responsibility to serve their load customers. However, based on stakeholder input during the development of the original ERAS proposal, MISO changed course and recognized that the vast majority of the Interconnection Requests, including those that would be submitted

through ERAS, may not be initially submitted by the LSE that ultimately used the resource to serve their load, but rather an Independent Power Producer ("IPP") that would eventually transfer the resource over to an LSE via an offtake agreement. Given the importance of maintaining the inclusivity and open-access aspects of ERAS, MISO updated the eligibility requirements accordingly to ensure that any project developer can apply to participate in ERAS as long as the project meets all of the ERAS eligibility requirements. The refined ERAS proposal has not changed this.

Q. PLEASE DESCRIBE THE ELIGIBILITY REQUIREMENTS FOR INTERCONNECTION SERVICE VIA ERAS.

A. In determining what the necessary eligibility requirements were for ERAS, MISO established requirements that would allow a project to efficiently move through a study process while still being considered "shovel ready." Based on multiple rounds of feedback from stakeholders and additional analysis, MISO is proposing the following technical requirements for ERAS that must be met at the time of application submission:

1. The project must be for new capacity.
2. The project must request Network Resource Interconnection Service (NRIS).
3. Evidence of a written verification from the RERRA where the load to be served is located by the Generating Facility that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency.

4. Evidence substantiating an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need.
5. D1 and M2 payments will ensure increased financial commitment when the ERAS Interconnection Request is submitted. The D1 will be a $100,000 non-refundable fee and the M2 will be $24,000 per MW.
6. 100% Site Control for the generator as well as 100% Interconnection Customer's Interconnection Facilities (ICIF) Site Control will be required when the application is submitted.
7. COD requested in the ERAS application that is no more than 3 years from submission.
8. The project's requested Interconnection Service must not exceed 150% of the identified MW need.
9. The project and the identified resource adequacy and/or reliability need must be in the same Local Resource Zone (LRZ), unless as previously noted.

I provide additional details on each requirement below.

Q. WHY IS MISO REQUIRING AN EXECUTED AGREEMENT TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEED?

A. Requiring executed documentation by an authorized representative of the entity submitting an ERAS Interconnection Request is reasonable because it allows MISO to balance the appropriate level of "shovel ready" certainty for the critical project. The executed agreement with an off-taker requirement also reduces speculative projects and connects a specific project with a claimed resource adequacy and/or reliability need. Additionally, it

helps verify the accuracy of the information set forth in the ERAS application, which will ensure that MISO will be able to expeditiously transition to studying the project.

Q. WHAT IS THE PURPOSE OF THE BROAD AGREEMENT DOCUMATENTION LANGUAGE IN PROPOSED TARIFF SECTION 3.9.1.2.d?

A. The following language was added to the executed agreement requirement:

> d. Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier, or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy and/or reliability need.

MISO recognizes this language is broad, but the intent of this subsection was to establish a minimum requirement that an arrangement exists between the driver of the need and the project to address that need. As MISO developed this language through the stakeholder process, we determined that requiring a "PPA" or other specified form of agreement, or specific terms, may prove too onerous, especially in jurisdictions where need determinations or commercial commitments are contingent on identified project costs or previous MISO study. What is important is a demonstration that an ERAS Interconnection Request is the solution intended by the entity with the need. The language balances two goals: 1) it prevents speculative requests by entities that are merely hoping to be selected to address a need later, and do not have buy in from the need driver, and 2) it avoids requirements for MISO to evaluate the details of commercial arrangements that may still be in development, which would frustrate use of the ERAS process in many cases. The addition of Alternative Retail Electric Supplier specifically allows agreements with such entities operating in retail choice states.

Q. WHY IS MISO LIMITING ERAS PROJECTS TO 150% OF THE IDENTIFIED MW NEED BASED ON NAMEPLATE CAPACITY?

A. In working to refine the ERAS process, MISO looked at how SPP, CAISO, and PJM structured their corresponding processes. The CAISO proposed a cap of 150% of total available transmission capacity for each of its Deliverable Zones arguing that the "percentage-based nature of the cap ensures that the studies are scaled to the resource and transmission planning completed by the State and local regulatory authorities, while still enabling competition."[37] SPP took a different route – it plans to calculate a maximum amount of capacity that each LRE may propose for inclusion in ERAS and will use a "LRE Ceiling Capacity," which is calculated using "the sum of the LRE's projected capacity, and RAR obligations to obtain the Projected LRE Deficiency and then multiplying that number by the Ceiling Multiplier of 1.25 (i.e., 125%)."[38]

MISO is proposing to limit ERAS projects to 150% of the identified need because MISO's goal is to tighten the nexus between the load need and the proposed ERAS project. Understanding that accredited capacity, depending on the fuel type, is generally lower than 100% for many resources, MISO wanted to establish a closer connection between what is needed and what is being proposed by the ERAS project. The limitation of 150% of identified MW need will strike the proper balance between having a sufficient amount of interconnection service advancing through the study process to support the identified spot

[37] *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter at 6 (filed Aug. 1, 2024).

[38] *Southwest Power Pool*, "Tariff Revisions to Implement the Expedited Resource Adequacy Study" at 29, Docket No. ER25-2296-000 (filed May 22, 2025).

load or resource adequacy deficiency and preventing the overbuilding of resources through ERAS.

Q. HOW IS MISO MEASURING THE 150% OF THE IDENTIFIED MW NEED?

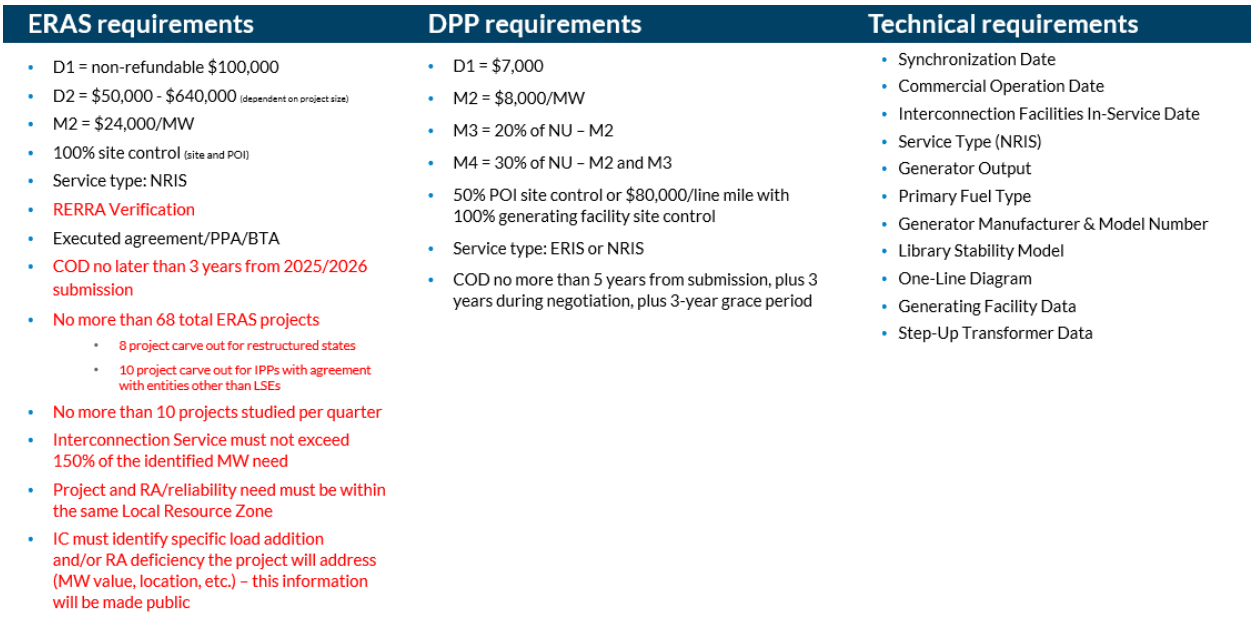
A. MISO is measuring the identified MW need the amount of Interconnection Service requested. Interconnection studies are based on the amount and type of interconnection service requested and they do not assess a generator's potential accreditation. Also, the accreditation of a generator associated with any particular interconnection service may change over time based on the operating characteristics of the generator, the generators attributes, and whether surplus or replacement service is utilized. Additionally, the load an ERAS request will service could have some level of demand response and the ERAS process is fuel agnostic both of which can impact eventual accreditation needs. Based on these different elements, MISO determined that the maximum amount of Interconnection Service that can be associated with an ERAS request would be linked to the amount of load being served rather than on the generator's potential accreditation.

Q. WHY IS MISO STILL REQUIRING HIGHER FINANCIAL COMMITMENTS TO PARTICIPATE IN THE ERAS PROCESS?

A. First, a higher D1 application fee is necessary to implement the temporary ERAS process and cover costs related to processing ERAS Interconnection Requests such as tools improvement, including improvements to MISO's application portal, and/or any additional staffing. This higher and non-refundable application fee will also increase the financial obligations of the applicants, which will ensure that only "shovel ready" projects will be submitted to ERAS.

Second, it is critical that ERAS Interconnection Customers have a greater financial stake upfront for ERAS Interconnection Requests beyond study deposits spent in the study process, as it will encourage a higher level of due diligence and commercial readiness. The increased M2 financial exposure of $24,000 per MW is based on the existing MISO Provisional Interconnection Service's milestones requirements as it represents the same level of upfront commitment for M2, M3, and M4 an Interconnection Customer would make in the DPP three phased process (i.e. $8,000 per MW per phase). Figure 3 presented below demonstrates the differences between the refined ERAS proposal and existing DPP financial requirements. The red font indicates what requirements were added or changed since the original ERAS proposal.

Figure 3: ERAS, DPP, and Common Requirements



Q. WOULD ERIS REQUESTING NRIS QUALIFY UNDER ERAS?

A. No. One of the eligibility requirements for ERAS is that it must represent new incremental capacity. In the instance of an interconnection request with ERIS working to add NRIS to

their request, this would not represent new capacity but rather an uprate to existing interconnection service. This type of request does qualify for an exemption to the queue cap though and can proceed through the next DPP cycle automatically.

Q. CAN EXTERNAL GENERATING RESOURCES REQUESTING NEW INCREMENTAL NEW CAPACITY REQUEST ERAS?

A. Yes. An ERAS request associated with an external generating resource, requesting External NRIS, would be studied under the standing NRIS study procedures covered under the proposed section 3.9.3 of Attachment X. This proposed project must still meet all the other ERAS eligibility requirements including providing a RERRA verification.

Q. WHY IS MISO STILL REQUIRING 100% SITE CONTROL FOR ERAS PROJECTS?

A. The increased gating requirements involving Site Control and financial milestones for ERAS Interconnection Requests are reasonable because they reflect the importance of preserving the integrity and certainty of these projects. It also helps to ensure that MISO will not get inundated with projects that are not shovel ready even with the new ERAS cap. Requiring 100% Site Control to the POI with the ERAS application submittal, along with the existing requirement of 100% Site Control for the Generating Facility encourages only shovel ready project applicants apply to ERAS. ERAS Interconnection Requests must address a resource adequacy and/or reliability need in the short-term, which essentially requires the project to be shovel ready in the next few years. The 100% Site Control requirement is also designed to discourage speculative and non-ready projects from

entering ERAS. To that end, MISO also determined that there would be no Financial Security option for the POI Site Control like is available within the DPP process.

Q. WHY DOES AN ERAS INTERCONNECTION REQUEST NEED TO HAVE AN ACCELERATED COMMERCIAL OPERATIONS DATE ("COD")?

A. Under the current DPP timeline requirements, to use an example, an Interconnection Request submitted in the 2025 DPP study cycle would not need to come online before 2036. First the applicant into the DPP process can have a COD that is no more than 5 years out. Second, during GIA negotiations the Tariff allows the IC to extend the application COD by an additional 3 years. And finally, the *pro forma* GIA allows for a 3 year grace period beyond the COD documented in the GIA for a total of 11 years after initial submission.

Given the urgent resource adequacy needs identified earlier, another tool or mechanism is needed to ensure that the ERAS Interconnection Requests come online as soon as possible. MISO is requiring that ERAS projects have a COD within 3 years of their ERAS submission date unless the project is deferred to a later quarter at which point the COD can be adjusted during GIA negotiations to be no more than 3 years from the kickoff of that project's ERAS quarterly study cycle. Interconnection Service granted through ERAS would continue to have an additional grace period of 3 years from the COD date in the EGIA to become commercial as noted in MISO Appendix 6 Generator Interconnection Agreement (i.e. the *pro forma* GIA). This COD requirement in addition to other eligibility requirements, including increased financial commitments and obtaining 100% Site Control, will ensure that only projects that can achieve commercial operations quickly participate in ERAS.

Q. HAVE STAKEHOLDERS OR OTHER INTERESTED PARTIES EXPRESSED CONCERNS REGARDING THE COD REQUIREMENT?

A. Yes. ERAS has ultimately been crafted in a transparent and collaborative manner to achieve a near term resource adequacy goal to maintain reliable grid operations. MISO worked to balance the end date to enable projects at differing points in the preparation process to participate in ERAS – some projects will be ready to participate this year, while others are working to have their projects ready to participate in 2026 or later. MISO will allow an extension on an ERAS project's COD deadline if it is deferred to a later study quarter.

Q. HAS MISO CONSIDERED THAT ERAS INTERCONNECTION REQUESTS WILL BE SUBJECT TO THE POTENTIAL DELAYS (SUPPLY CHAIN, REGULATORY, SITE CONTROL, ETC.) THAT DPP PROJECTS ARE SUBJECT TO?

A. Yes. MISO has taken these concerns into consideration. During the original ERAS discussions, we continued to hear from our Interconnection Customers that these issues persist. For this reason, MISO is proposing that Interconnection Service granted through ERAS would utilize the same grace period of 3 years from the COD date in the ERAS application to become commercial that all other Interconnection Customers have as noted in the MISO *pro forma* GIA. MISO recognizes there are numerous industry challenges outside of developers control and wanted to provide a sufficient amount of time for the developers to get their projects ready within this context. The current timeframe proposed

for ERAS should be sufficient to provide developers with time to overcome any supply chain or other unknown delays.

It should also be noted that as previously mentioned, given the increased gating requirements (Site Control, increased financial commitment), this ultimately helps to ensure that MISO will not get inundated with projects that are not shovel ready.

Q. HOW WILL MISO CLOSE OUT THE ERAS PROCESS?

A. The ERAS process will sunset at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or by August 31, 2027. This time limitation also applies to the projects proposed by the retail choice states – if the eight projects are not submitted by the sunset date, the ERAS process will still close on August 31, 2027. The same is true for the projects proposed under the carve out for IPPs with agreements with entities other than LSEs – if the ten projects are not submitted by the sunset date, the ERAS process will still close as planned. MISO will only accept applications to be included in the last Quarterly Study Period prior to the sunset date. MISO will post the application deadline for each Quarterly Study Period on the MISO public website.

VI. ERAS PROCESS COORDINATION

A. Coordinated Study Processes

Q. PLEASE DESCRIBE THE EXPEDITED PROCESSING OF THE EGIA.

A. The refined ERAS process will still enable all parties to move expeditiously through EGIA negotiations. Because of the critical reliability need for ERAS Interconnection Requests and to ensure an overall expedited process for commercial operations, the EGIA follows an expedited timeline. The drafting of the EGIA by the MISO team will begin as soon as possible. Additionally, under the EGIA timing requirements for ERAS, MISO will tender

a draft EGIA within five (5) Business Days after the Interconnection Customer provides notice to proceed to EGIA negotiations. Following this, an EGIA would be tendered in less than 30 business days.

Q. HOW WILL MISO PROVIDE INTERCONNECTION CUSTOMERS SUFFICIENT TIME TO EXECUTE A GIA?

A. In crafting the ERAS process, MISO recognized the need to implement a shorter timeframe for the EGIA negotiation process to ensure that the overall ERAS process could be completed within 90 days. To that end, MISO will begin drafting an EGIA document as soon as possible. This ultimately enables the EGIA negotiation process to work in parallel with the study process and therefore the EGIA draft will be substantially further along at the end of the ERAS study process. As a result, after the Interconnection Customer issues their notice to proceed, an EGIA can be tendered for the execution in less than 30 business days.

Q. CAN INTERCONNECTION CUSTOMERS WITHDRAW FROM ERAS?

A. While there is a critical need for these ERAS Interconnection Requests, the proposed requirements still allow the Interconnection Customers an opportunity to withdraw once they are aware of the Network Upgrade costs. Moreover, it is possible that an Interconnection Customer may discover various issues with the proposed site in the ERAS process that would influence their desire to withdraw, or the RERRA could ultimately deny the project through their own processes. If the Interconnection Customer withdraws and terminates its EGIA after execution by all parties or after the EGIA is filed unexecuted, the Interconnection Customer will remain liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements ("FCAs") or Multi-Party

Facilities Construction Agreements ("MPFCAs"), including those Network Upgrades arising from the Affected System Study process. If the ERAS Interconnection Request is withdrawn prior to EGIA execution, then there is no agreement to fund Network Upgrades and no impact on downstream planning processes. In these cases, the Interconnection Customer would be refunded their M2 payment and any remaining D2 payments not utilized to perform the study.

The increased penalties for Interconnection Customer withdrawals after the execution of the EGIA, along with the other requirements like the off-taker agreement and the RERRA notification, will help ensure that only critical projects needed for maintaining reliability and/or resource adequacy will apply to ERAS. Under the current effective GIP and DPP process, when an Interconnection Request is potentially withdrawn from the queue, there would be minimal financial exposure to the Network Upgrades. Given the urgent need for ERAS projects, MISO is requiring increased penalties to discourage Interconnection Customers from withdrawing from the ERAS process. More stringent requirements have the added benefit of reducing the potential speculation of the ERAS Interconnection Requests. Fewer speculative projects entering the ERAS process will result in shorter timelines for completing the ERAS Interconnection Studies. This requirement will also motivate developers to run their own studies beforehand.

Q. PLEASE DESCRIBE HOW INTERCONNECTION SERVICE GRANTED THROUGH ERAS WILL BE STUDIED AND HOW IT WILL COORDINATE WITH THE CURRENT DPP PROCESS.

A. The ERAS process will kick off starting September 2, 2025, and will integrate with existing processes without disrupting the ongoing DPP process. As explained previously in my

testimony, Interconnection Requests submitted through ERAS will be studied in a regional serial "first-come, first served" fashion based on the order the projects were submitted. It will follow a quarterly cadence established by proposed MISO timelines, ultimately culminating in the project receiving an EGIA in approximately 90 days. MISO proposes to utilize the existing engineering study process utilized in the DPP for ensuring full generator deliverability to the load. During the ERAS model build, all Existing Generating Facilities, included those from completed DPP cycles, the ERAS Interconnection Request, and the latest MTEP base case with all approved MTEP projects, including any recently approved Expedited Project Request ("EPR") projects. This is the same process utilized for the DPP process except the DPP models include all higher queued Interconnection Requests from early cycle and all Interconnection Requests within that DPP cycle. ERAS studies will not include Interconnection Requests currently in the generator interconnection queue that do not have a GIA. This is important as many of the projects within the queue are speculative in nature given that more than 70% of the Interconnection Requests submitted into the DPP withdrawal or never get built.

Before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but are not included in any ongoing DPP studies. The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements. This ensures that the transmission capacity made available for DPP projects is not being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.

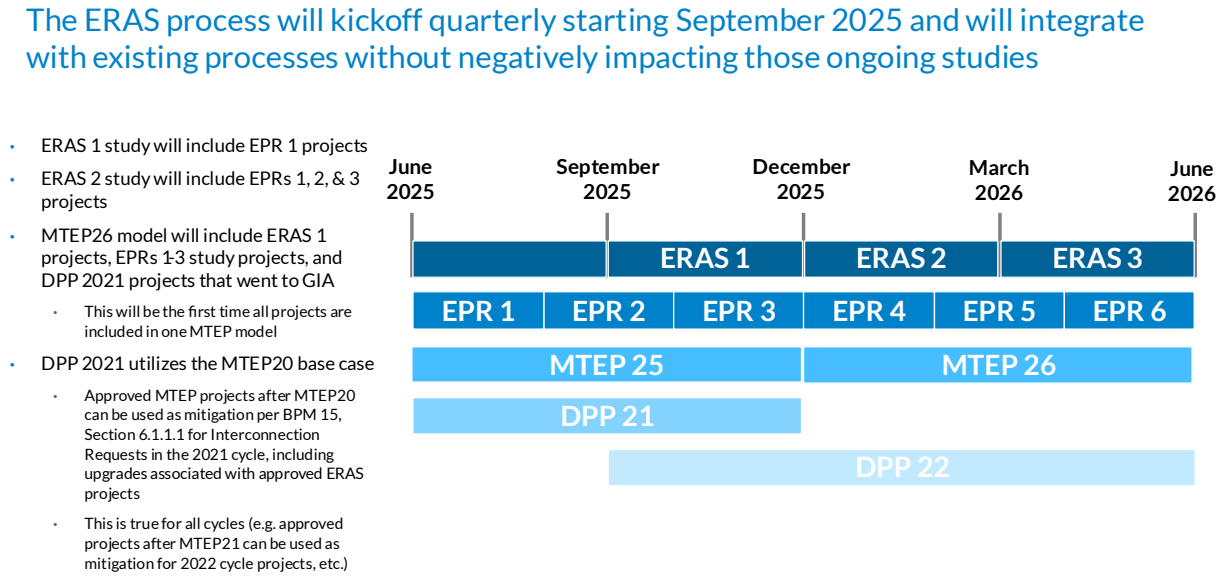
Once the DPP cycle has concluded, the output from that process, and any completed ERAS and EPR projects will be used to populate a new MTEP base case. Any transmission issues identified by reconciling the cases will thus be addressed through the existing MTEP process. The next DPP cycle will then use the latest approved MTEP base case that has reconciled the models. This insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process. The contingent facilities listed in the EGIA would only be those facilities in the model used for the ERAS study and those Network Upgrades that come up as part of the ERAS study.

Q. WILL ERAS PROJECTS NEGATIVELY IMPACT EXISTING PROJECTS IN THE GENERATOR INTERCONNECTION QUEUE?

A. No. Under this model framework, the standing MISO DPP three phase process will not be impacted by ERAS as ERAS Interconnection Requests will not be included in ongoing DPP studies thereby not utilizing any available transmission capacity in those studies. The normal DPP process uses the most up to date MTEP base case when the study is kicked off and is not modified to include later approved MTEP projects or ERAS Interconnection Requests. Although these projects approved after the kickoff the DPP process are not included in the study, there is an existing process that allows these projects to mitigate constraints within the DPP process with MTEP projects. Network Upgrades approved through the ERAS process will also be used to mitigate constraints in the DPP process. ERAS will only positively impact the Network Upgrade identification process of these other processes.[39] This coordinated process is demonstrated in Figure 4 below.

[39] This is further addressed in section 6.1.1.1 of the BPM-015 Generator Interconnection Business Practice Manual.

Figure 4: MISO Coordinated Study Processes



Q. WHAT WILL HAPPEN IF TRANSMISSION CAPACITY IS OVERALLOCATED DUE TO AN APPROVED INTERCONNECTION REQUEST IN ERAS AND THE DPP?

A. On the rare occasion that overallocation may occur, it would be discovered as part of the standing MTEP Deliverability Analysis. The process has been structured so that there cannot be any negative impact to the projects currently in the DPP process, but this can lead to a potential occasion of overallocation. There will be no negative implications for either the DPP Interconnection Request or the ERAS Interconnection Request due to this rare occurrence. Both will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO performs generator deliverability analysis as a part of the current MTEP process to ensure continued deliverability of generating units with Network Resource Interconnection Service. Results of the assessment are based on an analysis of near-term (5-year) and long-term (10-year) summer peak scenarios. Any

constraints that are identified as needing mitigation would be formalized in a future MTEP project.

Q. WHO IS ASSIGNED THE COST OF THE MTEP PROJECT APPROVED TO MITIGATE ANY OVERALLOCATION SCENARIO?

A. The cost of the MTEP project will be allocated based on the existing Tariff rules, which is likely to be the load within the transmission pricing zone where the transmission upgrade is located. However, it is also expected that this load will include the load that is benefiting from the ERAS and DPP Interconnection Requests and benefits from the Network Upgrades that were funded by the generators that went through those processes. In addition, the cost shift is consistent with existing processes. In particular, MTEP projects that are approved after the start of a DPP cycle or even MTEP projects that are approved after the execution of a GIA, can be utilized to mitigate constraints identified in the DPP process. Therefore, an Interconnection Request can be contingent on that MTEP project instead of relying on the original Network Upgrade identified through the DPP process to mitigate that DPP constraint. As a result, the elimination of that Network Upgrade, the Interconnection Customer will not have to pay those costs. This is a cost shift where the load will pay for the MTEP project instead of the Interconnection Request paying for the Network Upgrade.

Q. ARE THERE OTHER INSTANCES WHERE PREVIOUS PARALLEL STUDIES CAN RESULT IN NEW CONSTRAINTS THAT ARE IDENTIFIED LATER IN A FUTURE MTEP PROCESS?

A. Yes. MISO has multiple planning processes, many performed in parallel. These processes have their own unique modeling assumptions that are vetted through the stakeholder

process. These processes also have different cost allocation methodologies based on "but for" and "beneficiary pay" principles that are vetted through the stakeholder process. Some examples are Baseline Reliability Projects, identified to meet standards for both NERC and regional reliability; Market Efficiency Projects, which address economic driven congestion; Multi-Value Projects, identified through the Long Range Transmission Planning process; Transmission Deliverability Service Projects, identified to support transmission service; Interregional Transmission Projects, identified to improve reliability and/or economic driven congestion within MISO and a neighboring RTO; Other Projects, identified to support local reliability issues like those identified to add load in the EPR process; Generator Interconnection Projects, which are Network Upgrades identified to reliably connect new Interconnection Requests; and new Generating Facilities that are approved through the DPP, surplus or replacement processes.

After all these projects are approved through their relevant processes, they are then included in the base cases of subsequent studies based on the modeling assumptions for those studies. It is not uncommon for new constraints to arise in subsequent studies driven by all of the approved transmission and generation projects, as well as due to new load growth, and the retirement of generation. Constraints could also be negatively impacted by similar processes in neighboring Transmission Providers. As these new constraints are identified new mitigation is identified, which could include another new transmission project necessary to ensure reliability.

B. ERAS and the EPR Process

Q. WHY IS THERE AN EPR GENERATION SHORTAGE?

A. Expedited Project Reviews ("EPRs") are requests by a Transmission Owner for MISO to quickly review the impacts of a proposed transmission project on the MISO Transmission System. A Transmission Owner requests these reviews when it determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project.[40] By default, MISO reviews such projects for inclusion in MTEP within a thirty-day timeframe. EPR requests generally reflect an emergent need on the Transmission System that must be evaluated more quickly than the normal MTEP planning process and timeline allow. The announcement of a large and concentrated load addition at a given point on the Transmission System, such as a data center, is a common driver for EPRs. The EPR process reflects the fact that this load must be served and that doing so may require rapid enhancements to the transmission system. Recently, MISO has had to rely on increased transfers to serve these large loads due to the lack of local generation to serve the load, thereby increasing the amount of transmission upgrades necessary to support the load additions. Additionally, Transmission Owners have been unable to support the full amount

[40] EPRs are governed by Appendix B, Section VII of the Transmission Owners' Agreement, Section I.D.1.c of Attachment FF to the Tariff and Section 4.1.4 of Business Planning Manual 20 (Transmission Planning).

of load a customer would want to connect at a particular location due to the inability to quickly add local generation to support the load.

Q. HOW ARE EPRs CONNECTED TO ERAS?

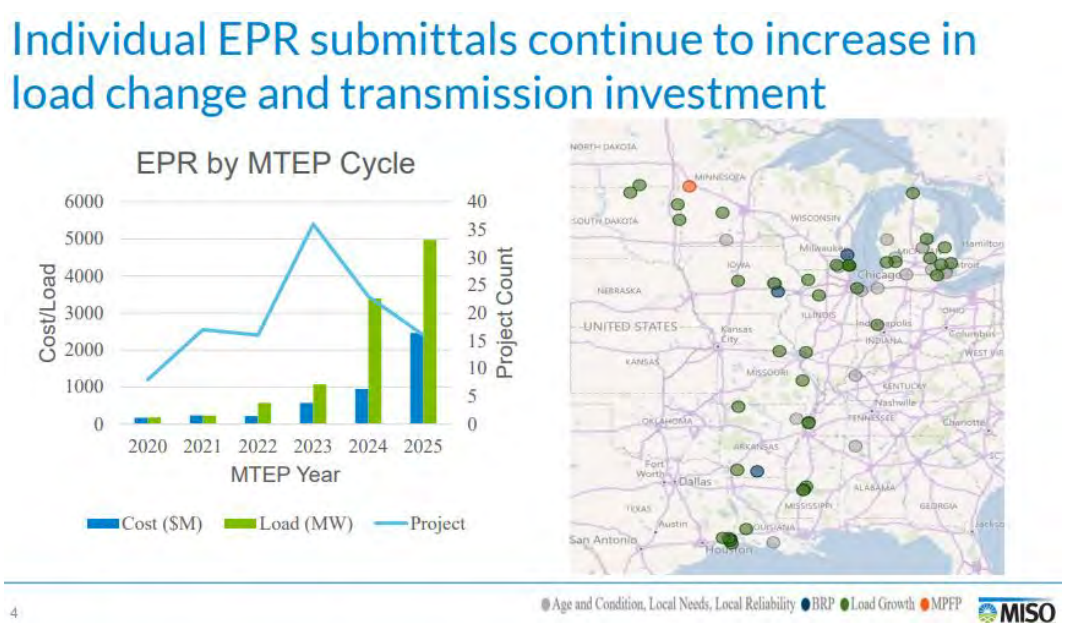
A. While EPRs address the transmission development demands associated with large load additions, these additions may also require a corresponding need to evaluate generation on an expedited basis to serve this load. The EPR process models generation that has a signed GIA, but there is no guarantee that new generation will be interconnected to the Transmission System at a point that can reliably and cost effectively serve the emergent load need. In fact, given the length of MISO's DPP queue delays and the typical generation development timeframe, it is unlikely such load demand was known at the time that any generation projects with a GIA were originally submitted into the queue. Thus, it is unlikely that a generating unit with a high degree of certainty of being online by the needed date of that load driver also happened to be situated in a place where it could reliability serve the emergent load need without significantly extending the length (and cost) of the EPR in order to connect at a point on the Transmission System where excess generation is available. This is especially true given the fact that the EPR can be the first and only connection from that load source to the Transmission System. The EPR process is about approving the transmission necessary to support new load growth, but not the load itself. The EPR process allows for a faster study method to allow these loads to connect sooner than going through the traditional MTEP process. A similar expedited process is needed to study new generation that is necessary to serve spot loads added through EPR. ERAS

supplies this previously missing and much needed connection that complements the EPR process.

Q. HOW OFTEN DOES MISO RECEIVE EPRs?

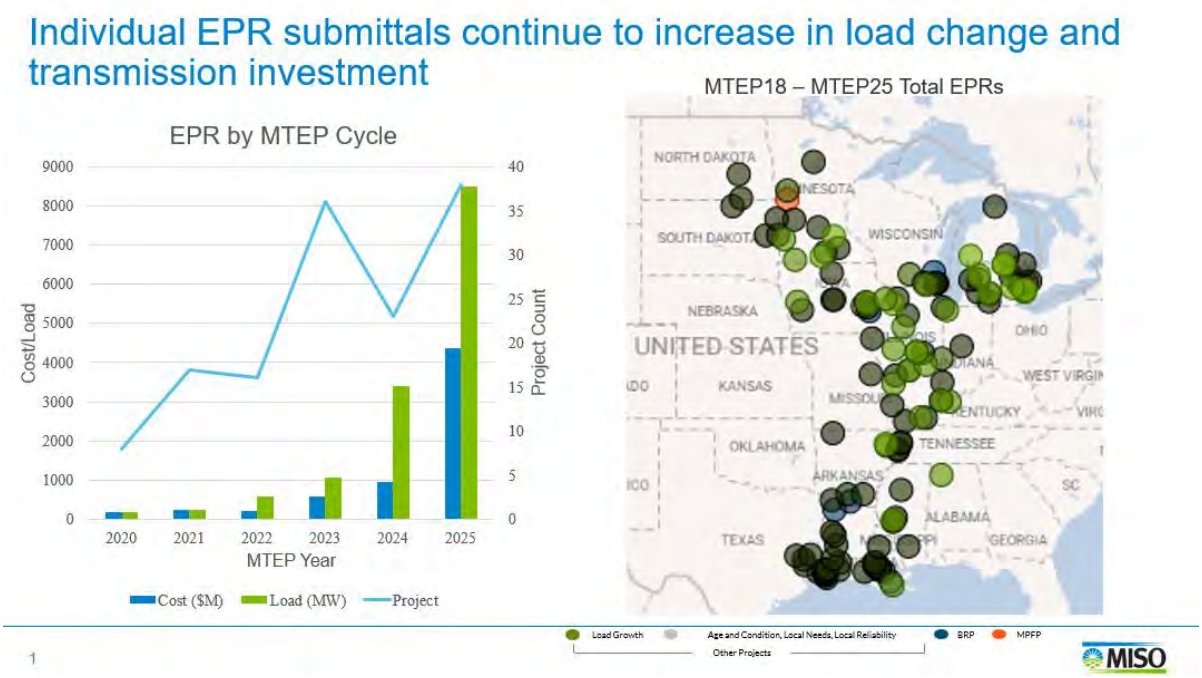
A. In the past, EPRs were comparatively uncommon. However, MISO's most recent data shows a sharp increase in the number of EPRs being submitted in the last few years. As an example, simply comparing the difference from the January PAC Meeting EPR presentation to the current version as of April PAC Meeting EPR presentation, which takes into account the new EPR projects that have recently been submitted, the following figures demonstrate the huge increase and the need for generation to cover this immediate spot load growth.

Figure 5: January 2025 PAC EPR Presentation[41]



[41] MISO EPR Process Improvement Update, PAC-2024-1, Planning Subcommittee, Jan. 29, 2025, available at: https://cdn.misoenergy.org/20250129%20PSC%20Item%2004%20EPR%20Process%20Improvement%20(PAC-2024-1)674593.pdf.

Figure 6: April 2025 PAC EPR Presentation[42]



The data in these figures demonstrates two important trends. First, there has been a substantial increase in the number of EPRs being submitted to MISO. In MTEP 20 and MTEP 21, MISO received only 8 and 17 EPRs respectively. However, MISO has already received more than 38 such requests for MTEP 25. Second, this increase in EPRs is linked to a significant increase in the associated Network Upgrade costs needed to accommodate the EPRs – jumping from an average of $13.7 million in 2022 to $175 million so far in 2025 as shown in the graphics above. This is in part because there is insufficient local generation to serve this load.[43] Absent an accelerated process like ERAS, it is unlikely that

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[42] *MISO Sharing and Coordinating MTEP and DPP to Accommodate Large Loads*, PAC 2024-7, Planning Subcommittee, Apr. 23, 2025, available at: https://cdn.misoenergy.org/20250423%20PSC%20Item%2005%20Sharing%20and%20Coordinating%20MTEP%20and%20DPP%20to%20Accommodate%20Large%20Loads%20(PAC-2024-7)692381.pdf.

[43] A further compilation of some of these projects was recently presented at the April PAC meeting. *Expedited Project Reviews*, Planning Advisory Committee (PAC), Apr. 16, 2025, available at: https://cdn.misoenergy.org/20250416%20PAC%20Item%2004a%20Expedited%20Projects%20Reviews690477.pdf.

the generation needed to support spot load will be located in close proximity to the load being added, thus increasing the need for and cost of additional transmission to bring in generation from remote areas.

Q. WHY IS LOCAL GENERATION PREFERABLE WHEN ADDING LARGE SPOT LOADS?

A. Local generation is preferable when adding large spot loads for multiple reasons. First, local generation will reduce the need for large transmission upgrades to support the new load and generation. Instead of making transmission investments around the remote generation to support the generation exports or making transmission investments to support importing power to serve the load, the load and generation rely on each other and negate the needed transmission investment. Second, there is a limited amount of import capabilities between Local Resource Zones. Relying on generation within the same zone will remove the need to import power from another zone, which benefits and helps all load within the zone. Third, relying on generation within the same zone removes price divergences between the load and generation. The EPR process uses whatever generation it can to support that load addition. ERAS will help reduce network upgrade costs by providing a process to quickly add local generation that the EPR process can rely on. The new LRZ requirement in the refined ERAS process will also ensure that the new generation is local to the resource adequacy and/or reliability need.

Q. WHY IS ERAS NEEDED TO ADDRESS THE EPR GENERATION SHORTAGE?

A. Some protestors in the original MISO ERAS filing argued that MISO should not attempt to meet the load need by its anticipated need-by date. Instead, they argue that MISO should wait and utilize the existing 53 GWs or more of generation with signed GIAs that are

currently delayed in coming online in the time period needed to address the imminent resource adequacy and/or reliability needs.[44] I have evaluated this approach and have concluded it is impractical and unreasonable for several reasons.

First, the EPR process already includes in its models any generation units with signed GIAs that may or may not come online in time. Thus, even with MISO taking into account these GIAs, there is still a local generation deficiency to meet the load need. Second, it is not reasonable to assume in all cases that generation coming online will meet the specific needs of emerging spot load. For example, while a superficial glance at the number of units with signed GIAs may suggest that there is a sufficient number of MW somewhere on the MISO system, these specific units may not always be sufficient to meet the load need. For instance, if a data center with a 2 GW load need plans to run continuously (or mostly at night), the fact that there are 2 GW of uncommitted solar with a near term Commercial Operation Date is likely insufficient to reliably meet this need. Third, these generation units with signed GIAs may not be geographically situated in proximity to the spot load and, due to the nature of their agreements, are precluded from modifying their designated Points of Interconnection. Finally, there is no guarantee that these units with a near-term Commercial Operation Date will actually come online by that necessary start date. I have observed a significant increase in the number of units with GIAs that are not in service by their Commercial Operation Date and are using or expect to use much of the three-year grace period allowed by the *pro forma* GIA.[45] In addition, an increasing number of these

[44] A dashboard of this 50 GW in generation is available in MISO Generator Interconnection COD Report: Overview, last updated June 5, 2025.

[45] *MISO Generator Interconnection COD Report: Overview*, last updated June 5, 2025, available at: https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5OD

units are requesting extensions of their Commercial Operation Date through waivers. These facts lead me to conclude that there is an urgent need for a specialized interconnection process that can deliver highly certain generation that is tailored towards the specific load need and already has some level of commercial arrangement to serve it, on an accelerated basis. Absent the ERAS tool, I expect to see: (1) a continued escalating number of EPR submissions relying on remote generation; (2) increasing Network Upgrade costs associated with EPRs; (3) and instances where load that cannot be served as of the date it plans to come online.

Q. WHAT CAN BE DONE TO IMPROVE THIS IMPENDING SITUATION?

A. It is necessary for MISO to establish a new process from the existing that can enable Interconnection Customers to work with RERRAs to identify load needs and work with LSEs or other developers to address them. After working together to develop the best project to address a resource adequacy and/or reliability need, the Interconnection Customers can propose highly certain projects to participate in ERAS and ideally be brought online on an expedited basis to meet the load need. A new process is needed that will enable potential Interconnection Customers to confer with RERRAs and load drivers about urgent reliability or resource adequacy needs; scope and present their proposed projects to the RERRA and need/driver or LSE; and then come to MISO with highly certain projects that can be studied and brought online on an expeditated basis to meet the load need. While MISO expects that the vast majority of Interconnection Customers and resource adequacy needs will not require such a process, as they will continue to rely on

k0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

the DPP queue, MISO still requires a temporary and specialized process to rapidly study those few projects that are slated to address those critical and urgent needs. MISO cannot force generation to come online, or cherry pick which generation projects should be expedited over others. But what it can do is create a pathway for generation that is shovel ready, slated to meet specific needs that the applicable RERRA has validated, and for which MISO should study on an accelerated basis. This process should have the guardrails proposed in this refined ERAS filing to ensure that the process is available to those critically needed projects with commercial certainty without otherwise becoming a substitute for the DPP.

C. ERAS and the Affected System Studies Process

Q. WHAT IS THE PROCESS FOR CONDUCTING ERAS AFFECTED SYSTEM STUDIES?

A. The refined ERAS proposal was designed with the expectation that MISO would utilize existing affected system studies processes. MISO is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process. MISO is committed to and planning to be able to deliver those on an expedited basis consistent with ERAS even before specific processes are addressed and would follow the existing tariff language and does not prevent MISO from doing this faster.

Q. IS MISO CONTINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?

A. Yes. MISO always seeks proactive continuous improvement of its interconnection queue. In addition to these proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. Examples of ongoing or completed initiatives include the

queue reforms approved in January 2024 to increase readiness, the queue cap approved in January 2025, implementation of SUGAR software to automate and increase the speed of the Phase I study, further improvements to the generator interconnection portal which automates some manual processes in the interconnection application process, and the Commercial Operation Date tracker, which debuted in early 2025 and provides greater transparency into the status of future Generating Facilities in MISO.[46] These initiatives will strengthen Interconnection Customer workflow throughout the Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process and outside vendors. MISO is also working to identify additional processes and tool improvements to improve the overall DPP process.

Q. WILL ERAS INTERCONNECTION REQUESTS GO THROUGH THE AFFECTED SYSTEM EVALUATION PROCESS?

A. Yes. MISO must coordinate the impact of these projects with its existing Affected Systems partners to ensure they do not cause reliability impacts on non-MISO transmission systems. The Affected System Studies analysis is an important part of the standing interconnection process and must be performed as part of this evaluation. Subsequently, where available, MISO will incorporate the results of the associated Affected System Studies analysis in the EGIA. For those instances where the results from the Affected System Study analysis are not available to incorporate, given the accelerated timeframe for ERAS, the results will be provided at a later date.

---

[46] MISO, *SUGAR Implementation* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2005%20SUGAR%20Implementation682016.pdf MISO, *Liaison Report* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2002%20Liaison%20Report681818.pdf.

It should be noted that in the event that the Interconnection Customer withdraws and terminates its EGIA after execution of the EGIA by all parties or after EGIA is filed unexecuted, the Interconnection Customer will be liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements or Multi-Party Facilities Construction Agreements, including those Network Upgrades arising from the Affected System Study process. This will ensure that MISO will be able to expeditiously process the shovel ready ERAS Interconnection Requests while providing a protection mechanism to the existing Affected Systems coordination process. Additionally, ERAS Interconnection Requests will be subject to JTIQ requirements if they meet the criteria for inclusion in the JTIQ Screening Group or Participation Group on the same basis as projects in the DPP. Participation in JTIQ will serve as Affected System process with the Southwest Power Pool ("SPP").

Q. WILL THE AFFECTED SYSTEM STUDIES BE CONDUCTED IN A CLUSTER?

A. MISO will request that these studies be completed on a serial basis, but MISO is unable to control how an affected system will perform its own studies or on what timeframe. MISO will explicitly request that these be studied on a serial basis and MISO will transfer ERAS projects to the affected system serially and not as a cluster in order to enable the affected system to study the proposed projects serially. At the end of the day, only the affected system can determine for itself how and when it will carry out these studies. MISO will work with its seams partners to determine if changes to relative queue priority are necessary for ERAS. For those seams partners that utilize a close of study phase or decision point to establish queue priority, MISO will assert a queue priority date of when the ERAS quarterly study cycle is kicked off.

Q. DOES REQUIRING ERAS CUSTOMERS TO SIGN EGIAS WITHOUT POTENTIALLY HAVING THE AFFECTED SYSTEM STUDY RESULTS VIOLATE ORDER NO. 2023?

A. No. This is a separate limited process that was created outside the traditional DPP process and thus is out of scope of Order No. 2023, which is designed for cluster-based studies. ERAS is not a traditional queue process but is still consistent with the goals of Order No. 2023 which included enabling reforms of current generator interconnection procedures. Moreover, ERAS project participants are aware of the EGIA requirements prior to submitting their projects to the ERAS process. As MISO noted in its transmittal letter, because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach.

D. A Transparent ERAS Process

Q. WILL MISO PUBLICIZE THE ERAS INTERONNECTION REQUESTS?

A. Yes. MISO commits to transparency in the refined ERAS process due to the critical nature of these projects. Similar to the EPR process, the ERAS information will be posted on the ERAS webpage located on the MISO public website, including the name of the Interconnection Customer that has submitted the ERAS Interconnection Request along with other details of the ERAS projects.

Q. WHAT INFORMATION DOES MISO PLAN TO POST ON ITS ERAS WEBPAGE?

A. On the newly created ERAS webpage, MISO plans to publish an informational guide regarding the requirements and process for participation in ERAS. After the first submission deadline for an ERAS quarterly study cycle, MISO plans to publish all ERAS projects that have been reviewed and accepted into the ERAS process. MISO will provide information similar to that found in its GI Interactive Queue for DPP projects, including items like the project number, request status, application in-service date, and fuel type.[47] And as previously explained in my testimony, MISO will additionally publish the non-confidential summary of the following information supplied by the applicant: the developer of the ERAS project, details of the need the ERAS project is addressing, what cap carve out was requested (if applicable), what LRZ region the project is located in, and a general description of what the load it is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). MISO is also planning to publish what quarters each of the approved ERAS projects will be studied in.

Q. HOW DID YOU ACCOUNT FOR OPEN ACCESS REQUIREMENTS WHEN DEVELOPING THE ERAS PROCESS?

A. The ERAS requirements are facially neutral, fuel agnostic and allow for the potential inclusion of any resource regardless of technology. These are shovel ready projects to meet

[47] *MISO GI Interactive Queue*, last updated June 5, 2025, available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

an urgent resource adequacy and/or reliability need within the MISO footprint. MISO also expanded who could apply to ERAS to include a wide variety of applicants.

ERAS Interconnection Requests will be subject to more stringent criteria than projects entering the generator interconnection queue. MISO's ERAS requirements will inevitably limit entry which strikes a reasonable balance between allowing project developers to help address the urgent reliability needs of the MISO footprint, while avoiding an influx of projects that could overwhelm the normal DPP queue and lead to further delays, exacerbating the current inability of projects to come online.

Q. WHAT ARE THE BENEFITS OF ESTABLISHING AN ERAS PROCESS?

A. If the proposed temporary requirements for the refined ERAS process are adopted, MISO expects to comprehensively address significant near-term resource adequacy and reliability concerns in the MISO footprint. ERAS is a temporary process designed to help speed up the time to obtain an executed EGIA so urgent reliability projects can be built more quickly until the DPP interconnection queue process improved timeliness takes effect. The queue will remain the standard way to add new resources to the system; ERAS is a temporary and targeted process to complement the generator interconnection queue process. With ERAS, MISO will be able to efficiently and effectively address near-term resource adequacy and/or reliability needs with specific projects that are tied to those needs.

IV. CONCLUSION

Q. IN YOUR OPINION, IS MISO'S FILING JUST AND REASONABLE?

A. Yes. This Filing addresses certain specific needs that MISO, the state Commissions, and the stakeholder process identified. To ensure that MISO is on the right track to resolving its resource adequacy shortfall potential, MISO requests that the Commission approve this

proposal. The proposed Tariff revisions enable MISO to take the necessary steps to ensure reliability on the Transmission System.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 4th day of June, 2025.

Kandi Hahn

Kandi Hahn

KANDI HAHN
Notary Public, State of Indiana
Marion County
Commission Number NP0740038
My Commission Expires
March 23, 2030

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 122
GridLab Report

1

GridLab Analysis: Department of Energy Resource Adequacy Report

Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026**

the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

Previous post
London Calling: How UK Grid Innovation ...

Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 123
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

Nicholas Institute for Energy, Environment & Sustainability nicholasinstitute.duke.edu

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https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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Nicholas Institute for Energy, Environment & Sustainability

The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

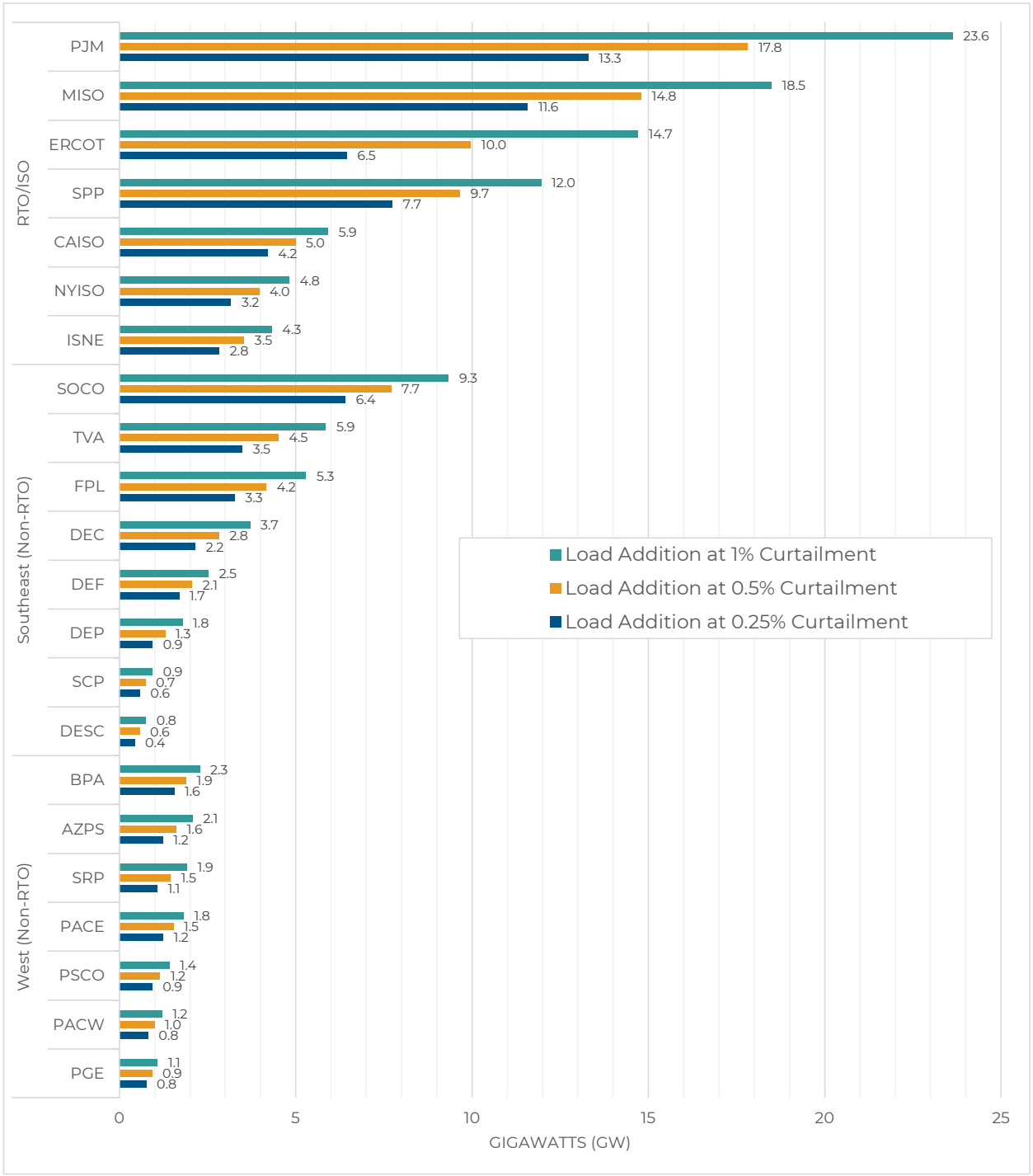
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

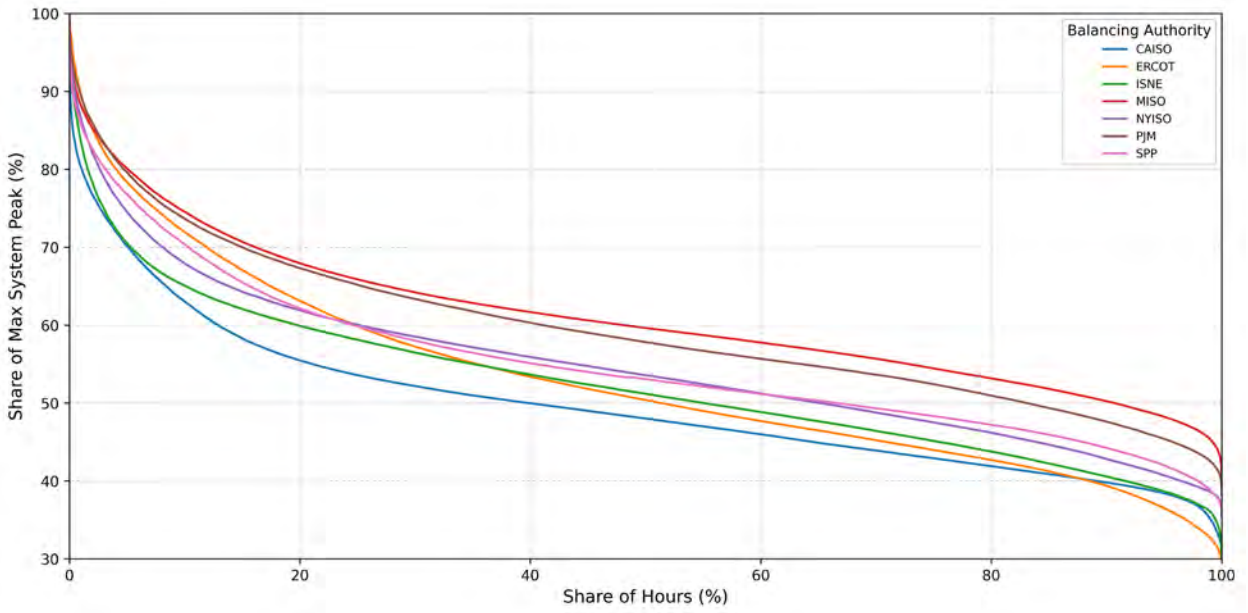
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

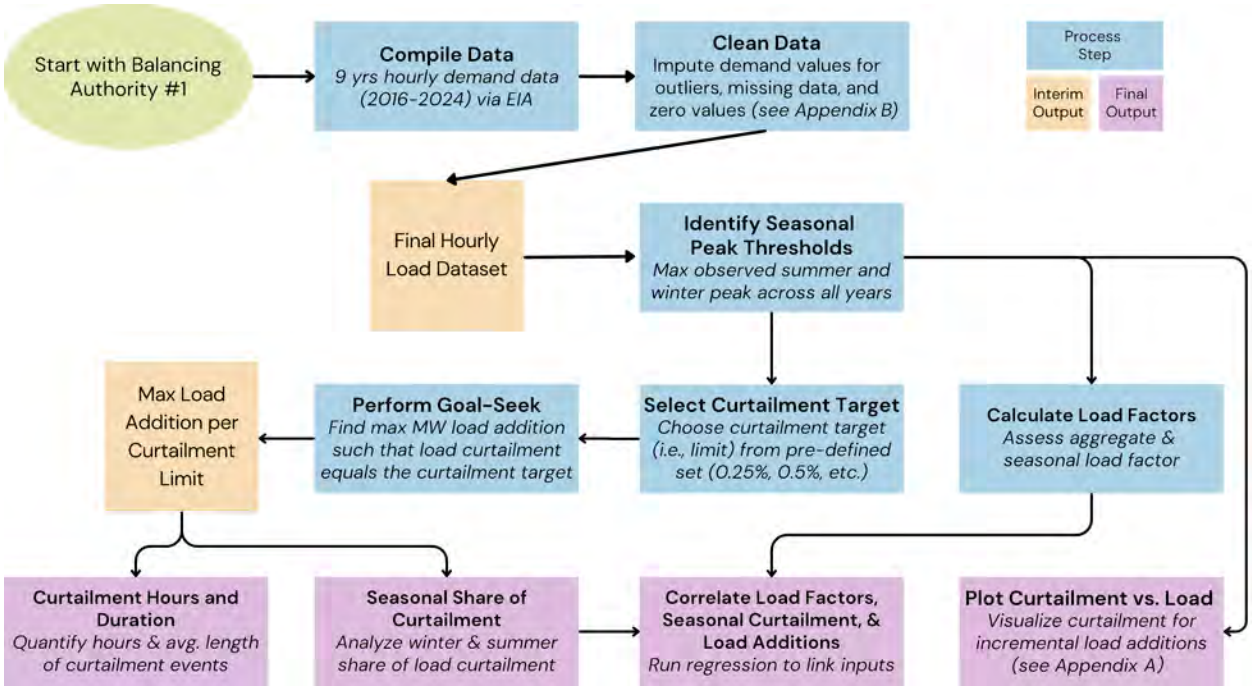
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

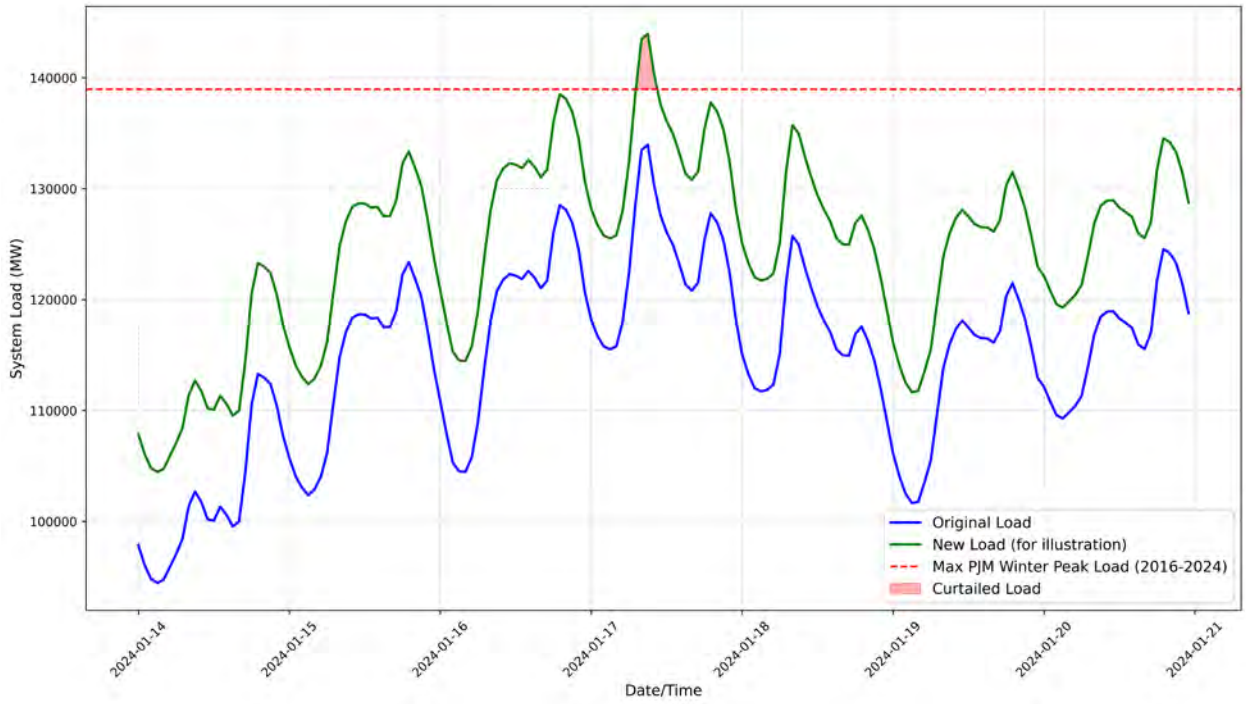
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

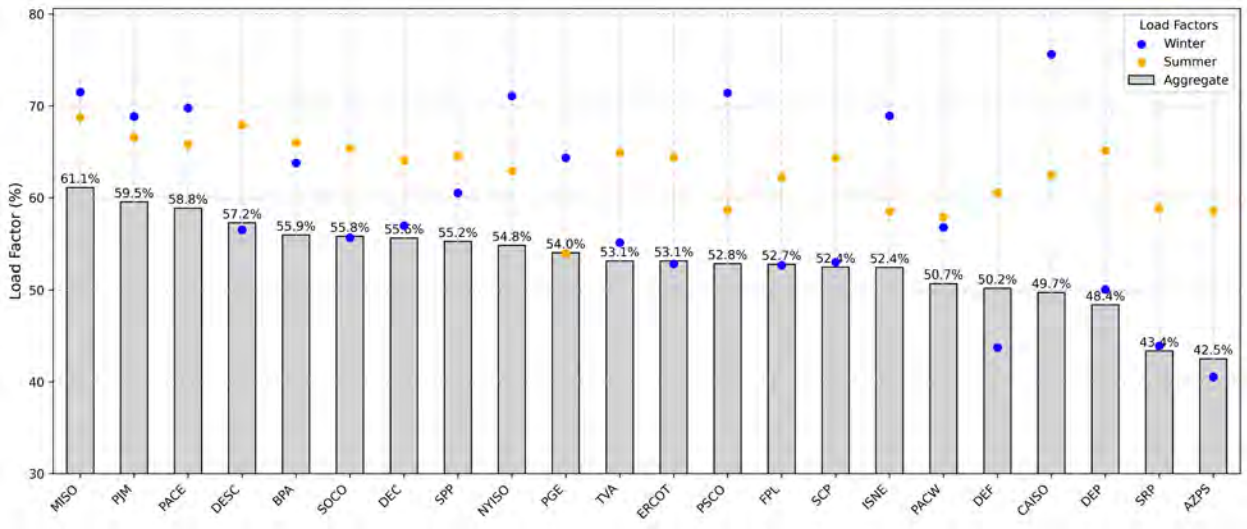
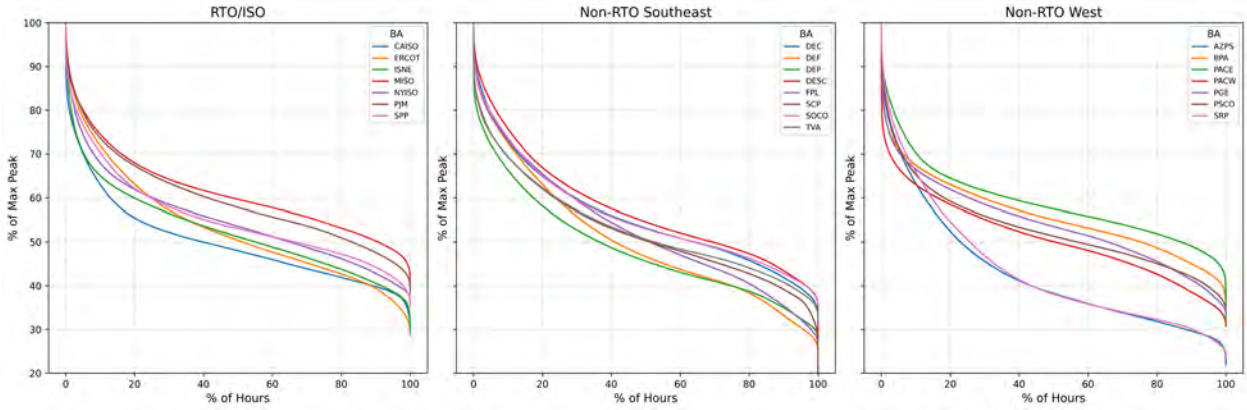


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

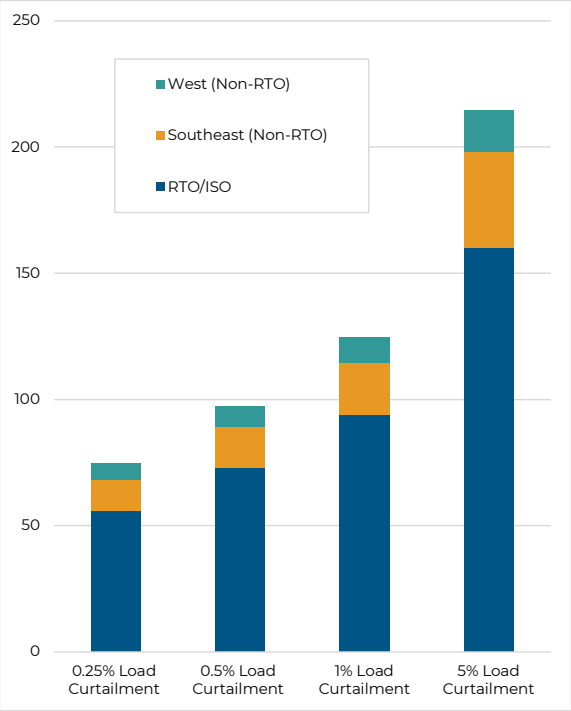


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

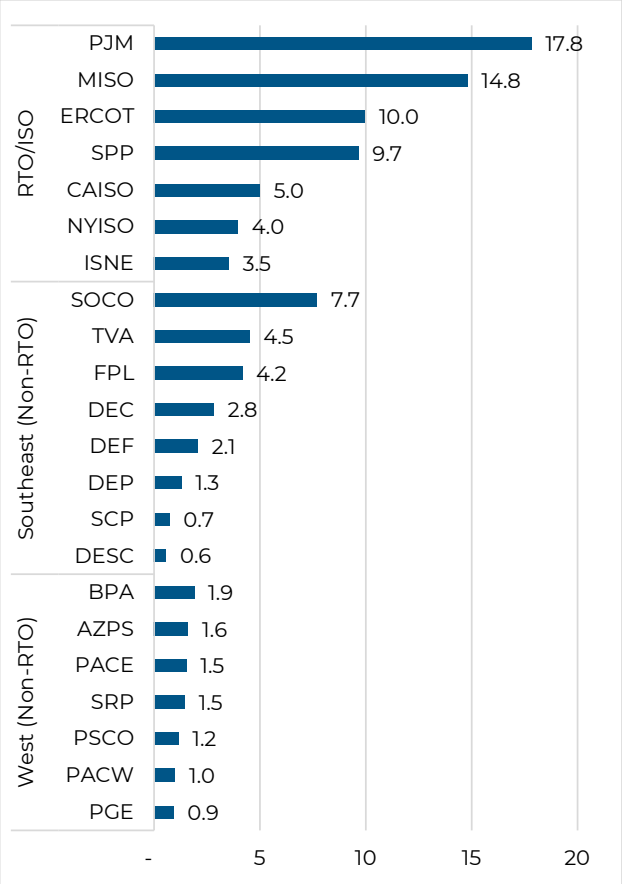
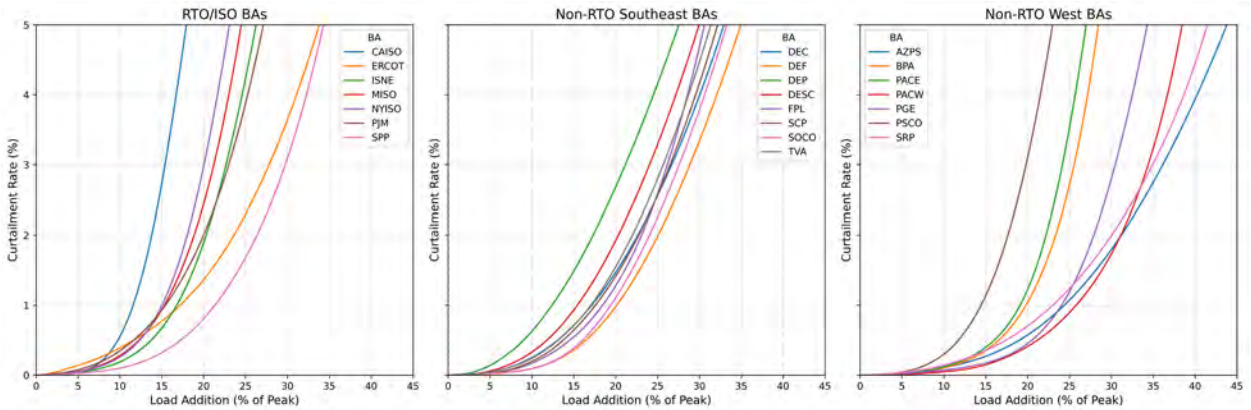


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

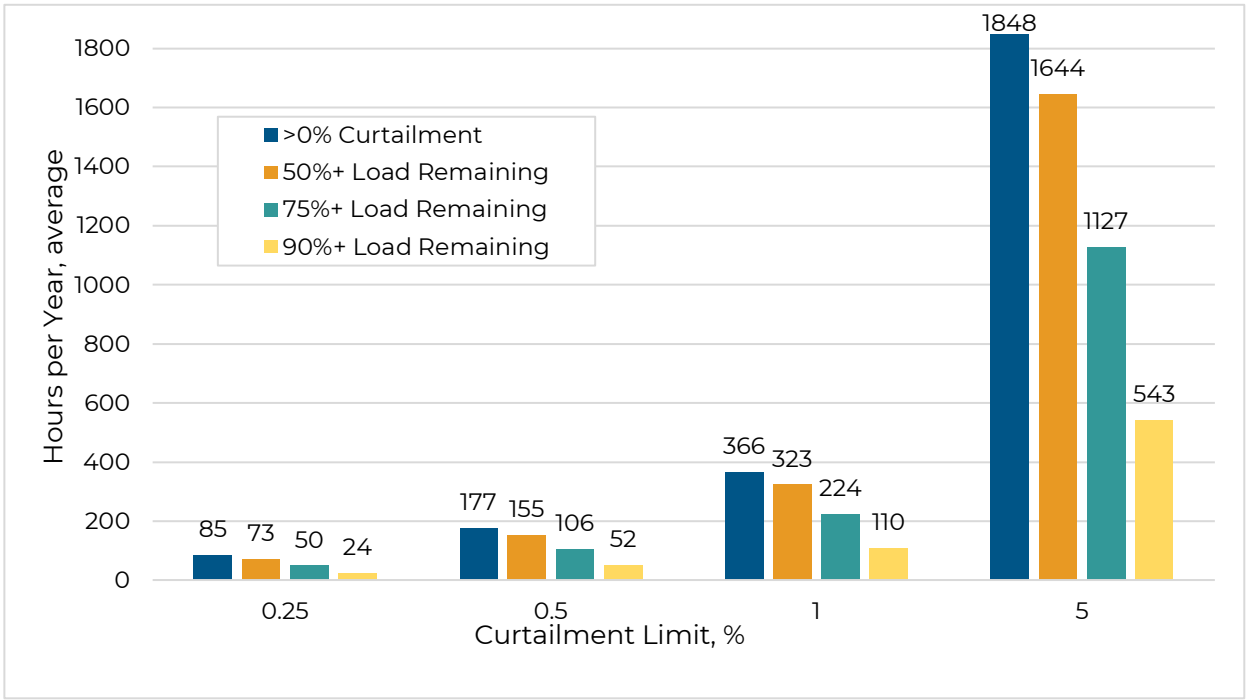
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

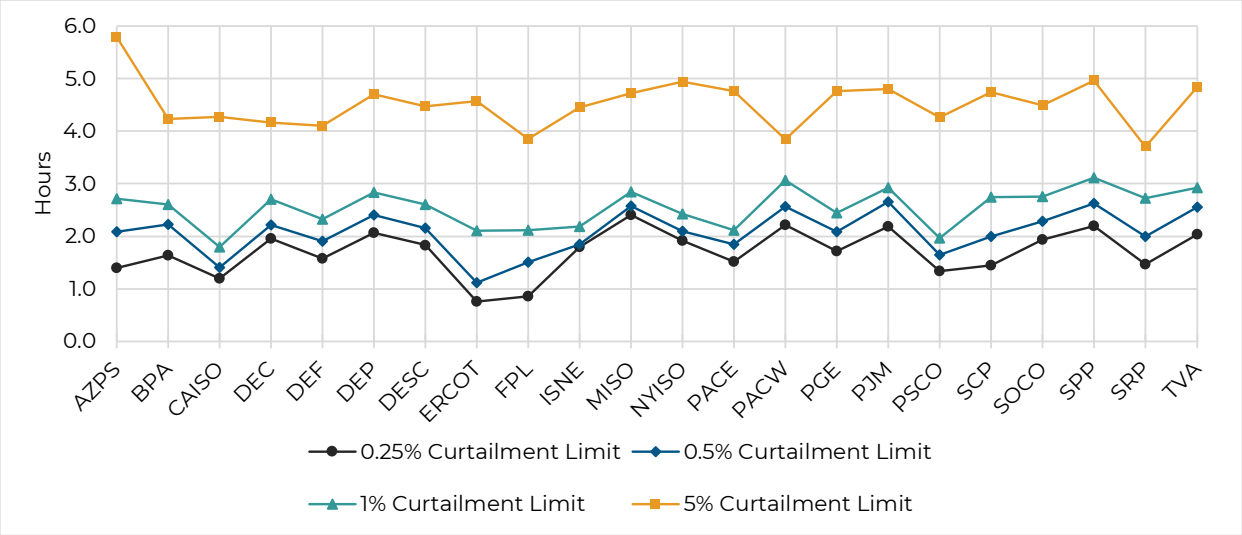
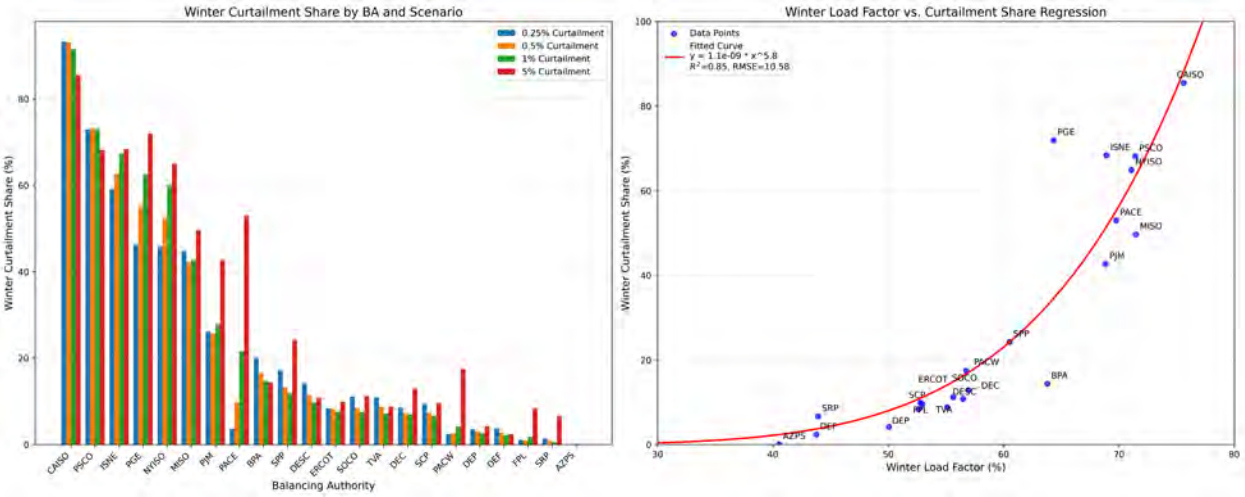


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

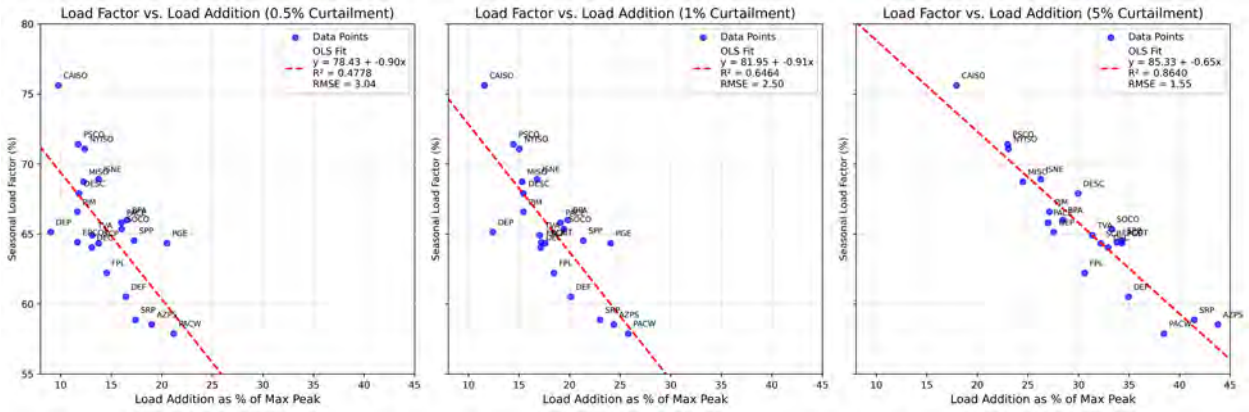
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

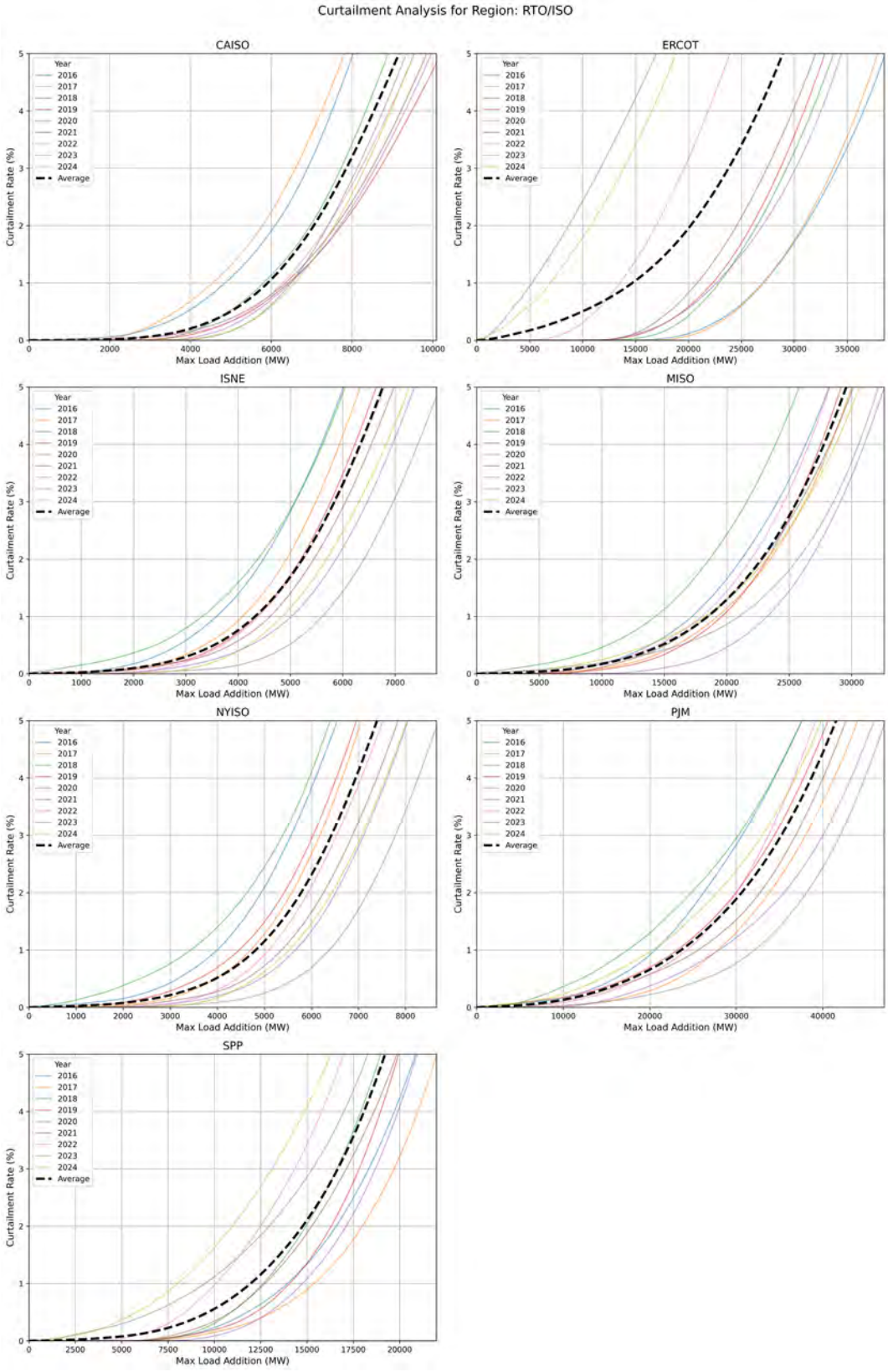


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

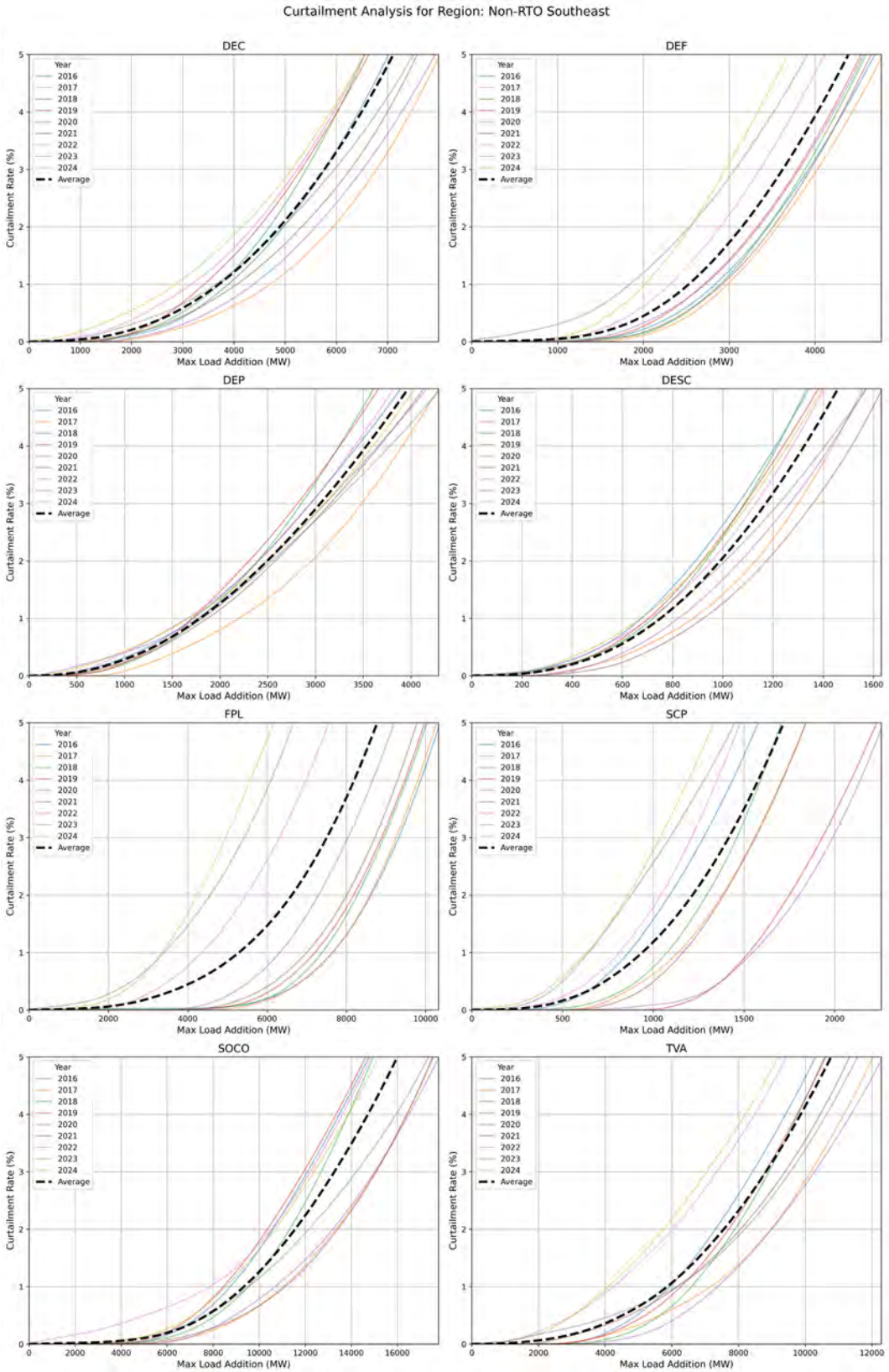
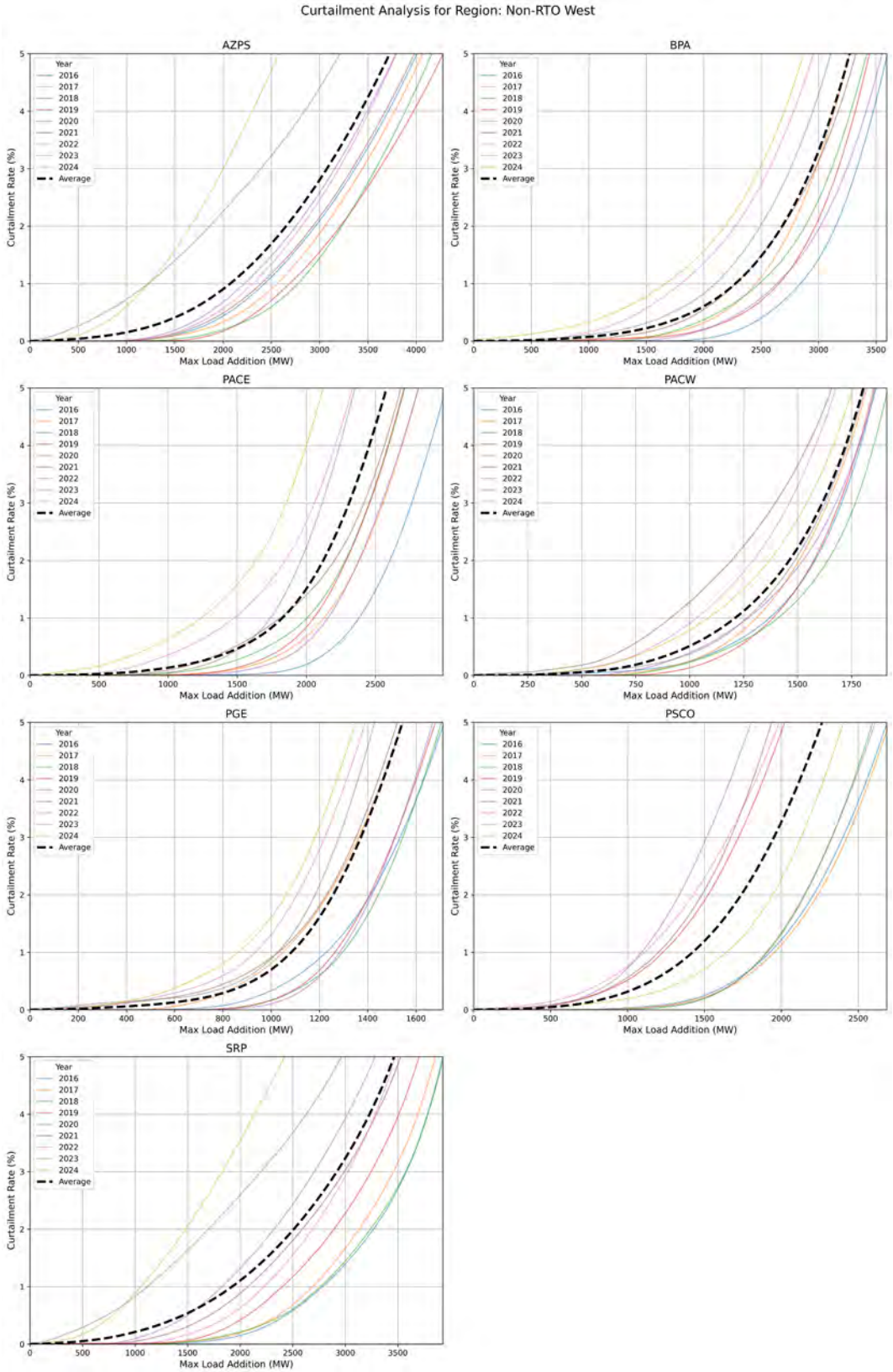


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 124
November Campbell Order

Department of Energy
Washington, DC 20585

Order No. 202-25-9

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-3 and 202-25-7

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. §7151(b).
[3] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[4] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[5]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[6] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[7] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year…."[8]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[9]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[10] While the results "demonstrated sufficient

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[4] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

[5] *Id.*

[6] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[7] *Id.*

[8] *Nuclear plants face decadelong timeline to meet AI energy needs*, Los Angeles Times. (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

[9] NERC 2025 Summer Reliability Assessment at 16.

[10] *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[11]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.[12] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,[13] providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[14] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[15] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[16]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[17] Among other things, this report described changes in the time of year during

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[11] *Id*. at 2,12. For further information regarding the determination that emergency conditions existed, *see* Order No. 202-25-7.

[12] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[13] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September." The data can then be filtered to only include the JH Campbell Plant.)*

[14] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

[15] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

[16] Id. at 3-4.

[17] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[18]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *"MISO's Response to the Reliability Imperative."*[19] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment[21] and the 2023 – 2024 NERC Winter Reliability Assessment[22]) have assessed the MISO assessment area as an elevated risk, with the "potential for insufficient operating reserves in above-normal conditions." Specifically, the 2024 – 2025 Winter Reliability Assessment noted that "[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[23]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased

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[18] *Id.* at 11.

[19] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf

[20] *Id.* at 12.

[21] 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

[22] 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf

[23] 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[24]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[25] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[26] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[27] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[28]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[29] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[30]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[31] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[32] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

[24] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.
[25] *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
[26] *Id.* at 2.
[27] *Id.* at 7.
[28] *Id.* at 9
[29] *Id.* at 7, 9.
[30] *Id.*
[31] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[32] 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.[33] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[34] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[37] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[38] In addition, as just one example,

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[33] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

[34] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[35] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[36] *Id*.

[37] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[39]

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[40] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[41] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

[39] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).
[40] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf
[41] *Id.* at 6.
[42] *Id.* at 7.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3 and 202-25-7 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand and determined shortage and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.[44]

Based on my determination of an emergency set forth above, I hereby order:

A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

[44] 16 U.S.C. § 824a(c)(4).

D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc:

FERC Commissioners
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps

Commissioner Katherine Peretick

Commissioner Shaquila Myers

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 125
IURC AB Brown CT Order

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.5 FOR THE CONSTRUCTION OF TWO NATURAL GAS COMBUSTION TURBINES ("CTs") PROVIDING APPROXIMATELY 460 MW OF BASELOAD CAPACITY ("CT PROJECT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.4 FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("COMPLIANCE PROJECTS"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS THROUGH CEI SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM ("ECA"); (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS AND (B) POST-IN-SERVICE CARRYING CHARGES, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CT PROJECT AND COMPLIANCE PROJECTS UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) IN THE EVENT THE CPCN IS NOT GRANTED OR THE CTs OTHERWISE ARE NOT PLACED IN SERVICE, AUTHORITY TO DEFER, AS A REGULATORY ASSET, COSTS INCURRED IN PLANNING PETITIONER'S 2019/2020 IRP AND PRESENTING THIS CASE FOR CONSIDERATION FOR FUTURE RECOVERY THROUGH RETAIL ELECTRIC RATES; (7) ONGOING REVIEW OF THE CT PROJECT; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CT PROJECT AND COMPLIANCE PROJECTS ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ.*, AND 8-1-8.5-1 *ET SEQ.*	**CAUSE NO. 45564** **APPROVED: JUN 28 2022**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Stefanie N. Krevda, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

On June 17, 2021, Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner" or "CEI South") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking, among other relief, a certificate of public convenience and necessity ("CPCN") for two new natural gas combustion turbines ("CTs") providing 460 megawatts ("MW") of capacity ("CT Project") pursuant to Ind. Code ch. 8-1-8.5, CPCNs for certain environmental projects related to a subset of Petitioner's generation facilities pursuant to Ind. Code ch. 8-1-8.4, and associated ratemaking and accounting treatment for these projects.

Also on June 17, 2021, Petitioner filed the testimony, attachments, and, for certain witnesses, workpapers, of the following (all of whom are employees of Petitioner except as otherwise noted): Steven C. Greenley, Senior Vice President of Generation Development for CenterPoint Energy, Inc. (Petitioner's Exhibit 1); Wayne D. Games, Vice President, Power Generation Operations (Petitioner's Exhibit 2); Erin M. Carroll, Senior Vice President, PowerAdvocate (Petitioner's Exhibit 3); Angila M. Retherford, Vice President, Environmental and Corporate Responsibility (Petitioner's Exhibit 4); Matthew A. Rice, Director of Indiana Electric Regulatory and Rates (Petitioner's Exhibit 5); Nelson Bacalao, Principal Consultant, Siemens PTI (Petitioner's Exhibit 6); Jason A. Zoller, Chief Engineer, Black & Veatch ("B&V") (Petitioner's Exhibit 7); Paula J. Grizzle, Director of Gas Supply and Portfolio Optimization (Petitioner's Exhibit 8); Kara R. Gostenhofer, Director and Assistant Controller (Petitioner's Exhibit 9); Rina H. Harris, Director of Energy Solutions and Business Services (Petitioner's Exhibit 10); and F. Shane Bradford, Director of Power Supply Services (Petitioner's Exhibit 11).

Petitions to intervene were filed by the Citizens Action Coalition of Indiana, Inc. ("CAC"), CenterPoint Energy Indiana South Industrial Group ("Industrial Group"), Sierra Club, Hoosier Chapter ("Sierra Club"), and Sunrise Coal, LLC ("Sunrise Coal"), all of which were granted.

A public field hearing was held in Evansville, Indiana on October 13, 2021, during which members of the public presented testimony related to the relief sought in this Cause.

On November 19, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of its witnesses, all of whom are employees of the OUCC's Electric Division: Peter M. Boerger, Ph.D., Senior Utility Analyst (Public's Exhibit 1); Anthony A. Alvarez, Utility Analyst (Public's Exhibit 2); Cynthia M. Armstrong, Senior Utility Analyst (Public's Exhibit 3); and Kaleb G. Lantrip, Utility Analyst (Public's Exhibit 4). Also on that date, intervenors filed the testimony and attachments of their witnesses, including the following: Michael P. Gorman, Managing Principal, Brubaker and Associates, Inc. (Industrial Group's Exhibit 1); Kerwin L. Olson, Executive Director of CAC (CAC's Exhibit 1); Anna Sommer, Principal, Energy Futures Group (CAC's Exhibit 2); Josh Keeling, Director, Cadeo Group (CAC's Exhibit 3); Michael

Goggin, Vice President, Grid Strategies, LLC (Sierra Club's Exhibit 1); Emily S. Medine, Principal, Energy Ventures Analysis, Inc. (Sunrise Coal's Exhibit 1); Michael J. Nasi, Partner, Jackson Walker LLP (Sunrise Coal's Exhibit 2); and Tommy L. Sutton, Engineering Manager, Sunrise Coal, LLC (Sunrise Coal's Exhibit 3).

The OUCC also filed written consumer comments with its prefiled evidence on November 19, 2021 (Public's Exhibit 5) and additional consumer comments on January 19, 2022 (Public's Exhibit 6). The CAC filed supplemental testimony of Ms. Sommer (CAC's Exhibit 4) on November 22, 2021, and Sunrise Coal filed supplemental testimony of Mr. Sutton (Sunrise Coal's Exhibit 4) on December 17, 2021.

On December 20, 2021, CEI South filed the rebuttal testimony, attachments, and workpapers of Mr. Greenley (Petitioner's Exhibit 1-R), Mr. Games (Petitioner's Exhibit 2-R), Ms. Retherford (Petitioner's Exhibit 4-R), Mr. Rice (Petitioner's Exhibit 5-R), Ms. Grizzle (Petitioner's Exhibit 8-R), Ms. Gostenhofer (Petitioner's Exhibit 9-R), Ms. Harris (Petitioner's Exhibit 10-R), Mr. Bradford (Petitioner's Exhibit 11-R) and Steven A. Hoover, Petitioner's Regional Director of Gas Engineering (Petitioner's Exhibit 12-R).

On January 14, 2022, the Commission issued a docket entry requesting that Petitioner provide certain attachments to its Engineering, Procurement, and Construction ("EPC") Agreement filed as Attachment WDG-R4 to Petitioner's Exhibit 2-R. Petitioner filed its response to this docket entry on January 18, 2022 (Petitioner's Exhibit 13).

On January 21, 2022, the Presiding Officers granted the unopposed motion filed by intervenors seeking a remote evidentiary hearing due to the ongoing COVID-19 pandemic.

The evidentiary hearing in this matter commenced on January 26, 2022 at 10:30 a.m. via WebEx, at which time evidence was offered by CEI South, the OUCC, CAC, Sierra Club, Sunrise Coal, and the Industrial Group. Among the evidence offered at the hearing were certain stipulations between Petitioner and various intervenors with respect to certain facts and admissibility of specific exhibits.

Based upon the applicable law and the evidence of record, the Commission finds:

1. Notice and Jurisdiction. Due, legal, and timely notice of the public field hearing and evidentiary hearing in this Cause was given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Pursuant to Ind. Code chs. 8-1-8.4 and 8-1-8.5, Petitioner may seek Commission approval of the CPCNs requested in this Cause. Under applicable law, the Commission has jurisdiction over the relief sought by Petitioner in this Cause.

2. Petitioner's Characteristics. Petitioner is a public utility incorporated under Indiana law and has its principal office at 211 NW Riverside Drive, Evansville, Indiana. CEI South owns, operates, manages, and controls, among other things, plant, property, equipment, and facilities which are used and useful for the production, storage, transmission, distribution, and furnishing of electric service to approximately 145,000 electric consumers in southwestern

Indiana. Its service territory is spread throughout Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

3. Background. In Cause No. 45052, filed on February 20, 2018, CEI South requested, among other things, approval of a CPCN for a new 850 MW combined gas cycle turbine ("CCGT") generation facility to be located at its A.B. Brown generating station located on the Ohio River in Posey County, Indiana ("A.B. Brown" or "Brown"). On April 24, 2019, we issued our final order in that case ("45052 Order"), which, among other things, denied CEI South's requested CPCN for the CCGT and discussed the reasons for the denial. The 45052 Order explained in detail how CEI South could improve its planning prior to future CPCN requests. We noted that, while CEI South's request in Cause No. 45052 was "'consistent' with its 2016 [Integrated Resource Plan ("IRP")], the subsequent modeling for this case effectively screened out multiple less-expensive alternatives." 45052 Order at 26. We also found CEI South's risk analysis to be inadequate for multiple reasons, including its failure to update the risk modeling from its 2016 IRP prior to filing and failure to account for material risks associated with the preferred portfolio identified in the 2016 IRP. *Id.* at 27.

In addition, we stated in the 45052 Order that CEI South failed to consider that "[t]he acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036[,]" making us "hard pressed to see how reliance on one facility for so much of the [CEI South] system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change." *Id.* at 28. We concluded that CEI South's request

> does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of [CEI South's] size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT.

Id.

4. Relief Requested. In this Cause, CEI South has requested the Commission issue a CPCN pursuant to Ind. Code ch. 8-1-8.5 for two CTs to be located at the A.B. Brown site, approve associated ratemaking and accounting treatment for the two CTs, establish a depreciation rate for the CT Project, and grant its request for ongoing review of the CT Project. If the CPCN for the two CTs is not granted or the CTs are otherwise not placed in service, CEI South requests that the Commission authorize it to defer, as a regulatory asset, costs incurred in planning its 2019/2020 IRP and presenting this case for consideration, for future recovery through retail electric rates.

CEI South has also requested the Commission issue CPCNs pursuant to Ind. Code ch. 8-1-8.4 for the construction of equipment and facilities necessary to comply with the United States Environmental Protection Agency's ("EPA") Coal Combustion Residuals ("CCR") rule for the handling and disposal of dry ash (the "Dry Ash Compliance Project") and to construct two new small ponds (one at A.B. Brown and one at Petitioner's F.B. Culley generating station in Warrick County, Indiana ("Culley")) to handle coal-pile runoff, flue gas desulfurization ("FGD") wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's CCR rule (the "Pond Compliance Project") (collectively with the Dry Ash Compliance Project, the "CCR Compliance Projects"). CEI South also has requested that the Commission approve accounting and ratemaking treatment for the CCR Compliance Projects and establish a depreciation rate for the CCR Compliance Projects.

5. The Parties' Evidence.

A. Petitioner's 2019/2020 IRP. Mr. Rice described how CEI South developed the portfolios modeled in the 2019/2020 IRP. He testified that, following the 45052 Order, CEI South, with the help of Burns & McDonnell, conducted an all-source request for proposals ("All-Source RFP") to gather resource availability and pricing information for various resources, including resources such as solar, solar plus storage, and standalone storage. Mr. Bradford testified that 22 individual respondents submitted complete responses to the All-Source RFP, resulting in 110 proposals, 91 of which were for projects located in Indiana. The proposals included eight for battery storage, two for coal, seven for combined cycle, one Load Modifying Resource ("LMR")/Demand Response ("DR"), 57 solar, 19 solar plus storage, three system energy, and 13 wind.

Mr. Rice summarized the 15 optimized portfolios examined and explained the carbon dioxide and gas prices used within the scenario modeling. Each portfolio was evaluated utilizing simulated dispatch in the reference case, which led to the exclusion of several portfolios from further consideration. The remaining ten portfolios were then evaluated using a balanced scorecard approach. From this analysis, CEI South identified the Preferred Portfolio, which includes a diverse mix of resources including energy efficiency, wind resources, solar and solar plus storage, and the CT Project. Mr. Rice also explained Petitioner's Generation Transition Plan and how the Preferred Portfolio offers future flexibility, should the future turn out different than expected. He testified that CEI South incorporated stakeholder input throughout the process.

Dr. Bacalao testified that Siemens PTI developed and managed Petitioner's IRP modeling (including some input development), strategic consulting, participation in the stakeholder process, and scorecard development. He stated that Siemens PTI used a balanced scorecard approach to illustrate the reasonableness of the Preferred Portfolio.

Mr. Rice testified that the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard and stated that the Preferred Portfolio avoids long-term reliance on the capacity market or heavy reliance on emerging technology. He opined that the fast start and ramping capability of the two CTs that are part of the Preferred Portfolio allows for high penetration of low-cost renewable energy resources, which were consistently selected in all portfolios, regardless of potential future events. He noted that the CT Project will allow CEI South to build renewable resources with the confidence that dispatchable resources such as the CTs will

be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

The OUCC's position is that refueling A.B. Brown with natural gas is preferable to the proposed CTs. Dr. Boerger testified that gas conversions can be completed at a very low capital cost compared to the cost of a new CT. He discussed the net present value of revenue requirements ("NPVRR") values for the gas conversion and presented his analysis of CEI South's modeled operation and maintenance ("O&M") costs for gas-converted units. He opined that NPVRR values for the gas conversion portfolios incorporate a significant overestimation of O&M costs, based on the reduction in O&M costs AES Indiana experienced after converting its Harding Street Station units to burn gas.

Testifying on behalf of the CAC, Ms. Sommer stated that she found errors in CEI South's 2019/2020 IRP and opined that correcting for these errors would result in the selection of a plan that is lower cost, includes more renewables and battery storage, and avoids the construction of the CT Project. She explained she had transparency concerns with CEI South's modeling because she could not access all of the Siemens PTI data to run her own modeling. Even though CEI South and Siemens provided an analyst to perform additional Aurora simulations, Ms. Sommer did not find this to be a satisfactory resolution to her transparency concerns. She questioned the veracity of CEI South's industrial sales and load forecast and suggested the Commission add a condition that if the additional industrial load upon which the IRP modeling was based fails to materialize, the Commission should disallow certain costs.

Ms. Sommer also testified that her analysis of additional modeling runs performed by Siemens PTI on behalf of CAC, CAC High Tech, and CAC Renewables by 2030 supported using a combination of DR, solar, wind, and storage to replace retiring coal. Ms. Sommer also raised concerns with the stochastic gas price analysis, again citing an inability to independently verify the modeling results without full access to all data.

Mr. Gorman, testifying for the Industrial Group, opined that CEI South has not demonstrated that constructing two CTs to serve its capacity needs is reasonable, arguing that the 2019/2020 IRP did not demonstrate that the capacity offered by both CTs would be needed until 2033. He acknowledged that CEI South has reported some increases in projected industrial load, which may support the need for additional capacity relative to the IRP load studies, but noted that CEI South has not rerun its IRP to show these new load changes. He also opined that potential changes since the IRP (such as increased gas prices) may affect the reasonableness of building the CT Project.

Testifying for the Sierra Club, Mr. Goggin opined that, if Petitioner's 2019/2020 IRP were conducted today using updated cost assumptions, the modeling would likely select even greater amounts of wind, solar, and storage instead of gas capacity. Mr. Goggin explained why he believes batteries have superior technical capabilities to gas CTs and opined that CEI South's increasing reliance on gas poses significant economic and reliability risks. He opined that CEI South's 2019/2020 IRP called for significantly more solar and storage capacity. He opined that imports and exports are an efficient tool for integrating large amounts of wind and solar generation and can help meet reliability needs, including during extreme weather events. He also testified that the capacity value of renewable and storage resources is understated. He also noted economic and

reliability risks associated with dependence on natural gas and CEI South's plan to eventually operate the CT Project on hydrogen. He recommended the Commission deny the CPCN for the CT Project.

Ms. Medine, testifying on behalf of Sunrise Coal, opined that, due to changes in the natural gas and power markets after the 2019/2020 IRP, continued use of the A.B. Brown plant to burn coal for several more years is a superior alternative to the proposed CT Project and a better exit ramp to incorporating more renewable options in Petitioner's generation portfolio.

On rebuttal, Mr. Rice responded to the non-utility parties' concerns with gas prices, stating that the Preferred Portfolio performed well on multiple objectives, including cost, which considered the full range of probable gas price forecasts. He testified that recently volatile gas prices appear to be returning to expected levels.

Regarding criticisms of CEI South's load forecasts, Mr. Rice stated that CEI South has lost nearly all industrial DR since filing the 2019/2020 IRP. He also disagreed with Mr. Goggin's testimony regarding relying on imports and exports for reliability, noting that CEI South, as a North American Electric Reliability Corporation ("NERC") Load Serving Entity ("LSE") within the Midcontinent Independent System Operator ("MISO") footprint, has responsibility to provide adequate resources to meet its load. He opined that, if MISO and CEI South relied solely upon imports to serve the system load during peak times, CEI South would subject its customers to significant reliability and price risks. He stated that inadequate transmission system voltage can cause partial and cascading grid collapse, but the CT Project alleviates this issue.

Mr. Rice discussed the OUCC's proposal that CEI South convert the existing A.B. Brown units to natural gas, noting that Dr. Boerger ultimately agreed in deposition that his calculations show that gas conversion will cost more than the Preferred Portfolio. Mr. Rice explained how the OUCC's position that the cost of the conversion at A.B. Brown could be $78.2 million less was miscalculated. He also discussed how the capital cost recovery for the CTs was not assumed to have a 100-year life, as implied in Dr. Boerger's testimony; CEI South assumed a 30-year life. Mr. Rice also stated that Dr. Boerger was incorrect to estimate the depreciation rate by subtracting the discount rate from the capital cost recovery factor. He testified that the capital cost recovery factor is a multiplier that is used to determine the annuity that needs to be recovered to obtain a return on the capital invested and repay the original capital. He stated the 8.64% reported corresponds to a 30-year life and a discount rate of 7.71%. Thus, Mr. Rice concluded that the OUCC's calculation of a $47.8 million impact is incorrect. Mr. Rice stated that the impact, when correctly calculated, is zero. Mr. Rice also responded to Dr. Boerger's statement that the cost of removal was not included in the Preferred Portfolio, noting that it was included in confidential attachments to Dr. Boerger's own testimony.

Mr. Bradford stated that, although Mr. Alvarez testified that a refueled A.B. Brown would receive the same nameplate capacity as it had when run on coal, MISO's Independent Market Monitor ("IMM") had made different recommendations for MISO capacity accreditation in the 2020 State of the Market Report ("IMM Report"). Mr. Bradford explained that the IMM ultimately recommended that MISO move away from unforced capacity ("UCAP"), because "it does not recognize that inflexible resources with long lead times are less valuable than more flexible resources" and "[t]his reflects reality because MISO often does not see tight conditions coming

day-ahead or many hours in advance, which causes long-lead time offline units to contribute less to overall reliability than online or quick start resources." Petitioner's Exhibit 11-R, Attachment FSB-R1 at 91; Petitioner's Exhibit 11-R at 22. He said that, under the IMM's recommended available capacity ("ACAP"), the nameplate capacity of a converted Brown would be approximately 25% lower than when it was run on coal.

Mr. Bradford disagreed with Mr. Gorman's testimony that the most recent IRP did not demonstrate that the capacity offered by both CTs would be needed until 2033, citing Table FSB-R2 attached to his rebuttal testimony, which shows a capacity deficit as early as 2028, requiring additional generation or capacity to meet CEI South's needs.

Mr. Bradford also responded to Mr. Goggin's assertion that CEI South should rely on capacity market purchases rather than the CTs to meet its capacity needs. He opined that Mr. Goggin incorrectly extrapolates MISO Planning Reserve Auction ("PRA") clearing prices as the future cost to CEI South to cover its capacity requirements. Mr. Bradford stated that MISO is fundamentally not a long-term capacity market, as evidenced by the fact that the auction for capacity during a given planning year running from June-May is conducted only a few months prior to the start of the planning year. The 2021 Organization of MISO States ("OMS") Survey Report shows Zone 6, including CEI South's service territory, as having the greatest potential capacity shortage across all zones in the 2026 outlook and as being critically dependent on potential new resources to meet local clearing requirements by 2026. To the extent potential new generation is critical to meeting its local resource requirements, the CTs are already included in the OMS survey results as part of the potential capacity needed to ensure reliability.

B. CT Project. Mr. Games testified that CEI South's generation portfolio heavily relies on coal generation, totaling 1,032 MW. He stated that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of CEI South's coal-fired units. Instead of running continuously, CEI South's coal-fired units are now cycled up and down throughout the day or are shut down altogether, decreasing unit efficiency, increasing wear and tear on the units, and enhancing environmental compliance risk. He testified that the A.B. Brown generation units, at a net 245 MW each, are among the smallest and least efficient coal units remaining in Indiana and do not provide the flexibility required to reliably provide the back-up for a large renewable portfolio in an economic manner.

Mr. Games testified on direct that the estimated cost of the CT Project was approximately $323 million; this estimate was updated on rebuttal to approximately $334 million following Petitioner's execution of the EPC contract with Kiewit Power Constructors Co. ("Kiewit") on November 30, 2021. He stated that the proposed two F-Class natural gas CTs would have an output of approximately 460 MW and would replace the A.B. Brown coal plant and support the 700-1,000 MW of solar and solar plus storage and 300 MW of wind in Petitioner's generation portfolio. He testified that CEI South considered a range of natural gas CT options, but found that the proposed F-Class turbines are among the most efficient units currently available in this class, with the lowest capital cost per kilowatt ("kW") versus other new natural gas options evaluated. He stated that the F-Class CTs together will be able to ramp up at a rate of 80 MW per minute.

Ms. Retherford discussed the federal regulations, such as Effluent Limitation Guidelines ("ELG"), CCR, and the cross-state air pollution rule ("CSAPR"), that impact CEI South's coal-

generating units. She testified that CEI South must cease operations by December 31, 2023 to comply with the firm deadline for prohibition of fly ash transport by water under ELG. She explained that CEI South's Preferred Portfolio avoids additional incremental compliance costs for CCR and ELG at A.B. Brown by retiring the two coal-fired units and replacing them with renewables and the CT Project.

Mr. Bradford described how the CT Project fits within the overall capacity composition forecast for the MISO footprint and explained congestion impacts. He opined that, for consistent reliable generation to Indiana customers, renewable generation must be supported by dispatchable generation, such as the proposed CTs that have the ability to quickly ramp up and down. He stated that the CT Project will thus support renewables in CEI South's service territory and in and around MISO Zone 6.

Dr. Boerger opined that the OUCC's proposed alternative to the CT Project, refueling A.B. Brown with natural gas, would minimize capital outlays for CEI South customers, provide the dispatchable capacity CEI South indicates it needs, and provide needed flexibility. Mr. Alvarez also testified that refueling the A.B. Brown units would require low capital outlay, which would serve to protect ratepayer interests in existing assets. Ms. Armstrong explained that gas conversion will qualify for the same air permits and emissions netting benefits as the new gas CTs.

Mr. Olson of the CAC testified that CEI South has some of the highest bills in the country and that the CT Project is not in the best interest of ratepayers. Ms. Sommer opined that the gas pipeline proposal is oversized relative to its need. Mr. Keeling testified that untapped DR potential in CEI South's electric service territory exists, and he suggested changes to CEI South's interruptible tariff language necessary to access this untapped potential.

As noted above, Mr. Gorman testified on behalf of the Industrial Group that CEI South has not demonstrated that both CTs would be needed prior to 2033.

Testifying on behalf of the Sierra Club, Mr. Goggin opined that CEI South failed to correctly account for declining electricity demand, the capacity surplus in Indiana and elsewhere in the MISO footprint, and the large capacity value contributions of renewable and storage resources in proposing the CT Project. He argued that the extremely low capacity factors in CEI South's modeling indicate that the proposed CT Project, and particularly the second proposed CT, are uneconomic and not needed for reliability. He also noted a risk that one or both of the proposed CTs will become stranded assets.

Ms. Medine, testifying on behalf of Sunrise Coal, noted that the viability of the CT Project is unclear due to the Federal Energy Regulatory Commission ("FERC") requirement for an environmental impact statement ("EIS") for the pipeline project. She interpreted the FERC's decision to prepare an EIS for the pipeline extension as an apparent repudiation of Petitioner's position that the CT Project would have a net benefit on the environment (allowing for the retirement of A.B. Brown's coal units) and that the CT Project is necessary for CEI South to serve its customers. Ms. Medine also stated that continuing to burn coal at A.B. Brown would not require expensive scrubber replacement and ELG compliance investment, as claimed by Petitioner, as long as coal burning ends by 2028. She opined that the only impediment to continuing to burn coal at A.B. Brown for several more years relates to CCR compliance.

Mr. Nasi, also on behalf of Sunrise Coal, opined that CEI South did not examine all reasonable alternatives in its filing to the EPA for an extension to continue to use the Brown pond past the original April 2021 cease disposal date and described additional alternatives which he said would allow A.B. Brown to continue operation through October 2026. He testified that the timing for the cessation of the operation of the boilers depends on the amount of time it takes to complete closure of the surface impoundment.

On rebuttal, Mr. Greenley testified that, if CEI South's request for a CPCN for the CT Project is denied, CEI South risks losing, among other things, the benefits of the signed EPC contract for the CT Project, the interconnection rights from building new generation at the A.B. Brown site, and the benefits of environmental netting. He opined that a denial would subject CEI South customers to risk from a higher cost portfolio and potentially volatile swings in the price of energy and capacity while awaiting further analysis.

Mr. Games explained why the OUCC's alternate proposal of refueling A.B. Brown with natural gas is not viable, stating that refueling will not provide the dispatchable power needed to ensure a reliable supply of electricity as CEI South and others in MISO's footprint transition generation to renewable energy resources. He noted that, while there are many benefits to adopting renewable energy, the intermittent nature of renewable resources necessitates incorporating resources like the proposed CTs that can react and ramp up quickly to provide power when renewable resources cannot. Mr. Rice identified a number of errors in Dr. Boerger's analyses leading to the OUCC's recommendation that CEI South refuel A.B. Brown with natural gas.

Ms. Retherford discussed why Sunrise Coal's proposal to burn coal at A.B. Brown beyond October 2023 is not feasible, noting that this would require significant expenditures for environmental compliance and the termination of the existing A.B. Brown Ash Pond Compliance Plan approved by the Commission in Cause No. 45280. She opined that Sunrise Coal's proposal oversimplifies the extension mechanisms provided in the CCR Part A Reconsideration Rule and fails to consider the full suite of environmental compliance requirements applicable to the A.B. Brown coal units.

Ms. Retherford also addressed FERC's decision to prepare an EIS for the gas lateral to serve the CT Project, stating that Ms. Medine's interpretation of that decision as a repudiation of the need for the CT Project is incorrect. Ms. Retherford testified that FERC has begun preparing an EIS rather than the less-robust environmental assessment ("EA") in an increasing number of pipeline cases to lessen the likelihood of FERC orders being overturned by courts. Ms. Retherford noted that this will reduce risk for project developers who rely on FERC orders when investing significant amounts of money on new projects.

Mr. Rice responded to the Sierra Club's suggestion that the capacity market can be used to support large amounts of renewables, stating that MISO and CEI South cannot rely solely on imports to maintain reliability. He noted that the basic concepts of interconnected grid operations are based on generation and load being equal in real time, which stabilizes the operational frequency of the grid at 60 hertz ("Hz"). According to Mr. Rice, if MISO and CEI South were to rely solely on imports to serve the system load during peak times, they would be subjecting customers to significant reliability and price risks. He also noted that, when operating, the CTs automatically provide dynamic reactive power to the system at a point close to the system load.

Mr. Rice addressed the CAC's claims that DR programs could be utilized in place of the CTs. He testified that DR involves risk and requires that customers voluntarily sign up for DR programs. In emergency DR programs, customers can choose not to participate during peak conditions. He stated that DR is similar to wind or solar resources in that it may not be present when most needed.

Ms. Harris also discussed the prospects for additional DR, addressing customer and industrial DR, assumptions, and modeling inputs in the market potential study and CEI South's industrial load forecast. She testified that she disagreed with Mr. Keeling's conclusion that CEI South could achieve an additional DR of 200 MW, noting that CEI South's customer makeup does not lend itself to achieving this level of DR. She stated that CEI South only has seven customers with more than 10 MW of load, and many of those customers are not in industries that readily permit idle manufacturing operations for curtailment. According to Ms. Harris, even if CEI South could achieve an additional 200 MW of DR, it would still need the two CTs, as DR programs are only issued during emergency MISO events, and the CTs more broadly support reliability.

Mr. Bradford discussed the NERC 2021 Long-Term Reliability Assessment (December 2021) (the "NERC 2021 LTRA" or "NERC Assessment"), which is included in Petitioner's Exhibit 13-R as Workpaper MAR-R3. He opined that the NERC Assessment supports CEI South's request to install fast-starting, quick-ramping generation via the CTs in order to support the growing portfolio of renewable resources and maintain reliable service. He testified that MISO's IMM, Potomac Economics, noted in the IMM Report that "MISO has correctly concluded that the availability and flexibility of its nonintermittent resources will be paramount in maintaining its ability to operate the system reliably." Petitioner's Exhibit 11-R at 4.

C. Federally Mandated CCR Compliance Projects.

i. Dry Ash Compliance Project. Mr. Games discussed the Dry Ash Compliance Project, which will involve the construction of a dry fly ash loading facility at the Archer Daniels Midland ("ADM") site in Evansville, Indiana on the Ohio River. The Dry Ash Compliance Project consists of three components: (1) a silo for accepting ash from Brown and Culley, (2) a facility to load ash onto barges for transport to Missouri for beneficial reuse, and (3) a new dry ash handling system since the previous conveyor system was converted for handling of ponded ash.

Ms. Retherford described the CCR rule, a self-implementing regulation under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"), which prohibits ash from being placed in unlined ash ponds after April 2021, unless an extension is granted. She also described the EPA's ELG rule under Section 201 of the Clean Water Act, which (1) prohibits the discharge of fly ash transport water at existing facilities, (2) prohibits the discharge of bottom ash transport water at existing facilities, and (3) sets stringent new arsenic, mercury, selenium, and nitrate/nitrite discharge limits for scrubber wastewater.

Mr. Games discussed the cost estimate for the Dry Ash Compliance Project, including $12 million in estimated capital costs and annual estimated O&M expenses of $1.35 million for 2021 through 2023 and $680,000 for 2024 and beyond. He described the EPC agreement with Penta

Engineering for this project. He also discussed the various alternatives for dry ash disposal considered by Petitioner, the site that was chosen for the project, and the estimated project schedule.

ii. Pond Compliance Project. Ms. Retherford discussed Petitioner's request for a CPCN to construct a lined CCR-compliant pond at Culley and a lined CCR-compliant pond at A.B. Brown to handle coal pile runoff, FGD wastewater, and other flows such as stormwater and landfill leachate in compliance with EPA's CCR rule.

Ms. Retherford described the recent modification to the CCR Rule ("Part A Reconsideration") requiring Petitioner to pursue the fastest technically feasible option to obtain alternative disposal capacity. She explained that the Pond Compliance Project is necessary to demonstrate to the EPA that Petitioner is complying with the CCR Part A Reconsideration. She testified there were no alternative plans considered to the Pond Compliance Project because CEI South found no other options that would achieve compliance with the "fastest technically feasible" requirement of the Part A Reconsideration.

Mr. Games discussed the cost estimate for the Pond Compliance Project, including $19 million in estimated capital costs and annual estimated O&M expenses of $350,000.

Ms. Armstrong of the OUCC testified that Petitioner's request for a CPCN for the Pond Compliance Project should be denied because CEI South has not adequately shown continuing to operate A.B. Brown Units 1 and 2 and Culley Unit 2 until October 2023 is the most reasonable, least-cost option for meeting resource needs. She stated that CEI South did not provide reasonably adequate cost estimates for the Pond Compliance Project and expressed concern that Class 5 estimates such as those presented by Petitioner could increase by 30% to 100%. She also opined that the proposed Pond Compliance Project should be denied (or recovery reduced to 50%) due to uncertainty that the EPA will grant CEI South's extension request.

Mr. Nasi, testifying on behalf of Sunrise Coal, opined that CEI South could have extended the use of coal at the A.B. Brown Units 1 and 2 if CEI South converted only the fly ash handling system to dry handling and then constructed a pond to receive only FGD and bottom ash wastewater. He asserted that this option would have allowed A.B. Brown Units 1 and 2 to continue burning coal until October 17, 2028.

Ms. Retherford opined on rebuttal that no lower cost, viable alternatives to the Pond Compliance Project exist. She stated that, if Petitioner followed the OUCC's suggestion to retire A.B. Brown Units 1 and 2 and Culley Unit 2, it would require the immediate shutdown of approximately 900 MW of CEI South's 1,200 MW of generation capacity without any replacement.

In response to Mr. Nasi's proposal, Ms. Retherford explained that the CCR Part A Reconsideration Rule provides two extension mechanisms: (1) a site-specific alternative deadline under 40 C.F.R. § 257.201(f)(1), which requires a demonstration that the development of alternative capacity is technically infeasible by April 2021; and (2) permanent cessation of a coal-fired boiler by a date certain under 40 C.F.R. § 257.103(f)(2). CEI South filed its request for

extension under 40 C.F.R. § 257.201(f)(1) for the Pond Compliance Project, which requires a demonstration what is the fastest technically feasible alternative.

Due to the voluminous nature of the parties' evidence, additional evidence will be discussed as relevant below.

6. Commission Discussion and Findings on CT Project. CEI South's request for a CPCN for the CT Project is the end result of the process that began with our denial of its requested CPCN for an 850 MW CCGT, which would have cost an estimated $781 million, in Cause No. 45052. CEI South followed the guidance we issued in the 45052 Order and engaged in a thorough RFP process in which it considered many potential options for generation resources. This process ultimately resulted in CEI South's 2019 IRP and Preferred Portfolio, including the two CTs requested here. The Preferred Portfolio calls for the addition of a significant amount of renewable generation from 2022 through 2024, including approximately 300 MW of wind and up to 1,000 MW of universal solar and battery storage. *See* Petitioner's Exhibit 5, Attachment MAR-1 (2019/2020 IRP) at 53. The flexible and controllable nature of the gas CTs will support the intermittent nature of the renewable generation in the Preferred Portfolio to ensure system reliability. We believe that this step of implementing the Preferred Portfolio, moving forward on the two CTs, is the best economic decision for CEI South's customers. In addition, MISO, the operator of the electric grid in which CEI South is a participant, has indicated a system-wide need for controllable resources such as the CTs to ensure system reliability as more intermittent resources are added to the system.

Thus, for the reasons explained further below, we grant the requested CPCN for the CT Project.

A. Request for CPCN for Two CTs Under Ind. Code § 8-1-8.5-5. Ind. Code § 8-1-8.5-2 states that a public utility must obtain a CPCN from the Commission prior to constructing, purchasing, or leasing a facility for the generation of electricity. Ind. Code § 8-1-8.5-5 sets forth the criteria for approving a utility-specific generation proposal. In granting a CPCN, the Commission must make findings on the best estimate of the project's cost based on the record, whether the proposal is consistent with our statewide analysis or a utility-specific proposal, and whether public convenience and necessity require the project. The Commission must also consider the items set forth in Ind. Code § 8-1-8.5-4. We address the required findings and review each factor in Ind. Code § 8-1-8.5-4 below.

i. Best Estimate of Costs. Under Ind. Code § 8-1-8.5-5(b)(1), a CPCN may be granted only if the Commission makes a finding "as to the best estimate of construction, purchase, or lease costs based on the evidence of record[.]"

Mr. Games described CEI South's RFP for an EPC contractor and for the purchase of major equipment. He stated that CEI South, B&V, and Power Advocate reviewed and analyzed bids received in response to the RFP to ensure compatibility with the different phases of the project. Mr. Games and Ms. Carroll both discussed how Kiewit was chosen as the EPC contractor. Mr. Games described the project schedule.

As noted above, Mr. Games testified on direct that the estimated cost of the CT Project was approximately $323 million; this estimate was updated on rebuttal to approximately $334 million following execution of the EPC contract with Kiewit on November 30, 2021. According to Table WDG-4 in Mr. Games's direct testimony, explaining the breakdown of the original $323 million estimate, the EPC estimate was $188 million, including the cost for Kiewit to engineer, procure, and construct the two CTs and the direct and indirect costs of EPC overhead and profit, escalation, bonding, warranty, and builder's risk insurance. $70 million of the estimate was the owner's cost, including allowances for the owner's project management teams, the owner's engineer, support engineering and training, environmental and other permitting activities, legal fees, construction utilities, regulation and code changes, price escalation, the owner's contingency, and unresolved work scope items and terms and conditions. The cost estimate for internal labor and loadings to support the CT Project from planning through completion was $10 million. Administrative and general overhead and allowance for funds used during construction ("AFUDC") were estimated to be $35 million, and critical and long-lead-time spare parts were estimated to cost $8 million. The estimate also included $12 million in study and pre-work costs, including costs associated with CEI South's 2019/2020 IRP process (2016-2019) and preparation starting in 2019 for the filing in this Cause. The estimate did not include pipeline costs. Mr. Games opined that the estimate is consistent with Petitioner's 2019/2020 IRP.

Changes to the components of the cost estimate following the execution of the Kiewit contract are confidential and are included in Mr. Games's rebuttal testimony in confidential Table 1. Petitioner's Exhibit 2-R at 33. On rebuttal, Mr. Games testified that the adjusted base price estimate for the CT Project is $317 million, which is lower than the initial $323 million base price estimate. He identified an estimated range of the total CT Project cost between $317 and $351.4 million, with $334 million in the mid-point of this range.

In his direct testimony, Mr. Games stated that the terms of the agreement with Kiewit that remain to be resolved include indemnification, limitations of liability and consequential damages, the definition of material change, and excused delays. However, Mr. Games stated that the majority of the EPC contract price is firm. Mr. Games provided the signed agreement in Petitioner's Exhibit No. 2-R, Confidential Attachment WDG-R3.

Ms. Sommer, on behalf of the CAC, opined that "[k]ey commodity indices show concerning levels of escalation that appear to be more significant than [CEI South] has assumed in its project cost estimate." CAC's Exhibit 2 at 66. On rebuttal, Mr. Games explained that CEI South negotiated pricing adjustment mechanisms to address escalation concerns rather than accept a large firm price increase including large contingencies in order to cover a worst-case scenario. He stated that the overall base price under the executed EPC contract is lower than in the original estimate, but remains subject to price adjustments. During cross-examination, Mr. Games testified that he was reasonably confident the project would not exceed this high end of the range of costs presented in his rebuttal.

Mr. Alvarez of the OUCC opined that CEI South's estimate for the CT Project was unrealistically low. He stated that he calculated a higher capital cost of $720 per kW (compared to Mr. Games's $702 per kW estimate) for the CT Project. Mr. Alvarez evaluated the estimate using Lazard's Levelized Cost of Energy Analysis Version 14.0 (2020) ("Lazard Study") and the United States Energy Information Administration ("EIA") Annual Energy Outlook. Mr. Alvarez testified

that the Lazard Study shows a range of capital cost per kW of $700 (for a 240 MW peaking unit) to $925 (for a 50 MW peaking unit). Mr. Alvarez also took issue with the fact that the CT Project cost estimate did not include the costs necessary to build the gas lateral.

On rebuttal, Mr. Games noted that CEI South's initial cost estimate was within the range of negotiated outcomes. He observed that the Lazard Study cited by Mr. Alvarez actually demonstrated that the proposed CTs are at the lower end of the range of potential capital cost per kW for peaking units, which Mr. Games attributed to the large size and efficiency of the F Class CTs proposed for the CT Project.

After reviewing the evidence of record, we find that CEI South has submitted extensive evidence supporting its cost estimate, and the other parties' evidence addressing the best cost estimate does not call CEI South's estimate into question. Thus, based on the evidence of record, we find that $334 million is the best estimate of the costs of the two CTs.

ii. Consistency with Petitioner's 2019/2020 IRP. Ind. Code § 8-1-8.5-5(b)(2) provides that a CPCN shall be granted only if the Commission has made a finding that either:

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under [Ind. Code § 8-1-8.5-3(e)(1)] and approved under subsection (d).

Ind. Code § 8-1-8.5-3(e)(1) provides that a public utility may submit "a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility[.]" Mr. Rice sponsored Petitioner's 2019/2020 IRP as Petitioner's Exhibit 5, Attachments MAR-1 and MAR-2 (Confidential). Thus, we find that CEI South has submitted a utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

The record demonstrates that the CT Project is consistent with the Preferred Portfolio identified in Petitioner's 2019/2020 IRP. Consistent with direction from the Commission in the 45052 Order, CEI South engaged in an IRP planning process to evaluate how different portfolios performed under a range of future potential market conditions and uses and to determine the optimal mix of supply or demand resources to provide electricity to CEI South's customers. As part of its 2019/2020 IRP process, CEI South engaged in a detailed resource planning analysis and worked with several industry experts to conduct an All-Source RFP, to develop scenarios, to conduct technical modeling, and to conduct risk assessments. The record reflects that, within this process, CEI South considered 110 proposals comprising different generation resources for modeling, including battery storage, coal, combined cycle gas, load modification and demand response, solar, solar plus storage, system energy, and wind. From this analysis, 15 portfolios comprising a mix of supply- and demand-side resources were developed and modeled. CEI South also engaged and considered stakeholder input throughout the process.

The Preferred Portfolio identified through the 2019/2020 IRP called for the retirement or exit of energy provided by coal-burning units at the Brown and Culley generating stations. The Preferred Portfolio and the associated 2019/2020 IRP short term action plan which describes the early steps to pursue it, calls for CEI South to make changes to its generation portfolio in the next three years. The Preferred Portfolio mapped a shift from a generating fleet of predominantly coal-burning resources to one of intermittent renewable resources supported by gas generation to ensure reliability. One early step in implementing the Preferred Portfolio was the addition of solar generating resources approved by the Commission in Cause Nos. 45501 on October 27, 2021 and 45600 on May 4, 2022. A next step is the addition of the two new CTs requested in this Cause.

We have previously stated that, "[i]nherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions." *Northern Indiana Public Service Co., LLC*, Cause No. 45462, at 62 (May 5, 2021). The evidence demonstrates, and the Commission has previously found, that Petitioner "utilized an array of best practices, including basing model inputs on its All-Source RFP, which allowed for an informed forecast at that time." *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021).

Several intervenors criticized CEI South's 2019/2020 IRP process and modeling and argued in favor of alternative resources to support the Generation Transition Plan instead of the two CTs identified, as discussed further above. However, after considering the evidence of record, we find that the resource planning and selection process used by CEI South for selecting the Preferred Portfolio and Generation Transition Plan, including the two CTs requested here, is consistent with its 2019/2020 IRP, which was conducted in a manner consistent with the Commission's direction in the 45052 Order, and is therefore consistent with CEI South's utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

iii. <u>Consistency with Commission's Energy Analysis</u>. Ind. Code § 8-1-8.5-3(a) provides that "the commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion facilities for generation of electricity." The Commission issued its 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis") in October 2018. *See* Petitioner's Exhibit 5, Attachment MAR-16.

The data and analysis underlying CEI South's proposal and the state of the overall electric industry have continued to develop since the 2018 Statewide Analysis. Mr. Rice noted on rebuttal that all Indiana utilities that submitted IRPs in 2021 (Duke Energy Indiana, LLC, Indiana Michigan Power Company, and Northern Indiana Public Service Company LLC) propose to retire all coal generation over the full planning period and add a large amount of solar and wind resources, supported by gas CTs, CCGTs, and some battery storage. The record in this Cause contains findings by MISO's IMM (Petitioner's Exhibit 5-R, Attachment MAR-R1; Petitioner's Exhibit 11-R, Attachment FSB-R1) and the NERC (Petitioner's Exhibit 13-R, Workpaper MAR-R3) supporting the need for flexible, controllable resources to pair with increasing levels of renewable generation to ensure reliability.

Based on the evidence of record, we find that CEI South's proposal to build the two CTs, which are flexible, controllable resources that will support the increasing use of renewables by

CEI South and other Indiana electric utilities, is consistent with the Commission's energy analysis, including the 2018 Statewide Analysis and developments since that report was issued.

iv. Public Convenience and Necessity. Under Ind. Code § 8-1-8.5-5(b)(3), before granting a CPCN, the Commission must make "a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility[.]" "The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need." *Indiana Michigan Power Co.*, Cause No. 44871, at 30 (March 26, 2018). CEI South contends the CTs are suited to the public need because they are necessary to follow CEI South's load and meet adequate reserve margins. Based on the evidence of record, we agree, as explained further below.

Our determination of public convenience and necessity under Ind. Code § 8-1-8.5-5(b)(3) is also guided by Ind. Code § 8-1-8.5-4(b), which provides that the Commission must, in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity, consider the following:

> (1) The applicant's current and potential arrangement with other electric utilities for:
> (A) The interchange of power;
> (B) The pooling of facilities;
> (C) The purchase of power; and
> (D) Joint ownership of facilities.
> (2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

We address these considerations below.

1. Ind. Code § 8-1-8.5-4(b)(1). Mr. Rice testified that CEI South approached other electric utilities in Indiana about joint owning generation, and no partnership opportunities materialized. In addition, we note that CEI South, as a MISO participant, is already involved in the interchange of power, pooling of facilities, purchase of power, and sharing of capacity resources through MISO's market-based systems. The evidence of record shows that CEI South's participation in MISO was specifically considered in the development of the Preferred Portfolio, including the two CTs proposed here, as a result of the Commission's directive in denying the CPCN in Cause No. 45052.

Thus, the evidence of record supports the conclusion that Petitioner's current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated, and Ind. Code § 8-1-8.5-4(b)(1) has been satisfied.

2. Ind. Code § 8-1-8.5-4(b)(2). We now analyze "[o]ther methods for providing reliable, efficient, and economical electric service, including the

refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources."

The other parties' proposed alternatives to the CT Project are as follows:

- OUCC: Refuel A.B. Brown with natural gas;
- CAC: Use a combination of demand response, renewables, and battery storage;
- Sierra Club: Use a combination of capacity purchases, renewables, and battery storage;
- Industrial Group: Approve at most one CT, not the two proposed (based on the argument that a second CT will not be required until 2033); and
- Sunrise Coal: Continue to burn coal at A.B. Brown for several more years, assuming regulatory requirements can still be met or amended as needed.

a. <u>Reliability</u>. As it did in Cause No. 45052, the OUCC argues that Petitioner should modify Brown to burn natural gas. In response to our direction in the 45052 Order, CEI South's 2019/2020 IRP thoroughly evaluated this option, but it was not selected in the Preferred Portfolio, and the evidence of record supports a finding that it will not satisfy the need for reliability as well as the proposed CTs. Similarly, Sunrise Coal's proposal to continue burning coal at Brown for several more years does not provide the same level of flexibility in support of system reliability. In the IMM Report, MISO's IMM noted that "older gas steam and coal-fired resources . . . have long notification and start-up times. These resources provide much lower reliability value to the system because they cannot be utilized if fluctuations in intermittent resources, unexpected changes in loads, or generation outages lead to tight conditions when they happen to be offline." Petitioner's Exhibit 11-R, Attachment FSB-R1, at 120. Due to the intermittency of the renewable resources in the Preferred Portfolio, resources with quick ramp capabilities are necessary to complement the addition of such intermittent resources to the system to ensure reliability. We disagree with the OUCC and Dr. Boerger that fast start and quick ramp capabilities are not significantly relevant to these proceedings; the NERC advises otherwise. *See* Petitioner's Exhibit 13-R, Workpaper MAR-R3 (NERC 2021 LTRA), at 9-11. Refueled Brown units would not be capable of cold starts and producing energy quickly enough to satisfy the usually short-term demand periods discussed above and, thus, could not effectively follow net load.

The CAC and Sierra Club opined that the Preferred Portfolio should include more renewables and battery storage and avoid the construction of the CTs. As noted elsewhere herein, renewables such as wind and solar are dependent upon weather conditions and are, therefore, not as controllable as other sources of generation.

Regarding the use of storage, Mr. Rice explained on rebuttal that the long-duration battery storage that would be needed to replace the proposed CTs is not yet cost effective. Dr. Boerger of the OUCC testified that battery storage is not yet ready to be implemented at a utility-scale level because it is not yet economically feasible and noted technical challenges in incorporating batteries into the grid and maintaining reliability. NERC's 2021 LTRA also indicates that battery storage at the level relied upon for CAC's preferred plan will not be a viable solution until after 2030. *See*

Petitioner's Exhibit 13-R, Workpaper MAR-R3 (NERC 2021 LTRA), at 7. The three Indiana IRPs that have been completed in 2021 have preferred portfolios with storage additions constituting a modest inclusion of approximately 5% of the total capacity additions in the next six years. *See* Petitioner's Exhibit 5-R at 11 (Figure 3). We agree that, while battery storage is an emerging technology, it is currently not a viable and reliable alternative to the proposed CTs.

CAC witness Mr. Keeling opined that there is untapped DR potential in CEI South's electric service territory and suggested changes to CEI South's interruptible tariff language to access this potential. However, Ms. Harris refuted this contention, noting that Petitioner's industrial customers are much more heterogeneous than other customer segments. She stated that extrapolating results such as those presented by Mr. Keeling for industrial customers fails to account for nuances associated with this unique customer group, such as their ability and willingness to participate. In addition, the CAC's recommendation to rely on DR comes at a time when CEI South has recently lost nearly all of its industrial DR. Thus, we decline to accept a recommendation that relies on DR that does not currently exist and, in light of Ms. Harris's testimony, appears unlikely to exist in the future in Petitioner's service territory. Even so, we encourage CEI South to continue engaging its industrial customers in discussions concerning DR despite the current lack of participation to better understand barriers to such participation.

While several parties criticized Petitioner's load forecasts and used those criticisms to question the need for the CT Project, Messrs. Rice and Bradford explained that the two CTs are needed by 2025 to meet MISO's Planning Reserve Margin Requirement ("PRMR"). Anticipated load additions were shown to be far less speculative than Ms. Sommer suggested, as an executed contract with a large new customer was admitted into the record confidentially as CAC's Exhibit 9-C. We also find that Mr. Gorman's suggestion that the second CT could be delayed until as late as 2033 is not a realistic option, given the updates to the load forecast from the increased load from the new customer and loss of demand response from another.

Sierra Club witness Mr. Goggin suggested that CEI South might rely on imports to meet its reliability needs, including during extreme weather events. However, Mr. Bradford identified several significant reasons that Petitioner cannot rely on the capacity market in the long term to ensure reliability. First, he noted that Mr. Goggin extrapolated selected, low-cost MISO PRA clearing prices to conclude that market capacity should be available just as inexpensively in the future, when prices on the capacity market have, at times, been much higher than the figures utilized by Mr. Goggin in his calculations. Mr. Bradford also noted that MISO is fundamentally not a long-term capacity market, as evidenced by the fact that the auction for capacity during a given planning year running from June to May is conducted only a few months prior to the start of the planning year. Mr. Bradford also discussed MISO's position that LSEs such as Petitioner should not "free ride" on the capacity investments of other LSEs without incurring any meaningful risk. He stated that MISO has identified several consequences of "free riding," including unreasonable cost shifts, long-term harm to reliability, and decreased efficacy of the PRA as a tool to address important resource adequacy needs in MISO. He also referred to recent OMS data indicating that Zone 6 of MISO, which includes Petitioner's service territory, has the greatest potential capacity shortage across all zones.

After considering the evidence of record, we find that the CT Project is needed, consistent with the 2019/2020 IRP, and shown to be a reasonable cost-effective solution to address reliability.

b. Efficiency. We find that the two proposed CTs are an efficient and cost-effective solution and compare favorably among the other options proposed to follow net load. The evidence of record demonstrates that the CTs can start and ramp up or down quickly and therefore can be dispatched for short periods several times a day or for prolonged periods, whichever is necessary, to cover shortfalls. As discussed in more detail above, Mr. Games explained how the proposed F-Class CTs are much more efficient than older gas combustion units and explained why the proposed CTs are a better option as opposed to refueling A.B. Brown with natural gas, as suggested by the OUCC. Petitioner's IRP modeling concluded that repowering the Brown units with natural gas would result in higher costs from frequent energy purchases and inefficient operation.

c. Economical Electric Service. The Preferred Portfolio is among the lowest net present value of any of the proposals, as illustrated in Petitioner's 2019/2020 IRP. The 2019/2020 IRP results also support the conclusion that continuing to run A.B. Brown on coal or refueled with natural gas would be less affordable to customers in the near term due to high O&M and ongoing capital expenditures to keep the units running. According to Mr. Games, refueled Brown units, which cannot be started or ramped up quickly to operate only when needed to follow net load, would need to operate at an economic loss much of the time in order to be available when called on. Thus, refueled units would have a higher capacity factor than the CTs even though they theoretically are far less efficient than the CTs. A CT can run when the price of energy is high enough for the CT to be profitable and then it can quickly shut down during other less profitable hours, whereas refueled units would need to run for longer periods of time, such as 24 or 48 hours, including hours in which they operate at a loss, in order to be online during that one hour of high energy prices.

As previously noted, other parties raised issues with various aspects of CEI South's modeling. We addressed the load forecast arguments of the Industrial Group and CAC above in finding that the record supports as realistic CEI South's anticipated large customer additions and anticipated capacity shortfall by 2025 absent the two CTs. The CAC also suggested an alleged lack of transparency in Petitioner's modeling. However, the evidence reflects that CEI South offered reasonable accommodations for the CAC and other stakeholders to analyze its proprietary data, and we find that none of the parties were prejudiced by the reasonable proprietary constraints and resulting lack of a full release of the Aurora model.

Dr. Boerger and Mr. Alvarez of the OUCC criticized the cost assumptions associated with the coal-to-gas conversion as compared to the CT Project. On rebuttal, Mr. Rice addressed Dr. Boerger's analysis, noting that Dr. Boerger agreed that, even after incorporating certain changes for which he had calculated a specific dollar value effect, his calculations showed that coal-to-gas conversion of the Brown units costs customers more than the Preferred Portfolio. Regarding Dr. Boerger's concern over the discount rate used in Siemens's modeling, he acknowledged this issue would overvalue costs and benefits in the near term.

Mr. Goggin, testifying for the Sierra Club, opined that the Renewables 2030 Portfolio, which includes no CTs, had a lower cost than the Preferred Portfolio. However, CEI South noted on rebuttal that Mr. Goggin did not consider in his analysis that portfolio's performance across the full range of probabilistic futures. When doing so, the Renewables 2030 Portfolio had a higher cost and cost risk than the Preferred Portfolio.

The Industrial Group and Sierra Club suggested that the CT Project is not cost justified based on recent high gas prices. On rebuttal, Mr. Rice responded that the Preferred Portfolio performed well on multiple objectives, including cost, which considered the full range of probable gas price forecasts. The evidence also supports the reasonableness of the reference case gas price forecast in CEI South's 2019/2020 IRP.

Sunrise Coal advocated the continued operation of Brown as coal units, at least temporarily. However, the evidence of record demonstrates that CEI South cannot operate A.B. Brown as coal units beyond October 2023 without making significant expenditures for environmental compliance. The environmental regulatory requirements and timelines for completion of various actions demonstrate that continued operation of Brown without interruption is not feasible. In addition, it would require abandoning the Commission-approved settlement reached on these issues in Cause No. 45280. The evidence of record indicates that the cost to upgrade Brown to comply with CCR and ELG regulations and continue operating beyond October 2023 would be greater than the projected cost of procuring capacity in the event the CT Project were delayed beyond its anticipated in-service date. In addition, as discussed above, continuing to run A.B. Brown on coal or refueled with natural gas would be less affordable to customers in the near term due to high O&M and ongoing capital expenditures to keep the units running. We do not find that it would be prudent to attempt to keep Brown operating on coal when it is clearly not in the best interest of customers or the public to do so.

While we have indicated in previous CPCN cases that least-cost planning is an essential component of our CPCN law, we have also recognized that least-cost planning does not require selection of the absolute lowest cost alternative. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No. 44339, at 20 (May 14, 2014) (quoting *Southern Indiana Gas & Elec. Co.*, Cause No. 38738, at 5 (Oct. 25, 1989)). We have defined least-cost planning as a planning approach that will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined. We also consider the risk created by future uncertainty. Ind. Code ch. 8-1-8.5 does not require a utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment on how best to meet its obligation to serve. If a utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting options to implement which minimize the cost of providing such services. *Id.*

We are concerned about the risks of further delay that would be caused by rejecting Petitioner's selection in favor of further study (beyond that already performed as part of the 2019/2020 IRP process) of the options proposed by the other parties. None of the options being proposed by the OUCC, CAC, Sierra Club, or Sunrise Coal would address the concerns raised by the NERC and MISO to encourage the development of flexible, controllable resources, such as the CTs proposed here, to complement the transition to intermittent, renewable resources. In the event of a denial, Petitioner would still need to secure the capacity offered by the CTs. In addition, other variables, such as the cost of iron and steel, could result in increased cost if the requested CPCN is denied. For example, CAC's Exhibit CX-1 shows the significant growth in the Producer Price Index for Metal and Metal Products: Iron and Steel. As discussed above, Mr. Games testified that Petitioner's proposal is protected against this inflation as a result of the EPC contract that has already been negotiated. None of the other options being urged by the various stakeholders would

be similarly protected by contract. In light of the evidence of record, we find that CEI South has exercised its reasonable judgment in selecting an option that both minimizes the risks of future cost uncertainty and will allow it to meet its obligation to provide reliable service to its customers.

3. Conclusion. Petitioner conducted an All-Source RFP to meet its capacity needs, and the RFP responses enabled CEI South to consider a variety of alternatives, described above. Given the foregoing evidence, the Commission finds that Petitioner has satisfied the requirement under Ind. Code § 8-1-8.5-4 that it consider alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. Ultimately, CEI South's 2019/2020 IRP has shown that the proposed construction of two new CTs at the A.B. Brown site is a reasonable, least-cost resource to support Petitioner's Generation Transition Plan and meet customers' needs for electricity. The CTs are capable of cycling reliably in response to the MISO market and will partially replace the retiring coal units with more efficient and controllable load-following capacity.

Therefore, based on the evidence of record, the Commission finds that Petitioner has shown a need for the proposed CT Project and that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. Competitive Procurement. Ind. Code § 8-1-8.5-5(b)(5) requires us to make certain findings under Ind. Code § 8-1-8.5-5(e) if the proposed facility has a generating capacity of more than 80 MW, as is the case here:

> Before granting a certificate to the applicant, the commission:
> (1) must, in addition to the findings required under subsection (b), find that:
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
> (2) shall also consider the following factors:
> (A) Reliability.
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.
> The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

Petitioner conducted two RFPs for EPC bids and major equipment purchases and utilized Power Advocate to administer the RFP process. These RFPs informed Petitioner's best estimate of the costs for the CT Project. Accordingly, we find Ind. Code § 8-1-8.5-5(e)(1)(A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially

practicable, the result of competitively bid engineering, procurement, or construction contracts. The EPC contractor was selected as a result of this RFP process, and the executed EPC contract was admitted into the record on a confidential basis. Petitioner's Exhibit 2-R, Attachment WDG-R4 (Confidential). The contract for construction of the CT Project was the result of competitive bidding in satisfaction of Ind. Code § 8-1-8.5-5(e)(1)(B).

Regarding Ind. Code § 8-1-8.5-5(e)(2), we have found herein, based on the evidence of record, that the proposed CT Project is reliable. The record has also established that Petitioner engaged in an All-Source RFP process to inform its Generation Transition Plan. Thus, we have considered reliability and solicitation by CEI South of competitive bids to obtain purchase power capacity and energy from alternative suppliers, and we find that the requirements of Ind. Code § 8-1-8.5-5(e) are satisfied.

vi. Gas Pipeline Lateral. Intervenors and the OUCC raised concerns about the gas lateral pipeline to be constructed by Texas Gas Transmission, LLC ("TGT") pursuant to the Precedent Agreement between CEI South and TGT. We recognize that the pipeline and the ability to secure adequate gas on that pipeline are both critical to CEI South's ability to operate the CTs as proposed.

However, we note that ruling on the public convenience and necessity of natural gas-fired generation before the establishment of the gas supply to serve it is not unprecedented. In Cause No. 44339, in which Indianapolis Power & Light ("IPL") sought a CPCN for its Eagle Valley CCGT, IPL initially pursued constructing the natural gas lateral itself, but eventually changed its plans and sought bids from several companies to build the lateral. In other words, we issued the CPCN without evidence that IPL had even entered a contract for the gas supply lateral. *See Indianapolis Power & Light Co.*, Cause No. 44339, at 23-24 (May 14, 2014).

However, it is possible that the assured cost recovery provided by the CPCN statute could enable CEI South to begin incurring significant costs to construct the CTs before FERC approval of the pipeline. The contracts that CEI South has with TGT for the pipeline and Kiewit for EPC matters are not dependent on one another; the timing and conditions precedent within them could allow for the progression of one without the other. If the FERC does not approve the pipeline, Petitioner will have incurred CT construction costs for a facility that cannot be built and operated in its proposed location.

The EPC contract includes a feature that allows for different notice to proceed ("NTP") issuance dates and associated deliverables, which balance the price and time to build risk between Kiewit and CEI South as the NTP date is delayed. After the Final Anticipated NTP issuance date (which is confidential), the contractual arrangements between Petitioner and Kiewit will be subject to further negotiation. Given that the pipeline contract with TGT cannot proceed until FERC approves the pipeline, and the unknown of when and even if that will occur is outside this Commission's control, we find that Petitioner shall utilize the EPC contract's NTP feature to minimize risk to the greatest extent possible in order to coordinate the construction of the CTs with FERC approval of the pipeline. If applied reasonably, this will limit potential sunk costs incurred before FERC pipeline approval with the delayed in-service date of the CTs. For these reasons, our approval of the requested CPCN for the CT Project is conditioned on the requirement that Petitioner issue the NTP under the EPC contract with Kiewit no earlier than the Final Anticipated

NTP issue date or the date of FERC approval of the TGT pipeline, whichever is earliest. Under this condition, the CT construction might still proceed before FERC approval of the pipeline, but potential CT construction costs will be limited to the greatest extent possible, should the pipeline not be authorized by the FERC.

Should Petitioner reach the conclusion that it should not move forward with the NTP because of emergent concerns not considered herein, it shall submit a compliance filing in this docket describing its decision no later than 15 days before the Final Anticipated NTP date. In addition, Mr. Greeley, in response to a question from the bench during the hearing, noted the possibility of Petitioner considering some form of "limited" NTP, if needed. Should such a limited NTP be issued, Petitioner is directed to submit a compliance filing in this docket within 15 days of the issuance of a limited NTP.

vii. Conclusion on CPCN for CT Project. Ind. Code § 8-1-8.5-5(d) requires us to "consider and approve, in whole or in part, or disapprove a utility specific proposal . . . jointly with an application for a certificate under this chapter[, but] solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity."

In the 45052 Order, the Commission discussed in detail the reasons the CPCN was denied in that case and how CEI South could improve its planning prior to future CPCN requests, including by incorporating flexibility and removing restrictions that might screen out multiple less-expensive alternatives. In this case, CEI South lessened the restrictions on its RFP, considered refueling and other potential options, and considered the diversity of its generation fleet. The 2019/2020 IRP process resulted in a Preferred Portfolio with a mix of generation resources that have flexibility for changing circumstances. In Cause No. 45052, CEI South sought approval of an 850 MW CCGT generation facility, as opposed to the two CTs for which a CPCN is sought in this case, which have a combined generation capacity of 460 MW. It appears that CEI South has considered and implemented the guidance of the 45052 Order in its 2019/2020 IRP and the requests made in this Cause.

Based upon the evidence of record, the Commission finds that CEI South has met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity require construction of the CT Project. Therefore, we grant CEI South's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

B. Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a). Ind. Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

CEI South requested that the Commission conduct ongoing review of the CT Project, proposing to submit construction progress reports, any revisions to the cost estimates, and other information regarding the CT Project to the Commission on an annual basis during construction.

We find that CEI South shall report, at least semi-annually, to the Commission a summary of the information related to the CT Project, including safety, scope, schedule, and owner's cost contingency, as well as the: (1) manufacturer, model number, and operational characteristics of the turbine generator; (2) anticipated total annual MW-hour ("MWh") output for the CT Project; (3) revisions to the cost estimate; and (4) update on the natural gas transportation and lateral pipeline.

The initial CT Project report shall be filed on or before December 30, 2022 as a compliance filing in this Cause. The final project report shall contain the following information: (1) the actual total cost of construction; (2) the total MW output for the facility; and (3) the actual in-service (commercial operation) date for the facility.

In addition, due to recent global supply chain issues that could potentially limit the availability of components necessary to build the CTs, Petitioner shall provide an update on any supply-chain-related challenges and/or delays on December 30, 2022 and continuing on a semi-annual basis thereafter until both CTs are placed into commercial operation. Such updates shall be filed under this Cause.

C. <u>Accounting and Ratemaking for CT Project</u>. CEI South is not seeking to adjust customers' rates to recover the costs of the CT Project before its next base rate case. CEI South requests accounting authority, starting with the date the CT Project is placed in service, for the deferral of depreciation and financing costs, including post in-service carrying costs ("PISCC"), related to the CT Project investment until such time as those costs and the CT Project's investment is reflected in CEI South's retail electric rates. The estimated construction costs for the CT Project are approximately $334 million compared to an estimated electric rate base as of December 31, 2020 of $1.5 billion.

Ms. Gostenhofer testified that CEI South proposed applying its approved depreciation rate for combustion turbines to the CT Project, resulting in a 3.44% annual depreciation rate, including the cost of removal. She stated that CEI South may evaluate adjustments to this depreciation rate in its next base rate case as part of a depreciation study. No party presented any evidence specifically opposing the application of this depreciation rate.

According to Ms. Gostenhofer, an estimated $11.1 million of annual depreciation expense and $20.7 million of incremental financing costs will be unrecoverable through rates due to the timing of recovery of the financing costs associated with the plant being placed in service. She also stated that, in addition to the new capital investments made in the CT Project, CEI South is making other large investments to comply with environmental regulations. She opined that the proposed accounting treatment helps mitigate the negative impact on income the CT Project would have between the period it is placed in service and until it is recovered in rates. She said that deferral and recovery of PISCC and depreciation expense helps Petitioner manage its increased carrying costs during a period of increased investments.

Industrial Group witness Mr. Gorman opined that recovery of the deferred costs in CEI South's next rate case should be contingent on CEI South proving that: (1) the revenues CEI South collected in existing rates during the deferral period were not adequate for it to recover its cost of service during the deferral period; and (2) CEI South made every reasonable effort to coordinate the timing of its rate case with the in-service date of the CT Project. He stated that, because CEI South can file a rate case utilizing a future test year, CEI South should be permitted to defer cost recovery for no more than six months.

Petitioner's request for deferral of PISCC and depreciation is not novel. We have frequently heard and granted such requests, and the test we have consistently applied is whether the cessation of AFUDC and commencement of depreciation will cause severe earnings erosion. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No. 44339 (May 14, 2014). The evidence of record demonstrates that CEI South will suffer severe earnings erosion during the time between the date the two CTs are placed in service and CEI South's next rate case order authorizing recovery of a return on the CTs and depreciation expense. During this interim period, CEI South will also not be recovering carrying costs of the construction project. CEI South's requested accounting treatment would allow it to offset the erosion to monthly pre-tax earnings by approximately $2.65 million due to the deferral of the depreciation expense and continuation of the $20.7 million of financing costs incurred by the utility and previously recovered through AFUDC. The additional conditions Mr. Gorman seeks to impose on this accounting relief are inconsistent with the earnings erosion standard.

Therefore, we authorize CEI South to: (1) apply the 3.44% depreciation rate discussed above; (2) accrue PISCC, at CEI South's currently approved weighted average cost of capital ("WACC"), on the two CTs beginning with the month after the in-service date of each individual CT Project asset until the date CEI South's base rates include a return on the CT Project; (3) record the depreciation expense on each individual CT Project asset beginning with the month after its in-service date; (4) record deferred PISCC and depreciation in a regulatory asset in Account 182.3, Other Regulatory Assets, through the date CEI South's base rates include a return on the CT Project and recovery of the depreciation expense; (5) amortize the regulatory asset as a recoverable expense for ratemaking purposes over the estimated life of the CTs commencing on the date of the order authorizing recovery in CEI South's rates of a return on the CTs and depreciation expense; and (6) include the unamortized portion of the regulatory asset in CEI South's rate base upon which it is permitted to earn a return.[1]

Petitioner also sought authority to capitalize allocable costs of preparing the IRP and preparing this case to the costs of the CT Project and to amortize these costs over the life of the asset.[2] Mr. Lantrip of the OUCC recommended that the Commission follow the 45052 Order and reject CEI South's proposed treatment of the CT Project's planning costs, including the $5 million in IRP planning costs. He testified that IRP planning costs are a non-recurring cost of doing business, and there is no Commission precedent allowing for the separate recovery of IRP planning costs. Similarly, Mr. Gorman testified for the Industrial Group that CEI South has not proven that its IRP costs are properly capitalized to the CT Project, as opposed to expensing those costs

[1] We have previously held that WACC is the appropriate rate for post-in-service carrying charges. *See, e.g.*, *Indianapolis Power & Light Co.*, Cause No. 44339, at 35 (May 14, 2014) (citing orders).

[2] Petitioner also sought in the alternative to defer such costs as a regulatory asset to be recovered through rates in the event the CPCN for the CT Project is denied. Because we have issued the CPCN, this part of the request is moot.

currently as ongoing system planning costs. He stated that CEI South has offered no proof that the IRP costs could not be recovered via rate revenue in the year the cost was incurred.

On rebuttal, Ms. Gostenhofer testified that all the planning costs, including the $5 million in IRP planning costs identified by Mr. Lantrip, to be included in the CT Project are incremental expenditures specifically related to the CT Project and must be incurred as part of the construction of the CTs. She stated these costs initially meet the criteria to be deferred on the balance sheet, in accordance with FERC 183 or FERC 107, as applicable, and are therefore not considered operating costs of CEI South in accordance with the FERC Uniform System of Accounts ("USOA"). She explained that CEI South's IRP generation asset planning pool costs that are the subject of Petitioner's deferral request do not include any costs stemming from CEI South's request for a CPCN for the CCGT that was denied in Cause No. 45052. She stated that, after the 45052 Order was issued in April 2019, CEI South reviewed all planning costs deferred for future recovery in the generation asset planning pool to identify any costs that related to activities supporting a large-scale gas generation asset, such as the then-proposed and ultimately denied CCGT, that would not be applicable to future assets developed under the IRP that would need to be either charged to a regulatory asset or to operating expense. She stated that the remaining costs in the generation asset planning pool had been in support of smaller-scale options. Thus, she opined that it was reasonable to expect the studies and activities for those costs to become used and useful in support of the construction of assets resulting from the IRP, such as the CT Project at issue in this Cause.

After considering the evidence of record, we find that Petitioner's best estimate of costs includes an estimate of $12 million in planning costs. About $5 million of that total consists of Generation Asset Planning Pool costs that relate to Petitioner's request for a CPCN for the CT Project. This consists of costs as described by Ms. Gostenhofer related to the 2016 and 2019 IRPs, excluding costs related to a large-scale generating asset such as a CCGT that was denied in Cause No. 45052. We have adopted the FERC USOA by rule. 170 IAC 4-2-1.1(a). FERC 183B provides, "This account shall also include costs of studies and analyses mandated by regulatory bodies related to plant in service. If construction results from such studies, this account shall be credited and the appropriate utility plant account charged with an equitable portion of such study costs directly attributable to new construction." The costs at issue in Petitioner's Generation Asset Planning Pool fit this definition, and the evidence of record indicates that Petitioner has allocated an equitable portion to the CT Project. Thus, we find that Petitioner's proposal to include these costs in the capital costs of the CT Project is consistent with the FERC USOA and is appropriate.

D. <u>Other Gas Pipeline Lateral Issues</u>. As mentioned previously, several of the parties' witnesses expressed concern regarding various issues related to the gas pipeline lateral. CAC witness Ms. Sommer opined that TGT's proposed pipeline is oversized and that CEI South is acquiring gas transmission capacity that greatly exceeds that which is needed to supply the proposed CTs. She opined that a smaller pipeline could serve the CTs at a lower cost.

Industrial Group witness Mr. Gorman testified that he believed CEI South did not make every reasonable effort to reduce the $27.3 million annual cost burden on ratepayers. He also opined that CEI South has not demonstrated that it has structured the arrangement with TGT to facilitate sales of unused capacity on the lateral to third parties. He stated that CEI South has not established that the proposed location of the lateral pipeline is the most prudent and least cost

option. Mr. Gorman also took issue with the binding nature of the agreement and the timing of the construction of the pipeline.

Sunrise Coal witness Ms. Medine noted the lack of certainty that the pipeline will be approved by the FERC, noting the EIS requirement imposed by FERC. Mr. Nasi, also testifying on behalf of Sunrise Coal, opined that it would not be prudent to proceed with the CT project prior to resolution of the FERC matter.

In response to criticism of the pipeline's location, Mr. Hoover testified on rebuttal that TGT decided that, to obtain the most effective balance of pipeline pressure, reliability, and capacity, the optimal location for the lateral interconnection to the TGT mainline system was near Robards, Kentucky. While some of TGT's interstate pipelines extend into Indiana, Mr. Hoover stated that necessary improvements to those pipelines for capacity and pressure requirements, additional compression to meet the pressure requirements, and more congested routes make them less economically feasible as the interconnection location for the lateral. He noted that the existing Dogtown lateral is of insufficient size and operating pressure to serve the CTs, and the other TGT interstate pipelines are routed north through the east side of Vanderburgh County, making them farther from A.B. Brown than the Robards, Kentucky location. Using those pipelines would also require a lateral to be installed through much more populated and congested areas.

Mr. Hoover also responded to Ms. Sommer's assertion that TGT's proposed pipeline is oversized, stating that a 20-inch lateral is required to provide the required gas flow rate and pressure to the combustion turbines. He said that the 16-inch lateral size does not have adequate margin, and installation of an undersized lateral cannot be easily or cheaply remediated. He testified that TGT informed CEI South that the price for demand on the lateral would be the same for all of the capacity or a portion of it; given this, CEI South contracted for the full pipeline capacity.

Based on our review of the evidence of record, we are satisfied with CEI South's decision to secure transportation capacity pursuant to the Precedent Agreement with TGT rather than pursuing some combination of alternatives, including use of the Dogtown lateral, an alternative TGT route, or on-system storage. The evidence of record supports a finding that the Dogtown lateral is incapable of supporting the CT demand or pressure requirements. A different route would have required additional improvements to TGT's system to meet capacity and pressure requirements and would have involved a more congested route for the lateral.

The evidence is unrefuted that Petitioner will require service from a lateral pipeline to serve the two CTs. Further, we find that the evidence supports that the proposed TGT pipeline will provide the required service to the two CTs. Accordingly, it is appropriate that Petitioner should receive reasonable cost recovery for the expenses it incurs for the service it receives from the TGT pipeline.[3] However, the specific amount and the means of that cost recovery will be subject to further proceedings as discussed below.

[3] We have previously allowed a utility to recover fuel costs associated with a CCGT in its FAC mechanism. In Cause No. 44339, IPL proposed to recover fuel costs associated with its Eagle Valley CCGT and Harding Street Refueling projects through its FAC, which has now occurred. *Indianapolis Power & Light Co.*, Cause No. 38703 FAC 127, at 3 (June 3, 2020) ("[T]he cost of gas generation contains the delivered cost of natural gas including firm transportation.").

The Industrial Group also disputed CEI South's proposal to recover the costs associated with the gas lateral through its FAC. Mr. Gorman testified that fixed pipeline capacity costs and the gas lateral costs should not be recovered through CEI South's FAC because customers should pay for the CTs in line with the benefits provided, which are related to system capacity and not energy. He proposed that the TGT fixed costs be allocated to CEI South customers based on their contribution to system capacity needs. He stated that the fixed costs of the gas delivery pipeline, while not varying with electricity generated from the CTs, are critical capital costs needed so the CTs can be available to support system reliability when called upon. Mr. Gorman opined that allocation of the CT Project capacity costs in this way, including the TGT fixed gas lateral costs, produce price signals that would encourage customers to make efficient consumption decisions.

Once FERC decides whether TGT is permitted to build the pipeline, the question of how the costs of that gas service should be recovered from CEI South's customers can be addressed by the Commission. Mr. Rice noted on rebuttal and during the hearing that a subdocket could be opened to investigate the appropriate allocation for cost recovery purposes of the cost of the gas lateral throughout the term of the Precedent Agreement. We agree and find that such a subdocket shall be opened within 30 days of FERC approval of the pipeline. Petitioner shall notify the Commission within five business days of the FERC's final order regarding the pipeline lateral and file a copy of that order under this Cause. To the extent that reasonable pipeline costs allocated to Petitioner's customers are not ultimately recovered through Petitioner's fuel adjustment clause ("FAC") mechanism, we grant CEI South's alternative request for deferral of such costs until such costs are recovered through base rates following a general rate case.

7. Commission Discussion and Findings on CCR Compliance Projects.

A. CPCN Request for CCR Compliance Projects. CEI South also seeks CPCNs for the CCR Compliance Projects (the Dry Ash Compliance Project and the Pond Compliance Project), both of which are "federally mandated" projects under Ind. Code ch. 8-1-8.4.

When considering a petition under Ind. Code § 8-1-8.4-7, the Commission must grant the CPCN if it:

> (1) made a finding that public convenience and necessity will be served by the proposed compliance project;
> (2) approved the projected federally mandated costs associated with the proposed compliance project; and
> (3) made a finding on each of the factors set forth in [Ind. Code § 8-1-8.4-6(b)].

Ind. Code § 8-1-8.4-7(b).

The factors we must consider in Ind. Code § 8-1-8.4-6(b) are as follows:

> (1) The following, which must be set forth in the energy utility's application for the certificate sought, in accordance with section 7(a) of this chapter:
> (A) A description of the federally mandated requirements, including any consent decrees related to the federally mandated requirements, that the

energy utility seeks to comply with through the proposed compliance project.

(B) A description of the projected federally mandated costs associated with the proposed compliance project, including costs that are allocated to the energy utility:

(i) in connection with regional transmission expansion planning and construction; or

(ii) under a Federal Energy Regulatory Commission approved tariff, rate schedule, or agreement.

(C) A description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements described by the energy utility under clause (A).

(D) Alternative plans that demonstrate that the proposed compliance project is reasonable and necessary.

(E) Information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension.

(2) Any other factors the commission considers relevant.

i. <u>Federally Mandated Requirements (Ind. Code § 8-1-8.4-6(b)(1)(A))</u>. Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government[,]" including, but not limited to, "[t]he federal Water Pollution Control Act (33 U.S.C. 1251 et seq.)" and "[a]ny other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

Petitioner has proposed to undertake the CCR Compliance Projects to comply with the EPA's CCR and ELG rules. No party has disputed that these rules constitute federally mandated requirements under Ind. Code § 8-1-8.4-5. Thus, we find that Petitioner has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(A).

ii. <u>Projected Costs (Ind. Code § 8-1-8.4-6(b)(1)(B))</u>. Energy utilities seeking recovery of federally mandated costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax, or financing costs, and describe the costs to be recovered. Ind. Code § 8-1-8.4-4. Mr. Games testified about the costs of the CCR Compliance Projects.

No party disputed Petitioner's cost estimates for the Dry Ash Compliance Project. However, Ms. Armstrong of the OUCC opined that CEI South did not provide reasonably adequate cost estimates for the Pond Compliance Project, given that the estimates were Class 5 and could increase by 30% to 100%. However, we note that, under Ind. Code § 8-1-8.4-7(c)(3), "[a]ctual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by

the energy utility with the commission." Ind. Code § 8-1-8.4-7(c)(3). If Petitioner's actual costs prove to be 30% to 100% more than its estimates, CEI South will be required to justify them.

Thus, based on the evidence of record, we find that CEI South has identified federally mandated costs (as defined by Ind. Code § 8-1-8.4-4) for the CCR Compliance Projects and reasonably described those costs. The total capital costs for the CCR Compliance Projects are estimated at $31 million ($12 million for the Dry Ash Compliance Project and $19 million for the Pond Compliance Project). Annual O&M costs for the Dry Ash Compliance Pond are estimated at $1.35 million through 2023 and $0.68 million for 2024 and beyond; annual O&M costs for the Pond Compliance Project are estimated at $350,000.

. We find that these estimated costs are reasonable and are therefore approved.

iii. How the Proposed Projects Allow Compliance with Federally Mandated Requirements (Ind. Code § 8-1-8.4-6(b)(1)(C)). Ms. Retherford testified that the CCR Compliance Projects are required to comply with the CCR and ELG rules, which prohibit the continued wet sluicing of fly ash transport water for disposal in an unlined ash pond.

1. Dry Ash Compliance Project. Petitioner presented evidence that the Dry Ash Compliance Project will allow it to remain in compliance with the CCR and ELG rules and continue to load dry fly ash for transport and shipment for beneficial reuse, as dry fly ash can no longer be disposed of in the ash ponds. Ms. Retherford testified that dry fly ash cannot be loaded at the Ohio River loading facility located at A.B. Brown, as that system has been converted to load-ponded ash under the CCR closure plan. With the conversion of the loading facility at A.B. Brown, Petitioner was required to find an alternative loading facility for dry fly ash in order to remain in compliance with the CCR and ELG rules' prohibition against disposal of dry fly ash in an unlined ash pond. The Dry Ash Compliance Project will ensure that Petitioner can continue to burn coal and beneficially reuse fly ash through the retirement of the coal-fired units at A.B. Brown in October 2023 and the continued operation of F.B. Culley Generating Station's Units 2 and 3 through their retirement dates. The Dry Ash Compliance Project also supports the Part A Reconsideration extension requests under the CCR rule for both Brown and Culley. The Dry Ash Compliance Project also directly provides alternative disposal capacity for dry fly ash and supports the extension request for the remainder of the CCR waste streams. No party disputed that the Dry Ash Compliance Project will allow CEI South to comply with the CCR and ELG rules, and we therefore find that Ind. Code § 8-1-8.4-6(b)(1)(C) is satisfied for this project.

2. Pond Compliance Project. The Pond Compliance Project will consist of two lined CCR-compliant ponds, one each at Culley and Brown. Ms. Retherford testified that construction of the ponds will serve to provide CCR-compliant wastewater containment between closure of the east ash pond and completion of the ELG wastewater treatment upgrades approved in Cause No. 45052. Given the small quantity of bottom ash generated by Culley Unit 2, one of the new lined CCR-compliant ponds provides Petitioner with the opportunity to use the new lined pond for short-term bottom ash disposal if Petitioner chooses to continue to operate Culley Unit 2 through December 2025 under the ELG Reconsideration rule. She stated that construction of the lined CCR-compliant ponds will serve to provide CCR-compliant wastewater containment for landfill runoff leachate, storm water, coal pile runoff until

decommissioning is complete, wastewater treatment, and continued mercury treatment of ash pond water during dewatering and ash pond closure activities. However, the new CCR-compliant ponds will not have sufficient size to permit effective hydraulic capacity and settling capacity for the additional ash flows currently entering the ash pond. The new lined CCR pond at Brown will serve as the stormwater pond for the CT Project.

The only disputed issue regarding the Pond Compliance Project concerns the deadline for achieving compliance. The CCR rule was finalized in 2015, and it contains three tests that require the closure of an ash pond if the tests are not satisfied. At the time of promulgation, the CCR rule required a pond failing the tests to cease receipt of materials by April 2017 and for closure be initiated within 30 days. All three of CEI South's ponds triggered closure requirements.[4] Under the original CCR rule, a utility could take five one-year self-implementing extensions of the final cessation deadline if there was no alternative capacity available. In July 2018, the EPA revised the final cessation deadline for cessation of receipt of materials to October 2020. In August 2020, the final cessation deadline was again revised to April 11, 2021, in what is known as the Part A Reconsideration Rule. The Part A Reconsideration Rule also eliminated the self-implementing annual extension option and replaced it with a new mechanism, which requires a utility to file a formal extension request with the EPA that would extend the cessation deadline to no later than October 15, 2023. In order to qualify for an extension, the utility must demonstrate it has no alternative capacity and that it is actively pursuing alternative disposal capacity in the technically feasible timeframe for each individual CCR waste stream. The evidence reflects that CEI South submitted a timely application for an extension under the Part A Reconsideration Rule, but the EPA has not yet ruled on this request. The Pond Compliance Project is the alternative disposal capacity that CEI South has been "actively pursuing" in accordance with the requirements for pond extension under the Part A Reconsideration.

Although the OUCC acknowledged that CEI South filed timely requests for extension, Ms. Armstrong argued that the proposed Pond Compliance Project should be denied (or recovery reduced to 50%) because of uncertainty regarding whether the EPA will grant CEI South's extension request. Ms. Retherford responded that the EPA has recently indicated that it may not finalize completeness reviews until late spring 2022, and she opined that CEI South has no viable alternative but to continue to implement the CCR compliance strategies as proposed in its extension packages.

No party disputed Petitioner's position that the Pond Compliance Project will allow compliance with the CCR Rule. We need not address at this time any consequences if EPA ultimately denies Petitioner's request for an extension of time. We find that the Pond Compliance Project will allow CEI South to comply with federally mandated requirements and that Ind. Code § 8-1-8.4-6(b)(1)(C) is satisfied for this project.

iv. <u>Alternative Plans (Ind. Code § 8-1-8.4-6(b)(1)(D))</u>. Mr. Games discussed potential alternative options to the Dry Ash Compliance Project, which were summarized in Table WDG-8 in his testimony. Options considered included the modification of

[4] The west pond at Culley has already been closed. CEI South has requested an extension from the EPA for the east pond at Culley while it completes the ELG upgrades for Culley Unit 3 that were authorized in Cause No. 45052. The Brown ash pond is being excavated for beneficial reuse as authorized in Cause No. 45280.

an existing landfill or building a new landfill; depositing ash in a coal mine; utilizing a municipal landfill; using separate ponded and dry loading systems at Brown; using a common loading system at Brown; constructing a loading system at Culley; and pugging or adding and mixing water to dry ash before shipping with ponded ash. After considering these options, CEI South identified the construction of a new dry fly ash loading facility at the ADM site as the best viable solution.

Ms. Retherford testified that no reasonable alternatives exist to the proposed Pond Compliance Project because CEI South is required to implement the alternative disposal capacity as fast as technically feasible. She stated that CEI South investigated five other options, none of which would achieve compliance because they cannot be completed more quickly than the ponds. She provided evidence of the extensive review of alternatives and links to thousands of pages of information submitted to the EPA regarding alternatives.

Ms. Armstrong of the OUCC argued that the Pond Compliance Project should be denied because CEI South has not adequately demonstrated that continuing to operate Brown Units 1 and 2 and Culley Unit 2 until October 2023 is the most reasonable, least-cost option for meeting resource needs. On rebuttal, Ms. Retherford responded that this alternative would require more immediate retirement of Brown Units 1 and 2 and Culley Unit 2, as suggested by Ms. Armstrong, but also the immediate shut down of Culley Unit 3 which must continue to use the Culley East ash pond until the completion of the wastewater treatment upgrades approved in Cause No. 45052 that are not scheduled to be completed until March 2023. Ms. Retherford stated that the OUCC's alternative option would require the immediate shutdown of approximately 900 MW of CEI South's 1,200 MW of generation capability with no approved replacement capacity. She opined that the OUCC's position that CEI South's proposed CCR Compliance Ponds should not be approved because CEI South did not provide a comparison between the costs associated with the immediate replacement of 900 MW of capacity and the costs to construct two small extension ponds is not reasonable. She stated that the OUCC's recommended approach would jeopardize CEI South's ability to meet its obligation to provide safe and reliable service to its customers.

Sunrise Coal witness Mr. Nasi proposed that Petitioner could extend the use of coal at the Brown Units if CEI South converted only the fly ash handling system to dry handling and then constructed a pond to receive only FGD and bottom ash. In his view, this option would allow Brown to continue burning coal until October 17, 2028. On rebuttal, Ms. Retherford opined that this is not a feasible option. The CCR Part A Reconsideration Rule provides two extension mechanisms: (1) a site-specific alternative deadline under 40 C.F.R. § 257.201(f)(1), which requires a demonstration that the development of alternative capacity is technically infeasible by April 2021; and (2) permanent cessation of a coal-fired boiler by a date certain under 40 C.F.R. § 257.103(f)(2). 40 C.F.R. § 257.201(f)(1), which applies to the Pond Compliance Project, requires a demonstration of what is the fastest technically feasible alternative. Mr. Nasi did not address how his proposal could be achieved more quickly than the Pond Compliance Project.

Based on the evidence of record, we find that CEI South considered alternative plans for compliance with the ELG and CCR rules and selected the most reasonable options in the CCR Compliance Projects. The evidence demonstrates that the CCR Compliance Projects are reasonable and necessary.

v. Extension of Useful Life of Existing Facility (Ind. Code § 8-1-8.4-6(b)(1)(E)). No party disputes that the issuance of CPCNs for the CCR Compliance Projects will extend the useful life of coal-burning units at Brown and Culley. Based on the evidence presented, we find that CEI South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

vi. Conclusion. As discussed above, we find that Petitioner has satisfied all five subsections of Ind. Code § 8-1-8.4-6(b)(1), and we find that there are no additional factors that need to be considered under Ind. Code § 8-1-8.4-6(b)(2). We find that the public convenience and necessity will be served by the CCR Compliance Projects, approve the projected federally mandated costs associated with the CCR Compliance Projects, and issue the requested CPCNs for the CCR Compliance Projects.

The only remaining issue that has been raised is Ms. Armstrong's request that we only allow CEI South to recover 50% of the federally mandated costs. However, having made the required findings, the statute directs that we "shall . . . grant a certificate." Ind. Code § 8-1-8.4-7(b). A certificate having been granted, the statute directs that 80% of the approved costs shall be recovered through a periodic rate adjustment, with 20% of approved costs deferred. There is no authority under any relevant statute to deny recovery as Ms. Armstrong has proposed, absent any evidence that the federally mandated costs could have been reduced by 50% through some alternative course of action.

B. Accounting and Ratemaking for Federally Mandated CCR Projects.

i. Recovery of Federally Mandated Costs (Ind. Code § 8-1-8.4-7). Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
>
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
>
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
>
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

CEI South requests authority to include the costs of the CCR Compliance Projects in its annual environmental cost adjustment ("ECA") rate adjustment mechanism pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs, with the remaining 20% of the revenue requirement to be deferred and recovered by CEI South as part of its next general base rate case. Ind. Code § 8-1-8.4-7 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code § 8-1-8.4-4 provides that such costs may include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Ms. Gostenhofer described how the eligible costs associated with the CCR Compliance Projects will be incorporated into Petitioner's annual ECA mechanism. She testified that CEI South will prepare in each annual filing a revenue requirement calculation which will accumulate all eligible costs incurred through December 31 of the previous calendar year. Those eligible costs will include return on new capital investments, calculated as the new capital investments in plant related to the CCR Compliance Projects, multiplied by the applicable rate of return for the ECA, plus incremental expenses, which will include depreciation, O&M, property tax expenses, and other costs associated with the CCR Compliance Projects. The revenue requirement on the CCR Compliance Projects will represent the basis for the recovery of 80% of the eligible revenue requirement requested in each annual ECA filing and deferral of 20% of the eligible revenue requirement for future recovery.

According to Ms. Gostenhofer, CEI South proposes to include in the revenue requirement for new capital investments the gross plant specific to the new capital investments for the CCR Compliance Projects, both in service and construction work in progress ("CWIP"). The project costs for these new capital investments will include various direct and indirect costs and financing costs incurred during construction, commonly referred to as AFUDC. She also described CEI South's proposal to defer and subsequently recover depreciation expense and costs associated with CCR Compliance Projects through the ECA. CEI South will amortize the cumulative deferred balances in the regulatory asset and include the amortization amount in the ECA revenue requirements. Specific to deferred depreciation expense, CEI South proposes to amortize the deferred balance through the ECA over the remaining life of the assets that generated the depreciation expense. She stated that CEI South has incurred and will continue to incur costs associated with the development of the solutions which generated the design and implementation of the CCR Compliance Projects. These costs have been and will continue to be debited to FERC Account 107, Construction Work in Progress, and included for recovery within the ECA.

CEI South proposes to accrue PISCC on all eligible new capital investment, beginning with the month after the investment is placed in service until the date when the investment is included in rates for recovery. The deferred PISCC balance accumulating in the regulatory asset will be included as new capital investment and will be multiplied by the pre-tax rate of return within the ECA revenue requirement. Ms. Gostenhofer stated that the PISCC rate used is the WACC required by the ECA revenue requirement.

Ms. Gostenhofer stated that CEI South will calculate a revenue requirement for the ECA mechanism in each annual ECA filing. The revenue requirement will be shown on Schedule 1 and will include the return on new capital investments, property tax, depreciation, and O&M associated with the CCR Compliance Projects, by category of investment, and the recovery of the regulatory

assets recorded through the interim deferral of depreciation expense, plan development expense, and PISCC. CEI South will then multiply the annual revenue requirement by 80% to calculate the recoverable portion of the revenue requirement for approved investments in the ECA. The recoverable amounts for the approved investments will be aggregated and included in CEI South's annual ECA rates and charges based on annualized billing determinants. She stated that CEI South is not proposing an ECA revenue requirement amount for recovery in this proceeding.

Ms. Gostenhofer testified that, pursuant to Ind. Code § 8-1-8.4-7, CEI South will seek timely recovery of all federally mandated costs associated with the CCR Compliance Projects, including capital costs, AFUDC, PISCC, O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in CEI South's next rate case.

Ms. Gostenhofer also stated that CEI South proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during construction of eligible CCR Compliance Project investments. Under this proposal, CEI South will recover, through the ECA, financing costs incurred during the construction period attributable to eligible capital investments. CWIP ratemaking treatment allows a utility to recover its costs in a timely manner and avoid the impacts of regulatory lag by recovering financing costs as the capital costs are being incurred. In connection with CWIP ratemaking treatment, CEI South will remove from the AFUDC-eligible balance the amount of investment included in the revenue requirement for the ECA, such that only the amount of CCR Compliance Project investment not currently being recovered in ECA rates or deferred in a regulatory asset for future recovery in base rates would be eligible for AFUDC.

None of the other parties in the case opposed CEI South's proposed recovery of federally mandated costs for the CCR Compliance Projects.

Based on the evidence of record, we find that CEI South's request for approval to adjust its authorized net operating income to reflect approved earnings associated with the CCR Compliance Projects for the purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1). CEI South is authorized to defer and recover 80% of the approved federally mandated costs incurred in connection with the CCR Compliance Projects through the ECA mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. In addition, CEI South is authorized to utilize CWIP ratemaking treatment for the CCR Compliance Projects through the ECA mechanism. CEI South is authorized to defer post-in-service costs of the CCR Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes, and O&M expenses, on an interim basis until such costs are recognized for ratemaking purposes through CEI South's ECA mechanism or otherwise included for recovery in CEI South's base rates in its next general rate case. CEI South's proposed cost allocation factors are also approved.

CEI South is not seeking authority to accrue and subsequently recover in the next base rate case PISCC on the balance of the 20% deferred revenue requirement included in the regulatory asset discussed previously.

ii. Depreciation. CEI South proposes to include for recovery the depreciation expense associated with the new capital investments for the CCR Compliance Projects at the current applicable depreciation rate for the asset class. To the extent the new investment associated with the CCR Compliance Projects results in the retirement of an existing asset, depreciation expense included in the revenue requirement will be reduced by the depreciation expense attributed to those retired assets. In its next base rate case, CEI South will evaluate adjustments to current depreciation rates as part of its formal depreciation study.

While no party opposed CEI South's proposed depreciation rate for the investments required for the CCR Compliance Projects, the OUCC took issue with CEI South's proposed accounting treatment for retired assets. Mr. Lantrip recommend excluding the costs of removal from CEI South's proposed retirement adjustment because the cost of removal is already considered as part of the process of establishing the depreciation rates approved in CEI South's base rate cases. He testified that the OUCC's recommendation is consistent with the Commission's order in *Indiana Michigan Power Company*, Cause No. 44182 (July 17, 2013).

On rebuttal, Ms. Gostenhofer testified that CEI South follows the FERC USOA "Electric Plant Instruction" 10(B)(2), which requires that the retirements of utility plant be recorded against the accumulated depreciation applicable to such property and that any incremental cost of removal and any salvage proceeds be charged or credited to the same account. The accounting treatment results in no change to overall rate base. Ms. Gostenhofer testified that Petitioner is not requesting to deviate from the FERC USOA for the accounting treatment of retirement. She stated that, when the FERC accounting for retirements, including the cost of removal, is applied, the retirement of an asset does not result in a change in net rate base, but results in a reclassification from plant in service to accumulated depreciation. She stated that CEI South intends to record any incurred cost of removal associated with the retired assets to accumulated depreciation, as required by FERC.

According to Ms. Gostenhofer, when depreciation expense, inclusive of cost of removal, is recorded, the balance of the amounts expensed for cost of removal aggregates in accumulated depreciation and ultimately decreases the net book value of the asset. She said that recording depreciation expense with the cost of removal both reduces rate base and also results in an accumulated depreciation reflecting a net credit balance on the plant asset or an over-depreciated asset equal to the total estimated cost of removal at the end of an asset's life. She testified that, when the actual costs of removal are incurred, the utility charges accumulated depreciation in accordance with the USOA, reducing the net plant balance to zero after incurring the cost of removal, assuming the estimated cost of removal in depreciation expense is equal to the actual costs of removal. Ms. Gostenhofer explained that any over- or under-recovery of the cost of removal will remain in accumulated depreciation, will continue to increase or decrease rate base, and will eventually be reflected in future depreciation rates determined in CEI South's next depreciation study.

Ms. Gostenhofer confirmed on rebuttal that it is not CEI South's intent to reflect in its rate adjustment mechanism the costs of removal associated with retired property. She testified that the ECA will recover the incremental capital spend and does not include an adjustment, or additional recovery, for the costs of removal.

We find that the ECA to recover the federally mandated costs associated with the approved CCR Compliance Projects should not include cost of removal for associated retirements. Based on the evidence presented, we find CEI South's depreciation proposal is reasonable and is approved.

8. Collaborative Process. In the Commission's order in Cause No. 45109, in which we reviewed CenterPoint Energy, Inc.'s acquisition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company, we encouraged consideration of an engagement of interested stakeholders in a collaborative process to develop open and transparent dialogue on utility operational efficiency. *Indiana Gas Company, Inc.*, Cause No. 45109, at 12 (Jan. 16, 2019). We further that encouragement here with a directive.

The Commission views the collaborative process as an opportunity for all parties to communicate on how to review utility operations. A collaborative process is currently in place for all Indiana investor-owned electric utilities except Petitioner. We believe performance metrics can be of significant value to CEI South, its customers, and the Commission. Thus, we find that CEI South shall facilitate a meeting with interested stakeholders within 12 weeks of the effective date of this order to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that this process will enable an analysis of CEI South's performance over time and comparison with similarly situated utilities.

Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, the Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and 1-1.5-4. So that the Commission and interested stakeholders may stay apprised of the collaborative process, we direct CEI South to make a progress update filing in this Cause within 90 days of the initial meeting of the collaborative. We also direct CEI South to file quarterly reports for the first year and an annual report one year from the date of this order and on that date every year thereafter until otherwise indicated by the Presiding Officers.

9. Confidentiality. CEI South filed motions for protection and nondisclosure of confidential and proprietary information on June 17, 2021, December 7, 2021, and December 20, 2021. The Industrial Group also filed a motion for protection and nondisclosure of confidential and proprietary information on November 19, 2021. All of these motions related to information CEI South claimed to be trade secrets and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. Docket entries were issued on July 1, 2021 and January 11, 2022, finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the information that is the subject of these motions is confidential pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. CEI South is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct two natural gas CTs providing approximately 460 MW of capacity to be located at CEI South's existing A.B. Brown site. This Order constitutes the certificate. This certificate is subject to the limitations described herein regarding the Notice to Proceed date under Petitioner's contract with Kiewit.

2. Should Petitioner reach the conclusion that it should not move forward with the NTP under the contract with Kiewit because of emergent concerns not considered herein, it shall submit a compliance filing in this Cause describing its decision no later than 15 days before the Final Anticipated NTP date.

3. If Petitioner issues a "limited" NTP to Kiewit as discussed herein, Petitioner shall submit a compliance filing in this Cause within 15 days of the issue date.

4. CEI South's estimated total cost of the CT Project in the amount of $334 million is approved as set forth herein.

5. CEI South's request for ongoing review of the CT Project is approved. CEI South shall file reports as described herein for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

6. CEI South shall file supply chain updates as described herein.

7. CEI South is authorized to depreciate the CT Project at the depreciation rate identified herein.

8. CEI South is authorized to defer depreciation and to accrue PISCC related to the CT Project, including carrying costs based on its weighted average cost of capital, until such costs are recognized for ratemaking purposes through CEI South's base rates in its next general rate case.

9. To the extent that reasonable pipeline costs allocated to CEI South's customers are not ultimately recovered through CEI South's FAC mechanism, we grant its alternative request for deferral of such costs until such costs are recovered through base rates following a general rate case

10. CEI South is issued a certificate of public convenience and necessity for the CCR Compliance Projects pursuant to Ind. Code ch. 8-1-8.4. This Order constitutes the certificate.

11. The CCR Rule and the ELG Rule constitute federally mandated requirements as defined by Ind. Code § 8-1-8.4-5.

12. The CCR Compliance Projects constitute compliance projects as that term is defined in Ind. Code § 8-1-8.4-2, and the costs incurred in connection with the CCR Compliance Projects are federally mandated costs as that term is defined in Ind. Code § 8-1-8.4-4. The federally mandated costs are eligible for ratemaking treatment described in Ind. Code § 8-1-8.4-7.

13. CEI South's cost estimates for the CCR Compliance Projects set forth above are approved.

14. CEI South is authorized to timely recover 80% of the approved federally mandated costs incurred in connection with the CCR Compliance Projects through its existing ECA mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on its weighted average cost of capital.

15. CEI South is authorized to utilize CWIP ratemaking treatment for the CCR Compliance Projects through its ECA mechanism.

16. CEI South is authorized to accrue AFUDC relating to the CCR Compliance Projects until such time as the projects included in the CCR Compliance Projects are placed into service or receive ratemaking treatment.

17. CEI South is authorized to accrue PISCC related to the CCR Compliance Projects, including carrying costs based on its WACC, and to defer depreciation, taxes, and O&M expenses on an interim basis until such costs are recognized for ratemaking purposes through CEI South's ECA or otherwise included for recovery in CEI South's base rates in its next general rate case.

18. CEI South is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the CCR Compliance Projects for the purposes of Ind. Code § 8-1-2-42(d)(3), as allowed under Ind. Code § 8-1-8.4-7(c)(1).

19. CEI South is authorized to defer 20% of the federally mandated costs incurred in connection with the CCR Compliance Projects for recovery in its next general rate case.

20. CEI South is authorized to depreciate the individual projects included in the CCR Compliance Projects according to depreciation rates set forth herein.

21. CEI South is authorized to record all PISCC and deferred depreciation authorized herein as regulatory assets in Account 182.3, Other Regulatory Assets.

22. A subdocket shall be created to address cost recovery and allocation issues related to the costs incurred pursuant to the Precedent Agreement with TGT as discussed herein. In the event CEI South is ultimately not permitted to reflect the fixed lateral demand charge in its FAC as a result of such subdocket, CEI South is authorized to defer as a regulatory asset for future recovery the demand costs it incurs until such time as such costs are recovered through CEI South's base rates.

23. Within five business days of the FERC order regarding the construction of the gas lateral, CEI South shall file a copy of the order under this Cause.

24. CEI South shall establish a collaborative process as discussed herein.

25. The Confidential Information submitted under seal in this Cause pursuant to the parties' requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

26. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, AND ZIEGNER CONCUR:

APPROVED: JUN 28 2022

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco

Digitally signed by Dana Kosco
Date: 2022.06.28 14:12:34 -04'00'

Dana Kosco
Secretary of the Commission

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 126
IURC 2025 CenterPoint Rate Order

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT.	**)**	**CAUSE NO. 45990** **APPROVED: FEB 03 2025**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Veleta, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

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On December 5, 2023, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South" or "Petitioner") filed its Verified Petition for General Rate Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and an Alternative Regulatory Plan under Ind. Code Ch. 8-1-2.5 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") with the Indiana Utility Regulatory Commission ("Commission"), seeking (1) authority to modify its rates and charges for electric utility service through a phase-in of rates, (2) approval of new schedules of rates and charges, and new and revised riders including but not limited to a new tax adjustment rider ("TAR") and a new green energy rider, (3) approval of a Critical Peak Pricing ("CPP") pilot program, (4) approval of revised depreciation rates applicable to electric and common plant in service, (5) approval of necessary and appropriate accounting relief, including authority to capitalize as rate base all cloud computing costs and defer to a regulatory asset amounts not already included in base rates that are incurred for third-party cloud computing arrangements ("CCAs"), (6) approval of an Alternative Regulatory Plan ("ARP") granting CEI South a waiver from 170 IAC § 4-1-16(f) to allow for remote disconnection for non-payment, and (7) other requests as described in its Petition initiating this Cause.

That same day CEI South also filed the direct testimony and attachments and financial exhibit (in Excel and PDF format) constituting its case-in-chief in this Cause, including direct testimony from the following witnesses:[1]

- Richard Leger, Interim Vice President, Natural Gas Business,[2] Southern Indiana Gas and Electric Company
- Chrissy M. Behme, Manager, Regulatory Reporting, CenterPoint Energy Service Company, LLC ("Service Company")
- Stephanie E. Gray, Manager, Indiana Electric Finance Planning and Analysis, Service Company
- Stephen R. Rawlinson, Director of Electric Engineering, Southern Indiana Gas and Electric Company
- Amy L. Folz, Director, Indiana High Voltage Operations, Southern Indiana Gas and Electric Company
- Gregg M. Maurer, Director, Indiana Electric Distribution Operations, Southern Indiana Gas and Electric Company
- F. Shane Bradford, Vice President of Power Generation Operations, Southern Indiana Gas and Electric Company
- Ronald W. Bahr, Vice President, Information Technology, Service Company
- Christopher G. Wood, Director of Process and Data Governance, Service Company

[1] On March 1, 2024, corrections were submitted to the direct testimony of witnesses Behme, Gray, Maurer, Bradford, Bahr, Williford, Kopp, and Bulkley. On March 7, 2024, corrections were submitted to the direct testimony of witnesses Rice and Forshey. On August 28, 2024, additional corrections were submitted to witness Bulkley's direct testimony. At the evidentiary hearing witnesses Leger and Rice made minor corrections to their direct testimony.

[2] On January 12, 2024, Petitioner late-filed witness Leger's Attachments RCL-3 and RCL-4, consisting of Proofs of Legal Notice Publication and Customer Notice, and certified that the legal notice required to be published pursuant to Ind. Code § 8-1-2-61(a) and Ind. Code § 8-1-2.5-6(d) had been published and posted to Petitioner's website.

- Deneisia R. Williford, Vice President of Total Rewards & Technology,[3] Service Company
- Jeffrey T. Kopp, Senior Managing Director, Energy & Utilities Consulting, 1898 & Co.
- John J. Spanos, President, Gannet Fleming Valuation and Rate Consultants, LLC[4]
- Ann E. Bulkley, Principal, The Brattle Group
- Brett A. Jerasa, Assistant Treasurer, Service Company
- Jennifer K. Story, Vice President of Tax, Service Company
- Michael E. Russo, Senior Forecast Consultant, Itron
- Justin L. Forshey, Director, Energy Solutions and Business Development – Midwest, Service Company
- John D. Taylor, Managing Partner, Atrium Economics
- Matthew A. Rice, Director, Indiana Electric Regulatory and Rates, Service Company

On December 5, 2023, Petitioner also filed a First Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which motion was granted on December 20, 2023. Petitioner filed a Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 28, 2024, which was granted on April 10, 2024. Petitioner filed a Third Motion for Protection and Nondisclosure of Confidential and Proprietary Information on April 4, 2024 and a Fourth Motion for Protection and Nondisclosure of Confidential and Proprietary Information on April 9, 2024, both of which were granted on April 12, 2024.

Also on December 5, 2023, Petitioner filed its Submission of Minimum Standard Filing Requirements.

Petitions to Intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC") and CenterPoint Energy Indiana South Industrial Group ("CEIS Industrial Group" or "Industrial Group" or "IG"), SABIC Innovative Plastics Mt. Vernon, LLC ("SABIC"), and the Common Council of the City of Evansville, Indiana ("Evansville Council"). The Commission issued docket entries granting each of said petitions to intervene; thus, all of the entities requesting intervention were made parties to this Cause.

On December 28, 2023, the Commission issued a docket entry establishing a procedural schedule and the test year for determining CEI South's projected operating revenues, expenses, and operating income, which was amended on January 17, 2024, following an unopposed Motion to Amend Procedural Schedule Docket Entry filed by the Indiana Office of Utility Consumer Counselor ("OUCC"). The January 17, 2024 docket entry established the forward-looking test year as the 12-month period ending December 31, 2025 and established the rate base cutoff date at the

[3] Ms. Williford's title changed on February 12, 2024 after the filing of her direct testimony. Pet. Ex. 10-R at 1.

[4] On January 5, 2024, Petitioner submitted a corrected version of the pre-filed testimony of witness Spanos and filed a motion to substitute the initial public version of witness Spanos' pre-filed testimony, which inadvertently included confidential information, with the now corrected version.

end of the test year, with associated rate base cutoff dates for each phase of CEI South's proposed three-phase increase.

Pursuant to Ind. Code § 8-1-2-61(b), two public field hearings were held in Evansville on February 29, 2024, at which time members of the public presented testimony.

On March 12, 2024, the OUCC, CEIS Industrial Group, CAC, Evansville Council, and SABIC prefiled their respective cases-in-chief and/or direct testimony.

The OUCC's prefiled case-in-chief included customer comments[5] and testimony and attachments from the following witnesses:[6]

- Michael D. Eckert, Director, Indiana Office of Utility Consumer Counselor's Electric Division
- Brian R. Latham, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Kaleb G. Lantrip, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Brittany L. Baker, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Jason T. Compton, Utility Analyst, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- Margaret A. Stull, Chief Technical Advisor, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- Cynthia M. Armstrong, Assistant Director, Indiana Office of Utility Consumer Counselor's Electric Division
- Brian Wright, Utility Analyst II, Indiana Office of Utility Consumer Counselor's Electric Division
- Greg L. Krieger, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Shawn Dellinger, Senior Utility Analyst, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC
- Dr. David D. Dismukes, Consulting Economist, Acadian Consulting Group
- April M. Paronish, Assistant Director, Indiana Office of Utility Consumer Counselor's Electric Division

The OUCC filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 12, 2024, which was granted on April 10, 2024.

[5] Customer comments were supplemented by motion filed April 24, 2024, which was granted by docket entry dated April 25, 2024.

[6] On March 19, 2024, a correction to redact additional information in witness Wright's testimony was filed. On March 28, 2024, corrections were submitted to witnesses Eckert, Lantrip, and Paronish. On April 10, 2024, corrections were submitted to the testimony of witnesses Paronish and Krieger. On April 25, 2024, corrections were submitted to the testimony of witnesses Eckert, Latham, Lantrip, Compton, Stull, and Krieger.

CEIS Industrial Group's prefiled case-in-chief included testimony and attachments from the following witnesses:

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.
- Jessica York, Principal, Brubaker & Associates, Inc.

CEIS Industrial Group filed a First and Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 12, 2024, and March 14, 2024, respectively, which were both granted on April 10, 2024.

The CAC's prefiled case-in-chief included testimony and attachments from the following witnesses[7]:

- Kerwin Olson, Executive Director, CAC
- Benjamin Inskeep, Program Director, CAC
- Justin Barnes, President, EQ Research, LLC

The Evansville Council prefiled testimony from Zachary Heronemus, President, Evansville Common Council.

SABIC prefiled the testimony and attachments of Kyra J. Coyle, Senior Manager, NewGen Strategies & Solutions, LLC.[8]

On April 9, 2024, CEIS Industrial Group filed the cross-answering testimony of Jessica A. York,[9] and the CAC filed the cross-answering testimony of Benjamin Inskeep and Justin Barnes.

Also on April 9, 2024, CEI South filed rebuttal testimony, exhibits, and workpapers of witnesses Leger, Behme, Rawlinson, Folz, Bradford, Bahr, Williford, Spanos, Bulkley, Jerasa, Story, Russo, Forshey, Taylor, Rice, and Jason A. Cunningham, Manager, Property Accounting, Service Company.[10] Revised Excel and PDF versions of the revenue requirement model were also filed.

On April 22, 2024, the OUCC filed a Motion to Strike certain portions of rebuttal testimony and attachments filed by CEI South. Pursuant to the Commission's briefing schedule set by docket entry on April 23, 2024, CEI South responded on April 25, 2024, and the OUCC replied on April 29, 2024. No objections were raised to the admission of the testimony that was subject to the Motion to Strike at the evidentiary hearing. Thus, the Motion to Strike is denied as moot.

On April 26, 2024, CEI South filed a Motion for a Two-Day Continuance to reschedule the evidentiary hearing set for April 30, 2024, to continue settlement discussions with the parties. The Commission, by docket entry, granted CEI South's Motion for a Two-Day Continuance on

[7] On March 22, 2024, CAC filed an opposed revised redaction to witness Barnes's testimony.

[8] A correction to redact additional information was filed on April 18, 2024.

[9] A revised version of witness York's cross-answering testimony was filed on April 24, 2024.

[10] Corrections to Mr. Rice's rebuttal testimony were filed on August 20, 2024. Mr. Rice noted further minor corrections to his rebuttal testimony at the evidentiary hearing on September 11, 2024.

April 26, 2024, and rescheduled the evidentiary hearing for May 2, 2024. On April 30, 2024, CEI South filed a Motion for an Additional One Day Continuance to further continue settlement discussions which the Commission granted by docket entry on May 1, 2024, and rescheduled the evidentiary hearing for May 3, 2024. A Third and a Fourth Motion for a Continuance to continue settlement discussions were filed by CEI South on May 2, 2024, and May 8, 2024, respectively. The Commission, by docket entry, granted the third continuance on May 2, 2024, and the fourth continuance on May 9, 2024 and rescheduled the evidentiary hearing date for May 14, 2024.

On April 29, 2024, the Commission issued a docket entry requesting information from CEI South, to which CEI South filed a public and confidential response on May 2, 2024 (Pet. Ex. 23 and 23-C).

On May 10, 2024, CEI South provided an update on settlement discussions and filed an uncontested motion to vacate the current procedural schedule and stated it would file a proposed settlement procedural schedule for the submission date of the non-unanimous settlement and further proceedings by May 14, 2024. On May 13, 2024, the Commission by docket entry granted the motion and vacated all further proceeding dates and deadlines in the procedural schedule and stipulated that should the parties not reach an agreement on a settlement procedural schedule by May 14, then a new evidentiary hearing date will be set for May 29, 2024.

On May 14, 2024, CEI South filed a settlement proposed procedural schedule agreed upon by CEI South, CEIS Industrial Group, and SABIC (collectively, the "Settling Parties") which was granted by docket entry on May 15, 2024. On May 17, 2024, the Settling Parties filed an updated settlement procedural schedule to include additional proceedings for the non-settling parties to contest the Settling Parties' procedural schedule as indicated in the Commission's May 15, 2024 docket entry. The updated settlement procedural schedule was granted by the Commission by docket entry on May 22, 2024, and the hearing set for May 29, 2024, was rescheduled as a settlement hearing set for September 3, 2024.

On May 20, 2024, CEIS Industrial Group filed settlement testimony for witnesses York and Gorman. That same day, CEI South filed settlement testimony, exhibits, and workpapers for witnesses Behme, Jerasa, Taylor, and Rice. On May 21, 2024, CEI South submitted the Settling Parties' Joint Exhibit No. 1, the Stipulation and Settlement Agreement among the Settling Parties ("Settlement Agreement" or "Settlement") that was inadvertently omitted from its initial filing on May 20, 2024. On August 23, 2024, and August 28, 2023 corrections were submitted to witness Rice's settlement direct testimony and attachments. Mr. Rice noted further minor corrections to his settlement testimony at the evidentiary hearing on September 11, 2024.

On July 19, 2024, the OUCC filed settlement testimony, exhibits, and workpapers in opposition of the Settlement for witnesses Eckert (Pub. Ex. 1-S), Compton (Pub. Ex. 5-S), Stull (Pub. Ex. 6-S), Wright (Pub. Ex. 8-S), Krieger (Pub. Ex. 9-S), Dellinger (Pub. Ex. 10-S), Dismukes (Pub. Ex. 12-S), and Paronish (Pub. Ex. 13-S).

On July 19, 2024, the CAC filed settlement testimony, exhibits, and workpapers in opposition of the Settlement for witnesses Inskeep and Barnes. On July 23, 2024, CAC submitted corrections to witness Inskeep's testimony.

On August 2, 2024, CEI South, the CEIS Industrial Group and SABIC filed settlement rebuttal testimony of witnesses Jerasa, Taylor, Rice, Gorman, York, and Coyle.

On August 26, 2024, the Commission issued a docket entry requesting information from CEI South, to which CEI South responded on August 28, 2024 (Pet. Ex. 24).

The Commission held an evidentiary hearing in this Cause starting on September 10, 2024 at 1:30 p.m. and continuing on September 11, 2024 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. CEI South, the OUCC, and Intervenors were present and participated through counsel. The testimony and exhibits of the parties were admitted into the record without objection.

Having considered the evidence of record and based on the applicable law, the Commission now finds:

1. Notice and Jurisdiction. Due, legal, and timely notice of the Petition filed in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Pet. Ex. 1, Attachments RCL-3 and RCL-4. Due, legal, and timely notices of the public hearings in this Cause were given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code ch. 8-1-2 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by Indiana law. CEI South is also a "utility" within the meaning of Ind. Code § 8-1-2-42.7(c). As defined in Ind. Code § 8-1-2.5-2, Petitioner is an "energy utility" and its electric service constitutes "retail energy service" as defined in Ind. Code § 8-1-2.5-3. Petitioner elects to become subject to the provisions of Ind. Code §§ 8-1-2.5-5 and 8-1-2.5-6, to the extent necessary. Accordingly, this Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Organization and Business. Petitioner is a public utility incorporated under Indiana law with its principal office located at 211 NW Riverside Drive, Evansville, Indiana. Petitioner is engaged in the business of rendering retail electric service solely within the State of Indiana under duly acquired indeterminate permits, franchises, and necessity certificates. CEI South owns, operates, manages, and controls, among other things, plant, property, equipment, and facilities (collectively, the "Utility Properties") that are used and useful for the production, storage, transmission, distribution, and furnishing of electric service to approximately 150,000 electric consumers in southwestern Indiana. Its service territory is spread throughout Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

3. Rate Base and Existing Rates. The net original cost of Petitioner's rate base on December 31, 2023, as adjusted, was projected to be approximately $1,827,211,874. The net original cost of Petitioner's rate base in service on December 31, 2024, as adjusted, was projected to be approximately $1,930,379,152. The net original cost of Petitioner's rate base in service on December 31, 2025, as adjusted, is projected to be approximately $2,820,468,760. Further, in order to properly serve the public located in its service area and to discharge its duties as a public utility, Petitioner continues to make numerous additions, replacements, and improvements to its utility systems.

Petitioner's existing base rates and charges for electric utility service were established in its 30-day filing #50171, effective June 1, 2018, pursuant to the Commission's February 16, 2018 order in Cause No. 45032, its investigation into the impacts on Indiana utilities and customers resulting from the December 22, 2017 Tax Cuts and Jobs Act of 2017 ("TCJA"), as further reduced in Petitioner's 30-day filing #50548, effective July 1, 2022, to give effect to the repeal of the Utility Receipts Tax. The rates approved effective June 1, 2018 and July 1, 2022, reduced CEI South's existing base rates and charges for electric utility service established in its most recent retail base rate case order issued on April 27, 2011, in Cause No. 43839. More than 15 months have passed since the filing date of Petitioner's last request for a general increase in its basic rates and charges.

Pursuant to Ind. Code § 8-1-2-42(d), CEI South files a quarterly Fuel Adjustment Clause ("FAC") proceeding in Cause No. 38708 FAC XXX, to adjust its rates to account for fluctuations in its fuel and purchased energy costs.

CEI South files an annual proceeding in Cause No. 43405 DSMA XX to recover, via its approved Demand Side Management Adjustment ("DSMA"), demand side management costs, including costs associated with the direct load control inspection and maintenance program, performance incentives, and lost margins.

CEI South files an annual proceeding in Cause No. 44909 CECA XX to recover via its approved Clean Energy Cost Adjustment ("CECA") eligible costs of approved clean energy projects under Ind. Code ch. 8-1-8.8, including (a) engineering and project management, management and administration, permitting, contractor site preparation, equipment, and installation costs during construction; and (b) depreciation expense, post-in-service carrying costs ("PISCC"), taxes, and operation and maintenance ("O&M") expense once the projects are placed in service. CEI South's current CECA mechanism includes a component to pass back credits resulting from the Inflation Reduction Act of 2022 ("IRA"). As discussed below, CEI South proposes to remove this component from the CECA mechanism and include it in a separate TAR. In addition, CEI South uses the CECA mechanism to pass on to customers revenues from the sale of renewable energy credits ("RECs") related to CEI South's various renewable energy projects.

CEI South files annual Environmental Cost Adjustment ("ECA") proceedings in Cause No. 45052 ECA XX to effectuate timely recovery of 80% of its federally mandated costs (as defined by Ind. Code § 8-1-8.4-2) attributable to the following five compliance projects: (a) federally mandated requirements related to CEI South's Culley Unit 3 Generating Station ("Culley 3 Project"); (b) clean coal technology projects at CEI South's Culley Unit 3 and Warrick Unit 4 (collectively the "MATS Projects"); (c) federally mandated requirements to close CEI South's A.B. Brown ash pond ("Brown Pond Project"); (d) federally mandated compliance projects including a dry fly ash loading facility ("Dry Ash Compliance Project") and federally mandated lined ponds at the A.B. Brown and F.B. Culley generating stations to handle coal-pile runoff, flue gas desulfurization wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's coal combustion residuals ("CCR") rules ("Pond Compliance Project")

(collectively, "CCR Compliance Projects"); and (e) federally mandated requirements to close by removal ("CBR") CEI South's F.B. Culley east ash pond (the "CBR Project").[11]

CEI South files annual Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") proceedings in Cause No. 43354 MCRA XX to recover costs associated with nonfuel-related MISO Day 1, Day 2, and Ancillary Services Market costs. CEI South has proposed updates for the MCRA as described in the direct testimony of Matthew A. Rice.

CEI South files annual Reliability Cost and Revenue Adjustment ("RCRA") proceedings in Cause No. 43406 RCRA XX to track the differences between certain actual costs and revenues and the amounts of those costs and revenues included in CEI South's base rates. RCRA cost and revenue components include the non-fuel component of purchased power, cost of Environmental Emission Allowances ("EEAs"), Interruptible Sales billing credits, the retail sharing portion of Wholesale Power marketing margins, the margin from Municipal Wholesale Sales, and the retail portion of the margin from EEA sales (net of cost). CEI South has proposed updates for the RCRA as described in the direct testimony of Matthew A. Rice.

Pursuant to the Commission's September 20, 2017 order in Cause No. 44910, CEI South files a semi-annual proceeding in Cause No. 44910 TDSIC XX to recover 80% of approved capital expenditures and transmission, distribution, and storage system improvement costs incurred in connection with CEI South's TDSIC Projects through its transmission, distribution and storage system improvement charges ("TDSIC") Rider. CEI South's current TDSIC mechanism includes a component to pass back credits resulting from changes in the federal tax rates under the TCJA. As discussed below, CEI South proposes to remove this component from the TDSIC mechanism and include it in the TAR. CEI South's Cause No. 44910 TDSIC Plan expired December 31, 2023, and CEI South's new TDSIC Plan was approved in Cause No. 45894 on December 27, 2023.

As a result of the Commission's financing Order in Cause No. 45722, dated January 4, 2023, CEI South was authorized to implement, collect, and receive Securitization Charges associated with the securitization of A.B. Brown Units 1 and 2 pursuant to its Securitization of Coal Plants Tariff. Pursuant to that financing order, the accumulated deferred income taxes ("ADIT") associated with the retiring A.B. Brown Units 1 and 2 are segregated from all other ADIT and not included in the calculation of Petitioner's capital structure or otherwise used in finding CEI South's authorized return in future rate cases. The financing order also established a Securitization ADIT Credit tariff to provide an annual credit to customers for the ADIT associated with A.B. Brown Units 1 and 2. In addition, the financing order required that the excess ADIT associated with A.B. Brown Units 1 and 2 be amortized and returned to customers over the life of the related Securitization Bonds. The excess accumulated deferred income taxes ("EADIT") resulting from the TCJA is being flowed back to customers via the TDSIC. As described below, CEI South is proposing to continue to flow back this EADIT over the life of the bonds through the new TAR instead of the TDSIC. The Securitization Rate Reduction ("SRR") tariff was a temporary rider established in Cause No. 45722 to provide customers with a credit for A.B. Brown net plant.

[11] CEI South's request for a Certificate of Public Convenience and Necessity for the CBR Project was pending when this Cause was filed but has since been approved by the Commission's February 7, 2024 order in Cause No. 45903.

CEI South proposes to zero out (subject to variances) the SRR tariff in customer rates in this case, as the A.B. Brown Units 1 and 2 will no longer be included in base rates.

4. Test Year. As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period using projected data. As provided in the Commission's December 28, 2023 and January 17, 2024 Docket Entries, the test year to be used for determining Petitioner's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2025. The historical base period is the 12-month period ending December 31, 2022.

5. CEI South's Requested Relief. In its case-in-chief, Petitioner requested Commission approval of an overall increase in rates and charges for electric service that would produce additional electric revenues of approximately $118,757,693, which would reflect an overall revenue increase of 16.02% from the rates that would have been in effect had this case not been filed. As detailed in its case-in-chief, Petitioner also requested Commission approval of a new schedule of rates and charges, general rules and regulations, and riders applicable to electric utility service, revised depreciation rates applicable to electric and common plant in service; approval of a mechanism to modify rates prospectively for changes in federal or state income tax rates; and other necessary and appropriate accounting relief. On rebuttal, Petitioner revised its proposed revenue requirement increase to $115,445,697. In settlement, the proposed revenue requirement increase was further revised to $80,009,617.

Petitioner's current electric depreciation rates were approved by the Commission's order in Cause No. 43111 on August 15, 2007, and subsequently re-authorized (with a modification to the depreciation rate applicable to the Blackfoot landfill gas generating station) in Cause No. 43839 (April 27, 2011). Petitioner's current common plant depreciation rates were approved by the Commission's order in Cause No. 45447 on October 6, 2021. Depreciation rates for Petitioner's combustion turbine project (the "CT Project") and Posey Solar project ("Posey Solar") were approved by the Commission's orders in Cause No. 45564 on June 28, 2022, and Cause No. 45847 on September 6, 2023, respectively. Petitioner is seeking approval of new electric and common plant depreciation rates in this Cause, based on the study sponsored by witness Spanos, except that the rates for the CT Project and Posey Solar shall remain unchanged from what was approved in Cause Nos. 45564 and 45847, respectively.

Petitioner, in its case-in-chief, made additional requests for the approval of new riders, including a new TAR, a new Green Energy Rider ("Rider GE"), an aggregation demand response rider ("Rider ADR"), a CPP pilot program, regulatory accounting treatment for third-party CCAs, an ARP for a waiver from 170 IAC 4-1-16(f) to allow remote disconnections for non-payment, and other requests, all as more particularly described elsewhere in this order. Pet. Ex. 1, Attachment RCL-1 (Petition).

6. Overview of the Evidence.

A. CEI South's Case-in-Chief. Mr. Leger described CEI South's electric utility operations. Pet. Ex. 1 at 3-4. He discussed the guiding principles that inform CEI South's provision of electric service, and the challenges CEI South has faced. He discussed the primary drivers of CEI South's request for rate relief in this proceeding, primarily the TDSIC statutory requirements, rate base growth, and the industry transformation. He also explained the reasons CEI South's requested rate increase is reasonable and necessary. He discussed the Five Pillars of reliability, resiliency, stability, affordability, and environmental sustainability codified in Ind. Code § 8-1-2-0.6 as the framework to be used to guide decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs. He discussed how they have been considered by CEI South when developing its rate proposal. He also explained how the Five Pillars can sometimes conflict and what CEI South has done to specifically address affordability, including customer assistance and federal funding.

Ms. Behme supported CEI South's revenue requirement, explained the forecasted 2025 test year for ratemaking purposes and the pro forma adjustments to the test year, and sponsored the details around the phased in approach to implementing rates under Ind. Code § 8-1-2-42.7 and Commission General Administrative Order 2013-05. She also supported certain requests for deferred accounting treatment. Pet. Ex. 2.

Ms. Gray discussed and supported the 2025 unadjusted test year forecast. She also supported the 2024 – 2025 unadjusted Income Statement and Balance Sheet CEI South used in the development of the revenue requirement calculation. Pet. Ex. 3.

Mr. Rawlinson discussed CEI South's overall approach to transmission and distribution capital planning. He also provided information on transmission and distribution capital expenditures completed or planned from June 30, 2009, the rate base cutoff date in CEI South's last electric rate case (Cause No. 43839) (the "43839 rate base cutoff"), through the end of the 2025 test year. He also provided information on CEI South's electric system reliability performance. Pet. Ex. 4.

Ms. Folz discussed CEI South's ongoing reliability initiatives related to Advanced Metering Infrastructure ("AMI") capabilities and supported CEI South's request for ARP treatment and a waiver of requirements under 170 IAC 4-1-16(f). Ms. Folz further described CEI South's electric transmission system, substation, and underground network inspection programs. Additionally, she provided an overview of CEI South's Transmission System Operations and MISO affairs. Pet. Ex. 5.

Mr. Maurer described CEI South's commitment to electric service reliability and its operations and maintenance ("O&M") programs, including its overhead and underground maintenance programs, Vegetation Management Program, and Emergency Operations Plan. Pet. Ex. 6.

Mr. Bradford discussed CEI South's Generation Transition Plan and provided a summary of the material generation capital investments that have been made since the 43839 rate base cutoff through the end of the 2025 test year. He described CEI South's plan to give its customers 100%

of the Wholesale Power Market ("WPM") sales margins opportunity rather than the present sharing mechanism and provided an update on CEI South's Urban Research Living Center ("ULRC") project. Pet. Ex. 7.

Mr. Bahr described the information technology ("IT") services provided by the Service Company to CEI South, along with major enterprise-wide programs and associated charges. Pet. Ex. 8.

Mr. Wood described the services provided, and costs allocated, to CEI South by the Service Company and Vectren Utility Holdings, LLC ("VUH") and how the allocation process is managed. He also described the Service Level Agreements between Service Company and CEI South; the affiliate agreement between CEI South and VUH; the annual budgeting process; and controls in place to ensure that costs are managed, controlled, and billed properly. Pet. Ex. 9.

Ms. Williford discussed and supported CEI South's employee compensation and benefits. Pet. Ex. 10.

Mr. Kopp sponsored CEI South's Decommissioning Cost Study for CEI South's power generation assets. Pet. Ex. 11.

Mr. Spanos supported the updated electric and common plant depreciation study and new electric and common plant depreciation accrual rates. Pet. Ex. 12.

Ms. Bulkley supported CEI South's requested return on equity ("ROE") and appropriateness of the capital structure and projected cost of debt. Pet. Ex. 13.

Mr. Jerasa presented the components of CEI South's capital structure and the reasonableness of their projected balances and weighting. In addition, he supported CEI South's projected cost of debt and the overall weighted average cost of capital. Pet. Ex. 14.

Ms. Story discussed the impact of the IRA and addressed the corporate alternative minimum tax ("CAMT") and CEI South's proposed TAR. Ms. Story also supported the computation of the income tax expense included in CEI South's cost of service determination and addressed the accumulated deferred income taxes and excess accumulated deferred income tax regulatory liability balances included in CEI South's cost of capital calculation. She sponsored the property tax forecast and the Medicare Part D regulatory liability and associated amortization adjustment. Pet. Ex. 15.

Mr. Russo supported the projected class-level 2025 Test-Year sales and customer forecasts. Pet. Ex. 16.

Mr. Forshey discussed CEI South's Large Electric customers and the importance of attracting new large customers to southwestern Indiana. He provided support for proposed new and modified riders and CEI South's Energy Efficiency and Demand Side Management ("DSM") initiatives. Pet. Ex. 17.

Mr. Taylor presented the results of the Cost-of-Service Study ("COSS") and rate design, and discussed its effect on rates. Pet. Ex. 18.

Mr. Rice sponsored the proposed rates within the Tariff and proposals associated with new and existing adjustment mechanisms. He described the proposed Phase 1, Phase 2, and Phase 3 rate implementation proposals and supported CEI South's request for a Green Energy Rider (Rider GE) as well as a CPP pilot. Pet. Ex. 19.

Petitioner also provided its Financial Exhibit in support of its requested relief in this proceeding in Excel (Pet. Ex. 20) and PDF formats (Pet. Ex. 21).

B. OUCC and Intervenors' Cases-in-Chief. The OUCC and intervenors proposed several adjustments to CEI South's proposed revenue requirements and took issue with numerous other components of CEI South's case-in-chief and proposed rate increase.

i. OUCC's Case-in-Chief. The OUCC proposed an ROE of 8.8% (reduced from 9.00% based on the OUCC's claims of issues with reliability, customer satisfaction, and challenges faced by OUCC in analyzing Petitioner's requests). Pub. Ex. 10 at 3 and Pub. Ex. 1 at 25. The OUCC also recommended certain operating revenue and expense adjustments. *See, e.g.*, testimony of OUCC witnesses Eckert (Pub. Ex. 1), Latham (Pub. Ex. 2), Lantrip (Pub. Ex. 3), Baker (Pub. Ex. 4), Compton (Pub. Ex. 5), Stull (Pub. Ex. 6), Armstrong (Pub. Ex. 7), and Krieger (Pub. Ex. 9). After corrections to testimony, the OUCC ultimately concluded that Petitioner justified an increase of $48.315 million. Pub. Ex. 1 at 2. The OUCC further recommended the Commission deny CEI South's proposed increases to its monthly customer charges for residential and small business customers and approve modifications to certain depreciation rates. Pub. Ex. 12 at 71; Pub. Ex. 11 at 3.

Mr. Eckert testified regarding the OUCC's evaluation and analyses of Petitioner's revenue requirement requests contained in its case in-chief. He identified and addressed the OUCC's concerns related to affordability, risk assessment, and storm response. He also addressed the Five Pillars of affordability, reliability, resiliency, stability, and environmental sustainability and explained how cost trackers are shifting the risk of operating expense increases and capital expenditures from CEI South to ratepayers. He explained and supported specific adjustments and recommendations regarding certain CEI South requests for fuel cost, fuel inventory, Culley 3 outage capital expenditures, securitization expense, and amortization expense. Pub. Ex. 1.

Mr. Latham sponsored the OUCC's overall revenue requirement recommendation and testified regarding revenue requirement adjustments. He incorporated the impact of the other OUCC witnesses' recommendations in his revenue requirement calculations. He presented the OUCC's capital structure analysis and recommended a 6.29% weighted average cost of capital ("WACC") that includes the ROE OUCC witness Dellinger recommends. In addition, he calculated the OUCC's depreciation expense and recommended accumulated depreciation using Mr. Garrett's proposed depreciation rates. Pub. Ex. 2.

Mr. Lantrip addressed CEI South's request to embed in base rates Petitioner's CECA and RCRA investments. He recommended the Commission deny Petitioner's request to include approximately $219,348 of costs related to the CECA's ULRC. Witness Lantrip also discussed CEI South's affiliate company arrangements with CenterPoint Shared Services and VUH. Pub. Ex. 3.

Ms. Baker addressed Petitioner's adjustments to payroll expenses, including incentive benefits, and deferred Medicare tax liability. She recommended the Commission: 1) deny Petitioner's requested competitive pay adjustment; and 2) deny Petitioner's requested $1,737,007 in deferred Medicare tax liability. Pub. Ex. 4.

Mr. Compton recommended 1) rate case expense be shared equitably between shareholders and ratepayers because shareholders will benefit from new rates; 2) an adjustment to sponsorship expense; 3) removal of CEI South's IT investment and related O&M expenses from the revenue requirement; and 4) denial of CEI South's requested accounting treatment for cloud computing arrangement costs. Mr. Compton testified regarding the difficulties he had reviewing CEI South's case-in-chief. Pub. Ex. 5.

Ms. Stull addressed CEI South's proposals regarding 1) the TAR; 2) recovery of a return on any increase or decrease to the balance of the tax regulatory asset related to CAMT occurring between rate cases; 3) rate increase implementation before the start of CEI South's forward-looking test year; 4) implementation of interim rate increases between Phases 2 and 3 to reflect projected rate base additions; and 5) the process for implementing rates in each phase of the proposed rate increase. She discussed the OUCC's concerns regarding CEI South's presentation of its accounting schedules and revenue requirement in its case-in-chief, including a lack of evidence support Petitioner's requests and CEI South's non-compliance with GAO 2013-05 and 2015-05. Pub. Ex. 6.

Ms. Armstrong addressed several environmental-compliance-cost-related rate base items and O&M expenses CEI South included in its rate request, including 1) emission allowance inventory; 2) test year emission allowance expense; 3) the Culley East Ash Pond Closure by Removal Project costs; 4) additional costs CEI South incurred with respect to the ULRC; 5) unexplained land acquisitions around the A.B. Brown Generating Plant; and 6) CEI South's adjustment to decrease test year Integrated Resource Planning ("IRP") expense. Pub. Ex. 7.

Mr. Wright discussed CEI South's Rider GE and Rider ADR proposals and recommended changes to Rider GE and associated tariff language to ensure the program does not negatively affect affordability for ratepayers. He recommended the denial of Rider ADR based on a lack of basic, critical information on how the program will function. Pub. Ex. 8.

Mr. Krieger analyzed CEI South's capital investment request and discussed how project managers and project engineers distinguish between capital investment and maintenance costs. He described how an approved prudent capital investment may not be prudent in practice and recommended a $150.7 million reduction to the Steam Production Plant costs. Pub. Ex. 9.

Mr. Dellinger recommended an ROE of 9.00% for CEI South. Pub. Ex. 10.

Mr. Garrett analyzed CEI South's depreciable assets and developed reasonable depreciation rates and annual accruals. Specifically, he recommended the Commission: 1) remove $1.6 million in contingency costs; 2) adjust Transmission and Distribution ("T&D") service lives which reduces depreciation expense by $2.1 million; and 3) adjust net salvage rates for several T&D accounts by $1.4 million. Pub. Ex. 11.

Dr. Dismukes addressed Petitioner's proposed allocated cost-of-service study ("ACOSS"), revenue distribution, rate design, rate adjustment proposals, critical peak pricing, and related tracker mechanisms. He recommended CEI South's current residential and small commercial customer charges remain unchanged. He also recommended elimination of the current fixed component for monthly TDSIC charges for Rates RS, SGS, and water heating service customers. Pub. Ex. 12.

Ms. Paronish discussed CEI South's remote disconnection proposal, bill issues, and certain aspects of Petitioner's CPP proposal. Pub. Ex. 13.

ii. Industrial Group Case-in-Chief. Industrial Group witness Gorman recommended adjustments to Petitioner's revenue requirement. He testified that CEI South's claimed three-phase revenue increase is overstated by $29.5 million. IG Ex. 1 at 3. He took issue with the number of customers and the sales forecast used to calculate the Phase 3 revenue deficiency. He recommended an ROE of 9.20% which produces an overall return of 6.46%. He also rejected the inclusion of the prepaid pension asset in CEI South's capital structure. Mr. Gorman proposed a shorter amortization period to return Indiana EADIT and recommended removing a portion of the incentive compensation costs from cost of service. He recommended the Commission deny CEI South's request to establish a regulatory asset for future third-party CCAs, recommended removing the full revenue requirement impact from the test year for all capital costs associated with the 2022-2023 Culley 3 outage, if the Commission ultimately finds that CEI South was imprudent in Cause No. 38708 FAC 137 S1, and recommended the Commission reform the limitation of liability provision in CEI South's tariff.

Industrial Group witness York testified that CEI South's allocation of production costs on the basis of a 4-Coincident Peak ("4CP") demand is consistent with CEI South's historic practice, cost-causation, and sound ratemaking, and should be approved. IG. Ex. 2 at 3. She said CEI South's proposal to deviate from its method of allocating transmission costs by shifting to a 12-Coincident Peak ("12CP") basis should be rejected. In addition, she said CEI South's ACOSS does not accurately measure its cost of providing service to each customer class, due to an inaccurate classification and allocation of distribution costs. She explained that CEI South's ACOSS fails to classify a portion of costs included in Federal Energy Regulatory Commission ("FERC") Accounts 364, 365, 367, and 368 as customer related. She recommended an alternate revenue apportionment based on the results of her modified ACOSS, which reflects a more reasonable and correct classification and allocation of distribution costs in FERC Accounts 364, 365, 367, and 368, and uses a 4CP allocation of transmission costs. She said CEI South's FAC should be modified to recognize the capacity component of renewable resource costs. She explained that the capacity component of renewable resource costs should be allocated across rate classes using the production demand allocator established in CEI South's most recent rate case, and the renewable resource capacity costs should be recovered from Large Power Service ("LP"), Backup, Auxiliary, and Maintenance Power Service ("BAMP"), and High Load Factor ("HLF") customers using a demand charge.

iii. CAC's Case-in-Chief. CAC witness Olson discussed the reaction of the public and elected leaders to Petitioner's rate request. CAC Ex. 1. He presented resolutions and letters from impacted southwestern Indiana local units of government as attachments and cited local news articles. *Id.*, Attachments KO-2 and KO-3. He recommended the Commission strongly

consider the testimony presented in the field hearings in this Cause and reject Petitioner's proposals in this proceeding.

CAC witness Inskeep addressed the utility unaffordability crisis generally and specifically for CEI South customers. He testified about certain revenue requirement issues, rate design issues and the fixed charge component in the TDSIC rider, the proposed Cloud Computing request, the various demand response proposals, cost allocation for the Texas Gas Transmission ("TGT") pipeline, CEI South's request to disconnect customers remotely, and miscellaneous charges and fees. CAC Ex. 2.

CAC witness Barnes addressed base rate case and tracker allocation, rate impact mitigation, special contract issues, and residential rate issues. CAC Ex. 3.

iv. Evansville and SABIC's Cases-in-Chief. Evansville Council witness Heronemus provided a copy of the C-2024-05 Resolution of the Common Council of the City of Evansville and said it is the Council's position and request that the Commission reject Petitioner's requested rate increase. Evansville Council Ex. 1 at 1, Zachary Heronemus Attachment.

SABIC witness Coyle explained the service SABIC receives from CEI South and identified concerns with CEI South's proposed rates that would be charged to Rate Schedule Base, BAMP customers. She also identified concerns with CEI South's proposed ACOSS. SABIC Ex. 1 at 4.

C. CEI South Rebuttal. Mr. Leger responded to direct testimony from the OUCC, CAC, the Evansville Council, and comments from the public field hearing and addressed affordability. Pet. Ex. 1-R.

Ms. Behme responded to the direct testimony of various witnesses from the OUCC, CAC, IG, and SABIC. She addressed the changes to CEI South's revenue requirement occurring from corrections identified by CEI South as well as the changes from accepted positions recommended by intervening parties. She responded to certain recommendations of disallowance or treatment that CEI South does not agree with, including certain plant in service and corresponding accumulated reserve suggestions; trade association expenses; rate case expenses; shared services adjustment; deferred liability adjustment; regulatory asset for cloud computing arrangements; phase implementations; and transparency and case presentations. She also identified and described Petitioner's Exhibit No. 20-R, which is the revenue requirement model. She sponsored the actual rate base and capital structure as of December 31, 2023. Pet. Ex. 2-R.

Mr. Rawlinson addressed concerns raised by OUCC witness Eckert regarding CEI South's reliability, resilience, and stability (as they relate to the Five Pillars). He also addressed concerns raised by SABIC witness Coyle regarding CEI South's cost allocation and rates for Backup Transmission Service. Pet. Ex. 4-R.

Ms. Folz responded to the direct testimony of OUCC witness Eckert regarding his recommendations on storm response communications and reporting. She also responded to the direct testimony of OUCC witness Paronish and CAC witness Inskeep regarding their recommendations on CEI South's proposed remote disconnection for nonpayment program. Pet. Ex. 5-R.

Mr. Bradford responded to IG witness Gorman, who recommended that the Commission deny recovery of specific Power Generation capital investments; to OUCC witness Eckert, who recommended CEI South adjust the fuel inventory level; and to OUCC witness Armstrong who recommended the Commission deny recovery of the remaining ULRC project costs. In addition, Mr. Bradford responded to OUCC witness Baker's statement that CEI South has not had issues with filling and maintaining staffing positions. Pet. Ex. 7-R.

Mr. Bahr responded to OUCC witness Compton's recommendation that the Commission disallow IT investments in rate base along with test year costs related to the SAP S/4HANA Transformation Program and Cloud Computing Arrangement. Pet. Ex. 8-R.

Ms. Williford responded to Ms. Baker and Mr. Gorman regarding certain compensation costs CEI South is seeking to recover. She testified that CEI South's requested levels of compensation costs are reasonable and necessary, given that the compensation and benefits offered by CNP[12] are necessary to attract and retain employees at all levels. Pet. Ex. 10-R.

Mr. Spanos responded to OUCC witness Garrett and addressed adjustments proposed by the OUCC to the depreciation expense calculated in CEI South's Depreciation Study. These adjustments include eliminating a contingency factor in the calculation of decommissioning costs and making changes to service life and net salvage estimates to a few transmission and distribution accounts. Pet. Ex. 12-R.

Ms. Bulkley responded to the direct testimony of OUCC witnesses Dellinger and Eckert, Mr. Gorman, and Mr. Inskeep regarding the just and reasonableness of Petitioner's proposed ROE and the appropriate capital structure for CEI South in this proceeding. Pet. Ex. 13-R.

Mr. Jerasa responded to Mr. Gorman's commentary on CEI South's equity in its capital structure and his recommendation that the prepaid pension asset and other post-employment benefits be removed from the capital structure. His testimony also responded to OUCC witness Stull regarding the CAMT impact on credit metrics. Pet. Ex. 14-R.

Ms. Story responded to Ms. Stull's recommendation that CEI South's proposal to include the CAMT in its proposed TAR should be denied. She also responded to Ms. Stull's and Mr. Gorman's recommendations regarding Indiana state income tax EADIT. Pet. Ex. 15-R.

Mr. Russo responded to Mr. Gorman's recommendation that the 2025 test-year residential average use should be 866 kWh per month and commercial average use 5,106 kWh per month. Pet. Ex. 16-R.

Mr. Forshey responded to OUCC witness Wright's concerns with the proposed Rider ADR, and the concerns of OUCC witnesses Paronish and Dismukes related to the Critical Peak Pricing Pilot. He also responded to SABIC witness Coyle's direct testimony regarding Section 24 contracts. Pet. Ex. 17-R.

[12] CNP is used in Ms. Williford's testimony to refer to CenterPoint Energy, Inc. and its affiliates, which include the Service Company and CEI South. Pet. Ex. 10 at 1; Pet. Ex. 10-R at 1.

Mr. Taylor addressed specific sections of the direct testimony submitted by other parties and elaborated on the updates made to CEI South's ACOSS and the integration of CEI South's revised revenue requirement. He covered the areas of ACOSS, revenue distribution and special contract revenue treatment, rate design and customer charge, and tracker allocation. Pet. Ex. 18-R.

Mr. Rice addressed concerns raised by the public at the field hearing; responded to testimony from other parties regarding affordability; responded to suggestions from OUCC witness Wright regarding the proposed Green Energy Rider; responded to the OUCC's opposition to Rider ADR; responded to OUCC objections to the CPP Pilot; addressed customer satisfaction concerns; responded to issues raised by SABIC witness Coyle concerning Rate BAMP; and addressed a number of other isolated issues raised by various witnesses. Pet. Ex. 19-R.

Mr. Cunningham responded to Mr. Krieger's recommendation to reduce rate base by $104.7 million in Steam Production Plant capital investment.

D. Cross-Answering Testimony. Certain intervenors filed cross-answering testimony on various topics. IG witness York responded to concerns about rate affordability raised by Dr. Dismukes on behalf of the OUCC and Mr. Barnes on behalf of the CAC. She responded to Dr. Dismukes's and Mr. Barnes's recommendations on the allocation of production and distribution-related investment cost in CEI South's ACOSS, as well as their recommendations with respect to the apportionment of any revenue requirement increase granted in this case. She responded to CAC witness Inskeep regarding his request for the Commission to direct CEI South to implement an Affordable Power Rider, and to fund such a program via an energy charge for all customers. She addressed the recommendations of CAC witness Barnes regarding the allocation of costs within certain tracker mechanisms, including costs associated with the TGT Pipeline, the ECA, and the CECA. She also responded to Mr. Barnes's recommendations regarding Section 24 contract customers. IG Ex. 3 at 2-29.

CAC witness Inskeep provided cross-answering testimony concerning other parties' positions on overarching issues and demand response. CAC Ex. 4 at 1-15. CAC witness Barnes provided cross-answering testimony regarding IG witness York, SABIC witness Coyle, and OUCC witness Dismukes positions on cost allocation, reasonable methodology for rate impact mitigation, and the appropriate classification of distribution system costs. CAC Ex. 5 at 1-45.

7. Settlement Agreement; Commission Discussion and Findings.

A. Overview.

i. Settling Parties' Testimony. CEI South witness Rice sponsored the Stipulation and Settlement Agreement ("Settlement Agreement" or "Settlement") entered into by the CEIS Industrial Group, SABIC, and CEI South. He opined that the Settlement Agreement represents reasonable resolutions of all issues in this proceeding and supports a Commission order adopting the terms. Pet. Ex. 19-S at 1.

Mr. Rice provided the following outline of the Settlement Agreement:

- Section A provides background on CEI South's current rates and charges and the status of the rate case pending under this Cause.

- Section B.1 discusses the two phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service.

- Section B.2 addresses the stipulated revenue requirement, revenue increase and authorized net operating income ("NOI").

- Section B.3 discusses the resolution of issues impacting the agreed upon revenue requirement and resulting rate increase, including: (a) original cost rate base; (b) other rate base items; (c) capital structure; and (d) fair return.

- Section B.4 addresses the resolution of issues related to depreciation rates and amortization expense, respectively.

- Section B.5 addresses the resolution of issues related to pro forma revenues and expenses, including: (a) base cost of fuel, (b) interruptible sales billing credits, (c) capacity purchase costs, and (d) O&M expense.

- Section B.6 addresses the stipulation and agreement for the accounting treatment for cloud computing costs.

- Section B.7 describes proposed riders, including (a) CPP Pilot, Rider ADR, and Green Energy Rider and (b) TAR.

- Section B.8 describes other tariff matters, including: (a) Interruptible Contract ("IC") and Interruptible Option ("IO") Riders and (b) limitation of liability provision in the tariff.

- Section B.9 addresses Petitioner's proposed ARP for Remote Disconnection.

- Section B.10 addresses customer protection provisions, including: (a) Low Income Home Energy Assistance Program ("LIHEAP") Customer Deposits, (b) residential late payment charge, (c) LIHEAP Qualified Participant fees and reporting, and (d) disconnections / reconnection.

- Section B.11 discusses CEI South's commitment to collect data on residential customer housing types and analyze cost differentials between single- and multi-family rate residential customers in advance of its next rate case.

- Section B.12 discusses CEI South's commitment to customer bill transparency.

- Sections B.13 and B.14 address cost of service, cost allocation, and rate design.

- Section B.15 discusses other disputed items, including BAMP rates and all other items.

- Section C addresses the effect, scope, and approval of the stipulation.

Pet. Ex. 19-S at 5-6.

Under the Settlement Agreement, the Settling Parties have agreed that CEI South's requested rate increase should be reduced significantly below CEI South's request. The revenue requirement increase in the Settlement Agreement is closer to that proposed by the OUCC in its case-in-chief than CEI South's rebuttal position and lower than the Industrial Group's litigation position. The Settlement Agreement makes multiple other changes to CEI South's requested relief in this Cause. As reflected in Section B.2 of the Settlement Agreement and Settlement Agreement Appendix A, the Settling Parties have agreed to a net revenue increase of $80,009,617, which is a decrease of $38,748,076 from the amount requested in Petitioner's original case-in-chief, and an ROE of 9.8%.

Mr. Rice expressed his opinion that the Settlement Agreement is in the public interest, reasonably resolves all issues in this case without further expenditure of the time and resources of the Commission and the parties in the litigation of these matters and should be approved in its entirety by the Commission, without modification. Mr. Rice stated that the Settlement Agreement represents the result of arm's-length negotiations by stakeholders with differing views on the issues raised in this case. He explained that Settling Parties' experts were involved with legal counsel in the development of both the conceptual framework and the specific terms of the Settlement Agreement. The Settling Parties devoted many days to discussions, collaborative exchange of information, and settlement negotiations.

Mr. Rice stated that while the Settling Parties agree and represent that the Settlement resolves all issues in this case, three parties — the OUCC, the CAC and the Evansville Council — have not joined in the Settlement Agreement. Pet. Ex. 19-S at 2. He testified that the non-settling parties were all copied on communications and terms throughout the negotiation of the Settlement Agreement and were given the opportunity to weigh in on the terms of the settlement during these negotiations. Mr. Rice noted that, while these parties did not join the Settlement Agreement, the Settling Parties recognized the issues they raised in this proceeding and addressed those concerns by including many of the positions from the OUCC and CAC in the Settlement terms. Mr. Rice also testified CEI South reviewed recent settlements with other Indiana investor-owned utilities ("IOUs") and included many consumer protections listed in those agreements.

Mr. Rice testified that it is important to recognize that the Settlement Agreement is presented as a complete negotiated package of terms that, taken as a whole, reflects compromise and the give and take of negotiations. He explained Section C.1 makes clear that the Settlement Agreement is the result of negotiations and compromise reached during those negotiations, and that neither the making of the Settlement Agreement nor any of its provisions shall constitute an admission or waiver by any Settling Party in any proceeding other than this case, now or in the future, nor shall it be cited as precedent. He opined that the Settlement Agreement is supported by and within the scope of the evidence presented by the Settling Parties. He stated that, taken as a whole, the Settlement Agreement represents the result of extensive, good faith, arm's-length

negotiations reflecting a fair and balanced outcome of the rate case issues reached among parties having divergent interests. CEI South's and the other Settling Parties' proposals were modified through the negotiations. The Settlement Agreement reasonably addresses the concerns raised in this proceeding, limits controversy, and provides a balanced, cooperative outcome of the issues in this Cause. He stated CEI South respectfully asks the Commission to issue an order approving the Settlement Agreement in its entirety, without modification, so that new rates may be placed into effect at the earliest possible time after the beginning of the test year.

CEI South witness Behme presented Petitioner's Exhibit No. 20-S, which provides CEI South's revised revenue requirement request based upon the terms of the Settlement Agreement. Where Petitioner's Exhibit No. 20-S does not reflect a change, the position, as filed in the original case in chief, as modified on rebuttal where applicable, is adopted under the Settlement Agreement. Pet. Ex. 2-S.

CEI South witness Jerasa supported Section B.3 of the Settlement Agreement addressing CEI South's original cost rate base, capital structure, and fair return. He stated the Settling Parties agree CEI South's authorized ROE should be 9.80%, which results in a weighted average cost of capital of 6.77%. Pet. Ex. 14-S.

CEI South witness Taylor's settlement testimony addressed (1) ACOSS, (2) Revenue Distribution, and (3) Rate Design and Customer Charges and the implications and benefits for all stakeholders of the resolutions reached by the Settling Parties. Pet. Ex. 18-S.

CEIS Industrial Group witness Gorman testified in support of the Settlement Agreement, recommending its approval as a comprehensive agreement among the Settling Parties which resolves all issues raised by the parties in this rate case in a fair and reasonable manner. IG Ex. 4. He opined that the terms related to the revenue requirement are within the range of outcomes which could have resulted if this case were fully litigated. He explained the Settlement Agreement results in a reasonable revenue increase which reflects a fair return of and on capital investment made by CEI South if the utility is operated efficiently and enables CEI South to continue to provide reliable service to its customers on an economical basis. He stated the Settlement Agreement is a comprehensive agreement resolving all of the issues in the case, with each term essential to the overall reasonableness and arrived at as part of the "give and take" of the negotiating process. He recommended the Commission approve the Settlement Agreement without material change.

Industrial Group witness York also testified in support of the Settlement Agreement, describing how the Settlement resolves the cost of service and rate design issues raised in this proceeding by adopting the COSS presented by CEI South in this proceeding, with certain agreed modifications. IG Ex. 5. She opined that the cost of service and rate design terms of the Settlement Agreement operate in conjunction with the revenue terms to produce rates that are just and reasonable for all classes.

ii. <u>OUCC and CAC Settlement Opposition Testimony</u>. OUCC witness Eckert stated the Commission should reject the Settlement Agreement because it is not in the public interest for the reasons described in his testimony and in the testimony of the other OUCC witnesses. Pub. Ex. 1-S. He stated CEI South and the other Settling Parties have not adequately justified multiple aspects of the Settlement Agreement. He recommends the

Commission: (1) reject the Settlement Agreement among CEI South, the Industrial Group, and SABIC insofar as the Settling Parties request the Commission to approve an annual rate increase of $80.0 million; (2) reject the Settling Parties' agreed ROE of 9.80% and approve the 9.00% ROE recommended by OUCC witness Dellinger, subject to the additional modification recommended next; (3) reduce OUCC witness Dellinger's 9.00% ROE or the Commission authorized ROE by an additional 20 basis points due to continued issues with CEI South's reliability, customer satisfaction, and the "roadblocks" CEI South posed when the OUCC analyzed Petitioner's requests; (4) adhere to Indiana's policy of promoting utility investment in infrastructure while also protecting the affordability of utility service, and only approve necessary and reasonable requests required for CEI South's provision of electric service at reasonable rates; and (5) approve the other recommendations and proposals raised in his testimony and that of the OUCC's additional witnesses.

OUCC witness Compton testified that the Settlement Agreement did not adequately address the issues he raised with respect to the inclusion of certain IT investments in rate base and related operating expenses in the revenue requirement. Pub. Ex. 5-S.

OUCC witness Stull testified that the Settlement Agreement does not adequately address the issues and concerns she raised. Pub. Ex. 6-S at 2. More particularly, she discussed the Settlement Agreement's proposed treatment with respect to implementation of the TAR and reporting requirements and how it does not conform to her recommendations. She also discussed the Settlement Agreement's proposed treatment when implementing the phased rate increases, including adjustments to be made to pro forma net operating income and the information to be included in the compliance filings and urged the Commission to incorporate her recommendations in its Order. Finally, she testified that the Settlement Agreement does not address the transparency and completeness issues she raised concerning CEI South's case-in-chief.

OUCC witness Wright addressed issues and concerns with CEI South's rebuttal position, specifically with respect to Rider ADR and Rider GE. Pub. Ex. 8-S.

OUCC witness Krieger testified that the Settlement Agreement failed to adequately address issues he raised with respect to certain capital investment to be included in rate base, notwithstanding adjustments made in rebuttal and in the Settlement. In particular, he addressed the reasons he does not believe the Settlement Agreement adequately addressed the issues he raised with respect to Petitioner's capitalization of maintenance. He continued to recommend a $150.9 million reduction of capital investment in Steam Production Plant that CEI South proposes to include in rate base. He also recommended a complete audit review to ensure Petitioner's capitalization of maintenance was not more prevalent than Petitioner presented, as well as ongoing audits and a refund of excess earnings garnered by CEI South through this practice. He stated the impact of this recommendation also reduces annual depreciation and the annual revenue requirement. Pub. Ex. 9-S.

OUCC witness Dellinger testified in opposition to the ROE agreed upon in the Settlement Agreement. Pub. Ex. 10-S.

OUCC witness Dismukes filed testimony in opposition to the Settlement Agreement to address what he called the flawed provisions regarding allocated cost of service, revenue distribution, and rate design. He also included testimony on affordability generally and opposed the proposed CPP Pilot. Pub. Ex. 12-S.

OUCC witness Paronish testified in opposition to the Settlement Agreement, specifically with respect to communications with customers regarding remote disconnections, billing transparency, and the CPP Pilot. Pub. Ex. 13-S.

CAC witness Inskeep urged the Commission to deny the Settlement Agreement, stating the Settlement Agreement would impose extreme rate shock on the residential class and exacerbate affordability challenges for residential customers to benefit a handful of large industrial customers. He testified the "modest" consumer protection provisions and other terms included in the Settlement Agreement do not meaningfully alleviate these concerns. CAC Ex. 6.

CAC witness Barnes stated the Commission should reject the Settlement Agreement because it is biased in favor of the interests of industrial customers at the expense of residential customers stemming primarily from the retention of "outmoded cost allocation methods" that he says fail to reflect cost causation on CEI South's system. CAC Ex. 7 at 21. He objected to the "lack of any meaningful proposal for rate impact mitigation for residential customers and unwarranted handouts to SABIC via revisions to the BAMP tariff." *Id.*

iii. <u>Settlement Rebuttal Testimony</u>. CEI South witness Jerasa provided settlement rebuttal testimony to respond to the settlement opposition testimony of OUCC witnesses Eckert and Dellinger with respect to ROE. Pet. Ex. 14-SR.

CEI South witness Taylor addressed Settlement opposition testimony submitted by the OUCC and CAC with respect to the ACOSS, revenue distribution, and rate design and customers charges. Pet. Ex. 18-SR.

CEI South witness Rice responded to claims by the OUCC and CAC that the Settlement Agreement is one-sided, favoring large customers at the expense of affordability for residential customers. He addressed the updated affordability analyses performed by OUCC witness Dismukes and CAC witness Inskeep and responded to OUCC witness Krieger's recommendation that $150.9 million in utility plant in service be disallowed. He addressed OUCC witness Paronish's billing recommendations and provided responses to other issues raised by OUCC and CAC witnesses. Pet. Ex. 19-SR.

Mr. Rice stated his testimony and the testimony of the other Settling Parties in support of the Settlement demonstrate the efforts undertaken to balance the interests of not just the Settling Parties but all stakeholders. He stated the Settlement Agreement achieves a reasonable compromise on the issues in dispute in this Cause, even where the resolution of a particular issue might represent a benefit to parties who have chosen to oppose the Settlement Agreement. He opined that the Settlement Agreement will result in a reasonable revenue increase, fairly designed to balance the interests of CEI South and its customers, and it should be approved as in the public interest.

IG witness Gorman also filed settlement rebuttal testimony opining that the arguments raised by the OUCC and CAC boil down to an unreasonable criticism that the Settlement Agreement did not adopt the non-settling parties' litigation positions in their entirety. He explained that the fact that the non-settling parties chose not to join the Settlement does not indicate that the agreed terms are unreasonable, because the Settling Parties invited the OUCC and CAC to participate in the settlement discussions but those parties chose not to participate actively or provide substantive input on the terms. He also explained that preserving the 4CP allocation for generation and transmission plant preserves the status quo and is consistent with cost-causation. He noted that the Industrial Group agreed to a major concession with respect to foregoing its position on the Minimum System Study, namely, that allocation of distribution costs should include a customer component in FERC Accounts 364, 365, and 367. He noted that based on CEI South's as-filed revenue proposal and the Industrial Group's litigation position on cost of service, the increase to the residential class could have been as high as 24%, but under the Settlement, the residential increase will be 14.7%. IG Ex. 6.

Industrial Group witness York responded to the cost of service and rate design issues discussed in the OUCC and CAC settlement opposition testimony. IG Ex. 7.

SABIC witness Coyle addressed the settlement testimony of CAC witness Barnes regarding the Settlement terms relating to BAMP service. Ms. Coyle refuted Mr. Barnes's assertion that the Settlement Agreement will permit SABIC to avoid costs associated with historical investments that benefited SABIC before it installed its own generator. She stated that SABIC is still paying for these costs through the Base and Maintenance portion of its BAMP Service and noted the Settlement Agreement treats the Backup Service portion of BAMP Service the same as any other customer on the system who has reduced its load over time through energy efficiency or distributed generation investments. Ms. Coyle testified that Backup Service customers are required to pay for transmission service at all hours for their full contracted load, even if the customer-owned generator is serving its load.

Ms. Coyle opined that the Settlement Agreement represents a compromise between CEI South and SABIC, resulting in SABIC still paying higher than CEI South's FERC transmission rates, which represent the cost of transmission service for all other CEI South customers. Ms. Coyle observed that the settled rate is approximately 56% higher than the cost-based rate established at FERC. Ms. Coyle stated that as a result of this, the Settlement Agreement requires CEI South to evaluate transmission cost of service in the future. Ms. Coyle further refuted Mr. Barnes's testimony regarding Section 24 customers, noting that Mr. Barnes does not present the total picture of the change in cost allocation for customers when compared to CEI South's rebuttal position because he does not show the benefit to all customers from the Settlement for the reduction in the revenue requirement of approximately $35.4 million from CEI South's rebuttal position.

B. Phased Rate Implementation. As part of the Settlement Agreement, Section B.1 modifies the phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service. The Settling Parties agreed that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to increase its base rates and charges for electric utility service in two steps at a defined point in time as described in the Settlement Agreement. This stipulated term results in a savings to customers of approximately $13.25 million. While this stipulated term does not affect the revenue requirement,

it helps mitigate the bill impact by lowering customer bills and represents additional value to customers on top of the agreed adjustments to the revenue requirement. Pet. Ex. 19-S at 8-9.

Section B.1.c provides that the Settling Parties agree CEI South should be authorized to implement interim rate increase steps after Posey Solar and the CT Project are placed in service as described by CEI South witness Behme.

i. Pre-Test Year Phase and Process for Implementation of Phased Rates.

1. CEI South Case-in-Chief. CEI South witness Behme testified that CEI South was proposing to implement rates in a minimum of three phases. As originally proposed, Phase 1 would be implemented upon issuance of an order in this Cause, based on the actual rate base and capital structure as of December 31, 2023. Revenues and O&M expense would be updated to November 2024, rather than the beginning of the test year. For Phase 2, CEI South proposed to reflect most of the pro forma test year results of operations, updated to reflect the actual rate base and capital structure as of December 31, 2024. CEI South proposed to implement rates as soon as possible following the beginning of the test year. For Phase 3, CEI South proposed to update to reflect the fully adjusted test year and the actual rate base and capital structure as of the end of the test year. Phase 3 would be implemented as soon as possible following the end of the test year. Pet. Ex. 2 at 6-7. Ms. Behme testified that this three-phase approach was modeled after the approach proposed by Indiana American Water Company in Cause No. 45870. She said pro forma results of operations at present and proposed rates would be based upon the test year data, but the operating expenses in Phase 1 would begin with November 2024 for the 12-month period and certain revenue and expense adjustments would not be included or would not be included at the full amount at Phase 1 because the changes for which these adjustments are made will not occur until the test year. Ms. Behme testified that, because all the information necessary to calculate Phase 1 rates would be available before the evidentiary hearing (other than the findings that are contained in the Commission's Final Order in this Cause) there should not be a need to build in a post-order review process for Phase 1 as there would be with later phases.

For Phase 2 rates, Ms. Behme stated they would be implemented as soon as possible after January 1, 2025 and based on actual net plant certified to have been completed and placed in service no later than December 31, 2024. She stated other parties to this proceeding should be provided up to 60 days to verify or state any objection to the net plant in service numbers from those which CEI South certifies, and a hearing should be convened, as necessary, to resolve any objections. She testified that Phase 2 rates should be subject to refund during the review period, and, if necessary, upon resolution of any objections, rates should be trued up, with carrying charges at the weighted average cost of capital, retroactive to the date Phase 2 rates were submitted. Ms. Behme explained that pro forma results of operations for purposes of Phase 2 rates should reflect the adjusted test year results of operations, modified as needed to reflect certain revenue and expense adjustments that will not have been fully reflected by the beginning of the test year.

For Phase 3, CEI South proposed the same process as for Phase 2, except using the end of test year rate base and capital structure.

2. OUCC's Position. OUCC witness Stull recommended denial of CEI South's initial proposed implementation of a rate increase prior to the start of its forward-looking test year. Pub. Ex. 6 at 18, 21. She said CEI South's proposal differs materially from the two proposals where the Commission allowed rates to be implemented prior to the start of a utility's forward-looking test year, Cause No. 45545 and Cause No. 45870. She said in both of those cases the utility did not seek to recover costs before they were projected to be incurred and their initial rate increase only reflected the effects of projected data through the date an order was expected to be issued. Ms. Stull contended that, even if the Commission felt it was appropriate to implement a pre-test year phase in the same manner as has previously been authorized, Petitioner did not provide any monthly data reflecting its projected pro forma operating net income for the linking period. Ms. Stull further opposed updating depreciation rates before the beginning of the test year (with Petitioner's Phase 1 rates).

OUCC witness Stull testified that Petitioner's authorized increase to total rate base should be limited to the forecasted amount. Pub. Ex. 6 at 23. She also recommended that, to the extent CEI South does not actually invest what it forecasted it would invest in rate base, adjustments to depreciation expense and property tax expense may be warranted, along with associated adjustments to income tax.

Ms. Stull recommended that, if the Commission finds it is appropriate to implement rates before the beginning of the forward-looking test year, a post-order review process should be implemented similar to the process to be implemented at the beginning and end of Petitioner's forward-looking test year. Among other things, Ms. Stull recommended that the Commission find that a technical conference may be convened at the request of any party or Commission staff to allow further discussion in determining whether the compliance filing complies with the order and determine what additional information should be provided in each phase. She listed what she recommended be included in Petitioner's compliance filings, including:

1. Certification of Petitioner's actual utility plant in service and actual capital structure.
2. Actual rate base by component, in a similar format to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to Petitioner's forecast. Any variances between actuals and the forecast greater than 10% should be explained.
3. Actual utility plant in service balances by FERC Account similar to Exhibit No. 20, Schedule B-2.1.
4. Actual accumulated depreciation balances by FERC Account similar to Exhibit No. 20, Schedule B-3.1.
5. Actual capital structure by component, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital and comparing actuals to Petitioner's forecast. Any variance between actuals and forecast greater than 10% should be explained.
6. Calculation of Phase 1 rates based on the December 31, 2023 actuals as certified.

OUCC witness Eckert testified that CEI South's rates approved in this Cause should be implemented on a prospective basis applicable to service rendered after the rates become effective. Pub. Ex. 1 at 33.

3. CEI South Rebuttal. CEI South witness Behme disagreed with Ms. Stull's testimony that CEI South's proposal for Phase 1 rates differs from the pre-test year rates previously approved by the Commission. She said in both the Indiana American Water Company and the City of Evansville rate cases, the utilities' methods for calculating Phase 1 rates attempted to recover the revenue requirement being incurred at the anticipated date of order issuance. Pet. Ex. 2-R at 24. She said that, in both of those cases, the anticipated date of the Commission order was projected and that rates were proposed to be established upon issuance of the order that would recover the state of the projected revenue requirement as of that anticipated order date. Ms. Behme testified that, in both Cause No. 45870 and Cause No. 45545, the utility proposed to recover the level of costs beginning with the anticipated date of the order and not for the period leading up to the anticipated date of the order. Ms. Behme concluded that all three utilities have attempted to do precisely the same thing, which is to set Phase 1 rates at a level that will recover costs as they are being incurred during the period between the issuance of the Commission's order and the beginning of the test year.

Ms. Behme testified that, to the extent the OUCC's list of items required to be submitted and timing for review on pages 26-27 of Ms. Stull's testimony differs from the compliance filing requirements in Cause No. 45870, its request should be denied. Pet. Ex. 2-R at 28.

Witness Behme testified that CEI South would agree that forecasted additions to Utility Plant in Service ("UPIS") by the end of the test year should serve as a cap in calculating the actual rate base that is ultimately submitted as part of the compliance filing in any phase. However, the forecasted UPIS additions are only a cap for purposes of this proceeding (not a cap for purposes of a future general rate case or for purposes of capital trackers). Pet. Ex. 2-R at 28. She explained that, since the phase-in approach is required by the used and useful rule, any cap should be focused on the additions to used and useful plant that are forecasted to be placed in service before the end of the test year.

4. Settlement. CEI South witness Rice testified that Section B.3.a of the Settlement Agreement incorporated Ms. Stull's proposed cap on rate base for purposes of this case. Pet. Ex. 19-S at 9.

Mr. Rice stated that Section B.1 of the Settlement Agreement modifies the phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service. The Settling Parties agreed that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to increase its base rates and charges for electric utility service in two steps at a defined point in time as described in the Settlement Agreement. This stipulated term results in a savings to customers of approximately $13.25 million. While this stipulated term does not affect the revenue requirement, it helps mitigate the bill impact by lowering customer bills and represents additional value to customers on top of the agreed adjustments to the revenue requirement.

The first change in rates will be implemented pursuant to the process described below, which is essentially the same as that prescribed in Cause No. 45870, and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of December 31, 2024, subject to the Net Original Cost Rate Base Cap described in Section B.3.a of the Settlement Agreement ("Settlement Phase 1"), which incorporated Ms. Stull's proposed cap

on rate base for purposes of this case. As noted in the Settlement Agreement, CEI South will submit a certification of its actual utility plant in service and actual capital structure as part of its compliance filing. The compliance filing will calculate rates for the applicable phase based upon these certifications, subject to the Net Original Cost Rate Base Cap as described in the Settlement Agreement. If necessary to resolve any objections, the Commission shall schedule a hearing. The Settlement Agreement further provides that within a week of CEI South's compliance filing, a technical conference may be held at the request of either a party or Commission staff to allow for further discussion in determining whether CEI South's filing complies with the order in this Cause and to determine what additional information, if any, should be provided for the Settlement Phase 2 compliance filing. Following issuance of a Final Order in this Cause approving the Settlement Agreement, Settlement Phase 1 rates will go into effect after the beginning of the test year and upon the effective date of the Commission's approval of the Settlement Phase 1 compliance filing (currently anticipated to be on or around March 1, 2025) for services rendered after that effective date, on an interim subject-to-refund basis pending a 60-day review using the process described above.

CEI South will implement the second defined change in rates pursuant to the process described above for Settlement Phase 1 and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of the end of the test year (December 31, 2025), subject to the Net Original Cost Rate Base Cap described in Section B.3.a of the Settlement Agreement ("Settlement Phase 2"). Pet. Ex. 19-S at 9-10. Settlement Phase 2 rates will go into effect upon the effective date of the Commission's approval of the Settlement Phase 2 compliance filing (currently anticipated to be on or around March 1, 2026) for services rendered after that effective date, on an interim-subject-to-refund basis pending a 60-day review using the process described above for Settlement Phase 1.

5. <u>OUCC Settlement Opposition</u>. OUCC witness Stull stated that, while she generally accepts the process the Settling Parties agreed to, CEI South should provide additional information so the Commission, the OUCC, and other parties to this case may conduct a meaningful review of the compliance filing to ensure compliance with the Commission's order. Pub. Ex. 6-S at 7. In addition to the information the Settling Parties agreed should be included, she recommended the following additional supporting information be submitted with CEI South's compliance filing:

1. Actual rate base by component as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2), in a format similar to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to CEI South's applicable forecast. Any variances between actuals and the applicable forecast greater than 10% should be explained.
2. Actual utility plant in service balances by FERC Account as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) similar to Exhibit No. 20, Schedule B-2.1.
3. Actual accumulated depreciation balances by FERC Account as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) similar to Exhibit No. 20, Schedule B-3.1.
4. Actual capital structure by component as of December 31, 2023, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital for each phase and comparing actuals to the applicable forecast. Any variance between actuals and the applicable forecast greater than 10% should be explained.

5. Calculation of rates based on actuals on December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) as certified.

Ms. Stull also requested that the Commission order that net operating income be adjusted to the extent projected investments are not made. Pub. Ex. 6-S at 10.

Mr. Eckert stated the Settlement Agreement does not recommend that any approved rate changes apply on a services rendered basis on or after the effective date of the rate change. Pub. Ex. 1-S at 14-15.

6. Settlement Rebuttal. In Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal testimony, he indicated that CEI South addressed Ms. Stull's request for additional information as part of the compliance filing on rebuttal (Pet. Ex. 2-R at 28). To the extent she is requesting information required in the order in Cause No. 45870, CEI South agrees. Mr. Rice stated this was the intent of the language of the Settlement Agreement and to the extent she is asking for more than the Cause No. 45870 order requires, her request should be denied. The Commission has already considered her requests for additional information beyond that which is required for other utilities (in Cause No. 45870) has set forth the information that reasonably is needed. He testified there is no reason to treat CEI South differently. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

As for Ms. Stull's recommendation that net operating income be adjusted where projected investments are not made, Mr. Rice showed in his Attachment MAR-SR2 that the Settlement Agreement provides, at Section B.1.a (Phase 1) and B.1.b (Phase 2) that the revenue requirement will be adjusted at each phase to reflect actual capital structure and actual rate base, subject to the Net Original Cost Rate Base Cap.

With respect to Mr. Eckert's concern that rates be implemented on a "services rendered" basis, Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal refers to Sections B.1.a (Settlement Phase 1) and B.1.b (Settlement Phase 2) of the Settlement Agreement, both of which provide that rates will go into effect "for services rendered after the effective date." Pet. Ex. 19-SR, Attachment MAR-SR2 at 1.

ii. Phased Rates – Interim Phases.

1. CEI South Case-in-Chief. CEI South witness Behme described up to three additional interim steps Petitioner is proposing between Phases 2 and 3 (*i.e.*, the beginning and end of the test year) aligned with the placement in service of the CT Project and Posey Solar. She explained that, if the PISCC on these projects continue to accrue until the end of the test year, rate base and Phase 3 rates will be higher than if these projects were reflected in rates at an earlier time. As such, CEI South proposed to implement interim steps to reflect the additional after-tax return and depreciation expense on each of these projects (each CT, in the event there is a delay in implementation between the two, and Posey Solar) using the capital structure in effect at the beginning of the test year and used for Phase 2. Pet. Ex. 2 at 8-9. These interim steps would take effect upon filing of a certification in this Cause that the plant in question is in service. Ms. Behme clarified that, for Generally Accepted Accounting Principles ("GAAP") purposes, prioritization of recovery upon implementation of each interim step should mirror what presently

occurs in various rider filings, with the first dollars recovered collecting the PISCC (both debt and equity) related to these investments. The same interim-subject-to-refund basis as for Phases 2 and 3 would apply, with the same time period for other parties to raise objections. Precisely how many interim steps there would be or when they would occur is not currently known, as they are dependent upon actual in-service dates of the plant in question. Accordingly, the overall revenue requirement shown in Petitioner's Exhibit No. 20 does not reflect these proposed interim steps.

2. OUCC's Position. Ms. Stull opposed CEI South's proposal to implement rate increases *during* the forward-looking test year. Pub. Ex. 6 at 28. She opined that this proposal unnecessarily complicates CEI South's rates, is unprecedented, undermines an already well-established process for updating rate base in forward-looking test year cases, increases regulatory costs and burdens, and would serve to confuse customers without any quantification of the benefit to ratepayers in avoiding less than 12 months of carrying costs.

3. CEI South Rebuttal. Ms. Behme and Mr. Rice both expressed surprise at Ms. Stull's opposition to the additional interim phased rate increases as the CT Project and Posey Solar are placed in service, citing the benefits to customers in avoiding the PISCC and deferred depreciation associated with those projects from the time they are in service until the time they are reflected in rates. Pet. Ex. 2-R at 28; Pet. Ex. 19-R at 58. Ms. Behme reiterated that the ultimate rates customers would pay at Phase 3 (end of test year) would be higher without these interim phases. Pet. Ex. 2-R at 28. Both Ms. Behme and Mr. Rice said that every month of delay would cause a rate base increase of $3.4 million for the CT Project and $3.7 million for Posey Solar. Pet. Ex. 2-R at 28; Pet. Ex. 19-R at 58. Mr. Rice testified that if these projects are placed in service in May 2025, CEI South would expect that it could file and place into effect the new rates by July 1, eight months before they would be reflected under Ms. Stull's proposal. Pet. Ex. 19-R at 58. He concluded that is almost $57 million of PISCC and deferred depreciation (*i.e.*, rate base) that could be avoided with additional interim steps.

4. Settlement. Section B.1.c of the Settlement Agreement stipulates implementation of interim rate increase steps after Posey Solar and the CT Project are placed in service. Based on projected in-service dates of May 2025 for Posey Solar and July 2025 for the CT Project, this results in a projected reduction to proposed rate base as contemplated in Section B.3.a.iii of the Settlement Agreement and discussed in Section 0.D (Rate Base) of this order. The Settlement Agreement provides that the actual reduction to rate base and the Net Original Cost Rate Base Cap will be based upon the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps. Settling Parties' Jt. Ex. 1 at Section B.1.c. Mr. Rice testified this reduction totals $25,100,595 for avoided PISCC and deferred depreciation related to the Posey Solar and CT Project. Pet. Ex. 19-S at 11.

iii. Commission Discussion and Findings. The Settlement Agreement eliminated the controversy over Petitioner's proposed pre-test year rate implementation. Accordingly, we find the proposed Settlement Phase 1 (beginning of test year) and Settlement Phase 2 (end of test year) rate implementation to be a reasonable resolution of the dispute between the parties and therefore in the public interest.

CEI South witness Behme indicated Petitioner's acceptance of the requirements imposed for similar phased rate filings in our recent order in Cause No. 45870. This included the availability of a technical conference as needed for Petitioner to explain its compliance filing. We find this, along with the Settlement Agreement's provision for review and objection, as well as the potential for a hearing on any such objection, provides ample opportunity for the parties and Commission staff to conduct a thorough review of the compliance filing and resolve any questions. CEI South has accepted the same compliance filing requirements as set forth in Cause No. 45870, and we find those parameters sufficient to address the concerns raised by the OUCC.

With respect to CEI South's proposed interim rate implementations after Posey Solar and the CT Project are placed in service, the evidence demonstrates these additional steps will benefit customers through a reduction to rate base for avoided PISCC and deferred depreciation. We therefore find this term of the Settlement Agreement to be in the public interest.

Petitioner's Settlement Phase 1 and Settlement Phase 2 rates shall be implemented using the process described in Sections B.1.a and B.1.b of the Settlement Agreement. Petitioner's proposed interim rate increases to reflect Posey Solar and the CT Project shall be implemented as described in CEI South witness Behme's direct testimony, using the same process and compliance filing requirements as for Settlement Phase 1 and Settlement Phase 2 rates.

C. Overall Revenue Requirement and Authorized Net Operating Income. Section B.2 of the Settlement Agreement addresses the stipulated revenue requirement, revenue increase and authorized NOI.

CEI South witness Rice stated that, for Section B.2 of the Settlement Agreement, the Settling Parties have agreed to a total revenue requirement of $803,932,466, which requires a net increase in revenues at present rates of $80,009,617. Pet. Ex. 19-S at 10. He explained the increase in revenues is net of the reduction to revenues resulting from the stipulated reduction to the base cost of fuel based on the OUCC's recommendations, as well as the stipulated reduction to purchased power expense due to the reduction in purchased capacity cost set forth in the Settlement Agreement. CEI South originally requested a revenue increase of $118,757,693, modified to $115,445,697 on rebuttal. The stipulated agreement is a decrease of $35,436,080 from CEI South's request at rebuttal. The Settlement Agreement results in a proposed authorized NOI of $187,518,958.

CEIS Industrial Group witness Gorman opined that the revenue terms of the settlement are reasonable. IG Ex. 4 at 3. He explained in his direct testimony he recommended that the revenue increase be no more than $89.2 million. Even so, the Settling Parties were able to reach agreement on an increase of only $80.0 million. He stated the range of potential litigation outcomes was between CEI South's rebuttal position of $115.4 million and the OUCC's proposed $48.3 million increase. The settled increase falls below the $81.9 million midpoint of that range. In his opinion, the settled revenue requirement is a reasonable resolution of the revenue issues raised in this case, is fully supported by the record as a whole, and represents a fair compromise on the revenue disputes raised in the litigated phase of this proceeding.

The disputed components of Petitioner's revenue requirement, and the stipulated resolution of those issues within the Settlement Agreement, are discussed in greater detail in each of the subsections below. The Commission's ultimate finding on Petitioner's authorized revenue increase and NOI can be found in Paragraph 9 (Overall Authorized Increase) below.

D. Rate Base. Sections B.3(a) and (b) of the Settlement Agreement set forth the Settling Parties' stipulations regarding original cost rate base and other rate base items, respectively.

Specifically, the Settling Parties stipulated that the original cost rate base on which Petitioner should be authorized to earn a return for Settlement Phase 1 shall be the actual net original cost rate base as of December 31, 2024 and for Settlement Phase 2 shall be the actual net original cost rate base as of December 31, 2025. The Settling Parties further stipulated that the net original cost rate base at either Settlement Phase 1 or Settlement Phase 2 shall not exceed the forecasted end-of-test-year net original cost rate base of $2,769,851,666, as adjusted for the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar (the "Net Original Cost Rate Base Cap").

The stipulation as to net original cost rate base includes the following stipulated modifications to CEI South's forecasted rate base presented on rebuttal: (1) the reduction to coal inventory of an additional $2,949,966 as proposed by OUCC witness Eckert; (2) the removal of $212,036 in additional net investment in the ULRC, as recommended by OUCC witness Armstrong; and (3) the reduction for avoided PISCC and deferred depreciation in conjunction with the stipulations in the Settlement Agreement regarding interim phases of rates.

In addition, CEI South stipulated and confirmed: (1) that amounts reflected in Table B.3.b.i of the Settlement Agreement related to land acquisition and identified in OUCC witness Armstrong's testimony are not included in the forecasted rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates, and (2) that the amounts related to the Culley Unit 3 Natural Gas conversion and identified in OUCC witness Krieger's testimony and CEI South witness Bradford's rebuttal testimony will not be included in rate base in this Cause, but instead will be addressed as part of Petitioner's later anticipated proposed certificate of public convenience and necessity ("CPCN") proceeding related to said conversion. Settling Parties' Jt. Ex. 1 at Sections B.3(a) and (b).

Below is a summary of CEI South's case-in-chief evidence in support of its rate base, the contested issues resolved through Petitioner's rebuttal and/or the Settlement Agreement, and the remaining items in dispute.

Ms. Behme testified that the "Adjustments" column on Schedule B-2 and B-2.1 of Petitioner's Exhibit 20 reflects three primary adjustments to gross plant in service and accumulated reserve forecasted as of December 31, 2025. Pet. Ex. 2 at 14. First, she said an adjustment was made to remove utility plant in service and associated accumulated depreciation of MISO Regional Expansion Criteria and Benefit ("RECB") transmission plant in service. She said that, under the Commission's Order in Cause No. 43111, CEI South has treated MISO-approved RECB investments as FERC jurisdictional. The second adjustment is to remove utility plant in service

and associated accumulated depreciation of the assets associated with Troy Solar. Ms. Behme explained that CEI South was granted authority to recover the costs of Troy Solar using a levelized rate through the CECA annual tracker. As part of the settlement agreement in Cause No. 45086, the order states that the project will be excluded from the calculation of CEI South's electric revenue requirement in each rate case over the life of the project. Specifically, as it pertains to this adjustment, the order states that the project will be excluded from rate base in such future base rate cases. The third adjustment removes utility plant in service and associated accumulated depreciation of the assets associated with Crosstrack Solar. CEI South was granted authority to recover the costs of Crosstrack Solar using a levelized rate through the CECA annual tracker. The unadjusted forecast assumes that Crosstrack Solar would be placed in service during the test year as was detailed in Cause No. 45754. Like the way CEI South accounts for Troy Solar, per the Final Order in Cause No. 45754, when completed CEI South would have excluded Crosstrack Solar from rate base in future base rate cases. In addition, Ms. Behme noted that the commercial operation date for Crosstrack Solar has been updated to 2026, which is beyond the test year in this Cause. As a result, none of the costs associated with Crosstrack Solar should be included in this case.

Ms. Behme described the 11 specific items included in rate base as other rate base components (Schedule B-4): (1) fuel stock; (2) utility materials and supplies; (3) storeroom expenses associated with materials and supplies; (4) allowance inventory; (5) regulatory asset associated with deferral of PISCC related to CEI South's AMI project (approved in Cause No. 44910); (6) regulatory asset associated with deferral of PISCC related to CEI South's initial TDSIC plan (approved in Cause No. 44910); (7) regulatory asset associated with deferral of PISCC related to CEI South's second TDSIC plan (approved in Cause No. 45894); (8) regulatory asset associated with deferral of PISCC related to CEI South's annual CECA proceeding (approved in Cause No. 44909, with amounts approved in subsequent CECA proceedings); (9) regulatory asset associated with deferral of PISCC related to CEI South's annual ECA proceedings (approved in Cause No. 45052, with amounts approved in subsequent ECA proceedings); (10) regulatory asset associated with deferral of PISCC related to the F.B. Culley East Ash Pond Closure (approved in Cause No. 45903); (11) regulatory asset associated with deferral of PISCC related to the natural gas combustion turbines ("CTs") (approved in Cause No. 45564). The first four components are reflected using 13-month averages of the actual balances for the monthly periods ended December 31, 2022 except that fuel stock and utility materials and supplies were adjusted to reflect the retirement of A.B. Brown and Warrick Unit 4. Pet. Ex. 2 at 17-18.

CEI South witness Bradford provided an overview of CEI South's Generation Portfolio and its Generation Transition Plan. Of the new resources being added to CEI South's Generation Portfolio, he indicated the CT Project and Posey Solar are included in the forecasted rate base in this case. He provided an update on the CT Project and the Posey Solar. Pet. Ex. 7 at 13-14. He also described how CEI South has managed capacity needs until the replacement generation is placed in service in 2025. Attachment FSB-1 to Mr. Bradford's direct testimony is a summary of capital investments made at CEI South generating stations since the rate base cutoff date in CEI South's last base rate case, Cause No. 43839, with projects greater than $5 million individually identified. It excludes Troy Solar, Crosstrack Solar, and those investments that have since been retired with the securitization of A.B. Brown Units 1 & 2.

In rebuttal, Ms. Behme described in rebuttal an adjustment to the ECA PISCC balances in Petitioner's Exhibit No. 20-R to reflect a correction identified after the OUCC and intervenors had filed their cases-in-chief. Pet. Ex. 2-R at 4. She said CEI South reduced the PISCC balances for the ECA mechanism by $20,783,641. Ms. Behme explained that it was discovered that there were balances in the forecast for these accounts that are attributed to the Mercury and Air Toxics Standards ("MATS") Program in the ECA mechanism. The PISCC balances associated with MATS were removed from the general ledger in 2023 and included in CEI South's Securitization filing in Cause No. 45722. Since these balances were removed from the general ledger, CEI South has removed these balances from Petitioner's Exhibit No. 20-R in this proceeding, resulting in a reduction to the revenue requirement of $2,729,234.

i. Rate Base Items Resolved through Rebuttal.

1. Culley East Ash Pond. OUCC witness Armstrong testified that the Commission had denied CEI South's recovery of the Cause No. 45795 legal costs in Cause No. 45903. Pub. Ex. 7 at 12. Accordingly, she recommended an increase to accumulated depreciation to remove the disallowed legal costs for the Culley East Ash Pond project and an associated reduction to test year amortization expense.

Ms. Behme testified on rebuttal that, to comply with the Final Order received February 7, 2024 in Cause No. 45903, CEI South removed certain disallowed legal fees from the rate base reflected in Petitioner's Exhibit No. 20-R. Pet. Ex. 2-R at 5. She stated CEI South has also made the necessary adjustments to ECA revenues, accumulated depreciation, and amortization expense associated with this reduction.

2. Emissions Allowance Inventory. OUCC witnesses Lantrip and Armstrong recommended the Commission deny the Emissions Allowance portion of costs in base rates, contending that Petitioner has not demonstrated prudence regarding the management of its allowance inventory. Mr. Lantrip recommended embedding a zero balance in base rates and Petitioner's approval of its Emissions Allowance inventory variance be contingent upon an improvement of its practices, as demonstrated through updates of less volatility in inventory levels presented in its RCRA Rider testimony. Pub. Ex. 3 at 13-14. Ms. Armstrong testified that the 2022 historical period CEI South used to forecast allowance inventory is not representative of what its operations are likely to be going forward due to unusual events in 2022 that she stated inflated the monthly allowance inventory balances. Pub. Ex. 7 at 3. She said that, because CEI South will be retiring all but one of its coal units by 2026, its need to purchase emission allowances will decrease in future years. She also stated that CEI South's filed exhibits and workpapers did not provide detailed monthly emission allowance inventory calculations by allowance type, which she said was necessary to verify the monthly allowance inventory balance and expense. She testified that, to reflect the changes in the NOx Seasonal market and the benefits of CEI South's Generation Transition Plan, it is reasonable to value test year allowance inventory at zero. This recommendation would remove $1,282,707 of rate base and $3,519,952 of Emission Allowance O&M costs from the test year. Pub. Ex. 3 at 14; Pub. Ex. 7 at 10.

On rebuttal, Ms. Behme indicated CEI South's acceptance of the OUCC's proposal, resulting in the removal of $1,282,707 from rate base. Witness Behme testified that while CEI South believes there would be a balance of emission allowance inventory represented on the

balance sheet in the test year, she acknowledged that the actual historical balances used for the basis in this case are not representative of what the balance will be for the test year, and Petitioner agrees to remove the balance entirely. Pet. Ex. 2-R at 5.

ii. Rate Base Items Resolved in Settlement.

1. Coal Inventory. OUCC witness Eckert disagreed with CEI South's proposed coal inventory level. Pub. Ex. 1 at 34. He testified that CEI South had excessive coal inventory during most of 2023, imposing an additional and unnecessary cost on ratepayers. He calculated a recommended coal inventory level of $8,990,701, a reduction of $2,949,966 from CEI South's proposed amount of $11,940,667.

CEI South witness Bradford testified on rebuttal that Mr. Eckert's simplistic calculation of a recommended coal inventory level was incomplete and used debatable assumptions. Pet. Ex. 7-R at 10-11. He explained that as shown in Schedule B-4 of Petitioner's Ex. No. 20, the fuel stock rate base component has additional constituents besides the Culley coal inventory, such as the natural gas underground storage inventory, the Brown Unit 3 gas turbine fuel oil inventory, and the fuel coal inventory – which totals approximately $775,000. Mr. Bradford also disagreed with Mr. Eckert's assumptions regarding the Culley coal pile inventory, including the optimal number of days' supply. He said the reduced fleet coal inventory warrants a higher optimal number of days. He also stated Mr. Eckert did not account for the Culley Unit 2 maximum daily coal burn. He also disagreed with Mr. Eckert's use of a single point of reference versus a time-based average coal pile inventory cost.

In his settlement testimony, Mr. Rice stated that the Settlement Agreement reduces coal inventory by an additional $2,949,966 as proposed by Mr. Eckert. Pet. Ex. 19-S at 10.

2. Urban Living Research Center. CEI South witness Bradford gave an overview of the ULRC Project which was approved in Cause No. 44909. He explained that the Commission originally approved an estimated investment of approximately $2 million to be recovered through the CECA mechanism. Pet. Ex. 7 at 19. In Cause No. 44909 CECA 2 ("CECA 2"), the Commission approved a change in scope and corresponding decrease to the project cost estimate to $1.5 million. Pet. Ex. 7 at 19-20. In Cause No. 44909 CECA 4 ("CECA 4"), CEI South provided updates to the ULRC design, as well as updates to the estimated final project cost of $1.15 million. Mr. Bradford testified that CEI South did not request approval of, nor did the Commission approve, any revisions to the cost estimate in CECA 4 from the $1.5 million approved in CECA 2. In Cause No. 44909 CECA 5 ("CECA 5"), the Commission approved recovery of $1,150,000 out of the final project cost of $1,465,288, finding that although the final project cost was within the $1.5 million approved in CECA 2, CEI South had not established that the remaining costs were reasonable or appropriate for a project with significantly less capacity than was projected in CECA 2. CEI South sought to recover the remaining unrecovered balance of the ULRC project in this case, which is $219,348. Mr. Bradford explained that, with the ULRC being a pilot project, CEI South ran into unforeseen challenges beyond its control to get the project to fruition in 2022. He described those challenges in detail and said the cost increases were beyond CEI South's control and were necessary costs for the completion of the ULRC project. To address the Commission's finding that CEI South failed to establish the

additional costs were reasonable or appropriate, he provided a detailed breakdown of the additional $219,348.

OUCC witnesses Lantrip and Armstrong recommended Petitioner's request to include $219,348 of net project costs related to the ULRC be denied. Pub. Ex. 3 at 4; Pub. Ex. 7 at 28. Mr. Lantrip said the Commission's most recent Order in CECA 5 found ratemaking recovery should be limited to the $1.15 million project estimate given in CECA 4, due to the project's changes in scope from the previous approved cost in CECA 2. He stated CECA 5 also required Petitioner to update the Commission on the outcome of Petitioner's U.S. Department of Energy reimbursement request for $60,000. Pub. Ex. 3 at 4. Ms. Armstrong testified that the detailed breakdown and associated justification of the additional ULRC costs in his direct testimony in this Cause is information that the Commission already had when it made its decision in CECA 5 to disallow the additional costs. Pub. Ex. 7 at 15. Ms. Armstrong noted that CEI South did not file a petition for reconsideration in CECA 5. She also asserted that CEI South made the decision to request that the ULRC be exempt from the requirements of Ind. Code ch. 8-1-8.5, and it should not be entitled to benefits similar to the guaranteed rate recovery under Ind. Code § 8-1-8.5-6.5 afforded to projects that have provided enough evidence to persuade the Commission to issue a CPCN under Ind. Code § 8-1-8.5-5(b) and (d).

On rebuttal, CEI South witness Bradford disagreed with OUCC witness Lantrip that the Commission's CECA 5 Order "found ratemaking recovery [for the ULRC project] should be limited to $1.15 million." He explained that he did not interpret the CECA-5 order as prohibiting CEI South from seeking to include that amount in rate base in this proceeding or foreclosing the request included in this case. Pet. Ex. 7-R at 13.

Mr. Rice testified that the Settlement Agreement removed a net amount of $212,036 in additional investment in the ULRC as recommended by OUCC witness Armstrong. Pet. Ex. 19-S at 10.

3. PISCC and Deferred Depreciation Avoided for Interim Phases. By virtue of the stipulations included in the Settlement Agreement related to interim phases of rates implementation, discussed in Paragraph 0.B (Phased Rate Implementation) of this order, reductions to rate base totaling $25,100,595 will be realized due to the avoided PISCC and deferred depreciation for the CT Project and Posey Solar. Pet. Ex. 19-S at 11; Settling Parties' Jt. Ex. 1 at Section B.3.a.

4. Land Acquisitions. OUCC witness Armstrong recommended the removal of amounts from rate base related to the acquisition of five properties bordering the A.B. Brown Generating Station. Pub. Ex. 7 at 21. She testified that, in response to discovery, CEI South stated that the land was purchased as buffer property and that these properties may be impacted from a nuisance perspective by activities related to completing closure of the ash pond. Ms. Armstrong contended that CEI South did not adequately justify the need for these land purchases and they are not currently used and useful for the provision of electric service. She said that although purchasing these properties likely reduced CEI South's future litigation risk, allowing CEI South to recover these costs shifts the risk of CEI South's management decisions and business operations from its shareholders onto its customers. She testified that if CEI South invests in future improvements to the property that are found to be reasonable and prudent for

providing electric service to customers, then it may be appropriate seek recovery of the land as part of its request to recover these investments. However, she said it is premature for CEI South to recover these land purchases now and recommended removal of the costs of these acquisitions, reducing Petitioner's rate base.

While CEI South witness Bradford initially offered rebuttal objecting to the OUCC's proposed exclusion of the land acquisition costs in rate base, Petitioner's response to the Commission's April 29, 2024 docket entry questions made clear that the acquisition costs were not actually included in rate base in the revenue requirement. Pet. Ex. 23.

Section B.3.b of the Settlement Agreement stipulates and confirms that $2,143,866 related to a land acquisition and identified in OUCC witness Armstrong's testimony is not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1; Pet. Ex. 19-S at 11.

iii. Remaining Disputed Rate Base Items.

1. Steam Production Plant, Coal Silo, and Culley Expenses. OUCC witness Krieger recommended a $150.7 million reduction of capital investment in Steam Production Plant CEI South included in rate base, resulting in a reduction to the revenue requirements of $9.2 million. Pub. Ex. 9 at 2 and 15. This reduces annual depreciation by an estimated $8.6 million and reduces the annual revenue requirement by an additional $9.2 million. He identified certain utility plant investments as concerning. He reviewed Mr. Bradford's attachments and workpapers showing all capital investment at Steam Production Plan following the rate base cutoff in Petitioner's last general rates case. He said certain investments in replacement and refurbishments should have been expensed as maintenance instead of capitalized and he has concerns about CEI South's project management and accounting discipline. He said the $104.7 million he sought to remove from rate base reference repairs, replacements and refurbishments, and other categories that are maintenance, not investment. He said these items keep an asset running but do not extend the asset's useful life.

Mr. Krieger also took issue with the inclusion of amounts for modifications to a coal silo that later failed. Mr. Krieger does not believe this amount should be added to rate base or borne by consumers because the cost is a result of poor project management. Pub. Ex. 9 at 13. He recommended removal of $8,821,876 from rate base related to the 2016 Culley Unit 3B Coal Silo Failure.

OUCC witness Eckert recommended that, if the Commission finds CEI South was at fault for the Culley Unit 3 outage, the Commission should reduce rate base by $7,139,191 to remove the capital cost to repair Culley Unit 3. Pub. Ex. 1 at 39. IG witness Gorman recommended that, to the extent the Commission ultimately finds imprudence caused the outage at issue in Cause No. 38708 FAC 137 S1, then the full revenue requirement impact of the test year for all imprudent capital costs associated with the Culley outage should be removed from CEI South's cost of service. IG Ex. 1 at 136-137.

Mr. Krieger also argued that the Commission should disallow amounts included in rate base for FB Culley 3 major projects. He contended that these amounts should not be included in rates until a future CPCN for FB Culley Unit 3's conversion to natural gas is approved by the Commission. Pub. Ex. 9 at 14.

CEI South witness Cunningham responded to Mr. Krieger's proposed removal of $104.7 million in utility plant in service based on his position that those items were inappropriately capitalized. He said Mr. Krieger has paraphrased CEI South's capitalization policy and taken it out of context. He also said Mr. Krieger's proposed capitalization test is inconsistent with the FERC Uniform System of Accounts ("USOA"). Pet. Ex. 22-R at 3. Mr. Cunningham stated the FERC USOA sets forth the rules for capitalization when individual items of property that are part of a larger asset are replaced and that Mr. Krieger's proposed test that the replacement should increase the entire useful life or salvage value of an asset is not part of the analysis. He said CEI South has a written listing or catalogue as alluded to by Mr. Krieger but the OUCC did not ask for that catalogue to be produced in discovery. A copy of the catalogue was attached as Petitioner's Exhibit No. 22-R, Attachment JAC-R1. He said that if a retirement unit is replaced, it is to be capitalized. If a component part of a retirement unit is to be replaced, it is expensed. And, as the USOA makes clear, "consistency" in application is key. Mr. Cunningham testified that the items identified by Mr. Krieger, including pumps, valves, and process piping are considered discrete retirement units, or assets, for CEI South. These retirement units were established almost 20 years ago and replacements of these retirement units have been consistently capitalized by CEI South in the normal course of operations. Mr. Cunningham said replacements of retirement units result in the prior asset being retired and the new asset being added to the plant-in-service records. The newly installed asset does represent additional investment with a new useful life. Mr. Cunningham testified that CEI South has an internal controls team that reviews and confirms CEI South is appropriately capitalizing assets and its financial statements are audited by independent certified public accountants for compliance with GAAP. Finally, the regulatory financial statements that are reported to FERC are also audited by the same firm of certified public accountants. He stated CEI South undergoes considerable diligence to assure that the capitalization decisions are correct and in compliance with the FERC USOA. Mr. Cunningham also explained that Instruction 10 of the USOA dictates Mr. Krieger is incorrect. When a retirement unit is removed from service, the utility is to credit Utility Plant in Service and debit Accumulated Depreciation for the original cost of the unit, regardless of how many years the unit has been in service. In this fashion, the retirement of a retirement unit has zero effect on net original cost rate base (except for salvage and cost of removal). Consequently, the entries that are booked to retire a retirement unit do not imply that the unit was fully depreciated.

Mr. Bradford explained in rebuttal that, when the Culley Unit 3B Coal Silo failed in July 2016, an outside engineering firm performed a root cause analysis ("RCA"). He noted that the engineering firm determined the root cause to be the liner modification not being installed in 1978, by the contractor as specified in the 1976 design document thereby causing the coal silo skirt-to-cone weld to fail from approximately 40 years of corrosion. He added that the third-party RCA is provided as Petitioner's Exhibit No. 7-R, Attachment FSB-R2. Pet. Ex. 7-R at 5. Mr. Bradford described the amounts covered by the insurance carrier and amounts included in rate base in this case. He said the amount associated with the Culley Unit 3B Coal Silo Failure nets to $4,600,428, reducing Mr. Krieger's recommendation by more than $4 million. *Id.* He pointed to the RCA and the insurance carrier to argue that there is no evidence of poor project management. Specifically,

the RCA states "[a] likely scenario that would allow this to occur is that the 204 SS liner installation detail was modified in the field without knowledge of Vectren Power Supply."

Mr. Bradford provided a breakdown of the $41.4 million of rate base Mr. Krieger sought to disallow with respect to certain capital investment projects related to Culley, explaining they relate to turbine overhaul and rotor replacement, boiler components and air heater baskets replacements, environmental emission monitoring equipment replacement, coal-pulverizer piping replacement, expansion joint replacement, station battery replacement, and cyber security monitor equipment for the control system, as well as including approximately $7.8 million for the Culley Unit 3 Outage capital expenditures. Mr. Bradford agreed that the Culley Unit 3 conversion should not be included in rates until the Commission has approved a CPCN or an alternative recovery method such as a new tracker. He explained that his Workpaper FSB-1 (Confidential) set forth the capital spend during a period of time but not necessarily amounts included in rate base in this case. Pet. Ex. 7-R at 9.

Mr. Bradford did not agree with the proposed disallowance of the other Culley capital projects. With respect to the turbine overhaul, he testified that the original equipment manufacturer ("OEM") – General Electric – recommends a turbine overhaul, such as Culley Unit 3, every seven to ten years. He noted that the last turbine overhaul performed on Culley Unit 3 was in 2014, putting the next scheduled overhaul at 11 years. CEI South has already delayed the overhaul until 2025 due to the previous Culley Unit 3 Forced Outage from June 2022 – March 2023; therefore, Mr. Bradford stated it would not be prudent to push the turbine overhaul beyond 2025 given OEM guidance. With respect to the remainder of the projects, Mr. Bradford testified that they will continue to be used after the gas conversion project, but these projects are prudent and will be needed even if a CPCN is not issued for the gas conversion project. He said the turbine and boiler remain essential if the gas conversion occurs, and, if the Commission does not approve the Culley Unit 3 conversion, one cannot assume that Unit 3 will no longer be used and useful. Mr. Bradford stated if the Commission denies the natural gas conversion, it is more than likely the unit would continue to operate until the next IRP cycle provides further guidance on a suitable replacement or until environmental requirements require closure.

With respect to the OUCC and IG recommendations that the Commission remove from rate base costs associated with returning Culley Unit 3 to service following the forced outage in the event the Commission should find CE South was imprudent in Cause No. 38708 FAC 137 S1, Mr. Bradford indicated CEI South opposed the OUCC's and IG's recommended findings of imprudence and disallowance in that subdocket. That said, to the extent the Commission's Final order differs from that proposed by CEI South in either Cause, Mr. Bradford stated CEI South will update its schedules to comply. Pet. Ex. 7-R at 3.

In his settlement testimony, Mr. Rice described Section B.3 of the Settlement Agreement, which addresses, among other things the original cost rate base. He said the Settlement Agreement reflects CEI South's test year end net original cost rate base on which it should be permitted to earn a return at $2,769,851,666, which will be adjusted for the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar. He noted that this includes CEI South's original proposal less a reduction to rate base of $50,617,095:

(1) to reduce coal inventory for an additional $2,949,966 as proposed by OUCC witness Michael Eckert;

(2) to remove a net amount of $212,036 in additional investment in the ULRC as recommended by OUCC witness Cynthia Armstrong;

(3) for a reduction totaling $25,100,595 for avoided PISCC and deferred depreciation in conjunction with the stipulations set forth in Section B.1.c of the Settlement Agreement related to Posey Solar and CT Project;

(4) for a reduction of $20,783,641 for PISCC associated with ECA projects as described on pages 4-5 of the rebuttal testimony of CEI South witness Behme;

(5) for a reduction of a confidential amount for Culley East ash pond legal fees, as accepted by CEI South on rebuttal and further described in Ms. Behme's testimony and

(6) to reduce rate base NOx allowance inventory by $1,282,707 as accepted by CEI South on rebuttal and further described on page 5 of Ms. Behme's rebuttal.

Section B.3.b of the Settlement Agreement also stipulates and confirms that $2,143,866 related to a land acquisition and identified in the pre-filed testimony of OUCC witness Armstrong is not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates. Section B.3.b also stipulates and confirms that amounts related to F.B. Culley Unit 3 natural gas conversion identified by OUCC witness Krieger will not be included in this Cause.

OUCC witness Krieger opposed the Settlement Agreement because it did not address his allegations that CEI South had capitalized maintenance. He reiterated his position that CEI South's request for certain capital investment to be included in rate base remains unreasonable. Pub. Ex. 9-S at 2. He recommended a $150.9 million[13] reduction of capital investment in Steam Production Plant that CEI South proposed to include in rate base. Mr. Krieger also recommended a complete audit review to ensure Petitioner's capitalization of maintenance was not more prevalent than Petitioner presented, as well as ongoing audits and a refund of excess earnings garnered by CEI South through this practice. He stated that the impact of this recommendation would also reduce annual depreciation and the annual revenue requirement. He then said that information provided in CEI South's response to the Commission's docket entry dated April 29, 2024, CEI South confirmed that it had capitalized component items of multiple retirement units over a period of 11 years. He said this merits Commission scrutiny and future audits following a Final Order in this Cause. He said CEI South did not properly implement its policies and procedures. He called capitalizing valve replacements an "egregious violation" of the utility's policy when it occurs for 11 years. He further asserted that CEI South has shown a "longstanding disregard for proper treatment of rate base by capitalizing expense items." He said another example of Petitioner's deficient capitalization procedures is its failure to issue a Property Unit Catalog for solar

[13] Mr. Krieger recommended $150.9 million in Settlement opposition testimony (Pub. Ex. 9-S at 2), but did not explain the discrepancy between this number and the $150.7 million recommended disallowance in his direct testimony. Pub. Ex. 9 at 9.

generation assets, although CEI South has owned and operated solar generating facilities since 2018. Mr. Krieger requested the Commission order two types of audits: first, a complete historical audit, at CEI South's expense, and second, routine audits that last until CEI South's next rate case and are performed by a reputable accounting firm to ensure this practice is discontinued. Mr. Krieger recommended the cost of these audits should also be borne by CEI South and its shareholders.

Mr. Krieger reiterated his recommendations to exclude from rate base amounts for F.B. Culley 3 major projects and natural gas conversion as described in his direct testimony and amounts related to the replacement of a coal silo failure as described in his direct testimony. Pub. Ex. 9-S at 7.

On Settlement rebuttal, Mr. Rice noted that it appeared Mr. Krieger had adjusted his proposed disallowance related to the silo failure to $4.6 million from $8.8 million. He also testified that the $7.8 million to restore Culley Unit 3 following its forced outage should also no longer be in dispute given that the Commission found in Cause No. 38708 FAC 137 S1 that CEI South was not imprudent. In addition, Mr. Bradford had clarified on rebuttal that a significant portion of the Culley expenditures Mr. Krieger proposed to disallow were not included in rate base in this Cause. Pet. Ex. 19-SR at 17. Mr. Rice objected to Mr. Krieger's claims that CEI South had improperly capitalized component items of multiple retirement units over a period of 11 years. He stated CEI South has already conducted an audit of every expenditure since the last rate case making up Mr. Krieger's proposed disallowance. As indicated in CEI South's response to the Commission's docket entry dated April 29, 2024, CEI South identified 21 individual listings that would be in the test year and rate base in this case that may be component parts of retirement units. This was 21 out of a total of 12,161 lines of expenditures representing 1,139 individual projects placed in service over more than a decade. He said that, out of the $104.7 million in expenditures, CEI South identified $2.3 million, or 2.2%, for which CEI South does not have an explanation for why the expenditures were capitalized. He explained that CEI South did not "admit" that these amounts were improperly capitalized but stated it cannot identify why they were capitalized. Mr. Rice said that was an unfortunate circumstance that has arisen due to the passage of time as personnel who would have made the decisions over the years are no longer with CEI South. He testified that Mr. Krieger's suggestion to disallow $150.9 million has been refuted by the audit, Mr. Cunningham's and Mr. Bradford's rebuttal, and the Commission's Order in the FAC Subdocket. Further, Mr. Rice stated, his claim that this is an "egregious violation" warranting a presumption that CEI South does not properly keep its books is completely unjustified.

2. <u>IT-Related Investments</u>. CEI South witness Bahr presented testimony describing CEI South's cost optimization and resiliency strategies. He described the major IT investments that have been, or are in the process of being, implemented, namely: investments consistent with Cost Optimization, including Enterprise Integration Program ("EIP"), AMI, Advanced Distribution Management System ("ADMS"), Supervisory Control and Data Acquisition ("SCADA"), Digital Delivery, Cloud Acceleration, Transformation, and Optimization ("CATO"), and the SAP Business, Planning, and Consolidations ("BPC") Program; and

investments consistent with Resiliency, including Cybersecurity, Network Transformation, and Data Center Refresh and Resiliency. Pet. Ex. No. 8 at 8 through 27.

OUCC witness Compton opposed CEI South's proposed inclusion of IT investments in rate base, stating CEI South had not substantiated its proposed IT investments in its case-in-chief or provided sufficient evidence demonstrating the necessity of all the investments. Pub. Ex. 5 at 4. He stated there are no studies, reports, and projections supporting or identifying how CEI South's IT investments will benefit the resiliency and security of its systems, the difference in efficiency between the old and new applications, or how much application maintenance and support costs might decrease. Mr. Compton argued that the benefits Mr. Bahr claimed are merely broad assertions without support. He testified that, while CEI South did claim two of its applications have reached or will reach obsolescence, it did not explain, support, or show that its other technologies have reached that stage in their lives. He testified that CEI South simply stated its new investments will increase the efficiency of its operations without any cost-benefit study analyzing the level of improvements compared to investment cost. He contended that, with the evidence provided, there is no way to determine whether the investments CEI South has made and plans to make for its IT development are prudent or reasonable. Mr. Compton commented that it seemed incongruous for CEI South to claim it will realize decreased maintenance costs, increased resiliency, and improved efficiency but will still require the same FTE support staff as it did prior to the proposed IT investments. He derived a pro rata allocation methodology he used to allocate his recommended reduction in utility plant in service and accumulated reserve for his recommended disallowance. He recommended the Commission deny CEI South's request to include any of the IT investments described by Mr. Bahr in rate base.

CEI South witness Bahr noted on rebuttal that Mr. Compton proposed a broad disallowance and rejection of all IT investments without specifically identifying any proposed investments he considered unnecessary or excessive. Pet. Ex. 8-R at 2. He stated that, while Mr. Compton may be looking for a formal study, report, or analysis to justify or support the IT investments included within this Cause, in his 22 years of experience, IT departments do not necessarily conduct formal studies or analysis to evaluate which or whether IT software or hardware requires replacement or upgrade. He stated these requirements to replace, update, or upgrade software or hardware are also often recommended or necessitated by a vendor, citing examples such as the many iterations of Microsoft Windows software or hardware such as Intel Pentium processors or an aging iPhone. He testified this is the type of scenario driving considerable portions of the IT investments CEI South is making. Mr. Bahr explained that instead of formal studies and analysis, third-party or otherwise, IT investments are determined based on a variety of factors that include, but are not limited to, alignment to overall strategy, efficiency, or business continuity; supportability (*i.e.*, end of life or unsupported systems); performance and age; vulnerability and reliability; and functionality or customer/end user benefits. He reiterated that aside from an end-of-life driver (*i.e.*, the above example where the application or system is no longer supported or available as a technology option), age, functionality, performance, and reliability are closely linked factors when evaluating the need to update or replace technology. Mr. Bahr opined that Mr. Compton's characterization that CEI South did not provide any analysis to support the IT investments was not a fair characterization. He said that, aside from his explanation of the investments and drivers requiring the update or replacement within his direct testimony, CEI South responded to several data requests and produced a large volume of supporting attachments concerning these IT investments. Copies of relevant discovery responses were attached to Mr. Bahr's rebuttal

testimony at Petitioner's Exhibit No. 8-R, Attachment RWB-R1 (Confidential). Mr. Bahr pointed to his direct testimony on the obsolescence of certain IT programs and the benefits to be realized upon their replacement or update. He stated that Mr. Compton's assertion that CEI South did not make any claim of obsolescence regarding its software or hardware is incorrect. He referenced discovery responses that indicated not only how CEI South systems might improve but gave examples of how IT investments will improve the system or reduce maintenance. Mr. Bahr testified that it is not incongruous to understand benefits can arise from areas other than a pure headcount view, citing reductions in software or hardware maintenance costs, streamlined training costs and other external support costs realized or anticipated to be realized due to a harmonization, or consolidation of platforms. Mr. Bahr also cited increased resiliency stemming from the IT investments his testimony supports. He explained that it is difficult to quantify the support and maintenance reductions for the EIP Phase 2 investment, because the license, support, and maintenance costs are not expected to materially change until the applications he identified are decommissioned, a process which usually occurs within 12-24 months after go-live of the updated or replaced application and is dependent on several factors.

The Settlement Agreement does not expressly address the OUCC's proposed disallowance from rate base of CEI South's IT investments. The stipulated rate base Section B.3.a does not exclude these investments. By virtue of Section B.15.b of the Settlement Agreement, the Settling Parties stipulated that the issue would be resolved as proposed and supported in CEI South's case-in-chief. CEI South expressly supported, but did not modify, its position on the IT investments included in rate base on rebuttal.

OUCC witness Compton testified that accepting the IT investments amount inherently included in the Settlement Agreement is not in the public interest because CEI South has not substantiated the prudency and/or reasonableness of the investments. Pub. Ex. 5-S at 6. He contended that CEI South's discovery responses effectively take the position that the burden of proof lies with the intervening parties and that the Commission is obligated to take CEI South's word at face value and approve all its requested IT investments without further discussions. He stated CEI South's analysis of prudency regarding its IT investments is, however, not comprehensive and places an arbitrary emphasis on qualitative metrics.

iv. Commission Discussion and Findings. While the disputed rate base items were narrowed considerably by CEI South's rebuttal and settlement positions, the OUCC continues to oppose inclusion of certain Steam Production Plant investments and IT-related investments in Petitioner's rate base. We will address each of those disputes, and their proposed resolution in the Settlement Agreement, in turn.

With respect to Mr. Krieger's proposed disallowance for items he believes were improperly capitalized, the record shows that, with the potential exception of 21 items identified in CEI South's Response to our docket entry dated April 29, 2024, CEI South has accounted for these items properly, and Petitioner's capitalization policy and the FERC USOA support Petitioner's capitalization of these expenditures. CEI South's capitalization policy states "Company expenditures for items that have a useful life greater than one year or that extend the useful life of an existing asset by more than one year, that meet the minimum dollar thresholds, and that are not intended for sale in the ordinary course of business shall be capitalized as per the guidance outlined below." Pet. Ex. 22-R at 4. At Instruction 10, the USOA states:

A. For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

B. The addition and retirement of retirement units shall be accounted for as follows:

(1) When a retirement unit is added to electric plant, the cost thereof shall be added to the appropriate electric plant account, except that when units are acquired in the acquisition of any electric plant constituting an operating system, they shall be accounted for as provided in electric plant instruction 5.

(2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

C. The addition and retirement of minor items of property shall be accounted for as follows:

(1) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account.

(2) When a minor item of property is retired and not replaced, the book cost thereof shall be credited to the electric plant account in which it is included; and, in the event the minor item is a part of depreciable plant, the account for accumulated provision for depreciation shall be charged with the book cost and cost of removal and credited with the salvage. If, however, the book cost of the minor item retired and not replaced has been or will be accounted for by its inclusion in the retirement unit of which it is a part when such unit is retired, no separate credit to the property account is required when such minor item is retired.

(3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate electric plant account.

Pet. Ex. 22-R at 4-5.

In essence, "retirement units" are the lowest level of asset record that a utility keeps and it consists of "those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which it is included." USOA Instruction 34. Minor items of property are "the associated parts or items of which retirement units are composed." USOA Instruction 18. The USOA requires that "[e]ach utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently." USOA Instruction 10A.

In response to our April 29, 2024 docket entry (Pet. Ex. 23), CEI South identified only 21 individual listings for projects that were placed in service since the cutoff in Petitioner's last rate case and that would be in test year end rate base in this case that "may" be component parts of retirement units. The total of these items is $2.3 million, and the evidence merely shows that CEI South's records do not disclose the reasons the decision was made to capitalize them. The evidence supports CEI South's capitalization practices, and we cannot agree with Mr. Krieger that there is evidence of "egregious" or any other violation of the applicable accounting guidelines. The record does not support Mr. Krieger's disallowance and does not rise to the level of rejection of the Settlement Agreement as not in the public interest over what amounts to an immaterial discrepancy in the historical justification for capitalization of a mere 21 items out of thousands for which the record shows the justification remains intact. We reject Mr. Krieger's arguments against capitalization of these items.

We also find that the OUCC's recommendation that an audit be conducted of CEI South's capitalization of maintenance expenses is unreasonable and ignores the evidence presented on rebuttal and in response to our April 29, 2024 docket entry. The record reflects that CEI South's financial statements are already subject to annual audits by a firm of certified public accountants for compliance with GAAP and the FERC USOA and the Petitioner undergoes considerable diligence to ensure that capitalization decisions are correct. While we find the discrepancy to be immaterial and have no compelling reason to believe Petitioner had materially misstated its rate base, we will highlight this history to inform the Petitioner's auditors of this risk of material misstatement.

In this Commission's Order dated July 3, 2024 in Cause No. 38708 FAC 137 S1, we found that CEI South acted reasonably and prudently with respect to the events that gave rise to the June 24, 2022 through March 14, 2023 Culley 3 outage. As such, we find in this case that there is no basis for the disallowance of the $7.8 million in investments to restore Culley Unit 3 after the outage.

Despite Mr. Krieger's reiteration of his proposed disallowance of costs related to natural gas conversion for Culley Unit 3, the evidence reflects, and the Settlement Agreement confirms, that these conversion costs are not included in CEI South's rate base for purposes of setting rates in this Cause.

As for the other major projects at Culley 3, the record reflects that these expenditures were reasonable and prudently incurred and required as a result of OEM-recommended maintenance schedules, regardless of any future plans for the unit's conversion. We reject Mr. Krieger's arguments to exclude these expenditures.

With respect to Mr. Krieger's proposed disallowance for investments related to the coal silo failure, we adhere to our position that "the prudence of an electric utility's actions is not judged with twenty-twenty hindsight. Rather, the Commission will focus on the prudency of the decisions when made, based on the facts and circumstances as they existed at the time." *Southern Indiana Gas & Elec. Co.*, Cause No. 38708 FAC 137 S1 (July 3, 2024), at 9-10, (citing *N. Ind. Pub. Serv. Co.,* Cause No. 38706 FAC 130 S1 (June 15, 2022)); *see also N. Ind. Pub. Serv. Co*., Cause No. 44340 FMCA 12, at 12; *N. Ind. Pub. Serv. Co*., Cause No. 43849 (July 13, 2011), at 11). The evidence reflects that Petitioner acted reasonably based on the facts and circumstances known at the time of the failure. Accordingly, we reject Mr. Krieger's claim of "poor project management" and his proposed disallowance.

With respect to the OUCC's proposed disallowance for IT-related investments, the OUCC's position appears to be based primarily on its perceived lack of support from a formal study. However, we find that it is reasonable to replace outdated or obsolete software (*e.g.*, Adobe Flash) and hardware (*e.g.*, computer with an obsolete processor or dated network adaptors that do not have the latest performance capabilities) with newer technology to reduce risks and improve activities or processes performed by the technology. A formal study to quantify the operational efficiencies that result from such replacement, such as faster response times, better integration between systems, or new feature functionality or improved capabilities for users, is not a requirement for prudency, although capital investments of material size are often supported by one. The evidence demonstrates that the IT-related investments will be used and useful in the provision of electric utility service to customers in the test year, and Petitioner's evidence supports the expenditures with extensive discussion of the benefits of these investments for CEI South and its customers. Because the evidence of record sufficiently substantiates CEI South's investment decision, we reject the OUCC's proposed disallowance.

The Settlement Agreement incorporated several reductions to CEI South's test year end rate base, and we find it reasonably resolves the contested issues while recognizing ongoing capital investment is necessary to maintain safe, reliable, efficient, and environmentally compliant service.

E. <u>Return on Equity</u>. Section B.3.c. of the Settlement Agreement stipulates that CEI South's authorized Return on Equity should be 9.80%. Table B.3.c sets forth the stipulated capital structure as of the end of the test year, including the 9.80% ROE, cost of debt and zero cost capital as agreed by the Settling Parties. The resulting weighted average cost of capital is 6.77%, as described in further detail in the Settlement Testimony of Brett A. Jerasa. Settling Parties' Jt. Ex. 1 at Section B.3.c; Pet. Ex. 19-S at 11.

Section B.3.d of the Settlement Agreement stipulates that the agreed weighted cost of capital times the stipulated net original cost rate base yields a fair return on the fair value of rate base for purposes of this case. Accordingly, the Settling Parties agreed that CEI South should be authorized a fair return of $187,518,958, yielding an overall return for earnings test purposes of

6.77%, based upon the stipulated net original cost rate base, capital structure, and ROE. Settling Parties' Jt. Ex. 1 at Section B.3.d.

i. CEI South's Case-in-Chief. Ms. Bulkley estimated CEI South's cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. Her recommendation also considered the following factors: (1) CEI South's small size; (2) flotation costs; (3) CEI South's capital expenditure requirements; (4) the regulatory environment in which CEI South operates; (5) CEI South's customer concentration; and (6) CEI South's projected capital structure as compared to the capital structures of the proxy group companies. While she did not make specific adjustments to her ROE recommendation for these factors, she did consider them in the aggregate when determining where her recommended ROE falls within the range of the analytical results. Pet. Ex. 13 at 2-3.

Ms. Bulkley considered the following key factors in her cost of equity analyses and recommended ROE for CEI South in this proceeding:

> (1) The United States Supreme Court's *Hope* and *Bluefield* decisions,[14] which established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates;
>
> (2) The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements;
>
> (3) The results of several analytical approaches that provide estimates of CEI South's cost of equity. Because CEI South's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model; a forecasted risk-free rate and market risk premium in the CAPM analysis);
>
> (4) Although the companies in her proxy group are generally comparable to CEI South, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, Ms. Bulkley considered CEI South's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where CEI South's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk. Pet. Ex. 13 at 3-4.

Ms. Bulkley presented the results of the models she used to estimate the cost of equity for CEI South in her Figure AEB-1, summarizing the range of results produced by the Constant Growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses based on data through the end of September 2023. She noted the range of results produced by the models used to estimate

[14] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

the cost of equity is wide and that while it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Considering the analytical results presented in Figure AEB-1, current and prospective capital market conditions, and CEI South's regulatory, business, and financial risk relative to the proxy group, Ms. Bulkley concluded that an ROE in the range of 10.00% to 11.00% would be appropriate, and within that range, an ROE of 10.60% would be reasonable. As discussed in the testimony of Petitioner's witness Richard C. Leger, taking into consideration the affordability for customers of the overall revenue requirement, CEI South requested an ROE of 10.40%.

ii. OUCC's Position. OUCC witness Dellinger recommended the Commission approve a 9.0% authorized ROE based on his studies and analysis. He testified that he ran multiple models and identified certain differences between his analyses and those performed by Ms. Bulkley. Pub. Ex. 10 at 4. Mr. Dellinger conducted a constant growth DCF analysis, a two-stage DCF analysis, and two CAPM scenarios as his preferred cost of equity models.

Mr. Compton supported a 0.2% reduction to CEI South's authorized return on equity due to its "lack of transparency and unwillingness to provide the OUCC a general ledger in a manner that provides meaningful, reviewable information." Pub. Ex. 5 at 20.

OUCC witness Latham stated he recommended the Commission accept the OUCC's recommended 8.80% ROE and utilize the OUCC's proposed capital structure incorporating OUCC witness Dellinger's ROE recommendation, which results in a WACC of 6.29%. Pub. Ex. 2 at 9.

OUCC witness Eckert complained of "roadblocks" encountered by the OUCC in its efforts to review CEI South's case-in-chief, citing formula errors, hardcoded numbers, an "unwillingness to provide information in a timely manner," an "unwillingness to provide a transparent general ledger," and informal meetings that proved "unproductive and required the OUCC to issue additional discovery." Pub. Ex. 1 at 24-25. He ultimately recommended the Commission reduce Petitioner's ROE to incent CEI South to approach future cases in a "more cooperative and transparent spirit."

Mr. Compton elaborated that although CEI South provided its general ledger for the historic base period, the format in which it was provided did not allow the OUCC to effectively complete its review. Pub. Ex. 5 at 12. He said a meaningful analysis of the general ledger can only be completed when descriptions for *all* transactions are provided. On this basis, he recommended the Commission authorize CEI South a less favorable return on equity than supported by OUCC witness Dellinger.

Ms. Stull elaborated on the OUCC's complaints with Petitioner's revenue requirement model. She identified four material "deficiencies": (1) the financial model presented in Exhibit No. 20 does not include the entire forecast because amounts were hard-coded; (2) the financial model presented only the overall revenue requirement and rate increase proposed; (3) a majority of the inputs to the schedules and workpapers were merely hard-coded cell entries, with no indication as to how the amount was determined or the basis for the calculation of the amount entered; and (4) lack of detailed supporting calculations for the adjustments that are included in

Petitioner's Exhibit No. 20. Pub. Ex. 6 at 30. Ms. Stull opined that, to allow a reasonable review of its revenues and expenses, any utility using a forward-looking test year must provide the forecast for each month of the forward-looking test year and each month of the linking period. Such provision also allows the reviewer to determine whether Petitioner is being consistent in its forecasting methodologies. It also aids in verifying the rate increase Petitioner states for each phase of its proposal. It is not enough for Petitioner to merely describe in testimony what it proposes. It is also necessary to provide the amounts and calculations in its financial forecast model so that it can be verified that what Petitioner said it was proposing was supported.

OUCC witness Eckert also raised concerns that CEI South has ranked 16th out of the 16 utilities in the "Midwest Region" "Midwest Segment" in J.D. Power Customer Satisfaction surveys in four of the last five years, with 2020 being the exception when CEI South was ranked 15th. Pub. Ex. 1 at 18-19.

iii. CAC's Position. CAC witness Inskeep opposed CEI South's proposed ROE, arguing it "reflects an excessive profit margin for CenterPoint's shareholders at the cost of higher rates for its customers." CAC Ex. 2 at 39. He opined that "high ROEs distort utility incentives to over-invest in capital, potentially leading to even more customer bill increases in the future, as it creates a distorted incentive for the utility to invest more than is reasonable in utility plant." He recommended that the Commission should significantly reduce CEI South's currently authorized ROE and set it at the lowest end of the range that the Commission determines to be reasonable.

Mr. Inskeep also referenced the J.D. Power annual Electric Utility Residential Customer Satisfaction Study, saying CEI South has ranked extremely poorly in residential customer satisfaction in every year since at least 2015. CAC Ex. 2 at 39-41.

iv. IG Position. IG witness Gorman opined that CEI South's requested ROE of 10.4% is excessive and would result in unjust and unreasonable rates being imposed on CEI South's customers. IG Ex. 1 at 6. Mr. Gorman conducted two constant growth DCF analyses (*i.e.*, one relying on analysts' projected earnings per share ("EPS") growth rates and another relying on a sustainable growth rate), a two-stage DCF analysis, two CAPM scenarios, and a Risk Premium analysis. While the results of Mr. Gorman's costs of equity models ranged from 9.20% to 9.80%, he condensed his recommended range by review of all his market return estimates that showed the current market ROE falls in the range of 9.20% to 9.65%, with an approximate midpoint estimate of 9.45%. IG Ex. 1 at 99. Mr. Gorman then reduced his midpoint ROE estimate of 9.45% by 25 basis points as a downward risk adjustment, stating that the adjustment is to "offset some of the excessive cost to ratepayers created by CEI South's unreasonable equity-thick ratemaking capital structure and mitigate, in part, its cost of service increase and the related adjustment to tariff rate charges in this case."

v. CEI South Rebuttal. On rebuttal, Ms. Bulkley testified that the primary factors that should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE are: (1) the importance of investors' actual return requirements and the critical role of judgment in selecting the appropriate ROE; (2) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (3) the need for a return that supports a utility's ability to attract needed capital at reasonable

terms; (4) the effect of current and expected capital market conditions; and (5) achieving a reasonable balance between the interests of investors and customers. Pet. Ex. 13-R at 3-4. She testified that nothing in the testimony of Mr. Dellinger, Mr. Gorman, Mr. Eckert, or Mr. Inskeep has caused her to change her recommendations. She updated her cost of equity estimation models to reflect the most current data, which demonstrated that the model results continue to support her recommended ROE of 10.6% and therefore the 10.4% ROE requested by CEI South remains reasonable.

With respect to Mr. Eckert and Mr. Inskeep, Ms. Bulkley testified that neither Mr. Eckert nor Mr. Inskeep have conducted any analysis to estimate the ROE for CEI South, nor have they conducted a relative comparison of the risk of the utilities of the proxy group companies relative to CEI South. Therefore, she contended there is no basis for either Mr. Eckert or Mr. Inskeep to comment on the relative risk of CEI South to the proxy group, let alone conclude that the ROE should be reduced by 20 basis points as recommended by Mr. Eckert.

CEI South witness Jerasa testified on rebuttal regarding credit rating agency reports on CEI South. In particular, he noted that on March 19, 2024, S&P updated its outlook on CenterPoint Energy, Inc. and its subsidiaries (including CEI South) to negative,[15] meaning that its rating could be downgraded in the next 12 months if "financial measures weaken due to higher-than-expected leverage stemming from elevated capital spending or weaker than-expected cash flow from pending rate cases."[16] Mr. Jerasa also testified that S&P also lowered the standalone credit profile on CEI South to A-minus from A to reflect weaker financial measures. He testified that the outcome of this rate case, including ROE and equity capitalization, will have a material impact on CEI South's credit ratings and future prices demanded by investors to purchase CEI South's debt. Pet. Ex. 14-R at 6. In light of S&P's comments, Mr. Jerasa testified that he disagreed with Mr. Gorman's assertion that a decrease in ROE from 10.4% to 9.2% would protect CEI South's financial integrity, support its current ratings, and not result in close rating agency scrutiny on the impact to CEI South's long term cash flows. He stated that Petitioner's projected 5.12% cost of debt is based upon its current ratings, and a ratings downgrade would increase the cost of long-term debt, impacting not only the capital proposed in this rate case, but any other capital afterwards included in all trackers that update cost of capital and future rate cases, which would increase costs to customers for years to come.

CEI South witness Behme responded to the OUCC's objections to the presentation of CEI South's financial exhibit. She stated there are hard-coded numbers because even if a model were so detailed as to identify every expenditure, employee, customer – it will still ultimately begin with a hard-coded number. She said the revenue requirement model is populated with data pulled directly from CEI South's computer data system. Ms. Behme described an informal meeting held with the OUCC to attempt to provide additional clarity to assist in transparency and noted that Petitioner's confidential "Revenue Model Workpaper" along with other support files produced in discovery were provided to the OUCC. With respect to the general ledger, she indicated the level of detail the OUCC sought simply was too much to be produced in Excel. She further noted the MSFR set forth at 170 IAC 1-5-7(2) requires "a listing of standard monthly journal entries" and

[15] S&P Global Ratings, "Research Update: CenterPoint Energy Inc. and Subsidiaries' Outlook Revised to Negative on Weak Financial Measures; Ratings Affirmed," March 19, 2024.
[16] *Id.*

not a general ledger with transaction descriptions and vendor names. She testified that she did not believe either of the OUCC's two main objections would have been an issue if the OUCC had conducted a site visit during their audit.

CEI South witness Rice responded to the criticism of the J.D. Power scores, acknowledging that they are lower than where CEI South would like them to be and stating CEI South works every day to drive customer satisfaction higher. Pet. Ex. 19-R at 40. He described the recently formed Customer Satisfaction Advisory Team that includes cross functional employees across CenterPoint Energy, Inc.'s footprint with representation from market research, communications, community involvement, billing, contact center, operations, continuous improvement, engineering, safety, IT, and legal functions and with executive sponsorship by the Senior Vice President and Chief Customer Officer. Pet. Ex. 19-R at 40. Mr. Rice explained that customer perception scores are highly correlated with the price a customer pays – as price goes up, overall customer satisfaction drops. He testified that, in 2022, price was the biggest factor driving customer satisfaction lower. Nevertheless, Mr. Rice provided evidence that CEI South was one of only ten Midsized electric companies out of 63 that showed an increase in customer satisfaction in 2023, improving by five points compared to the Midwest, Midsized segment that decreased by 13 points.

vi. Settlement. Mr. Jerasa testified in support of the ROE provided in the Settlement Agreement, explaining that, although it is below the lower bound of Ms. Bulkley's recommended range, the Settlement Agreement represents negotiations among the Settling Parties regarding several otherwise-contested issues. Pet. Ex. 14-S at 3-4. He opined the Settlement Agreement, including an ROE of 9.80%, should be viewed by the rating agencies as constructive and should allow CEI South to attract capital at reasonable rates. Mr. Jerasa testified that Settlements can signal a constructive outcome that balances the needs of the parties and demonstrates the ability of a utility to execute its capital investment plan. Reasonable settlement outcomes demonstrate the constructiveness of a utility's rate recovery and factor into investors' decisions to participate in capital markets issuances. He stated that the rejection of the stipulated ROE contained in the Settlement Agreement would likely signal a non-supportive regulatory environment, which could further deteriorate CEI South's credit ratings and financial integrity, increasing costs for customers in the near- and long-term.

IG witness Gorman opined that the agreed-upon 9.80% in this case is well within the range of reasonableness identified by witnesses in this case.

vii. Settlement Opposition. OUCC witness Eckert recommended the Commission reject the 9.80% ROE agreed upon in the Settlement Agreement, approve the 9.00% ROE calculated and supported by OUCC witness Dellinger, and further reduce the 9.00% by 20 basis points due to what he characterized as issues with Petitioner's reliability, customer satisfaction, and the challenges the OUCC encountered in conducting its analysis of Petitioner's case-in-chief. Pub. Ex. 1-S. Mr. Eckert testified that a lower ROE is warranted based on CEI South's reduced level of risk, particularly when compared to 2011 when its current base rates were established. Pub. Ex. 1-S at 13. He noted the various trackers Petitioner has had approved by the Commission, and stated these trackers shift the risk of increased operating expenses and capital expenditures from utilities to their ratepayers by reducing revenue recovery risk and investors' earning uncertainties. Mr. Eckert testified that a lower ROE is also warranted because, per the J.D. Power surveys, CEI South ranks last or near the bottom in each of the last five years. He referred

to past Commission orders in Cause Nos. 43526 and 44576 that adjusted ROE for utility management concerns. Pub. Ex. 1-S at 11.

OUCC witness Compton opposed the agreed-upon ROE and again cited CEI South's significant lack of transparency and unwillingness to provide a comprehensive general ledger. He said these concerns may not have negatively affected the industrial members of the Settling Parties, but Petitioner's reticence and lack of transparency should be addressed as he advocated, not tacitly endorsed. Pub. Ex. 5-S at 3. He acknowledged that CEI South's general ledger includes over three million transactions while Excel limits its spreadsheets to roughly 1.05 million rows. He said CEI South could have simply provided the general ledger with the additional requested information through multiple Excel files instead of just one, just as it had done voluntarily with respect to the multiple Excel files provided when complying with the Commission's MSFRs at 170 IAC 1-5-7(2). CEI South submitted four Excel files for assets and six Excel files for expenses for a total of ten separate files with its case-in-chief.

Ms. Stull opposed the Settlement Agreement in part due to her continued belief that the presence of hard-coded numbers in CEI South's financial model deprived the OUCC of a meaningful opportunity to review CEI South's request. Pub. Ex. 6-S at 13. She maintained that CEI South's financial model is an outlier and lacks much of the information available in the financial models of other utilities who have filed forward-looking test year rate cases. She specifically referenced Indiana American Water Company's model in Cause No. 45870. She opined that the Settling Parties' agreed ROE enables CEI South to "avoid accountability for its lack of transparency."

OUCC witness Dellinger testified that the simple fact that CEI South reduced its ROE request from 10.4% to 9.8% does not make the settled amount reasonable. Pub. Ex. 10-S at 3-4. He stated nothing in Mr. Gorman's settlement testimony indicates that his original ROE recommendation of 9.2% is unreasonable. He noted the 60 basis point increase from 9.2% to 9.8% in the Settlement Agreement would raise Petitioner's requested rate increase by approximately $10.2 million. *Id*. Mr. Dellinger also argued that because the OUCC and other consumer parties did not join this Settlement Agreement, the 9.80% ROE in this case is not a reasonable compromise for the concessions exchanged in the Settlement Agreement.

CAC witness Inskeep testified that the Settlement Agreement's stipulated ROE of 9.8% is "unreasonably high for CEI South given its poor track record when it comes to affordability, reliability, and customer satisfaction, and particularly so given the extraordinary residential bill increase proposed." CAC Ex. 6 at 19. He urged the Commission to find that the Settlement Agreement should be rejected as it would further erode CEI South's customer satisfaction.

viii. <u>Settlement Rebuttal</u>. IG witness Gorman testified that Mr. Dellinger's testimony appears to assume that the Industrial Group should have insisted that the Settlement adopt either the OUCC's litigation position on ROE (8.8%), or the Industrial Group's litigation position on ROE (9.2%). IG Ex. 6 at 3. Mr. Gorman stated that, while he believes the ROE analysis in his direct testimony is reasonable, he recognizes that there is risk that his position would not be fully adopted in a litigated outcome. Mr. Gorman explained that, for its part, CEI South correspondingly recognizes the risk that CEI South's litigation position would not be fully adopted in a litigated outcome, either. Mr. Gorman stated his recommendation for approval of an

ROE that is between the parties' positions is not, as Mr. Dellinger alleges, a "discrepancy" in his testimony, but is rather recognition of the reality of the risk that is inherent in litigation.

CEI South witness Rice stated that the punitive ROE sought by the OUCC accounted for approximately $18 million of the $31.7 million difference between the settled revenue increase and the OUCC's filed position. He testified that the OUCC cited no vertically integrated electric utility in the country with an authorized ROE that is that low. Pet. Ex. 19-SR at 4.

Mr. Rice responded to Ms. Stull's and Mr. Compton's opposition related to their assertion of a lack of transparency, reasserting the arguments he made on rebuttal.

In Attachment MAR-SR2 to his settlement rebuttal testimony, Mr. Rice reiterated the options CEI South has proposed that could help with customer satisfaction that the OUCC continues to oppose, including the CPP Pilot, Rider ADR, and the Green Energy Rider. Pet. Ex. 19-SR, Attachment MAR-SR2 at 1; Pet. Ex. 19-R at 42.

CEI South witness Jerasa opined that the 8.8% ROE proposed by the OUCC is unreasonable, 100 basis points below the Settlement Agreement, does not support CEI South's financial integrity, and would be ultimately harmful to CEI South's customers. Pet. Ex. 14-SR at 2. He testified that an 8.8% ROE would signal to investors, the rating agencies, and customers that Indiana is not supporting the investment necessary for reliability, resilience, stability, and environmental sustainability. He also opined that the proposed 8.8% ROE would have a negative impact on affordability for present and future generations due to probable credit downgrades and higher borrowing costs. He explained that 9.80% is not just "within the range of results" but is in fact what the financial community expects when compared to CEI South's Indiana peers and the vertically integrated electric industry in general. He said the Settlement Agreement, including an ROE of 9.8%, should be viewed by the rating agencies as constructive and should allow CEI South to attract capital at reasonable rates since the ROE is comparable to other vertically integrated electric utilities.

ix. Commission Discussion and Findings. The ROE is intended to provide a utility with a reasonable opportunity to attract capital on terms comparable with businesses of similar risk. In setting the rate of return, the Commission's decision must be framed by *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591 (1944); *see also Indianapolis Power & Light Co.*, Cause Nos. 44576 and 44602 (March 16, 2016), at 41. The general standards these cases established require a ROE set by the Commission to be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns of other businesses of comparable risk.

Both the OUCC and CAC have asked for punitive measures based on poor customer satisfaction ratings (inextricably tied to price/complaints over high rates) and a perceived lack of transparency in Petitioner's presentation of its case. We find these arguments unsupported by the evidence. Petitioner's presentation of its case is: (1) nearly identical to that of its most recent gas rate case and the gas rate case of its affiliate Indiana Gas Company, Inc. d/b/a CenterPoint Energy Indiana North; (2) similar to the presentation of other electric utilities' forward-looking test year rate cases; and (3) built differently from the forward-looking test year rate cases of Indiana-

American Water Company, Inc., which the OUCC cited to point to a lack of accountability by Petitioner. None of this supports a finding that Petitioner has failed to carry its burden or otherwise requires disciplinary action over the presentation of its case or a lack of transparency. There was extensive testimony offered to describe how Petitioner developed its forecasted test year and extensive discovery conducted in this case, and the record reflects Petitioner responded to discovery in a timely manner and made reasonable attempts to provide the OUCC with the information sought. *See ,e.g.*, Pet. Ex. 2 (Behme) at 32-33; Pet. Ex. 3 (Gray) at 3-13; Pet. Ex. 4 (Rawlinson) at 6-9 and 23-25; Pet. Ex. 5 (Folz) at 20-25 and 29-30; Pet. Ex. 6 (Maurer) at 2-9; Pet. Ex. 7 (Bradford) at 6, 13-17; Pet. Ex. 8 (Bahr) at 8-29; Pet. Ex. 9 (Wood) at 8-13; Pet. Ex. 10 (Williford) at 9-10; Pet. Ex. 14 (Jerasa) at 3-5; Pet. Ex. 15 (Story) at 13-19; Pet. Ex. 16 (Russo) at 2-14; Pet. Ex. 17 (Forshey) at 18; *see also* Pub. Ex. 6 (Stull), Attachment MAS-8. The OUCC's own testimony acknowledges the vast amounts of data Petitioner provided with respect to its general ledger. Moreover, regarding the J.D. Power Customer Satisfaction survey results, the record reflects that, relative to its peers, CEI South is improving both in rates relative to other utilities[17] as well as in customer satisfaction.

In Cause No. 46038, the Commission recently found that an ROE of 9.75% is fair and reasonable for Duke Energy Indiana. Notably, Duke Energy Indiana has a larger customer base than CEI South and an adjustment to account for their different size-related level of risk could be warranted. The record reflects that the agreed 9.80% ROE in the Settlement Agreement is within the range of evidence the Settling Parties presented and is within the range of current Commission-authorized ROEs or negotiated ROEs for other Indiana investor-owned utilities. Furthermore, in comparison, CEI South's ROE is appropriately based given a measured adjustment for utility size. The agreed ROE benefits ratepayers by reducing the return on rate base reflected in customers' rates as compared to CEI South's initial proposal. The record further shows the agreed ROE is an important part of the overall settlement package and that it is essential that Petitioner be provided the opportunity to earn an ROE that is consistent with the market. The Commission finds that, as part of the Settlement Agreement, the agreed ROE balances the parties' concerns while preserving Petitioner's financial integrity and should, therefore, be approved.

F. <u>Depreciation Rates and Amortization</u>. The Settlement Agreement provides for adoption of the OUCC's proposed depreciation accrual rates, except for the CT Project and Posey Solar, which will remain unchanged. It also provides for a three-year pass-back of state EADIT, with no carrying charges. Because the EADIT will flow through the TAR, this stipulated term does not affect the revenue requirement. In addition to this specific amortization term related to EADIT, the Settlement Agreement obligates CEI South to file a revised tariff to remove annual amortization amounts from base rates upon each such expiration, unless a new general rate case petition is pending at that time.

i. <u>Depreciation</u>.

1. <u>CEI South's Case-in-Chief</u>. Petitioner proposed new depreciation accrual rates for its electric and common plant and presented a depreciation study prepared by witness Spanos. For purposes of his calculations, Mr. Spanos included generation decommissioning estimates prepared by witness Kopp. Pet. Ex. No. 12. While Mr. Spanos

[17] See Pet. Ex. 19-SR at 8.

calculated depreciation accrual rates for the CT Project and for Posey Solar, Petitioner proposed to maintain the lower rates approved in the CPCN proceedings for the CT Project and Posey Solar in Cause Nos. 44564 and 45847, respectively. Petitioner also chose to have Mr. Spanos calculate depreciation rates using the Average Life Group method rather than the Equal Life Group method, producing an additional savings of $12.5 million in the revenue requirement. Pet. Ex. 1 at 15.

2. OUCC's Position. OUCC witness Garrett made several suggested changes to the calculations presented by Mr. Spanos. He removed contingency costs from the decommissioning estimates, adjusted several mass property account service lives, and recommended adjustments to proposed net salvage rates for several mass property accounts. His recommendations produced a $5.1 million reduction in CEI South's revenue requirement. Pub. Ex. 11 at 3. He proposed rates for the CT Project and Posey Solar that were higher than CEI South had proposed. Pet. Ex. CX-1.

3. CEI South's Rebuttal. In rebuttal, Mr. Spanos responded to all the critiques and adjustments recommended by Mr. Garrett and continued to support CEI South's originally filed depreciation rates. Pet. Ex. 12-R.

4. Settlement. The Settlement Agreement provides for the adoption of the depreciation accrual rates recommended by Mr. Garrett except for the rates for the CT Project and Posey Solar. For those two generation stations, the Settlement Agreement provides for the continuation of the rates approved in the CPCN orders for those projects. There was no opposition to this term.

ii. Amortization.

1. CEI South's Case-in-Chief. CEI South witness Behme presented the calculation of amortization expense related to regulatory assets and liabilities. Pet. Exhibit 2, pp. 24-30. Included in these amortizations were two income tax-related deferred liabilities sponsored by CEI South witness Story. Witness Story proposed that Indiana state EADIT be returned to customers over a five-year period, to match the period used in Cause Nos. 45447 and 45468. The pass back would be accomplished through the TAR and outside of base rates. Pet. Ex. 15 at 13. Ms. Story also sponsored amortization of a deferred Medicare Tax liability over five years. Pet. Ex. 15 at 19; Pet. Ex. 2 at 30.

2. OUCC's Position. OUCC witness Baker opposed the amortization of the deferred Medicare Tax liability because the amortization had been authorized in Petitioner's prior rate case and should have been completed already. Pub. Ex. 4 at 9. Witness Stull recommended that Indiana EADIT be passed back to customers over a three-year period. She made this recommendation because there is no requirement to normalize any portion of state EADIT as there is with protected federal EADIT. She also requested that state EADIT accrue carrying charges. Pub. Ex. 6 at 5-8.

3. Industrial Group's Position. Mr. Gorman also recommended that Indiana state EADIT be returned to customers over a three-year period. He did not recommend the accrual of carrying charges. IG Ex. 1 at 10-13.

4. CEI South's Rebuttal. Witness Story continued to advocate a five-year pass-back of state EADIT. She also explained why carrying charges on the balance were inappropriate. Regarding Ms. Stull's argument that the delay in implementing the pass back of state EADIT means customers have been deprived the use of money that has subsequently been devalued by inflation, Ms. Story responded that customers have already enjoyed the value of this balance. EADIT formerly (before the tax rate reduction) was deferred income tax. It was reflected in the capital structure at zero cost. After the tax rate reduction began, EADIT continued to be reflected as a zero-cost source of capital. As such, it reduced Petitioner's authorized rate of return. To now accrue carrying charges would be double counting. Ms. Story noted that Ms. Stull did not cite any other occasion in any rate case where carrying charges have been accrued on the state EADIT balance. She stated CEI South should not be singled out and treated differently from other similarly situated utilities. Finally, Ms. Story testified that CEI South could have lawfully begun amortizing the state EADIT balance in 2011 but it did not. With respect to Ms. Stull's and Mr. Gorman's arguments that the state EADIT should be amortized over three years instead of five, Ms. Story noted recent Commission decisions determining state EADIT should be normalized and not flowed back more quickly and the fact that CEI South's gas utility amortizes the balance over a five-year period.

Witness Behme responded to witness Baker's opposition to the amortization of the Deferred Medicare Tax Liability. She noted that this amortization produces a decrease to the revenue requirement. Pet. Ex. 2-R at 21.

5. Settlement. CEI South witness Rice stated Section B.4.b of the Settlement Agreement reflects an amortization period of three years for Indiana state EADIT as proposed by OUCC witness Stull and Industrial Group witness Gorman. Pet. Ex. 19-S at 12. He explained stipulating and agreeing to this settlement provision accelerates the amount being returned to customers, increasing the amount by $1,521,643 per year over the three-year period. However, the Settlement Agreement does not adopt OUCC witness Stull's further recommendation to impose carrying charges. He stated the total $11,412,320 in Indiana state EADIT is proposed to be passed back through the TAR. As such, this stipulated term does not affect the revenue requirement but helps mitigate the bill impact by lowering customer bills and furthering gradualism. Section B.4.b of the Settlement Agreement also stipulates that if not already addressed by an intervening base rate case order before the expiration of various amortization periods, CEI South agrees to file a revised tariff to remove the annual amortization portion from base rates unless a new general rate case petition is pending at that time.

There was no settlement opposition to either of these amortization terms.

iii. Commission Discussion and Findings. Neither the settled depreciation term nor the amortization terms were opposed. We find both to be reasonable compromises based upon the evidence and therefore approve them.

G. Pro Forma Revenues and Expenses. Section B.5 of the Settlement Agreement provides for adjustments to pro forma revenues and expenses, totaling $15,250,808, to address issues raised by the parties, including: (1) base cost of fuel, (2) interruptible sales billing credits, (3) capacity purchase costs, and (4) O&M expense.

Specifically, these adjustments incorporate recommendations from OUCC witnesses Eckert and Lantrip with respect to the base cost of fuel and interruptible sales billing credits, reduce the forecasted level of capacity purchase costs in the test year, and reduce the level of O&M expense to achieve a level representing a compromise on various reductions to O&M expense recommended by the OUCC and other intervenors. The overall reductions to forecasted test year O&M expense for purposes of the revenue requirement are partially offset by inclusion of $813,540 related to cloud computing arrangements in exchange for Petitioner's withdrawal of its request for regulatory accounting treatment with respect to those arrangements. Pet. Ex. 19-S at 13-14.

i. CEI South's Case-in-Chief. CEI South witness Gray presented the unadjusted forecasted test year financial data. Pet. Ex. 3, Attachment SEG-1 and Schedules C-1.1, C-1.1a, and C-2.1 within Petitioner's Exhibit No. 20.

In her direct testimony, Ms. Behme described various adjustments to CEI South's pro forma level of operating revenues and expenses, including for the following items: (1) removal of Section 24 contract revenues, (2) adjustments related to CEI South's 44910 TDSIC and 45894 TDSIC, (3) adjustments for annualized CECA revenues and removal of levelized rate projects, (4) adjustments associated with the ECA rider, (5) annualized DSMA revenue and allocation of DSMA over/under-recoveries to the rate classes from miscellaneous revenues, (6) allocation of MCRA over/under-recovery to the rate classes and matching of forecasted MCRA revenues with recoverable expenses, (7) allocation of RCRA over/under recovery to the rate classes and matching of forecasted RCRA revenues with recoverable expenses as well as to reflect anticipated purchases of capacity from a demand response aggregator, (8) adjustments to EADIT to reflect amounts forecasted to be passed back through the proposed TAR, (9) similar adjustments for EADIT related to securitization of A.B. Brown, (10) adjustments to reflect the change in operating revenues and operating expenses for normalized FAC associated with F.B. Culley Unit 2, (11) removal of operating revenues and expenses for RECB projects, (12) adjustments to reflect the change in operating revenues and operating expenses for various adjustments to Miscellaneous Revenue to synchronize to the forecasted test year revenue, (13) an adjustment of $414,956 ($2,074,780 amortized over five years) to increase test year expenses for the estimated incremental rate case costs associated with this proceeding, (14) an increase in operating expenses of $108,034 associated with the proposed five year amortization of COVID-19 deferred expenses, (15) pro forma level of IURC fees, (16) an adjustment in the amount of $9,946,645 to reflect annualized depreciation expense based on plant in service as of December 31, 2025 at the proposed depreciation rates discussed above, (17) removal of expense associated with Troy Solar, (18) removal of expense associated with Crosstrack Solar, (19) increase of $38,459 in VUH shared services charges for the test year, (20) annual amortization expense associated with the AMI deferrals related to PISCC and deferred depreciation, (21) annual amortization expense associated with the regulatory assets for the 44910 TDSIC and the 45894 TDSIC deferred revenues and deferrals related to PISCC and deferred depreciation, (22) annual amortization expense associated with the CECA deferrals, (23) annual amortization expense associated with the ECA deferrals, (24) amortization of PISCC that will accrue to a regulatory asset after completion of F.B. Culley East Ash Pond project, (25) annual amortization expense associated with CT Project deferrals related to PISCC, (26) pro forma adjustments decrease of $560,000 to normalize IRP expense, (27) annualized property tax expense on forecasted tax basis balance of assets as of December 31, 2025, (28) pro forma adjustment of $75,808 decrease to test year expense to annualize the level of

uncollectible accounts expense to the latest known level, (29) pro forma adjustment of $160,653 decrease to test year expenses associated with sponsorships including Indianapolis Colts and Ford Center that should have been recorded below the line, (30) pro forma adjustment of $347,401 decrease to test year expense associated with Deferred Medicare Tax Liability, (31) pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with the CT Project, (32) pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with Posey Solar, (33) pro forma adjustment decrease to test year expense associated with F.B. Culley Unit 2 (Phase 3 (end of test year) adjustment only), (34) pro forma adjustment to normalize outage operating expense, (35) pro forma adjustment increase to test year expense of $770,000 pertaining to the SAP S/4HANA Transformation Project described by CEI South witness Bahr, (36) pro forma adjustment decrease to test year expense of $1,368,371 pertaining to ash transportation and ash handling operating expenses that should have been deferred to a regulatory asset during the test year, (37) pro forma adjustment decrease to test year expenses of $159,143 pertaining to non-recurring miscellaneous forecast adjustments to correct FERC 5930 for distribution programs that should have been capitalized, and (38) & (39) Indiana state and federal income taxes for pro forma adjusted test year. Pet. Ex. 2 at 19-31.

CEI South witness Bahr described the IT-related components of the CPP pilot as well as the SAP S/4HANA Transformation Program. He said the expense allocated to CEI South for the SAP S/4HANA Transformation Program is $770,000 for 2025. Pet. Ex. 8 at 28.

ii. OUCC's Position.

1. Base Cost of Fuel. OUCC witness Eckert testified that CEI South is requesting a base cost of fuel that is too high given current market conditions. Petitioner is proposing a $0.048139 per kWh base cost of fuel as compared to the $0.038295 per kWh currently approved base cost of fuel. Mr. Eckert testified the cost of natural gas and the MISO market prices proposed to be used in the base cost of fuel by CEI South were too high. Pub. Ex. 1 at 36. He stated that, as of March 4, 2024, the forecasted cost of natural gas and MISO market prices for 2025 had decreased and are expected to stay low. The OUCC's adjustment lowers fuel costs by $8,175,808. *Id.* at 37.

2. Interruptible Sales Billing Credits. OUCC witnesses Lantrip and Wright recommended denial of CEI South's request to embed $725,000 in interruptible sales billing credits into base rates, due to lack of substantive support. Pub. Ex. 3 at 14; Pub. Ex. 8 at 6. Mr. Wright said CEI South has not provided evidence supporting the revenue adjustment of $725,000, which was based on a 2022 Request for Proposal. He said CEI South did not provide supporting evidence that the RFP represented a reasonable price for the demand response capacity. Pub. Ex. 8 at 6. He expressed concern over the lack of details regarding the function of the contract with an aggregator.

3. Emissions Allowance Costs. OUCC witness Lantrip recommended the Commission deny the Emissions Allowance portion of costs in base rates, contending that Petitioner has not demonstrated prudence regarding the management of its allowance inventory. He recommended embedding a zero balance in base rates and Petitioner's approval of its Emissions Allowance inventory variance be contingent upon an improvement of its

practices, as demonstrated through updates of less volatility in inventory levels presented in its RCRA rider testimony. Pub. Ex. 3 at 13-14.

Ms. Armstrong testified that CEI South's allowance cost assumptions to determine forecasted allowance expense do not reflect significant price decreases in the allowance market or the effect of zero-cost allowances allocated to CEI South's generating units. She argued that CEI South's forecasted emission allowance expense is likely to be overstated. Pub. Ex. 7 at 3. She also stated that CEI South's filed exhibits and workpapers did not provide detailed monthly emission allowance inventory calculations by allowance type, which she said was necessary to verify the monthly allowance inventory balance and expense. Ms. Armstrong said Petitioner does not appear to account for zero-cost allowances that will be allocated to its units during the test year. Instead, CEI South's method for estimating test year allowance expense assumes that it will need to purchase NOx allowances for every ton of NOx it will emit, which Ms. Armstrong says likely overstates the total cost of CEI South's allowance purchases in 2025. Since CEI South's actual allowance expenses are tracked through its RCRA, Ms. Armstrong contended it is reasonable to remove all forecasted allowance expense from the test year, thereby mitigating the risk of embedding overstated allowance expense in test year O&M, while providing CEI South the ability to recover allowance costs if future allowance prices increase substantially in reaction to changes in federal air rules. The OUCC's recommendation would remove from the test year $1,282,707 of rate base and $3,519,952 of Emission Allowance O&M costs. Pub. Ex. 3 at 14; Pub. Ex. 7 at 11.

4. IT O&M Expense. OUCC witness Compton recommended the Commission deny CEI South's request to include $770,000 in O&M expense for its SAP transformation program and $813,540 in O&M expense for cloud computing arrangement costs to be incurred in 2025 under the CATO Project. He based his recommendations on what he characterized as CEI South's failure to provide proof of the necessity behind the investments and failure to substantiate the claimed benefits for its system. Mr. Compton testified that CEI South's responses to discovery showed Petitioner performed no study and conducted no analysis to support the benefits it claims from these IT programs. Pub. Ex. 5 at 8.

5. Rate Case Expense. OUCC witness Compton testified that he does not dispute CEI South's estimate for rate case expense of $2,074,780, but he encouraged the Commission to not accept the premise that CEI South's ratepayers should be wholly responsible for reimbursing Petitioner for that expense through its rates. He advocated for rate case expense incurred in this Cause to be borne equally by CEI South as a below-the-line expense, making ratepayers responsible for $1,037,390 and shareholders responsible for $1,037,390, recognizing that significant benefits flow to shareholders. As to CEI South's proposal to recover any unamortized rate case expense in its next rate case, Mr. Compton stated that proposal is acceptable provided CEI South's customers be similarly protected from continuing to pay that expense after the authorized rate case expense has been fully amortized. He recommended CEI South be required to amend its tariff of rates and charges once its authorized rate case expense has been fully amortized to remove that expense from rates. Pub. Ex. 5 at 17. Mr. Compton testified that Indiana statutes do not prohibit the Commission from allowing rate case expenses to be shared among shareholders and ratepayers. He opined that "as evidenced in this case," requiring ratepayers to pay all rate case expenses removes any financial incentive for petitioning utilities to be transparent and cooperative when providing information in its case and through data requests. He asserted that a petitioner's lack of transparency requires the OUCC to ask extensive discovery

questions, which, in turn, can increase the legal costs incurred by the utility. He recommended the Commission allow CEI South to collect $1,037,390 amortized over five years for an annual pro forma revenue requirement adjustment of $207,478.

6. Sponsorships. OUCC witness Compton recommended removal of $6,654 for sponsorship of the Ohio Valley Conference Basketball Tournament and $3,025 for the University of Evansville sponsorship, stating these sponsorships are for image building and enhancing relations in the communities in which CEI South operates as well as advertising. Pub. Ex. 5 at 3.

7. Competitive Pay Adjustments. OUCC witness Baker recommended the Commission deny CEI South's requested recovery of a competitive pay adjustment ("CPA") of 3% due to the low number of job vacancies and total salaries being under budget for multiple years during the 2018-2023 period. Pub. Ex. 4 at 1 and 7. She testified that the surveys and studies relied on in CEI South witness Williford's testimony were not appropriate to determine a basis for the proposed CPA. Ms. Baker testified that the survey participants and data are not shown to be a fair comparison to a company of Petitioner's size, location, and characteristics. Ms. Baker testified that her review of base pay and job availability revealed CEI South is not experiencing difficulty maintaining reliable employees and CEI South has been consistently under budget for base pay and has had few job vacancies during the last three years. Ms. Baker also noted that the CPA is not granted to all employees and testified that CEI South did not indicate a separate adjustment to account for a percentage of employees not granted a CPA.

8. Shared Services Expense. OUCC witness Lantrip stated that Petitioner's $38,459 shared services adjustment for the VUH common asset charges should be denied due to lack of support in the Petitioner's case-in-chief. Pub. Ex. 3 at 18.

iii. Industrial Group's Position.

1. Incentive Compensation. Industrial Group witness Gorman recommended removing 70% of LTI tied to the financial performance of CEI South from cost of service, which he calculated to be approximately $1.4 million based on discovery responses indicating forecasted LTI expenses allocated to CEI South in the test year is $2.0 million. Industrial Group Ex. 1 at 8-9. He argued that incentive compensation costs tied to the financial performance of CEI South should not be included in ratemaking cost of service because they are designed to align the interests of employees with those of shareholders and are designed to enhance the value of shareholders' investments in CenterPoint Energy, Inc. and/or CEI South to the extent the financial incentive targets are achieved.

2. Number of Customers. Mr. Gorman also objected to CEI South's use of the average number of customers for the end of test year increase, which he said understated the revenues. He recommended an adjustment to reflect the end-of-test-year customer numbers. IG Ex. 1 at 4-5. This results in an increase in revenue at current rates of $390,000 and a corresponding reduction of the claimed Phase 3 (end of test year) deficiency.

3. Normalized Sales Adjustments. Mr. Gorman recommended that the Commission forecast CEI South's test year sales and revenues at present rates for the residential and commercial classes using a normalized use per customer forecast based on weather normalized historical data. He testified that CEI South is forecasting declining sales per customer due to energy efficiency and other factors that may not be realized. Instead, Mr. Gorman's adjustment relies on a three-year average use per customer for the residential and commercial classes. His recommended adjustment increases revenues at present rates and reduces CEI South's revenue deficiency by approximately $3.6 million. IG Ex. 1 at 9.

iv. CAC's Position.

1. DSMA Costs. CAC witness Barnes opposed the inclusion of DSM program costs in base rates. CAC Ex. 3 at 29. He noted that CEI South had indicated in response to discovery that CEI South would be willing to eliminate its proposal to include DSM program costs in base rates. CAC Ex. 3, Attachment JB-3. However, he stated such a withdrawal will not fully address the issues he identified with respect to allocation of demonstration and sales expenses logged in FERC accounts 911 and 912. CAC Ex. 3 at 28.

2. Rate Case Expense. CAC witness Inskeep recommended disallowance of the entirety of CEI South's rate case expense, testifying that Petitioner's experts and attorneys are working to increase CenterPoint's revenues and profits to benefit CenterPoint shareholders at the literal expense of ratepayers. He stated shareholders, not ratepayers, should pay all, or at least a substantial portion of, costs of experts and counsel in this case. He testified that CEI South was only required to file this rate case because it voluntarily elected to file a TDSIC Plan that ran through the end of 2023 and therefore, this rate case is entirely a result of actions within Petitioner's control and that were done to benefit shareholders. CAC Ex. 2 at 54-55.

3. Trade Associations. CAC witness Inskeep recommended the Commission deny CEI South's request to include in its revenue requirement all expenses related to trade association dues. CAC Ex. 2 at 53. He stated organizations like Edison Electric Institute, Indiana Energy Association, Indiana Manufacturers Association, and Consumer Energy Alliance, to name a few, engage in highly political, advocacy-oriented, and influence activities, which could include funding outside political and charitable contributions, litigation, regulatory advocacy, advertising, and efforts to shape the public and decision-maker opinion, in addition to numerous other activities that principally serve the private interests of the members rather than ratepayer interests. They can also promote contentious political and policy viewpoints that many individual utility customers would find highly objectionable and do not want to fund through their electric bills that they are compelled to pay to maintain essential utility service.

v. SABIC's Position. SABIC witness Coyle testified that CEI South had failed to include $546,518 of transmission revenues in the revenue requirement and the ACOSS. She noted CEI South committed to updating this value on rebuttal, which would lower the overall revenue increase requested in the filing. SABIC Ex. 1 at 39-40.

vi. CEI South Rebuttal. CEI South made various adjustments to its pro forma revenues and expenses on rebuttal, as more particularly described in Ms. Behme's rebuttal testimony and summarized in her Table CMB-R1. Pet. Ex. 2-R at 4.

1. Base Cost of Fuel. CEI South witness Rice testified on rebuttal that Mr. Eckert's recommendation was not based upon what people are paying today in the market for future gas but instead was based on the EIA's Short Term Energy Outlook. He said CEI South's forecast for natural gas was a reasonable forecast and lower than where NYMEX Henry Hub Natural Gas Futures (Settlements) are for 2025 at $3.49. Pet. Ex. 19-R at 52. He also disagreed with Mr. Eckert's recommendation to lower the Locational Marginal Price ("LMP") Prices, noting that natural gas prices help set the marginal price for energy, and CEI South's gas price is reasonable.

2. Interruptible Sales Billing Credits. CEI South witness Rice explained the calculation of the cost of interruptible sales billing credits and DR aggregator payments was based upon a bid received from a DR aggregator in CEI South's All-Source RFP for DR aggregation in its 2022/2023 IRP. Pet. Ex. 19-R at 27. He explained that this is a new program and CEI South does not yet know how many may participate. He said CEI South currently does not have any commercial and industrial ("C&I") customers in its IC Rider, IO Rider, or MISO tariffs with DR registered with MISO. Accordingly, Mr. Rice explained, CEI South did not include any DR for these tariffs in the forecast for 2025. Given the uncertainty about how many customers will sign with the DR aggregator and uncertainty around potential updates in any of the three other DR tariffs, CEI South proposed a reasonable level of $725,000 to be embedded in base rates, which Mr. Rice said is far less than the $1,686,350 embedded in rates today.

3. DSMA Costs. On rebuttal, Ms. Behme indicated that, as described in CEI South's Response to CAC Data Request 5.7 (CAC Ex. 3, Attachment JB-3), CEI South is removing $500,000 in revenues for performance incentives from base rates. She stated performance incentives will remain in the DSMA. Furthermore, Ms. Behme confirmed that CEI South is removing DSMA program costs from base rates, in line with CAC witness Barnes' recommendation. This adjustment involves the removal of expense as well as corresponding revenues. Pet. Ex. 2-R at 6. CEI South witness Rice also testified on rebuttal that CEI South agreed to recover all program costs and the performance incentive in the DSMA tracker rather than base rates. Pet. Ex. 19-R at 50. As such, CEI South removed all revenues and expenses were pulled out of base rates, as described by witness Behme. Summer Cycler costs remain in base rates, as they are today.

4. Emissions Allowance Costs. CEI South witness Behme testified on rebuttal that CEI South accepts the OUCC's position presented by witness Lantrip to remove $3,519,952 of emission allowance O&M costs from the test year and instead to track 100% of such costs through the RCRA. Pet. Ex. 2-R at 6.

5. IT O&M Expense. In rebuttal, Mr. Bahr reiterated that the $770,000 that Mr. Compton recommended the Commission deny represents the costs allocated to CEI South Electric to migrate the existing SAP ERP 6.0 system to the latest SAP ERP platform – SAP S/4HANA – before the current version's end of life in 2027. Pet. Ex. 8-R at 13. He said CEI South must prepare for this eventuality and it is the costs of doing so that Mr. Compton seeks to disallow. *Id.* He reiterated the benefits to CEI South and its customers of transitioning to the latest SAP platform – SAP S/4HANA.

With respect to the $813,540 CEI South requests to include for the cloud computing arrangement costs to be incurred in 2025 under the CATO Project, Mr. Bahr responded that Mr. Compton may have misunderstood certain points and he did not specify with details or support his recommendation that these costs be denied. Pet. Ex. 8-R at 14. He reiterated what Ms. Behme testified in her direct testimony, that this amount represents "[t]he baseline level of the third-party [CCA] expected to be recorded to expense during the test year . . . which CEI South proposes to recover through base rates and has included in this case[.]" Pet. Ex. 8-R at 14, quoting Pet. Ex. 2 at 37.

Mr. Bahr testified that the majority of the costs are related to Software as a Service ("SaaS"). SaaS solutions are a complete application solution provided by a vendor that is usually accessed by an internet browser or mobile device. Data related to the SaaS is stored in the cloud, allowing access anywhere via the internet. Examples of SaaS software used by CEI South include Microsoft 365 (productivity and collaboration tools like Outlook, Word, Excel, Teams), Oracle HR Solutions (for recruiting candidates, delivering training including compliance training, and employee performance management), and Service Now (IT service management tool used for incident management and change management used to deliver services). A smaller portion of the $813,540 is related to Infrastructure as a Service ("IaaS"), which is a cloud service where a vendor provides computing, storage, and networking resources. Examples for CEI South include Microsoft Azure. Through the CATO program, CEI South is moving on-premise applications to the Microsoft Azure cloud to enhance resiliency, efficiency, and security. The CATO program is a strategic investment that aligns with IT's Cost Optimization strategy that focuses on operating technology efficiently and delivering services in a more cost-effective manner. By establishing a foundation on the Microsoft Azure cloud, CEI South will gain more flexibility in deploying applications, increase automation of infrastructure operations, and establish a secure environment through multiple layers of defense to improve resiliency of the applications and protect CEI South assets in the cloud. Pet. Ex. 8-R, pp. 14-15.

6. Rate Case Expense. As to rate case expense, Ms. Behme testified on rebuttal that the OUCC's and CAC's positions are inconsistent with decades of precedence before this Commission and would result in treatment for CEI South that is different from other large public utilities in the State. Pet. Ex. 2-R at 18.

7. Sponsorships and Trade Associations. CEI South witness Behme testified that CEI South accepts OUCC's proposed adjustments to A&G for sponsorships in the amount of $9,679. Pet. Ex. 2-R at 16. With respect to trade association dues, Ms. Behme testified on rebuttal that CEI South has followed the methodology and application of prior cases where membership dues have been routinely recovered through rates in Indiana. Amounts attributed to lobbying activities and political contributions have been identified and removed from the cost of service. Ms. Behme explained that these amounts are specifically included on invoices received by CEI South. She argued CEI South's membership in trade associations such as the Indiana Energy Association provides benefits to CEI South and its customers by providing an opportunity to (among other things) discuss industry issues with peer companies to understand practices, procedures or other measures that can assist CEI South in ensuring the affordability, quality, efficiency, reliability, and security of service.

8. Incentive Compensation. CEI South witness Williford testified that the Commission has previously rejected arguments like those put forward by Mr. Gorman regarding incentive compensation. Pet. Ex. 10-R at 6. She testified that the fact that there are financial metrics in an incentive compensation plan does not make it a pure profit-sharing plan, and the Commission has historically not been receptive to excluding recovery of those portions of the plan that are tied to financial metrics. She stated Mr. Gorman did not contend that CEI South's incentive compensation does not satisfy the three-part test this Commission has applied for awarding recovery of incentive compensation. She reiterated how CEI South's incentive compensation satisfies this standard and testified that customers directly and materially benefit from the provision of financially based LTI awards to CEI South's employees, a practice that serves to align the interests of both shareholders and customers. Ms. Williford stated a specific purpose of the LTI plan is to focus employee attention toward ensuring sustained improvements in performance over longer periods of time. She testified that the achievement of strong financial performance is a benefit to both customers and shareholders enabling CNP to adequately maintain its assets and provide safe and reliable electric service to customers with a focus on controlling costs. She testified that LTI is necessary to recruit and retain executives and key employees and that CEI South's peer companies (against whom it competes for executive and key employee talent) provide both performance-based and time-based LTI awards as part of their LTI programs.

9. Competitive Pay Adjustment. CEI South witness Williford responded in rebuttal to Ms. Baker's proposed disallowance, stating that, as reflected in CEI South's response to a discovery request, the eligible employees for a CPA are those "[e]mployees who are full-time or part-time and on CEI South's payroll on December 31st of the plan year." Ms. Williford continued referencing the data response, which explained, "a yearly increase is not granted to all employees", rather, "[i]ndividual CPAs are based on performance and salary position to the market (compa-ratio)." Pet. Ex. 10-R at 3. Ms. Williford stated that CEI South's market-based, pay-for-performance philosophy means that CPA awards are not granted in a formulaic method and therefore, not all employees are granted an increase. She explained that the annual budgeted 3% CPA used to estimate CEI South's forecasted spend already accounts for certain employees not receiving a CPA, just as it accounts for certain employees receiving more than 3%; therefore, an adjustment to "account for a percentage of employees not granted a CPA adjustment" is not warranted.

Ms. Williford also testified that CNP does not rely solely on one source for market data, but rather, "uses a variety of national, regional, and local survey data that is refreshed annually to monitor and determine market pay values [with m]ost jobs [being] matched to multiple surveys." She reiterated that her direct testimony not only referenced the median budget increase implemented and reported for 2022 on a national basis but explained a similar "budget trend . . . was reported by those employers with operations in the state of Indiana." Pet. Ex. 10-R at 4. She also explained that CEI South Specific WTW Survey, provided as Attachment DRW-5 (CONFIDENTIAL) to her direct testimony, did compare CNP compensation to utility peer groups similar in size to CEI South, and concluded CNP compensation was aligned to market. CEI witness Bradford responded to Ms. Baker's testimony that the number of job vacancies and total salaries were under budget. He reiterated his direct testimony where he explained how Generation Operations avoided layoffs due to the closure of the A.B. Brown Units 1 & 2 in October 2023, by managing the Generation Operations workforce through attrition from approximately 188 full-time equivalents ("FTEs") in 2019 to approximately 138 FTEs year-end 2023 by utilizing

contractors and reassigning the A.B. Brown workforce to other departments within Generation Operations. Mr. Bradford explained it was this diligent management of the workforce, to mitigate employee hardship, that actually drove the variance of actuals to plan and low number of vacancies. Pet. Ex. 7-R at 14.

10. Shared Services Expense. Ms. Behme explained in rebuttal that this adjustment is pure math and that whatever the Commission finds as the WACC in this case should be the WACC used in the calculation of VUH asset charge. Additionally, she stated this calculation is using the same mechanics that were used in CEI South's gas rate case filed in 2020. Pet. Ex. 2-R at 21.

11. TSO Revenues. In response to SABIC's witness Coyle, CEI South updated the revenue requirement to include $1,349,242 of expected total annual forecasted TSO other revenues. Pet. Ex. 2-R at 6.

12. Number of Customers and Normalized Sales. CEI South witness Russo responded to Mr. Gorman's recommended average usage for residential and commercial customers, as well as Mr. Gorman's recommendations with respect to capturing customer growth. Mr. Russo testified that annual average customers are an accurate measure of the customer counts associated with total annual sales, particularly because the customers as of the end of the test year are not projected to be customers for the entire test year and so will not provide the revenues Mr. Gorman proposes. Pet. Ex. 16-R. Regarding Mr. Gorman's concerns that CEI South is understating the residential and commercial use per customer, Mr. Russo testified regarding certain corrections required for Mr. Gorman's calculation and opposed the use of a three-year historical average to determine test-year residential and commercial average use. His forecast model showed that both residential and commercial usage continues to decline.

vii. Settlement.

1. Items Accepted and Incorporated in Settlement.

A. Base Cost of Fuel. CEI South witness Rice testified that the Settlement Agreement incorporates an adjustment to reduce the forecasted base cost of fuel in the test year revenue requirement by $8,175,808 as recommended by OUCC witness Eckert. Pet. Ex. 19-S at 13; Settling Parties' Jt. Ex. 1 at Section B.5.a.

OUCC witness Eckert acknowledged that the Settlement Agreement incorporated his fuel cost and fuel inventory adjustments. Pub. Ex. 1-S at 15.

B. Interruptible Sales Billing Credits. Mr. Rice described the adjustment made in the Settlement Agreement to remove $725,000 in interruptible sales billing credits and aggregation demand response, as recommended by OUCC witness Lantrip. He stated any actual interruptible sales billing credits will be reflected in the RCRA. Pet. Ex. 19-S at 13.

OUCC witness Eckert acknowledged that the Settlement Agreement did incorporate CEI South's agreement to remove the interruptible sales billing credits as recommended by Mr. Lantrip.

C. Capacity Purchase Costs. The Settlement Agreement includes an adjustment to reduce forecasted capacity purchase costs in the revenue requirement for the test year by $5,000,000. Settling Parties' Jt. Ex. 1 at Section B.5.c. Mr. Rice explained, however, that CEI South is in the midst of a generation transition, and a level of capacity purchases will be necessary for the foreseeable future. Accordingly, actual costs above or below the remaining base amount will continue to be tracked in the RCRA, and variances will be charged or credited to customers. Pet. Ex. 19-S at 13.

D. Sales Forecast and Incentive Compensation. The Settlement Agreement does not expressly discuss Mr. Gorman's Sales Forecast and Incentive Compensation arguments, but it does provide that "items not expressly delineated herein shall be resolved as proposed in CEI South's case-in-chief, as modified by its rebuttal position." The Settling Parties have agreed that the Settlement Agreement resolves all disputed issues in this Cause, including those raised by IG witness Gorman with respect to Petitioner's sales forecast and incentive compensation.

2. Remaining Disputed Items.

A. Other O&M Expense. Mr. Rice testified that the Settlement Agreement contains an adjustment reducing CEI South's total forecasted level of O&M Expense by $1,350,000. He stated that the reduction is not assigned to particular FERC accounts but is in total. Pet. Ex. 19-S at 13-14.

OUCC witness Compton testified the while rate case expense may have been considered in the $1.35 million reduction in forecasted O&M incorporated into the Settlement, rate case expense is not expressly addressed in the Settlement Agreement. Pub. Ex. 5-S at 3-4. He stated if any of this annual pro forma revenue requirement can be attributed to the agreed $1.35 million reduction in O&M expense, it would not be in the public interest to leave to speculation the extent to which these expenses have been reallocated. He stated the most reasonable assumption is that the Settlement Agreement has accomplished no decrease in rate case expense. He maintained that it is inequitable for ratepayers to pay for the entirety of rate case expense. He said the Settlement Agreement was not in the public interest because it does not pronounce that shareholders are being considered responsible for some of this rate case expense, including the expenses incurred for their prospective benefits from the prosecution of this case.

Mr. Compton also objected to the absence of language in the Settlement Agreement incorporating his recommendation that CEI South also be required to amend its tariff once its rate case expense has been fully amortized.

CAC witness Inskeep expressed concern that the Settlement Agreement fails to adjust the revenue requirement to remove trade association membership dues and rate case expense, which he contends produces rates that are not just or reasonable. CAC Ex. 6 at 19-20.

In Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal testimony, Petitioner reiterated the rebuttal of Ms. Behme to Mr. Compton's proposed sharing of rate case expense, noting that the mere fact the OUCC may have taken the same position in other cases does not change that the OUCC position has never been accepted by the Commission. Pet. Ex. 19-SR,

Attachment MAR-SR2 at 1. Mr. Rice's attachment does indicate that CEI South did not oppose Mr. Compton's recommendation that rates be reduced upon the expiration of the amortization period of rate case expense if an intervening rate case has not been filed.

viii. Commission Discussion and Findings. Many of the disputed issues were addressed to the satisfaction of the non-settling parties either through rebuttal or settlement. The overall reduction to O&M expense contained in Section B.5.d of the Settlement Agreement represents further compromise given the various remaining disputes over expense levels. Section B.15.b of the Settlement Agreement provides that all disputed items not expressly delineated in the Settlement Agreement shall be resolved in accordance with CEI South's case-in-chief, as modified by its rebuttal position where applicable, to the extent expressly supported in CEI South's evidence and without waiving the right of any party to litigate such issues in future proceedings. This includes all the relief summarized in this order, which has not otherwise been modified by the Settlement.[18] The Commission finds Section B.15.b of the Settlement Agreement to be reasonable and it is approved. Further findings on certain disputes the OUCC and CAC continue to raise in their opposition to the Settlement Agreement are provided here.

With respect to the OUCC's and CAC's respective positions on disallowance of rate case expense, this Commission has, in the past, considered the propriety of rate case expense as a two-tiered test. The first level of inquiry is whether the item giving rise to the expense is reasonably necessary for the presentation of Petitioner's case. Assuming the satisfaction of the initial level of inquiry, then the next question is whether the expense incurred is reasonable in the light of the service provided. *Indiana Gas Co., Inc.*, Cause No. 38080 (Sept. 18, 1987). This Commission has also rejected invitations by the OUCC to allocate to shareholders rate case expense on previous occasions. See *Gary-Hobart Water Co.*, Cause No. 39585 (Dec. 1, 1993). No adjustment was made specifically with respect to rate case expense in the Settlement Agreement. As a result, pursuant to Section B.15.b, the Settlement incorporates CEI South's case-in-chief position, which we find to be reasonable. We further find that Petitioner shall file revised tariffs upon the end of the amortization period to remove the annual amortization expense from its rates if the amortization period expires before new rates are approved.

With respect to trade association dues, we again decline to depart from our prior findings on this issue. This Commission recently affirmed that inclusion of the non-lobbying portion of such expenses is proper because the collaboration and sharing of best practices benefits customers through more efficient and effective utility service. See *Indiana-American Water Co.*, Cause No. 45870 (Feb. 14, 2024), at 79. The record in this case shows that these organizations provide legitimate benefits for their members and their customers. Pet. Ex. 2-R at 16-17.

H. Regulatory Accounting Treatment – Cloud Computing Costs.

i. CEI South's Case-in-Chief. In its Verified Petition, CEI South requested authority to capitalize by establishing a regulatory asset all cloud computing costs not included in base rates. Witness Behme described the proposal and explained the differences for

[18] To the extent not expressly addressed elsewhere in this order, we reject the issues raised by the OUCC in opposition to settlement that were repeating their case-in-chief positions as outlined in Attachment MAR-SR2 to Petitioner's Exhibit 19-SR.

capitalization pursuant to GAAP and ratemaking and cited orders[19] from this Commission concerning the ratemaking for such costs. She then noted that for ratemaking during the test year in this case, Petitioner had followed the GAAP standards and included a forecasted level of cloud computing expense in O&M of $813,540. Petitioner's proposal is to capitalize to a regulatory asset all annual cloud computing expense above that baseline level. Pet. Ex. 2 at 35-37.

ii. OUCC's Position. OUCC witness Compton opposed the capitalization of costs that GAAP would treat as expense. He disagreed that it would be difficult to determine which portion should be expensed per GAAP. Pub. Ex. 5 at 8-9.

iii. CAC's Position. CAC witness Inskeep also opposed CEI South's request to capitalize cloud computing costs. CAC Ex. 1 at 10.

iv. Industrial Group's Position. IG witness Gorman also objected to Petitioner's request for authority to capitalize cloud computing costs. IG Ex. 1 at 135-36.

v. CEI South's Rebuttal. Witness Behme responded to the opposition to capitalize the cloud computing costs. She reiterated that CEI South's proposal was consistent with past orders of this Commission and noted that neither Mr. Compton nor Mr. Gorman had addressed those orders. In addition, since the filing of case-in-chief testimony, another order had been issued supporting CEI South's request.[20] Pet. Ex. 2-R at 22-23.

vi. Settlement. Mr. Rice described the Settlement term by which the forecasted $813,540 in GAAP expense would be included in O&M but the request for deferral authority above that amount would be withdrawn without prejudice to request again in another docket. This approach allows for more time to see how recovery of cloud computing evolves over the next few years. Pet. Ex. 19-S at 14. Mr. Gorman noted that the cloud computing expense term reflected compromise among the parties. IG Ex. 1-S at 4-5.

vii. Settlement Opposition. Mr. Compton testified in opposition to the Settlement Agreement, noting that it withdraws the request for regulatory accounting treatment. He stated that the Settlement Agreement did not expressly address his recommendation to disallow CEI South's IT investments because it did not substantiate the prudency and reasonableness of those expenditures. Pub. Ex. 5-S.

viii. Commission Discussion and Findings. We find the Settling Parties' resolution of the Cloud Computing Costs that would be recorded as expense pursuant to GAAP to be reasonable and that the resolution strikes a reasonable compromise, and we therefore approve it.

I. CAMT, EADIT, and TAR. Section B.7.b of the Settlement Agreement withdraws CEI South's request to include future CAMT effects in its TAR. The Settlement Agreement acknowledges that the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase

[19] *Northern Ind. Pub. Serv. Co.*, Cause No. 45159 (Dec. 4, 2019); *Aqua Indiana, Inc.*, Cause No. 45675 (Jan. 1, 2023).

[20] *Indiana American Water Co.,* Cause No. 45870 (Feb. 14, 2024), at 30-31.

1 and Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1 at Section B.7.b. No party opposed moving the existing EADIT schedules out of the TDSIC rider or inclusion of Production Tax Credits ("PTCs") that were approved to be passed back to customers via the CECA, to the TAR. CEI South still seeks the creation of the new rider for these purposes. Additionally, CEI South proposes to pass state EADIT back to customers through the TAR over a three-year period, per the stipulation in the Settlement Agreement discussed elsewhere in this Order. Pet. Ex. 19-S at 16-17.

i. <u>CEI South's Case-in-Chief</u>. CEI South witness Story presented CEI South's proposed TAR and explained that the IRA contains significant benefits for clean energy and renewable investments impacting the utility industry. Pet. Ex. 15 at 3. She testified that the CAMT was included in the IRA to offset the cost of tax incentives. Ms. Story summarized several provisions of the IRA applicable to public utilities, including:

- Restoration and extension of the renewable electricity PTC and clean electricity investment tax credit ("ITC");
- Creation of new tax credits designed to incentivize investment in renewable energy;
- Establishment of a non-deductible 1% excise tax on certain corporate share repurchases; and
- Imposition of a 15% CAMT based upon adjusted financial statement income ("AFSI").

She said the IRA imposes the new CAMT prospectively on AFSI of an Applicable Corporation for taxable years beginning after December 31, 2022. She said the CAMT represents the means within the IRA to fund the tax credit benefits of the IRA as described in her testimony. She described how the determination is made of whether CAMT must be paid. Ms. Story testified that CEI South is an Applicable Corporation for purposes of the CAMT. However, there will be no CAMT due in 2023. She stated CEI South expects to pay the CAMT in 2024 and 2025 based on current guidance. Ms. Story testified that payment of the CAMT means CEI South can no longer defer a portion of taxes to future periods and must therefore finance additional amounts to pay taxes in the current period. She said it may be necessary to increase borrowing to finance planned capital investments.

CEI South witness Jerasa testified that the cash outlay associated with CAMT presents a risk that will likely adversely impact CEI South's credit metric including Funds from Operations ("FFO")/debt if it is unable to recover the impact of the tax through rates. He said if credit ratings and metric deteriorate, CEI South's ability to invest in necessary projects may be impeded as incremental debt issuances may be otherwise limited based on lower credit metrics. Pet. Ex. 14 at 7-8.

Ms. Story testified that the CAMT has been calculated using CEI South jurisdictional amounts, with adjustments to financial statement income made for depreciation, pension expense, and federal income taxes. She said the CAMT credit carryforward is an asset and has been included in the cost-free capital calculation in this filing. When the minimum tax is paid, a CAMT credit is generated and can be carried forward indefinitely to offset the future regular income tax liabilities

in periods where the regular federal income tax liability exceeds the CAMT liability. The CAMT credit cannot be carried back to previous taxable years. Ms. Story testified that on a going-forward basis, CAMT carryforwards would be addressed through CEI South's proposed TAR. She explained that the TAR would capture tax rider adjustments that have already been approved by the Commission in other dockets and would also be expanded to include the effects of the CAMT and passback of Indiana state EADIT. She stated there are two already approved tax riders that would move to the TAR. First, as a result of the Commission's investigation into the effects of the TCJA, CEI South is flowing back to customers federal EADIT from the TCJA through its TDSIC rider. This passback would continue outside of base rates but would instead be done through the TAR rather than the TDSIC. Second, PTCs realized from approved wind and solar projects are to be tracked through CEI South's CECA mechanism. This adjustment would move from the CECA to the TAR. As for the CAMT, Ms. Story testified CEI South's proposal is that between rate cases, a return on the CAMT carryforward calculated using CEI South's weighted average cost of capital determined in this rate case would be included in the TAR.

Ms. Story testified it is necessary to reflect the net impact of both the CAMT and PTCs from renewable projects. The CAMT provisions of the IRA were used to fund the extended and enhanced tax credits, so she stated that it is reasonable to include the impacts of both in this rider. Ms. Story testified that including both the PTCs and the incremental return on the CAMT payment in the TAR is necessary to capture the full impact of the IRA. A rider is necessary since annual results could vary significantly, making this a more reasonable approach than including these items in base rates. Similar to the process after TCJA was enacted, additional guidance is expected to clarify provisions of the IRA. A rider will allow CEI South to capture the impact of these rules as they become available.

Ms. Story described how IRA tracking would work under the TAR. She stated for PTCs, tracking should begin in 2025. If approved, CEI South will file a TAR in November 2025 that will include an estimate of the 2025 PTCs. For the CAMT carryforward, tracking should begin in 2026 after the test period. The second TAR filing in November 2026 will include the difference between the minimum tax 2026 carryforward estimated balance and the carryforward included in cost free capital in base rates, the result of which will be multiplied by the approved cost of capital from this proceeding. Additionally, it will include an estimate of the 2026 PTCs and a true-up of the 2025 estimated PTCs to actual. With additional guidance and proposed regulations still expected, it is most appropriate to commence tracking with this rate case, since it coincides with the IRA recently becoming law.

Ms. Story also addressed the ADIT and EADIT regulatory liability balances included in CEI South's cost of capital calculation. She said the federal EADIT resulting from the TCJA is currently being refunded in CEI South's TDSIC mechanism and CEI South is proposing to move these credits to the new TAR mechanism as described by witness Rice. Pet. Ex. 19 at 11. CEI South is also proposing to include state EADIT credits into the TAR mechanism. In addition, the credits for accelerated EADIT associated with the issuance of securitization bonds related to the retirement of A.B. Brown Units 1 and 2 will be moved into the proposed TAR. The refund of protected and unprotected EADIT has been forecasted through the end of the 2025 test period. The pro-forma balance of the EADIT regulatory liabilities, as well as the associated ADIT deferred tax assets, has been included as cost-free capital on Petitioner's Exhibit No. 20, Schedule D-5 sponsored by witness Jerasa. Pet. Ex. 15 at 18-19.

Ms. Story stated CEI South proposes to include the refund of the excess deferred state taxes in the TAR along with the federal EADIT. Like federal EADIT, the amortization of state EADIT would be outside base rates. Ms. Story testified that future changes to the federal EADIT balance would be addressed in the same fashion that such changes are addressed in the TDSIC mechanism presently. Future events such as IRS audit adjustments to CEI South's previously filed income tax returns, future IRS rulings and/or clarifications to the normalization rules, and changes in federal tax laws or rates could change the federal EADIT balance, as well as the split between protected and unprotected. She said these changes would be addressed in future TAR filings.

Mr. Rice stated the proposed TAR would include two tax adjustments that are already approved to be reflected in riders (the CECA and the TDSIC) and would reflect two additional adjustments, the CAMT and the amortization of Indiana state EADIT. CEI South's proposal is that beginning with the year following the test year, the creation of new CAMT carryforward will be reflected in the TAR by multiplying the new carryforward by CEI South's Weighted Average Cost of Capital from this rate case. Pet. Ex. 19 at 11. He explained CEI South is proposing that the TAR will reflect federal EADIT (currently passed back to customers through the TDSIC) and PTCs associated with the two renewable projects approved in Cause Nos. 45836 and 45847 (currently included in CEI South's annual CECA filings). CEI South proposes to include in the TAR the State EADIT (proposed to be amortized over five years). CEI South also proposes that, to the extent the proposed TAR is approved, the earnings test for purposes of Ind. Code § 8-1-2-42(d)(3) be updated to reflect the additional return from inclusion of the CAMT.

ii. <u>OUCC's Position</u>. Witness Stull testified that she does not oppose the proposed TAR, provided the current tax mechanisms will continue to charge or credit the same customer classes in the same manner as they are currently being implemented; however, she does oppose reflecting the CAMT in the rider. Pub. Ex. 6 at 4-5. She said CEI South's parent company, CenterPoint Energy, does not normally have AFSI of $1.0 billion or more, but rather is only currently subject to the corporate alternative minimum tax because of the impact of recent utility asset sales in other jurisdictions. Ms. Stull also asserted CEI South is "cherry picking" by only requesting to track the CAMT carryforward and not proposing to include all other items of ADIT in the TAR. She asserted that Indiana ratepayers should not bear the costs of CenterPoint Energy's non-Indiana financial transactions, including any additional taxes that may be due because of those transactions.

Ms. Stull argued that many unknowns accompany CEI South's proposal, including final determinations about whether CEI South's parent company will be subject to CAMT and whether the proposal would materially ameliorate the effects of CAMT to credit metrics or ratings. She recommended CEI South's proposal be denied; in the alternative, should the proposal be authorized, she recommended CEI South be required to track all tax-related components of cost-free capital.

iii. <u>CEI South's Rebuttal</u>. Ms. Story responded to Ms. Stull's conclusions regarding reflecting the CAMT in the tax rider, stating Ms. Stull has confused requirements regarding the applicability of the minimum tax and the calculation of the minimum tax. Ms. Story said Ms. Stull also failed to address the risk to cash flow and credit metrics described in Mr. Jerasa's testimony that is the basis for CEI South's proposal to reflect the CAMT in the proposed TAR. Pet. Ex. 15-R at 3. Ms. Story reiterated that the determination of whether CEI

South is an Applicable Corporation for purposes of the CAMT requires CEI South to use the consolidated group's (single employer's) AFSI. However, the calculation of CAMT attributable to CEI South does not include tax gains, losses, or other results of operations for jurisdictions CEI South does not operate in. CEI South is currently subject to the CAMT. CEI South's CAMT will result only from CEI South operations. CEI South will only owe CAMT if the tentative minimum tax exceeds the regular tax from stand-alone jurisdictional operations.

Ms. Story said CEI South's proposal is consistent with the long-established practice of permitting recovery of taxes associated with jurisdictional operations. She said like any prudent cost of providing electric service, the CAMT, consistent with all other federal, state, and local taxes incurred in the provision of electric service, is an appropriate cost of service expense. Ms. Story responded to Ms. Stull's argument that CEI South is "cherry picking" by seeking to track only the CAMT credit carryforward deferred tax asset and not deferred tax liability items, stating that Ms. Stull has failed to address the important issue of the increased risk to credit metrics and cash flow resulting from CAMT. CEI South witness Jerasa testified that S&P expects CenterPoint Energy, Inc. to be an annual cash taxpayer as a result of the CAMT, and its base case assumes annual cash tax payments of $150 million through at least 2026. S&P defines FFO as earnings before income tax, depreciation, and amortization ("EBITDA"), minus cash interest paid minus cash tax paid.[21] Therefore, the cash tax payments associated with the CAMT will directly reduce FFO and weaken FFO to Debt and other credit ratios, for both CenterPoint Energy, Inc. and its subsidiaries, including CEI South. Pet. Ex. 14-R at 6. He said cash taxes, including those arising from the CAMT, will lower FFO and weaken credit metrics, which could potentially impede future capital investments since CEI South will not be able to issue as much debt to maintain its current ratings. He stated the requested revenue amount included in CEI South's proposed tax rider will help mitigate the cash flow impact and absent the rider, there will be additional pressure on CEI South's financial integrity.

Ms. Story testified that Ms. Stull's proposal to include all deferred taxes in the TAR would both result in a mismatch to rate base, as well as violate the normalization provisions of the Internal Revenue Code ("IRC"). She noted the inconsistency in Ms. Stull's position, stating that to suggest that it is appropriate to include only the results of the IRA that result in a credit to customer rates and to exclude the cost associated with providing that benefit is asymmetrical. Ms. Story explained that the rate base mismatch resulting from Ms. Stull's suggested inclusion of deferred tax liability updates in the TAR would inappropriately reduce CEI South's return for items not yet being recovered. She further testified that Ms. Stull's proposal would be prohibited under the normalization rules of the IRS, specifically because inclusion of the deferred tax liabilities in the rider would violate the consistency rules of the normalization provisions. She explained that if a normalization violation occurs, CEI South would no longer be able to utilize accelerated depreciation in its federal income tax return. A normalization violation would mean a large reduction to cost-free capital (*i.e.*, reduction in deferred tax liabilities) and a significant increase in current taxes payable ultimately translating into less cost-free capital and higher borrowing costs to the utility.

[21] Pet. Ex. 14-R at 6 n.16, citing S&P Global Ratings, "Criteria: Corporate Methodology: Ratios and Adjustments" December 21, 2023, p. 3.

iv. Settlement. Section B.7.b of the Settlement Agreement withdraws CEI South's request to include future CAMT effects in its Tax Adjustment Rider. The Settlement Agreement acknowledges that the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase 1 and Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1 at Section B.7.b.

v. Settlement Opposition. OUCC witness Stull stated she accepted CEI South's proposal to create a TAR with the stipulation that the current tax mechanisms will continue to charge or credit the same customer classes in the same manner as they are currently being implemented. The Settlement Agreement does not, however, set forth how the currently approved tracker and passback mechanisms will continue being implemented. She stated the Settlement Agreement is not in the public interest if the passback mechanisms do not continue to be charged or credited to the same customer classes and in the same manner as they are currently charged or credited through the TDSIC and CECA trackers.

vi. Settlement Rebuttal. CEI South witness Rice stated CEI South is proposing to simply move existing schedules for the federal EADIT from TDSIC and proposed schedules related to the PTC from CECA to TAR. Pet. Ex. 19-SR, at 25. He explained that CEI South is not proposing to change the way the previously approved trackers were applied, but is proposing to consolidate them into a single, annual tracker. Additionally, CEI South has not proposed any changes to customer classes, so there is no change from this perspective. However, if the TAR is approved, CEI South witness Taylor recommended that federal EADIT that is currently being credited via the TDSIC tracker be allocated consistent with his recommended Rate Base allocations as shown in Attachment JDT-5, Schedule 4 - Rate Base Allocation. If the TAR is not approved, then CEI South would continue to credit the same customer classes in the same manner as shown in Attachment JDT-5, Schedule 2 - TDSIC Allocation.

vii. Commission Discussion and Findings. The Settlement Agreement eliminates the controversy over Petitioner's proposed TAR except with respect to the allocation across customer classes. The evidence of record demonstrates that Petitioner is not proposing to change the way the previously approved trackers were applied, except to provide consistency between the federal EADIT and the proposed rate base allocations. We find this proposal to be reasonable and consistent with the cost-causation principles discussed elsewhere in this Order. Accordingly, the Settlement Agreement's proposed resolution of issues related to the TAR is reasonable and should be approved.

J. Additional Riders and Other Tariff Provisions. Section B.7 of the Settlement Agreement describes proposed riders, including (1) the CPP Pilot, Rider ADR, and Green Energy Rider and (2) the TAR.

Section B.8 of the Settlement Agreement describes other tariff matters, including: (1) IC and IO Riders and (2) limitation of liability provision in the tariff.

In summary, the Settlement Agreement provides that CEI South's CPP Pilot, Rider ADR, and Green Energy Rider should be approved as proposed by CEI South, with CEI South further committing to provide all parties a copy of the contract with the demand response aggregator for Rider ADR after it has been signed. Settling Parties' Jt. Ex. 1 at Section B.7.a. The stipulations

with respect to the proposed TAR are discussed in Section 0.I (CAMT, EADIT and TAR) of this Order.

With respect to the IC and IO Riders related to demand response, CEI South agrees to continue conversations with interested stakeholders. Settling Parties' Jt. Ex. 1 at Section B.8.a.

The Settlement Agreement also stipulates to the adoption and incorporation of IG witness Gorman's recommended changes to CEI South's limitation of liability provision in its tariff, with modifications as proposed by CEI South witness Rice on rebuttal. Settling Parties' Jt. Ex. 1 at Section B.8.b.

i. CEI South's Case-in-Chief.

1. CPP Pilot. CEI South is proposing a new time-of-use ("TOU") rate with a CPP Pilot program to allow for more efficient utilization of CEI South's system and provide a tool to help manage peak loads during hours of highest usage and provide customers with an opportunity to lower their bills. Pet. Ex. 19 at 12. Mr. Rice explained that this program may include multiple tiers of pricing with lower prices at off-peak times and higher prices at on-peak times. He stated this structure provides an economic incentive for customers to shift load from on- to off-peak hours. In addition, during times when usage is expected to be at its highest, the utility will communicate with customers that a critical peak event will occur on the following day. During the event, the cost of energy will be elevated above the typical on-peak period pricing to provide more incentive for customers to shift load. Mr. Rice testified this demand response-like component of the program, a CPP event, requires the customer to respond to the elevated price to be successful.

The proposed program will be implemented as a pilot program so that CEI South can better understand potential benefits of a full program and build effective communication tools to help ensure the future success of the program. The proposed CPP Pilot is estimated to cost approximately $1.75 million, consisting of an estimated $915,840 in capital expenditures and an estimated $838,762 to be expensed with the Year 2 evaluation included. The proposed pilot rate will be active for two years, after which CEI South proposes to evaluate impacts and processes associated with the CPP Pilot and lead a rate development study in year three of the Pilot. Mr. Rice testified that Cadmus helped to design the program and would perform the evaluation on the back end. If the CPP Pilot is approved, CEI South would file a request in a separate proceeding for approval of final TOU and CPP rates.

Mr. Rice described the eligibility requirements for the pilot. He said CEI South proposes to cap enrollment in the proposed CPP Pilot program to 500 residential customers to, "provide evaluators with a sufficient sample size for assessing the electricity demand impacts, participant experience, and pilot cost-effectiveness and to obtain useful insights for CEI South program administrators." To be eligible to participate in the CPP Pilot program, residential customers must have at least one year of automated meter data at the time of registration and must not be enrolled in an existing demand response program such as CEI South's Summer Cycler or Thermostat Load Control programs.

CEI South proposes a Rate RS-CPP that includes separate winter (defined as December through February) and summer (defined as March through November) rates. Proposed volumetric rates during the winter period would consist of a uniform volumetric energy charge of $0.16270 per kWh. Proposed volumetric rates during the summer period would consist of on-peak service of $0.28214 per kWh during weekdays from 1:00 p.m. to 7:00 p.m., and $0.07054 per kWh all other hours. Service during both winter and summer periods would also include a monthly service charge of $23.20 per customer and a volumetric charge during called CPP events of $0.56429 per kWh. Pet. Ex. 19 at 17. CEI South proposes to provide a one-time incentive of $75 for customers who enroll in the proposed program.

Mr. Rice described the goals for the CPP Pilot generally as "to help CEI South better assess the potential use cases and cost-effectiveness of TOU rates, like CPP, for managing residential electricity demand and the extent to which customers will embrace time-varying rates." Pet. Ex. 19 at 14. Specifically, he listed the following goals of the pilot program:

a. Gauge residential customer interest in time-varying pricing, determine expected participation rates, and gain an understanding of CEI South's likely marketing costs to enroll customers.

b. Learn the electricity demand and energy impacts of the TOU rate and CPP events, including the following:

    i. The average reduction in electricity demand per participant during the TOU rate on-peak period and the average increase in electricity demand per participant during the TOU rate off-peak period;

    ii. The average impact of CPP events on electricity demand per participant before, during, and after CPP events;

    iii. The impact of the CPP events on the participant's energy consumption;

    iv. The impact of the TOU rate on participant energy consumption; and

    v. To the extent possible given the small size of the pilot, whether the demand or energy impacts vary significantly by customer demographics, home type, or availability of different enabling technologies such as smart thermostats.

c. Learn the impacts of the TOU rates and CPP events on participant customer bills and whether the bill savings are commensurate with or exceed the cost to participants of attempting to shift their loads to lower priced periods.

d. Learn the avoided demand and energy costs and other non-energy benefits from the pilot as well as the likely cost-effectiveness of TOU rates with CPP.

Pet. Ex. 19 at 15.

2. Green Energy Rider ("Rider GE"). CEI South witness Forshey described Petitioner's proposed Rider GE, which would allow Petitioner's large customers with a minimum annual usage of 5,000 MWh to purchase and claim RECs received for up to 85% of the MWh of energy generated by CEI South's renewable resources, whether from Petitioner's renewable energy projects or those renewable generation facilities with which Petitioner has a power purchase agreement ("PPA"). Pet. Ex. 17 at 5-6. All REC transactions would be conducted through the Midwest Renewable Energy Tracking System ("MRETS") marketplace. CEI South would use the historic REC price from the previous year to set the base price. CEI South witness Rice explained that each month, 15% of RECs generated would be sold into the MRETS market to establish the current market price. Pet. Ex. 19 at 26. The monthly amount billed to each Rider GE customer would be modified according to the adjusted market price and all Green Energy amount proceeds received will be credited back to all customers through the CECA rider.

3. Rider ADR. CEI South witness Rice explained that, as part of the IRP stakeholder process, CEI South committed to evaluating the use of a third-party demand response aggregator to help partner with customers in shifting load to off peak hours. Pet. Ex. 19 at 29. Mr. Rice and Mr. Forshey testified that Rider ADR will allow customers to partner with an aggregator to successfully lower load during MISO events. It is available to commercial and industrial customers to provide interruptible load and receive incentive payments directly from the program administrator to help offset electric costs. The tariff will be available for customers to participate in year-round or seasonally. Dispatches will be limited to four consecutive hours per event. Pet. Ex. 19 at 29; Pet. Ex. 17 at 21.

4. Rider TLC. Mr. Forshey described the proposed Thermostat Load Control Rider ("Rider TLC") to be marketed to customers using various marketing strategies and cross-promotion through other programs such as Residential Marketplace, in conjunction with the phase out of Rider Direct Load Control ("DLC"). Mr. Forshey testified this shift represents a shift in focus to achieving an increased level of demand response through smart thermostats versus switches. Pet. Ex. 17 at 22.

5. Economic Development Rider ("Rider ED"). CEI South witness Forshey described CEI South's proposal to update its Rider ED to amend the current structure to be more intuitive and competitive with the economic development riders offered by other utilities in the State of Indiana. Pet. Ex. 17 at 10. Mr. Forshey testified that CEI South is proposing to eliminate the different level of incentives currently offered, thereby simplifying the applicability process while remaining firm on specific economic development requirements that are necessary to ensure current or prospective customers remain committed to the region and a long-term presence in Southwestern Indiana. These changes will also closely align CEI South's economic development incentives with those offered by CEI South's peers in the State of Indiana. Mr. Rice explained that CEI South is proposing to combine the two incentive levels currently in Rider ED and offer only one incentive level for projects at least 500 kVA/kW that result in capital investment at the customer's establishment of $1 million and the creation of ten new full-time jobs at the same location. Pet. Ex. 19 at 27. In addition, Mr. Rice explained CEI South is proposing to extend the credit from 24 months to 36 months and provide credit of up to $4.50 per kVA/kW.

6. Interruptible Contract Rider ("Rider IC") and Interruptible Option Rider ("Rider IO"). CEI South witness Rice described the proposed updates to Riders IC and IO, saying the tariffs were updated to reflect MISO's seasonal construct and expectations, which entails an associated increase in the number of interruptions the customer would be required to be available for annually. The amount of time per interruption was decreased to four consecutive hours per day. The amount of time to respond was increased from 10 minutes to 30 minutes. Metering requirements were added. Annual testing requirements and language around penalty for failure to interrupt were also included, consistent with MISO's BPM. Additionally, the size requirement to participate in the Rider IO was decreased to 100 kW from 250 kW. Pet. Ex. 19 at 28.

7. MISO Demand Response Rider ("Rider DR"). CEI South witness Rice testified that CEI South is proposing to remove the requirement that there be a minimum of 1 megawatt ("MW") load reduction to participate in this program and replace it with a threshold of 100 kW minimum, consistent with Emergency Demand Response, which is allowed within this tariff. Additionally, language was updated around communications processes to include proper equipment to receive MISO dispatch signals. Pet. Ex. 19 at 28.

CEI South witness Forshey described proposed updates to Rider DR to better align with current MISO market offerings. He explained that CEI South does not have a direct mechanism for customers with qualifying behind the meter generation ("BTMG") to participate in the MISO market as DRR Type 2 and potentially respond to market signals and collect revenues in the Day-Ahead and Real-Time MISO Markets. While customers with a BTMG could elect DRR Type I, it would not fully optimize the value of their resource in the MISO market. By allowing qualifying existing or prospective BTMG customers to participate in the MISO market as DRR Type 2, CEI South is providing those customers with an opportunity to supplement their revenue stream and support grid operations. Pet. Ex. 17 at 21.

8. Updates to DSMA, RCRA, and MCRA. Mr. Rice described certain proposed updates to the DSMA, RCRA and MCRA. He said all DSMA opt-out groups will be removed, since when new rates are put into place, CEI South will no longer collect lost revenue margin for programs prior to new rates being implemented. Mr. Rice said CEI South will file a compliance filing when new rates are implemented and remove approximately $12.1 million from DSMA rates for lost revenue margin. CEI South will begin calculating and recording lost revenues in 2026 to be recovered in the annual DSMA filing. CEI South will begin new opt-out groups at that time to the extent that other large customers opt out of DSM programs post new rates. Base amounts for DLC billing credits and DLC inspection and maintenance amounts have been adjusted to forecasted test year amounts. CEI South is also proposing that customers be allowed to opt back into EE programs at any time of the year. Pet. Ex. 19 at 30-31.

Mr. Rice described the updates to the RCRA to update base amounts for base level RCRA charges and revenues to reflect forecasted amounts. Additionally, CEI South is proposing to include Backup Capacity Generation Services variances generated from Rate BAMP in the RCRA. Pet. Ex. 19 at 31. The RCRA was also updated to reflect Petitioner's proposal, described by Mr. Rice and Mr. Bradford, to provide 100% of WPM sales margins to customers. Pet. Ex. 19 at 31; Pet. Ex. 7 at 18. Mr. Rice testified the move away from 50/50 sharing results in an estimated $7.1 million benefit to customers in 2025. Pet. Ex. 19 at 31.

The proposed updates to the MCRA reflect forecasted amounts for the base amounts for base level MISO charges and revenues. Pet. Ex. 19 at 31. Mr. Rice testified that CEI South is proposing to include Backup Transmission Services variances generated from Rate BAMP in the MCRA. Additionally, he said, CEI South added Real Time Schedule 49 and Real-Time Multi Value Project ("MVP") Distribution to the list of MISO charges.

9. Other Tariff Changes. Mr. Rice described various other proposed changes to CEI South's general terms and conditions of service, consisting of minor adjustments, clarifications, process updates and additions to align with the Indiana Administrative Code. Pet. Ex. 19 at 31-33.

ii. OUCC's Position.

1. CPP Pilot. OUCC witness Dismukes criticized the design of the CPP Pilot, saying it lacks clearly established goals and objectives, such that it will be difficult to measure future success or usefulness of the program. Pub. Ex. 12 at 58. He said the proposed CPP Pilot also lacks many consumer protection provisions that should be included in such a program. Dr. Dismukes opined that CEI South's proposed TOU-CPP goals are not well constructed to elicit meaningful insights to help CEI South or other stakeholders in designing effective time-variant rates. Specifically, he said CEI South's proposal: (1) co-mingles two separate rate structures into a single pilot program (both a proposed TOU rate structure and a CPP program), (2) fails to outline expected peak reduction or other benefits associated with the program, and (3) fails to outline in sufficient detail how the cost-effectiveness of the CPP pilot program will be evaluated in the future.

Dr. Dismukes also stated that CEI South did not estimate the expected benefits associated with and cost-effectiveness of the proposed CPP Pilot. Pub. Ex. 12 at 61. He further opined that CEI South has not indicated how it will evaluate future cost-effectiveness of the CPP Pilot and stated there is a need to establish a general outline for future evaluation criteria to ensure that the proposed pilot elicits results consistent with the goals of the pilot. Dr. Dismukes further opined that CEI South's CPP guidelines are insufficient, failing to address a multitude of aspects to the calling of CPP events which may lead to future customer confusion. He said that beyond limiting the future CPP events to 16 per year, the proposed CPP Pilot provides few restrictions on the frequency of potential called CPP events, such as the number of events during a given month or week, or even the potential for multiple consecutive days of called events. He also said CEI South explicitly leaves open the potential to call CPP events under the proposed CPP Pilot during adverse weather events, creating the potential for participating customers to receive significant electric charges for space heating and cooling requirements during oppressive weather situations. Dr. Dismukes stated that while the proposed CPP Pilot is intended to be revenue neutral, it is possible the final CPP Pilot could result in increased revenues for Petitioner over standard residential service rates based on the assumptions CEI South used about the timing of CPP events. He also expressed concern that CEI South does not propose an on-peak pricing period for winter use, which he said would send mixed messages to customers regarding when system peaks are expected to occur and how to change behavior to lessen electricity rate requirements. Dr. Dismukes also objected to CEI South's proposal to use the same consultant (Cadmus) that assisted CEI South in the design of the CPP Pilot in the eventual evaluation of the proposed pilot, saying this presents a

potential conflict of interest as CEI South's evaluator of the CPP Pilot will have a vested interest in overstating benefits of a pilot they were intimately involved in designing.

Dr. Dismukes took issues with the way CEI South developed its proposed Rate RS-CPP and opined that the proposed Rate RS-CPP includes "significantly high on-peak and CPP rates for extended durations that could potentially lead to rate shock in the future." Pub. Ex. 12 at 67-69.

OUCC witness Paronish testified that CEI South's CPP Pilot proposal did not satisfy the GAO 2020-05 requirements. In addition to Dr. Dismukes's criticisms of the goals and design of the program, Ms. Paronish said the OUCC is unable to determine whether the CPP Pilot's design allows for "reasonable flexibility," as required by Part D of GAO 2020-05. Pub. Ex. 13 at 20. She also said CEI South did not provide an adequate timeline because it indicated a start date would "follow approval of the pilot."

2. Rider GE. OUCC witness Wright recommended CEI South be required to consider more than one REC marketplace when setting REC prices for the Rider GE program and that CEI South revise the language in the Rider GE and CECA tariffs to ensure all revenues from the Rider GE are properly credited to customers. Pub. Ex. 8 at 8-9. Mr. Wright recommended that, given the variability in REC marketplace prices and the connection between REC value and ratepayer affordability, CEI South should ensure it sells RECs for the maximum available value. He stated large customers should not receive reduced REC costs at the expense of reduced affordability for other ratepayers. He expressed concern that CEI South did not conduct an analysis comparing REC prices between available REC marketplaces and recommended CEI South compare prices between multiple available REC marketplaces and adjust for the maximum REC value in its monthly Rider GE bill adjustment. He opined that this adjustment would ensure ratepayers not enrolled in the program would still receive maximum benefit from the sale of RECs. He recommended amendments to the tariff to clearly define what constitutes "Green Energy Amount proceeds" to ensure all revenue generated by the program and sale of RECs is being passed on to customers through the CECA. He also recommended CEI South provide a sample formula of each monthly bill in the tariff and amend the language to clarify the total monthly variance that would be applied to each bill. He also recommended changes to the CECA tariff to define "qualified Clean Energy Investment" and to clearly include all revenue from the sale of RECs and all revenue otherwise generated by Rider GE.

3. Rider ADR. Mr. Wright recommended the Commission deny Rider ADR because CEI South failed to provide crucial details regarding the function and budget of the program. Pub. Ex. 8 at 8. Specifically, he said CEI South did not explain in testimony how the program would be funded, how MISO-qualified energy and demand reductions from the program would be credited, or how success or failure of the program would be evaluated. Pub. Ex. 8 at 6. He said that, although CEI South has already begun the aggregator selection process through its 2022 All-Source RFP, CEI South's testimony lacks key details on a contract with this aggregator or CEI South's relationship with it, including the amount being paid to the contractor, the demand reduction capacity goal of the contract, how contractor success would be evaluated, and what happens if the contractor fails to perform the expected demand. Mr. Wright testified that without these details, it is impossible to evaluate whether this program is in the best interest of ratepayers and so it should not be approved.

iii. CAC's Position. Regarding CEI South's proposed demand response items, CAC witness Inskeep stated the CAC recommends the following revisions to the proposed tariffs and pilot:

1. Enhance flexibility and expand demand response offerings.
2. Develop a robust customer recruitment plan.
3. Simplify interruptible tariffs.
4. Expand residential demand response tariff options.
5. Expand residential CPP pilot options.
6. Conduct additional pilot rate analysis.
7. Aim for rapid pilot-to-program evolution.

CAC Ex. 2 at 70.

Mr. Inskeep opined that, by implementing these recommendations, CEI South could enhance its demand response initiatives, ensuring they are both customer-friendly and aligned with broader energy management goals. He requested that CEI South use its DSM Oversight Board ("OSB") to continue discussion and collaboration to refine these proposals and plan marketing, education, and other components that will be key to the success of these programs. Accordingly, he recommended that the Commission approve CenterPoint's demand response riders and programs with these revisions.

iv. Industrial Group's Position. IG witness Gorman recommended a change to CEI South's current tariff provision limiting its liability for service interruptions. He said the provision as written is unreasonably broad and would purport to eliminate any and all liability for damages caused by service interruptions, regardless of the degree of fault on the part of CEI South. IG Ex. 1 at 137-138. He said CEI South's provision is much broader than the limitation of liability tariffs of the other four investor-owned electric utilities in Indiana. He recommended changes to carve out of the limitation of liability CEI South's own willful default or negligence.

v. CEI South's Rebuttal.

1. CPP Pilot. Mr. Rice outlined how the CPP pilot proposal satisfies the six requirements set forth in GAO 2020-05. Pet. Ex. 19-R at 28-29. Mr. Rice summarized the conceptual evaluation criteria, both the explicit and implied mentioned in his direct testimony, in his Table MAR-R9. He said CEI South will continue to work with Cadmus to finalize evaluation criteria should the pilot be approved. Mr. Rice testified that CEI South chose a path that delivers maximum flexibility. He said the pilot is a small-scale, short-term experimental trial intended to test and learn how a large-scale program might work in practice and provide valuable data that can be utilized in CEI South's future evaluation of cost/benefits in its 2028 IRP. Pet. Ex. 19-R at 32. He opined that CEI South's approach of not including the costs of a fully developed, large scale program within its case in chief, *i.e.*, full cost of finalizing the program design and EM&V measures, fully drafting a contract for pilot participants, developing marketing and customer educational materials, and fully developing the rate, not only delivers maximum flexibility because there is opportunity to evaluate and modify the program based on pilot data and

stakeholder feedback but also benefits customers by saving money by only including costs related to implementing a pilot, and not a fully developed program, in this Cause.

With respect to the timeline for the CPP Pilot, Mr. Rice testified that, following an Order approving the pilot program, CEI South will kick off the rate development study; begin development of educational and marketing materials; begin the IT and billing infrastructure setup; and will work with Cadmus to finalize design work. CEI South plans to file for final rates in a separate docketed proceeding in Q2 2025 to have final rates approved by the end of 2025. Throughout 2025, IT will work on billing and infrastructure setup and will finalize that work by the end of 2025. By early 2026, CEI South plans to begin recruitment and train customer service and billing agents on the pilot program to equip them with the tools needed to fully support customers when the pilot begins. CEI South is targeting Q2 2026 to begin the pilot. CEI South will implement the pilot and begin capturing data for Cadmus' evaluation, with final results for year one by Q2 2027. Mr. Rice stated that if needed to gather sufficient data, CEI South may extend the pilot for up to one year, with a final evaluation to be completed by Q2 2028, which will provide CEI South sufficient time to incorporate results into the 2028 IRP. Mr. Rice stated CEI South plans to meet with interested stakeholders to discuss progress and solicit feedback about every six months until the 2028 IRP stakeholder process begins; from that point forward, any updates/feedback on CPP will come through cost benefit testing in the IRP.

Mr. Rice explained that the pilot is designed to include both TOU and CPP pricing elements in one rate structure because each pricing element addresses a different source of variation in demand. He said TOU pricing is meant to reflect prevailing changes in demand across hours of the day (*e.g.*, the normal summertime afternoon peak) and CPP pricing is intended to address changes in demand occurring due to emergency events (*e.g.*, a heat wave). He explained a rate structure that includes both pricing elements is expected to be more effective than either pricing element in isolation because it creates incentives for conservation in response to both sources of variation in demand. For this reason, he stated CEI South is most interested in deploying a TOU-CPP pricing structure. With respect to evaluation, he said the most straightforward way to evaluate a TOU-CPP rate structure is to directly include the TOU-CPP rate structure in the pilot.

Mr. Rice rebutted the notion that CEI South did not include testimony regarding why the CPP Pilot is in the public interest, citing to his direct testimony discussion of the short-term and long-term benefits of the program. Pet. Ex. 19-R at 34. He said if this tool proves to be effective, CEI South may utilize a CPP program to help offset the need for new generating resources.

Mr. Rice corrected an inaccuracy in Dr. Dismukes's description of how the customers will be notified of a called CPP event. He said there is a distinction drawn within the TOU-CPP Indicative Tariff between a CPP event and the potential to use the program for a system emergency, but Dr. Dismukes lumps these two different situations into one. Pet. Ex. 19-R at 35.

Mr. Rice testified that CEI South will develop educational materials to help customers understand the TOU-CPP program and potential risk of higher bills. He said CEI South has included $30,000 in its cost estimate to develop such educational materials. Pet. Ex. 19-R at 36-37. Mr. Rice quantified what a CPP event may cost a customer, which, based on the maximum annual number of MISO events in a year (16) would equate to about $80 for event hours for an average residential customer using 799 kWh per month. He reiterated that customers will be paid

$75 to participate in the pilot. Additionally, he noted this is a voluntary program, and customers may voluntarily leave the program if they have a bad experience.

Mr. Rice explained that CEI South did not propose a TOU rate during the winter because peak hours in the winter are much less predictable than summer peaks and may occur at different times of the day, depending on when cold fronts move in and settle over the area. The TOU portion of this rate is not applicable in the winter, as it would be much harder to educate customers to modify their consumption behavior to set hours of the day. He said while not proposing a TOU rate during the winter, CEI South does want to test the CPP portion of the rate in the winter months to evaluate its ability to offer the CPP program into the MISO market as a LMR during the winter season.

Mr. Forshey explained the benefits of having the same vendor both design and evaluate the CPP Pilot, including lower costs to be incurred as the vendor would not need to spend time learning and understanding the pilot design and expected outcomes. Pet. Ex. 17-R at 6. He said using the same vendor, instead of two vendors, will also streamline evaluation of the pilot by administering customer surveys in a timelier fashion, such as a few days after a critical peak event is called, offering advantages in higher customer response rates as well as better recall. Mr. Forshey testified that a company that both designed and then evaluates the pilot would not need to hit pause to survey the utility's staff on how it developed the program design before administering surveys, etc. Moreover, he stated the ongoing engagement of one vendor performing the evaluation will accelerate when final evaluation results will be available to inform program design and implementation recommendations for the second year of the pilot. He said the complex nature of pricing pilots using hourly time of use information demonstrates the need for vendors to understand CEI South's customer demographics and CEI South's implementation of the pilot in terms of education of time of use rates, informing customers of peak events, and data integrity to measure results. As a result of this complexity, Mr. Forshey testified that adding a vendor for design and another vendor for evaluation will increase costs, lengthen the Evaluation Measurement and Verification ("EM&V") reporting, and potentially increase the time for design changes identified in the final EM&V report to be implemented by CEI South.

2. Rider GE. In response to OUCC witness Wright's recommendations, CEI South witness Rice explained that CEI South is currently selling RECs for what the market will bear. CEI South's renewable resources are all located within MISO, making M-RETs the logical choice for registering these resources. Mr. Rice testified that CEI South believes it is better to offer these RECs to its customers to meet their sustainability goals than to others with no connection to the community. Pet. Ex. 19-R at 23. Mr. Rice reiterated points raised by witness Forshey, that eligible customers for Rider GE are CEI South's largest customers and contribute to the fixed cost recovery of CEI South's system. Mr. Rice said Rider GE helps ensure they can meet their sustainability goals without relocating, choosing to expand elsewhere, or avoiding some fixed cost recovery of the system by installing behind the meter generation. He stated all these possibilities would have a negative impact on affordability for CEI South's customers that are not participating in the program. Mr. Rice also noted the administrative burden and increased cost that would be imposed as a result of the OUCC's recommendation. He said CEI South would be required to monitor "multiple available REC marketplaces," and compile data. He further noted it is not clear what markets the OUCC would like CEI South to benchmark against or if the data is readily available without a fee. Mr. Rice gave an example of CEI South's recent

sale of RECs from Troy Solar to buyers in Ohio, which is the example market Mr. Wright pointed to in his testimony. He explained that to have the opportunity for a higher price, resources would likely need to be registered with other states bound by a Renewable Portfolio Standard, according to their requirements. Mr. Rice cautioned that this approach will likely increase volatility of REC pricing, which may drive requests by Rider GE customers to better understand how the benchmark is set, provide customer reconciliations with explanations of drivers, or something that will be almost impossible, forecasting a market that does not exist.

In response to Mr. Wright's suggestion to update the tariff language to better define "all Green Energy amount proceeds," Mr. Rice testified that the tariff was updated to reflect that Green Energy Amount proceeds are REC revenues from participating Rider GE customers, net of any necessary fees incurred from M-RETS. Mr. Rice disagreed with Mr. Wright's recommendation to amend the CECA tariff if Rider GE is approved. He said the current CECA tariff does not discuss the treatment of RECs. He explained that, should the Rider GE be approved by the Commission, CEI South will propose updated schedules within the next CECA filing following an order in this case, which will clearly break out any REC revenues, net of necessary costs, associated with Rider GE.

3. <u>Rider ADR</u>. Mr. Rice responded to Mr. Wright's criticisms of the proposed Rider ADR. He noted that the OUCC participated in the IRP stakeholder process, was engaged in multiple tech-to-tech calls, and reviewed CEI South's IRP, but did not question the need for the ADR resource during the IRP stakeholder process. Pet. Ex. 19-R at 24-25. Mr. Rice recited the portions of his direct testimony and Mr. Forshey's direct testimony that provided details on the program. He explained that because CEI South does not have an approved program, it has not entered into contract negotiations with a DR aggregator. He did say that CEI South routinely contracts for capacity and recovers costs via the RCRA and this would be no different in that respect. Mr. Rice opined that DR aggregation is a better solution to CEI South's capacity needs in that it will provide a potential new revenue stream to help offset rates paid by CEI South customers, helping with affordability, improving customer satisfaction, and providing reliability benefits to the local system. He said there would be less risk in working with a DR aggregator than posed by the current industrial DR tariffs as the DR aggregator would be a MISO market participant, held to the same standards and evaluation criteria for Load Modifying Resources ("LMR") as any other industrial customer participating in CEI South's applicable DR tariff. *Id.* Mr. Rice testified that DR aggregation can save customers money in the short and long-term, helping with affordability.

Mr. Forshey testified that if Rider ADR is approved, the contract with the DR Aggregator will be aligned with MISO's Tariff and Business Practices Manuals ("BPMs") to ensure CEI South receives the appropriate capacity accreditation with MISO. For example, the DR Aggregator selected would be the MISO participant and would bear the risk of penalties from MISO for non-performance, so CEI South customers would not bear that risk. CEI South would also ensure other appropriate customer protections are established within any contractual arrangement with a DR Aggregator to make sure the risk remains with the DR Aggregator and not CEI South's customers. Similarly, the DR Aggregator and participating aggregated DR customers must meet the requirements set by MISO for LMRs. Mr. Forshey testified that this requirement ensures that CEI South can register these resources with MISO and receive the appropriate capacity accreditation. As discussed in Rider ADR, the DR Aggregator or "Program Administrator" would be responsible

for communicating with participating customers prior to and during a load reduction event, for providing incentive payments to participating customers, and for delivering a post-event performance report to CEI South based on the results provided by the metering and control technologies put in place to monitor participating customers. Pet. Ex. 17-R at 3.

4. Limitation of Liability Provision. On rebuttal, Mr. Rice accepted Mr. Gorman's proposal to change the limitation of liability provision but suggested minor modifications to the language Mr. Gorman recommended. Specifically, CEI South proposed to include the phrase "willful or wanton misconduct or gross negligence" in the carveout recommended by Mr. Gorman to more accurately address the issue Mr. Gorman raised. Pet. Ex. 19-R at 48.

vi. Settlement. In Section B.7 of the Settlement Agreement, the Settling Parties stipulate and agree that CEI South's proposed CPP Pilot; ADR; and the Rider GE be approved as proposed by CEI South. Pet. Ex. 19-S at 14.

1. CPP Pilot. Mr. Rice reiterated the purpose and benefits of the proposed CPP Pilot. He noted that this program is not the first of its kind in Indiana, as Indiana Michigan Power ("I&M") has an approved CPP tariff, which CEI South utilized in developing the proposed pilot.

2. Rider ADR. Mr. Rice noted that Section B.7 of the Settlement Agreement states that CEI South agreed to provide all parties to this Cause a copy of the contract with the DR aggregator after it has been signed. This will allow the parties to see the protections alluded to in Mr. Forshey's rebuttal testimony. Pet. Ex. 19-S at 16. As discussed in Section 0.G (Pro Forma Revenues and Expenses), the Settling Parties, in Section B.5 of the Settlement Agreement, stipulated and agreed to remove the $725,000 from base rates, eliminating the controversy over the inclusion of that amount in base rates.

3. Rider GE. Mr. Rice reiterated that CEI South will sell RECs for what the market will bear, and creating an index creates an unreasonable administrative burden. He said Rider GE helps ensure eligible customers can meet their sustainability goals without relocating, choosing to expand elsewhere, or avoiding some fixed cost recovery of the system by installing behind the meter generation. All these possibilities would have a negative impact on affordability for our customers that are not participating in the program. Pet. Ex. 19-S at 16.

4. Rider IC and IO. Mr. Rice explained that in the Settlement, CEI South agreed to continue conversations with interested stakeholders regarding changes to its IC and IO Riders related to Demand Response. He noted that CAC witness Inskeep encouraged CEI South to continue to collaborate with CAC and the OUCC on these topics and continue to work with the DSM OSB to further refine and ensure the success of the programs. The Settling Parties stipulated and agreed to this term to continue to work with those interested parties on changes to its Rider IC or Rider IO. Pet. Ex. 19-S at 17.

In Section B.8.b of the Settlement Agreement, CEI South agreed to adopt and incorporate the changes to its limitation of liability provision in its tariff as recommended by IG witness Gorman and modified by CEI South witness Rice on rebuttal. Pet. Ex. 19-S at 17.

vii. Settlement Opposition. OUCC witness Wright testified that the Settlement Agreement did not address the issues he raised and nothing in CEI South's rebuttal or the Settlement or testimony supporting the settlement caused him to change his position or recommendations. He still recommends denial of the proposed Rider ADR due to lack of basic information provided on the budget and functioning of the program. He still recommends Rider GE consider multiple REC marketplaces when setting REC prices for the program to maximize the benefit of the RECs for all rate classes. Pub. Ex. 8-S at 2-5. Mr. Wright stated the OUCC disagrees with Mr. Rice's assertion that large industrial customers will relocate or build behind-the-meter generation. He said the assertion that large industrial customers would base this decision solely on the availability of low-cost RECs through the Rider GE is speculation.

OUCC witness Dismukes testified that the Settlement Agreement did not address his concerns regarding the CPP Pilot. Pub. Ex. 12-S at 4-5. He stated the few evaluation criteria CEI South has put forward associated with the CPP Pilot are lacking the specifics required for such a pilot. He said CEI South has not established any marker for potential load shifting it would realistically seek to accomplish through the proposed pilot program, has not established a prior baseline for estimated energy savings associated with the CPP Pilot, and has not established either a baseline bill savings estimate to judge performance from or, importantly, establish the level of negative bill impacts (*i.e.* increased bills due to the pilot) CEI South would find unacceptable.

Ms. Paronish testified she continues to have concerns with the CPP Pilot and that it is irrelevant whether the OUCC or other stakeholders commented on this issue during the IRP process. Furthermore, she opined it is extremely prejudicial and inappropriate for Petitioner to criticize the OUCC for not then raising concerns with the program now presented for approval. She emphasized that an IRP is a non-binding statement of general intention by a utility, and not a docketed proceeding in which a utility seeks specific relief. Pub. Ex. 13-S at 13. She compared DSM programs and the EM&V process to the proposed CPP Pilot, noting the EM&V vendor is independent of the utility and the vendor the DSM OSB selected to design programs. In the case of the CPP Pilot, there is no OSB, and there is no independence from the utility. She likened this to "the fox watching the henhouse." She also noted that during the DSM EM&V process the OUCC and other OSB members participate in regularly scheduled calls with the EM&V vendor to understand what is transpiring and to discuss issues. Also, the OUCC and other OSB members have the opportunity to look at the draft EM&V report prior to finalizing and filing with the Commission. She recommended that if the Commission approves this program, the Commission direct CEI South to choose two separate vendors – one to design its program and one to perform EM&V. However, if the Commission allows CEI South to use the same vendor to both design and perform EM&V on the CPP Pilot, Ms. Paronish stated an OSB-like process should be required. She said this would enable the OUCC and interested intervenors to participate and scrutinize the EM&V report prior to it being filed with the Commission. Pub. Ex. 13-S at 17.

Ms. Paronish recommended that if the Commission approves this program, CEI South should be required to provide a written plan explaining and committing to how the Commission, the OUCC, and intervenors can be involved throughout the CPP Pilot. Pub. Ex. 13-S at 18.

CAC witness Inskeep took issue with Mr. Rice's characterization of his testimony as "commend[ing] CEI South for moving forward with proposals such as the CPP Pilot," saying this omits that Mr. Inskeep also requested "that CEI South use the DSM OSB to continue discussion

and collaboration to refine these proposals and plan marketing, education, and other components that will be key to the success of these programs." CAC Ex. 6 at 20 citing CAC Ex. 2 at 69. He had proposed revisions regarding enhancing flexibility and expanding demand response offerings, developing a customer recruitment plan, expanding residential customer demand response tariff options, and expanding the CPP Pilot (*e.g.*, pilot time of use rates and peak time rebate options). Mr. Inskeep stated that CEI South largely ignored these recommendations, while the Settlement Agreement approves CEI South's proposals without incorporating most of his recommendations, with the exception that additional discussions will be held regarding interruptible tariff changes. He expressed concern that CEI South is moving forward with its demand response proposals without incorporating most of the constructive feedback provided by CAC to enhance these offerings and ensure their success for both the utility and its customers.

viii. Settlement Rebuttal.

1. CPP Pilot. Mr. Rice responded to Dr. Dismukes's repeated concerns over the CPP Pilot, expressing that it appeared Dr. Dismukes does not understand how the results from the CPP Pilot will be incorporated into an upcoming IRP. Pet. Ex. 19-SR at 22. Mr. Rice explained that the full evaluation of CPP is not limited to the pilot; it includes pre-evaluation with expected demand savings that were included in the 2022/2023 IRP. Once load shifting estimates and its demand response potential are evaluated and refined with results from the CPP Pilot, CEI South will utilize the CPP Pilot results to further evaluate CPP in the 2028 IRP as a resource option. Mr. Rice said the requirement of participants to have at least one year of automated meter data at the current premises is precisely for the purpose of establishing a baseline for estimated energy savings that Dr. Dismukes claimed was lacking. Mr. Rice said there is no absolute threshold for comparing bill savings relative to perceived benefits, which is better evaluated through customer engagement surveys, and the CPP Pilot will instead evaluate in absolute terms how well or poorly each customer fared. He said customer engagement surveys will also be used.

2. Rider GE. In Attachment MAR-SR2, Mr. Rice addresses Mr. Wright's opposition to Rider GE. He reiterates that the issue is not the ability to sell to multiple marketplaces but that once a resource is committed, it is a long process to withdraw and register in another market; CEI South cannot simply sell to one market one month and another the next. Also, time and effort is needed to understand the pros and cons of each market. Once CEI South sells outside of M-RETS the industrials cannot purchase them. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

3. Rider ADR. In Attachment MAR-SR2, Mr. Rice responds to Mr. Wright's arguments in opposition to the Settlement Agreement with respect to Rider ADR, which focus more on his argument that the information provided in rebuttal should have been contained in Petitioner's case-in-chief. Mr. Rice points out the time that elapsed between rebuttal

and settlement opposition testimony, noting there was ample time for a substantive response, which Mr. Wright did not provide. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

ix. Commission Discussion and Findings.

1. CPP Pilot. The record reflects that the CPP Pilot is designed to benefit customers by offering a tool to help keep electricity service affordable in the near- and long-term. The evidence shows a customer enrolled in the pilot that consumes a significant portion of their energy in off-peak hours is likely to realize bill savings. In addition to the benefit to customers, if proven effective, the tool could be used by CEI South to help offset the need for new generating resources. This tariff is not the first of its kind in Indiana and no party has denied the value of time varying rates. We find this program is in the public interest and should be approved, as incorporated into the Settlement Agreement.

2. Rider GE. CEI South proposed Green Energy Rider to provide CEI South's largest customers the ability to acquire locally sourced REC to help those customers meet individual sustainability goals. Eligible customers for Rider GE are CEI South's largest customers and contribute to the fixed cost recovery of CEI South's system. As for the OUCC's recommendation to require CEI South to price RECs based on multiple unidentified REC markets, we are not persuaded any potential benefit would outweigh the cost of such a requirement. We find Rider GE is in the public interest as is the Settlement Agreement provision adopting it as proposed in CEI South's case-in-chief.

3. Rider ADR. CEI South proposed Rider ADR, consistent with its IRP preferred portfolio to provide up to 25 MW of demand response. The tariff will allow for CEI South customers to partner with an aggregator for a customized solution to help them successfully lower load when needed. The record reflects how Demand Response Aggregation can save customers money in the short- and long-term, providing customers with a potential revenue stream to help offset CEI South bills, helping to avoid energy purchases when energy prices are highest and over the long-term helping avoid or delay the need to build new power plants. Pet. Ex. 19-R at 28. CEI South's Rider ADR is in the public interest as is the Settlement Agreement provision adopting it as proposed in CEI South's case-in-chief.

We find Petitioner's other proposed changes to its riders and tariffs were not disputed and should be approved as proposed in CEI South's case-in-chief.

K. ARP for Remote Disconnection. Section B.9 of the Settlement Agreement addresses Petitioner's proposed ARP for remote disconnection.

i. CEI South's Case-In-Chief. CEI South witness Folz presented CEI South's request for approval of an ARP to implement remote disconnect for non-payment process through a waiver of 170 IAC 4-1-16(f) and explained how the ARP satisfies the requirements of Ind. Code ch. 8-1-2.5 (the "Alternative Utility Regulation Act" or "AUR Statute"). She explained that CEI South is specifically seeking a variance from the requirement to be physically present on the customer's premise for the disconnect for non-payment. Pet. Ex. 5 at 11. She explained the communications with customers and information to be included in notices, which generally satisfy 170 IAC 4-1-16(f). Ms. Folz stated that medical need customers and life support customers will be exempt from this process and will continue to have field personnel on premise. She also stated

that, if at the time of the disconnect for non-payment, CEI South is notified that a customer is applying for, or received funds for, LIHEAP during that current LIHEAP season, CEI South would not process the disconnect for non-payment during that LIHEAP season.

Ms. Folz described the benefits to customers from CEI South's proposed process, noting that customers will have access to a customer service representative who has expertise responding to, and handling, calls related to non-payment. She said CEI South's proposed actions under the ARP eliminate an unnecessary step, allowing customers to more quickly, and conveniently, take action to resolve the disconnection of service. Ms. Folz noted that the Commission has granted waivers from 170 IAC 4-1-16(f) to other Indiana utilities – including Duke Energy Indiana, I&M, and AES Indiana – to allow for remote disconnection for non-payment. Ms. Folz testified that remotely performing disconnect for non-payment orders will further reduce safety risks, improve work efficiencies, and significantly reduce the reconnect charge for remote reconnects. She then described the notification process CEI South plans to utilize for performing remote disconnects as well as the notification process CEI South intends to use to notify all customers that may be subject to remote disconnection for non-payment prior to implementing the process. Ms. Folz indicated that if approved, CEI South would begin remote disconnects for non-payment once all system changes and communications have been addressed, using a phased approach.

ii. <u>OUCC's Position</u>. OUCC witness Paronish indicated that the OUCC does not oppose CEI South's request for waiver of 170 IAC 4-1-16(f) and recognized the potential customer benefit of CEI South's proposal, subject to certain recommendations for implementation of the ARP. Pub. Ex. 13, at 8. She stated that, in addition to medical need and life support customers receiving an in-person field visit for disconnection due to non-payment, the residential customers that have non-AMI meters should also receive an in-person field visit. Ms. Paronish suggested there could be "tens of thousands of customers that CEI South cannot contact if it initiates remote disconnects." Ms. Paronish recommended that "the company begin a proactive campaign to collect customer contact information at least three months before implementing the remote disconnection program and continue each month until the program is implemented." Ms. Paronish proposed specific language for communicating changes to CEI South's customers. She also proposed specific communication methods.

iii. <u>CAC's Position</u>. CAC witness Inskeep recommended the Commission deny CEI South's proposal to implement remote disconnection for nonpayment. He also recommended the Commission consider implementing a 12-month residential disconnection moratorium to allow time for CEI South to establish and implement additional affordability measures, including his proposed Affordable Power Rider. CAC Ex. 2 at 10. Mr. Inskeep contended the ARP for remote disconnects would make it easier for the utility to disconnect ratepayers without adequately informing them through an on-premises visit. He asserted that consumers may miss notices sent by a utility via phone call, text message, or email informing them of a bill delinquency and potential disconnection. An in-person visit is a critical backstop protection that can reach vulnerable customers who might otherwise miss notification. He referred to a "rising number of disconnections and increasing disconnection rate." *Id.* at 76.

Mr. Inskeep also contended CEI South's ARP is not consistent with Ind. Code ch. 8-1-2.5 requirements. He opined that while advancements in technology in the form of AMI has made remote disconnection technologically possible and facilitated additional communication channels

between the utility and some of its ratepayers, it does not mean that the need for an on-premises visit has been rendered unnecessary from a consumer protection perspective. He testified that CEI South's proposed ARP would be detrimental to its customers who would experience reduced protections compared to those who are currently afforded the on-premises visit prior to disconnection and asserted it would harm the utility by eroding its reputation and goodwill in the community. Mr. Inskeep stated CEI South's ARP would not promote energy utility efficiency because "disconnecting customers from electricity service is not necessary for – and indeed, is the very antithesis of – the provision of safe and reliable electricity service." *Id.* at 78. Finally, Mr. Inskeep argued that the exercise of Commission jurisdiction does not inhibit Petitioner from competing with other providers of functionally similar services or equipment, because Petitioner is a monopoly utility and the only entity legally able to sell electricity to retail customers within its service area and "is not in competition with Duke Energy Indiana and Indiana Michigan Power to serve customers in its service area." *Id.*

iv. CEI South Rebuttal. CEI South witness Folz responded to the concerns of Ms. Paronish and Mr. Inskeep with respect to the ARP for remote disconnections. CEI South accepted many of OUCC witness Paronish's recommendations, with slight modifications. Ms. Folz explained that the customers referenced by witness Paronish do not have an AMI meter installed and therefore, CEI South does not currently have the ability to perform the disconnect remotely, so until the meter is upgraded, these customers will continue to receive in-person visits prior to disconnecting electric service to their premises, if the situation ever arises. Pet. Ex. 5-R at 4. Ms. Folz provided data indicating that there are only 2,379 customers without a phone number in CEI South's system, so approximately 98.5% of the 134,972 eligible customers have phone numbers in the system. In addition, she stated CEI South has many methods of contacting its customers, and CEI South's remote disconnection for non-payment proposal includes the utilization of multiple communication channels to contact customers, including the disconnect bill itself through mail or email (depending on customer preference), outbound phone calls, text, and email prior to the disconnect. Ms. Folz testified that CEI South commits to proactively soliciting customer contact information through a communication campaign at least three months before implementing the remote disconnection program and to continue each month until the program is implemented. Communication methods include mailed bill messaging and emailed bill messaging (for those signed up for electronic billing). With respect to Ms. Paronish's specific language for customers communications about the change, Ms. Folz testified that CEI South agrees in principle with the proposed language, but noted it may require slight modifications, for example the CEI South name (from a branding standpoint), additional contact methods (including by customer bill and phone), and more clear steps to access the customer's online account. She stated CEI South will commit to providing the OUCC and other intervenors a copy of CEI South's language.

Ms. Folz indicated CEI South accepts the proposed methods with the addition of methods typically used by CEI South to communicate with customers (*i.e.*, social media and news release). She added that, in conjunction with CEI South's EIP, CEI South will require customers to update their online account passwords during the summer of 2024. With that, CEI South will prompt customers to update their contact information. She confirmed CEI South will commit to the following communication methods:

1. CEI South Website

    - Promotional popup/notification on home page.

    - Promotional popup/notification on customer account dashboard page.

    - Prompt for customers to update their contact information.

2. An alert to go to CEI South's website, in red font, on the customer's bill.

3. A bill insert regarding the process change and need for accurate contact information.

4. An auto dial notification message regarding the process change and need for accurate contact information.

5. A text notification message regarding the process change and need for accurate contact information.

6. An email notification to customers with e-mail addresses on file with CEI South notifying customers of the process changes, using the modified proposed language.

7. CEI South will use Nextdoor, Facebook, and X to provide information on this process change and the request for accurate contact information.

8. CEI South will use a news release to provide information on this process change and the request for accurate contact information.

Ms. Folz testified that Mr. Inskeep's recommendation to impose a moratorium on CEI South for disconnections is contrary to the Commission rules (170 IAC 4-1-16) that allow for disconnection due to non-payment under certain conditions. Aside from violating the Commission's rules, Ms. Folz asserted that imposing a mandatory, 12-month delay in disconnections due to non-payment would counteract affordability efforts. She explained that timely disconnections prevent customers from obtaining service without paying. The longer the amount of time of receiving service without paying for that service, the larger the customer's arrears payment will become. Pet. Ex. 5-R at 9. Contrary to Mr. Inskeep's assertion that the proposal would make it easier for utilities to disconnect residential ratepayers without adequate notice through an on-premise visit, Ms. Folz testified that CEI South's proposal actually will enhance and streamline the communication process, making it easier for customers to prevent a disconnection for non-payment. CEI South is proposing a process change for disconnects due to non-payment that will increase communication, which ideally will prompt quick action from CEI South's customers to either pay their bill, request payment assistance, or get low-income support, ultimately reducing disconnections due to non-payment. Ms. Folz also provided evidence of CEI South's compliance with each of the four criteria set forth in the AUR Statute.

v. <u>Settlement</u>. In his settlement testimony, CEI South witness Rice testified that, given neither the CAC nor OUCC joined the Settlement Agreement, the Settling Parties stipulated and agreed in Section B.9 that the approval of CEI South's request for approval of the ARP, as modified pursuant to Section B.9, will be left to the Commission's discretion and

determination. Section B.9 further provides that CEI South agrees to incorporate certain customer protections as set forth in Section B.10 of the Settlement Agreement. Pet. Ex. 19-S at 18.

vi. Settlement Opposition. OUCC witness Paronish provided testimony taking issues with certain positions taken in CEI South's rebuttal that she said did not fully transfer to the Settlement Agreement, noting an inconsistency between the rebuttal position incorporated into Section B.9 of the Settlement Agreement and Section B.10.d.i.1 of the Settlement Agreement, which states: "CEI South will provide at least thirty days advance notice to customers before implementing the remote disconnection/reconnection proposal." Pub. Ex. 13-S at 4-5. She continued to recommend there be at least a three-month communication campaign in connection with the remote disconnect program. She characterized the discrepancy as "CEI South inexplicably walk[ing] back its offer of a more reasonable approach that would have benefited residential ratepayers by giving these customers more time to become aware of Petitioner's new disconnection process." She concluded that this settlement term is not in the public interest and stated the OUCC objects to the Settlement Agreement's 30-day notice and recommends approval of the three-month communication campaign referenced in Ms. Folz's rebuttal testimony.

Ms. Paronish recommended that, since CEI South indicates the language she proposed may be modified, the Commission should afford the OUCC at least seven business days to review and comment, if necessary, on CEI South's proposed modified language. Pub. Ex. 13-S at 8.

CAC witness Inskeep testified that the consumer protections in the Settlement Agreement are "too modest to significantly reduce the rate of disconnection, especially in light of the proposed bill increase that will increase the likelihood of arrearages." CAC Ex. 6 at 21.

vii. Settlement Rebuttal. CEI South witness Rice responded to Mr. Inskeep's concerns about the consumer protections accompanying the ARP for remote disconnects, noting objection to Petitioner's proposed ARP is no reason to reject the Settlement, since the terms included within the Settlement Agreement that relate to remote disconnections are expressly left to the Commission's determination as to approval of the ARP. Pet. Ex. 19-SR at 24.

In response to Ms. Paronish's concerns that CEI South retracted its three-month minimum advance notice before remote disconnections begin, Mr. Rice explained that was not CEI South's intention. He reiterated that Section 9 of the Settlement Agreement specifically provides "CEI South agrees to incorporate the protections contained in the rebuttal testimony of CEI South witness Folz" and that Section B.10 of the Settlement Agreement then addresses the minimum amount of time that CEI South would wait following an order to disconnect, stating "CEI South will provide at least thirty days advance notice to customers before implementing the remote disconnection/reconnection proposal." He testified that CEI South will keep its commitment to communicate approval of the ARP in a campaign to update customer contact information three months in advance of beginning remote disconnections should the ARP be approved by the Commission. He explained that doing so will not conflict with the Settlement Agreement. Mr. Rice also indicated CEI South's agreement to afford the OUCC seven business days to review the language CEI South intends to use during the three-month campaign to solicit customer information.

viii. Commission Discussion and Findings. This Commission has previously granted waivers from 170 IAC 4-1-16(f) to electric utilities to allow for remote disconnection for non-payment. 170 IAC 4-1-16(f) provides that prior to disconnection of electric service, a CEI South employee is required to, among other things, make an on-site premises visit. On rebuttal and through the Settlement Agreement, CEI South has committed to undertake a campaign to notify its customers of its ability to remotely disconnect/reconnect upon our approval of the requested waiver. As discussed in greater detail in Paragraph 0.L (Customer Protection Provisions and Bill Transparency) of this Order, CEI South has agreed to certain continuing protections for its customers. Medical need customers and life support customers will be exempt from the remote disconnection process and will continue to have field personnel on premise, as will customers who do not have AMI installed. Pet. Ex. 5 at 12; Pet. Ex. 5-R at 4. In addition, if at the time of the disconnect for non-payment, CEI South is notified that a customer is applying for, or received funds for, LIHEAP during that current LIHEAP season, CEI South would not process the disconnect for non-payment during that LIHEAP season. Pet. Ex. 5 at 16.

Given that Petitioner's waiver request is part of an ARP under Ind. Code ch. 8-1-2.5, we proceed to our findings under the four criteria set forth in that chapter for granting an ARP. We must determine:

> (1) whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;
>
> (2) whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;
>
> (3) whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency;
>
> (4) whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

The record shows that, due to the advancement in technology and through the use of AMI, there are safer and more effective ways to notify a customer of potential disconnect due to non-payment and to ultimately disconnect the customer than what was historically available when 170 IAC 4-1-16(f) was promulgated. Modern technology allows CEI South to notify the customer multiple times and in many different forms in the event of a potential disconnect. Further, through the use of AMI and the remote connect/disconnect capability, CEI South does not need to be physically present on the customer's premises to connect or disconnect service. Thus, the goals of 170 IAC 4-1-16(f) – to sufficiently notify a customer of potential disconnect and to identify oneself while on a customer's property – can be achieved in a safer and more effective way through the use of modern technology because AMI allows for remote connect and disconnect.

The record also reflects that this Commission's approval of CEI South's proposed ARP will be beneficial for the utility, its customers, and the state, as remotely performing disconnect for non-payment orders will further reduce safety risks, improve work efficiencies, and significantly reduce the reconnect charge for remote reconnects. CEI South will be able to complete disconnects for non-payment more safely, quickly, and efficiently through the remote

disconnect capability through AMI than through the traditional truck roll and field personnel being dispatched to the customer's premise.

The exercise of this Commission's jurisdiction would inhibit CEI South from competing with other providers of functionally similar services or equipment insofar as it would deny CEI South a waiver of a requirement that has been waived for other similarly situated utilities in the State of Indiana. We have approved similar waivers for Duke Energy Indiana in Cause No. 45253, Indiana Michigan Power in Cause No. 45567, and AES Indiana in Cause No. 45911.

Based on the evidence of record, we find that CEI South's proposed ARP to provide a waiver of the requirement of an on-site premises visit prior to disconnection is in the public interest and so approve it. CEI South shall pursue the three-month customer communication plan outlined in Ms. Folz's rebuttal testimony and incorporated into the Settlement Agreement by reference regarding the Commission's waiver of the premises visit being approved in this order. We find that CEI South should provide the OUCC seven business days to review language to use during the three-month campaign to solicit customer information. Pet. Ex. 19-SR at 25.

We reject CAC witness Inskeep's recommendation to impose a moratorium on CEI South for disconnections, as it is contrary to the Commission rules (170 IAC 4-1-16) that allow for disconnection due to non-payment under certain conditions. The evidence shows that imposing a mandatory, 12-month delay in disconnections due to non-payment would counteract affordability efforts as it could cause customers' arrears payment obligations to become larger than they would be with timely disconnections for non-payment.

L. Customer Protection Provisions and Bill Transparency.

i. OUCC Position. OUCC witness Paronish raised issues about CEI South's billing. She alleged that the bills do not provide an itemization of the specific billing components. She noted that a customer can receive an itemization only upon request. She recommended that all customers receive an itemized breakdown of all components of the bill. Pub. Ex. 13 at 15-16. She also complained that there had been unusually higher bills received by customers during the period December 2023-January 2024 due to a longer-than-normal billing cycle. She recommended that the billing cycle be no longer than 32 days. Pub. Ex. 13 at 17-18.

ii. CEI South Rebuttal. Mr. Rice testified in response to Ms. Paronish's issues with the format of the CEI South bill. He noted that very few customers request an itemized bill – in 2023 it was 130 out of a total of nearly 2 million bills – and that most of those questions are about the gas portion of combined bills. He also explained that CEI South is willing to provide more detail on the bill and may be able to do so as a part of the new billing system being deployed in Summer 2024. He noted that the team's focus is currently on ensuring bills are accurate and go out on time when the cut over occurs. However, CEI South is reviewing options to increase the level of information on the bill following the cut over. Pet. Ex. 19-R at 49-50.

Mr. Rice also responded to the testimony about the longer-than-normal billing cycle issue, explaining that this was due to the implementation of the billing system change. CEI South had postponed conversion to a new billing system that was originally scheduled to take place at the beginning of the year. This created one-time bills that had a longer than normal billing cycle. He expressed regret and noted that CEI South works to keep the typical billing cycle as close to 30

days as possible. To help affected customers, CEI South had waived late fees for all customers that received a longer than normal billing cycle. He also noted that CEI South planned to move to the new billing system on July 1, 2024, and is working to keep billing cycles as close to 30 days as possible to minimize the potential for high bills caused by longer than normal billing cycles. Pet. Ex. 19-R at 4-5.

iii. Settlement. Mr. Rice summarized the customer protection provisions set forth in Section B.10 and compared those provisions to similar terms that had been included and recently approved in other proceedings before the IURC. He presented a comparison of the consumer protections incorporated in the Settlement Agreement and those approved in other settlement agreements. Pet. Ex. 19-S at 19. The protections include:

- Limiting the residential deposit for LIHEAP Qualified Participant customers (Settling Parties' Jt. Ex. 1 at Section B.10.a)
- Waiving, once a calendar year at the residential customer's request, a late payment charge (Settling Parties' Jt. Ex. 1 at Section B.10.b)
- Stipulating and agreeing to certain reporting requirements related to LIHEAP Qualified Participant customers, and waiving certain fees for such customers. (Settling Parties' Jt. Ex. 1 at Section B.10.c)
- Stipulating and agreeing to not disconnect service for any residential customer on Fridays, Saturdays, Sundays and during eight specified holidays. (Settling Parties' Jt. Ex. 1 at Section B.10.d.ii)
- Stipulating and agreeing to increase the current protection from disconnection for Medical Need (10 days) or Life Support (20 days) to 30 days for both categories. Before any disconnection of a LIHEAP Qualified Participant designated as Medical Need or Life Support, CEI South will place a collection call to such customer that prompts the customer to contact CEI South to establish an installment plan. (Settling Parties' Jt. Ex. 1 at Section B.10.d.iii).

In addition, if CEI South's request for an ARP is approved by the Commission, Section B.10.d includes several provisions related to remote disconnection/reconnection:

- Agreeing to provide at least 30-days advance notice prior to implementing any remote disconnect for nonpayment program (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.1)
- Reducing the fee for remote reconnection from $5 to $3 (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.2)
- Waiving, once a calendar year, the after-hours remote reconnection charge set forth in CEI South's tariff as $54.19 (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.3)
- Stipulating and agreeing to certain additional protections for customers designated as Medical Need or Life Support (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.4)

See Pet. Ex. 19-S at 19.

Mr. Rice testified that, as a result of the billing system upgrade, and in response to consumer concerns related to transparency of bills, the Settling Parties stipulated and agreed that CEI South will provide more transparency on its customer bills as soon as practicable after the

issuance of a Final Order and after implementation of its new billing system – EIP Phase 2, to include additional line items that break out: (1) Service Charge; (2) Variable charges (charges tied to usage); (3) FAC; (4) Sales Tax; and (5) the Total. In Section B.12 of the Settlement Agreement, CEI South agreed to provide a copy of these changes to the bill format to all parties to this Cause prior to implementation.

iv. Settlement Opposition. Ms. Paronish testified that the Settlement Agreement did not address all the issues she raised in her direct testimony. She indicated that the Settlement does not respond to bills that may be issued on more than a 30-day billing cycle, which can lead to high bills. She requested the Commission, to the extent possible, to enforce the "Bills will be rendered monthly" provision contained in CEI South's Terms and Conditions, Sheet No. 80, page 6 and the reference to "monthly" rates and charges in Rate RS Residential Service, Sheet No. 10, p. 1. Pub. Ex. 13-S at 9. As to the billing system upgrade, she testified "it is both unfortunate and nonsensical" that CEI South did not explore the potential for an automated detailed billing solution before cutting over to its new system as of July 1, 2024. She recommended the Commission direct CEI South to comply with the OUCC's position regarding bill transparency, as set forth in her direct testimony, and provide a more detailed breakdown within customers' bills. Furthermore, if CEI South cannot automate its process for customers to receive monthly detailed bills, she recommended the Commission direct Petitioner to find a way to capture the customers who want to have a monthly bill and effectuate this billing without customers needing to call each month. Pub. Ex. 13-S at 11.

CAC witness Inskeep took issue with the Settling Parties including terms to which the CAC had agreed in other settlements. He noted the other settled cases were non-precedential and argued they cannot be considered by the Commission in other proceedings. CAC Ex. 6 at 16-17. He also disputed that the inclusion of these consumer protection provisions alleviated his overall concerns with the Settlement Agreement.

v. Settlement Rebuttal. Mr. Rice disputed Mr. Inskeep's view of citation of past settlements and also responded to witness Paronish's opposition. As to her claim that it was "nonsensical" that CEI South had not evaluated an automated solution to her bill transparency concerns before cutting over to the new system, he testified that CEI South did evaluate this option, but it was not feasible to incorporate this update prior to the system cut over on July 1, 2024. He stated meeting that system cut-over was the most important task. Pet. Ex. 19-SR at 19. As to the level of detail in the bill, Mr. Rice testified that CEI South's bills fully comply with the Commission's rules, which set forth at 170 IAC 4-1-13 the level of detail that is required to be set forth on electric bills. Nevertheless, he stated CEI South committed to breaking out fuel cost on a separate line and including all other trackers in one line called variable charge. The variable charge would include all charges from trackers.

He stated that CEI South does not believe that it is necessary to create a rate from the variable charge line, as witness Paronish suggests. This rate would not be found in CEI South's tariff and would drive confusion rather than help provide clarity. Pet. Ex. 19-SR at 20. As to billing frequency, he explained that Ms. Paronish is referencing a single unfortunate isolated incident in December 2023, which was the original system cut over for the new billing system. Lessons were learned and the amount of time in each billing cycle was minimized to prevent this from happening again when the system cut over eventually occurred in July. He testified that Ms. Paronish's

request would impose a requirement that is unnecessary and not imposed on any other Indiana electric utility.

vi. Commission Discussion and Findings. Regarding the consumer protections, we find them to be appropriate concessions that assist with maintaining affordable electric rates for the most financially challenged customers in the residential class. As to Mr. Inskeep's objection to the Settling Parties including terms that the CAC had agreed to in other settlements, the Commission may consider the terms of past settlements as persuasive on a case-by-case basis. While prior settlements may not be precedential, they also are not inherently required to be completely ignored when considering settlements among other parties. In other words, the terms of other settlements may be persuasive. In this proceeding, we find these consumer protection terms to be reasonably included in the Settlement before us.

The level of detail in the billing statement to which CEI South has agreed is sufficient and reasonable based on the evidence of record. 170 IAC 4-1-13.

M. Cost of Service and Rate Design; Multi-Family Rates; BAMP.

i. CEI South's Case-in-Chief. CEI South witness Taylor presented CEI South's COSS and rate design. He proposed the use of the 4CP method for allocating production cost, which allocates demand-related costs based upon the coincident peak during the four summer months of the historic base period. He analyzed several years of monthly peak loads (2010-2022) and applied the FERC's three-peak ratio tests. These tests are used by the FERC to determine when a 12CP method is appropriate. The years 2022, 2021, 2020, 2019 and 2017 failed all three tests and 2018 failed two of the three tests. He recommended CEI South continue to use the 4CP methodology, consistent with CEI South's last rate case. Pet. Ex. 18 at 11-12.

For transmission demand-related costs, Mr. Taylor recommended the 12CP method. Pet. Ex. 18 at 13.

For the distribution system, he used non-coincident peak demand to allocate demand-related costs. Pet. Ex. 18 at 13. To determine the demand/customer split for distribution system costs, he relied upon a minimum system or zero intercept study for transformers, consistent with CEI South's last rate case.[22] Poles, overhead conductors, underground conductors, and conduit were classified as demand-related and allocated on non-coincident peak demand.

Mr. Taylor presented the results of his study, demonstrating the revenue deficiency/excess for each class and the class rate of return. He set street lighting service at its cost to serve, and the resulting increase in revenues was used to reduce outdoor lighting. Water heating service was increased by 1.5 times the system average. The remaining rate classes were increased proportionately. Pet. Ex. 18 at 21. Table JDT-4 presents the proposed revenue increase by class.

Mr. Taylor proposed increases in customer charges to move closer towards straight fixed variable pricing. Pet. Ex. 18 at 23-26.

[22] *CEI South,* Cause No. 43839, 289 PUR4th 9 (IURC 4/27/2011), p. 65, 2011 WL 1690057.

Within Rate BAMP, Mr. Taylor proposed modifications to make the Backup and Maintenance Service rate a daily charge, to use the applicable customer rate charge for base service charges, to set backup services for capacity at 110% of MISO's Cost of New Entry ("CONE"), to set backup services for energy at daily MISO LMP, and to base backup services for transmission and distribution on the ACOSS unit costs. Pet. Ex. 18 at 26-27.

Mr. Rice described CEI South's proposed updates to Rate BAMP, including updating the name to Base, Backup, and Maintenance. There are three main influences in the update of Rate BAMP. First, a better differentiation between firm and non-firm for both Rate BAMP transmission and distribution services was clarified. Second, Rate BAMP was adjusted to reflect backup on a daily basis, rather than monthly. Third, Rate BAMP now points to MISO's CONE to provide a more appropriate price signal for capacity. Pet. Ex. 19 at 22. Customers that require firm transmission and distribution service receive instantaneous backup without a break in electrical service. Interruptible customers have a minimum of one hour between a trip event and restoration of service. When backup events occur, these events tend to occur over days and not months. As such, CEI South is proposing to bill customers in a way that is more reflective of how co-generation equipment operates. The generation capacity used to supply the Backup Service provided by Rate BAMP is incremental by its nature. CEI South is located in MISO's Zone 6. MISO's Zone-specific CONE rate represents the generation capacity cost of the newest generation combustion turbine unit within a particular MISO geographical area. CEI South does not include Rate BAMP backup kW in its generation plan or reserve planning. Therefore, assigning a specific CEI South generation capacity amount to Rate BAMP does not make sense. Rate BAMP customers benefit by being able to pay generation capacity "rent" by the day, only when needed, and without prior notice for what is a year-round fixed cost for non-Rate BAMP customers. A Rate BAMP customer will have the choice to buy-through a trip event and pay the real time available MISO LMP for Backup Energy or reduce load and pay no Backup Energy charges. It is expected that these changes will better match Rate BAMP revenue with cost. The Rate BAMP transmission and distribution rates are subcomponents of other rate schedules that were updated in the ACOSS provided by witness Taylor. Mr. Rice also testified that CEI South is proposing to place in base rates $4,557,012 of backup charges and place variances from the base backup rates in the RCRA for capacity and the MCRA for transmission variances.

ii. <u>OUCC's Position</u>. OUCC witness Dismukes objected to Mr. Taylor's ACOSS to the extent it classifies fixed costs associated with production plant assets as exclusively demand-related. He testified that Mr. Taylor assumes that the only purpose of these assets is to support maximum system demands and that such an assumption is inconsistent with the dual role these production/generation assets play in serving both peak demand and low-cost energy requirements for off-peak periods on CEI South's system. He testified that equally important is the fact that CEI South's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related. Pub. Ex. 12 at 21. He noted that Average and Peak cost allocation methodology, also called the Peak and Average ("P&A") cost allocation methodology, as well as the Average and Excess cost allocation methodology, more appropriately recognize the dual functions of production plant. He further analyzed the split between demand and energy using individual generation unit capacity factors. For non-renewable generation, facilities with an annual capacity factor less than 15% were assumed to be fully classified as demand, while those units with a capacity factor greater than 15%

were divided between energy and demand. He presented Exhibit DED-5, showing that 47.32% of non-renewable generation was devoted to the provision of energy.

He next reviewed the levelized cost of each generation unit relative to established market analyses. Exhibit DED-6 presented the results of an analysis that examines the levelized annual cost for each of CEI South's non-renewable units compared with the CONE prices estimated by MISO in its most recent analysis of the 2023/2024 Planning Resource Auction results. He concluded that costs less than the MISO CONE price can be classified as demand-related, whereas prices above the MISO CONE can be classified as energy-related. Pub. Ex. 12 at 27-28. Based on this levelized cost analysis in Exhibit DED-6, he testified that, at most, 45.31% of CEI South's non-renewable production plant in service could be classified as being associated with the provision of demand functions.

Witness Dismukes was also critical that CEI South's classification ignores the significant portion of CEI South's production plant in service related to renewable generation. He stated that renewable generation facilities provide limited capacity service for a utility, mainly providing energy service for a utility. He noted that nearly 52.5% of CEI South's test year net plant in service is associated with non-dispatchable solar renewable generation resources. Pub. Ex. 12 at 33. He testified that renewable generation should be classified as 100% energy-related, and that when this is done, 26.2% of CEI South's test year net plant in service should be classified as energy-related, with the remainder classified as serving joint demand and energy. He ultimately concluded that 61.49% of CEI South's production plant costs should be classified as energy-related, with the inverse (38.51%) being classified as demand related for the test year.

He was also critical of the minimum system study ("MSS") because it assumes that there is a hypothetical "minimum system," even though a minimum system would have the capability of serving some load. He cited the National Association of Regulatory Utility Commissioners Cost Allocation Manual ("NARUC Manual") as recognizing this challenge. Pub. Ex. 12 at 39. He claimed that the true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, which he claimed is inherently ignored by a MSS. He ultimately recommended that the Commission reject CEI South's MSS. He instead recommended that distribution costs be allocated as 100% demand-related.

Witness Dismukes also disagreed with CEI South's proposed revenue allocation and rate design. He contended that capping the increase at 1.5 times the system average was inconsistent with gradualism and affordability. He instead recommended that limits to individual classes be capped at 1.15 times the overall system average increase. Pub. Ex. 12 at 4. Finally, he opposed CEI South's proposal to increase customer charges. He also recommended the Commission direct CEI South to eliminate its design of the TDSIC as a fixed charge. He claimed that CEI South's proposed increase to its base customer charges and its current practice of increasing its monthly customer charge through fixed TDSIC charges detrimentally impacts the public policy goals of promoting energy efficiency and burdens low-use customers.

iii. CAC's Position. CAC witness Barnes presented the CAC's alternative COSS and rate design. He recommended that production costs be allocated based upon the Probability of Dispatch ("POD") method. He testified that the 4CP method fails to reflect the diverse and evolving character of CEI South's generation fleet, ignoring factors such as the operational characteristics of different types of facilities (*e.g.*, baseload, peaker units, intermittent resources), the role that energy loads and long-term energy costs play in resource planning, and a shift in the MISO reliability planning paradigm to a seasonal construct. CAC Ex. 3 at 7. He testified that CEI South's projected suite of rate-based generation resources that would be allocated using the 4CP allocator includes multiple resource types with varying operational profiles and other characteristics, including Posey Solar and the CT Project. He also pointed to the MISO seasonal resource adequacy construct, setting requirements for each of the four seasons of summer, fall, winter, and spring. He testified that an accurate cost allocation methodology must consider the multitude of factors that drive investment decisions, which requires consideration of time-varying loads throughout the day and year, resource adequacy requirements, and how different resources are actually used to meet those needs. He ultimately concluded the POD method of production cost allocation provides the most accurate reflection of cost causation because it reflects the hourly characteristics of both electric demand and the generation resources used to meet that demand. The POD method establishes an hourly cost at the generation unit level by dividing each generation unit's costs by the hours that it operates, assigning those costs to those hours of operation, and then allocating those costs to customer classes based on their contributions to hourly loads. He prepared a POD allocation and compared it to the 4CP, which showed a reduction for residential. He cited the Commission's order in Duke Energy Indiana's rate case in Cause No. 45253 as a reason why cost allocation should evolve.

Witness Barnes also objected to the allocation of expenses included in FERC Accounts 911 and 912 as customer-related. He noted that CEI South had indicated in discovery that it had included DSM program costs in base rates in these accounts but was willing (if there was objection) to continue to recover these costs through the tracker. Witness Barnes indicated the DSM program costs should not be recovered through base rates and the remainder of costs included in these accounts ($1,165,148) should be allocated based on total revenue requirement. CAC Ex. 3 at 28.

After citing evidence concerning the magnitude of the requested increase, he testified that the Commission should conclude that a rate impact mitigation mechanism is not only warranted, but critically necessary to moderate disparate and ultimately unreasonable rate increases on different rate classes. He proposed a rate increase mitigation methodology under which no class receives a percentage revenue increase more than 20% greater or 20% less than the system average revenue increase. CAC Ex. 3 at 37.

Witness Barnes also proposed different allocations for various trackers. He disagreed in part with CEI South's correction to 12CP for the MCRA allocation because significant portions of the MISO costs that are incorporated within the MCRA are allocated to CEI South based on its share of monthly peak loads, not only loads during summer peak hours. He added that the use of a singular 12CP allocation factor for all MISO costs does not fully reflect the character of all MISO changes encompassed by the MCRA. CAC Ex. 3 at 42. He proposed that CEI South be directed to allocate costs reflected in the MCRA according to the way MISO charges CEI South for those costs. Likewise, he stated the base rates component of MISO costs should reflect an approximate or generalized portion of MISO costs consistent with a typical breakdown of energy-based or

demand-based MISO charges based on the recent history of MISO charges to CEI South. For the ECA, he disagreed with a 4CP production demand allocator, asserting it is not an accurate reflection of the cause of costs for CEI South's ongoing environmental projects, which include significant costs for CCR mitigation. He testified that the creation of CCRs has no plausible relationship to the peak demands used in the 4CP allocator, or any variety of peak demand allocator for that matter. He testified that, based on the most recently established revenue requirements, the allocation of ECA should be 42.5% energy and 57.5% demand. For the CECA, he testified that the costs should be allocated according to the POD method that he recommended for allocation of production related costs, which would create consistency between allocation regimes.

Finally, Mr. Barnes objected to the proposed treatment of special contract revenues in the COSS. CEI South excludes Ind. Code § 8-1-2-24 contract customers from the ACOSS used to establish the general class cost allocation proposal. That is, the allocator percentages that are used to allocate costs in the ACOSS (*e.g.*, 4CP and 12CP) exclude load from Section 24 contract customers. Instead, he stated that the proposed rates and revenue requirements for Section 24 contract customers are determined outside of the cost of service model, and associated revenues from Section 24 contracts are allocated to all classes as Other Revenues. Mr. Barnes instead recommended that CEI South be directed to fully incorporate Section 24 contracts into any new cost of service evaluations that they perform, such as in future rate cases or any other applicable proceedings, to provide a transparent picture of subsidization and cost-shifting issues that such special contracts inherently raise. CAC Ex. 3 at 58.

Regarding rate design, Mr. Barnes objected to the proposed customer charges. First, he questioned that the underlying premise that all costs associated with the shared distribution system are "customer-related" and should therefore be recovered via a fixed monthly customer charge design is inconsistent with cost causation. Second, he claimed that CEI South's calculation of the fixed ($/month) component of the residential TDSIC rate ignores the current limitation on increases in the fixed charge component under the settlement that gave rise to the TDSIC fixed charge, which, if continued through 2025, would limit it to an average 2025 rate of $7.75/month. Relatedly, he stated CEI South's assertion that the proposed residential customer facilities charge will not produce an incremental impact on low-usage customers is misleading because it assumes that the 2025 fixed charge component of the TDSIC will in fact be significantly higher than a rate constrained by the current fixed charge increase limits. CAC Ex. 3 at 60. He claimed that only those portions of the system that serve individual customers, the meter and the service drop, are allocated based on customer numbers. As to the TDSIC, he claimed that CEI South's current TDSIC is governed by a settlement adopted by the Commission which provides for a maximum semi-annual increase of $0.50/month capped at $7.00/month over the seven-year period of CEI South's TDSIC. He testified that if one were to accept CEI South's stated intention of a 1:1 movement of the TDSIC fixed charge into the residential customer facilities charge, the fixed rate would be $18.59/month, not $23.20/month. He recommended that the residential customer facilities charge be established based on the so-called "Basic Customer Method," which confines the customer charge to those costs that are directly attributable to an individual customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. He explained that many states do not accept the underlying conceptual premise that there is a customer-related component to the costs of the shared distribution system. Apart from that core reason, a rate design weighted towards fixed charges produces a smaller customer incentive to pursue energy efficiency because collecting a larger amount of revenue via fixed charges lowers

the amount to be collected from other charges. He calculated a residential customer facilities charge of $8.71/month based on the Basic Customer Method.

Mr. Barnes also recommended that a multi-family rate schedule be studied. CAC Ex. 3 at 71.

CAC witness Inskeep similarly opposed the proposed residential fixed charge and compared the proposal to Indiana's other five electric investor-owned utilities. CAC Ex. 2 at 59.

Mr. Inskeep also proposed an Affordable Power Rider. The Affordable Power Rider would be a new rider providing a tiered discount mirroring the current Universal Service Fund Rider discount percentages used by CEI South Gas (15% at Tier 1, 26% at Tier 2 and 32% at Tier 3), with costs recovered through a per kWh charge assessed identically on all retail sales. CAC Ex. 2 at 32. He claimed that bill discounts applied to low-income customer bills would first and foremost help eligible customers afford their CEI South electric bill, which would encourage timely bill payments, reducing delinquencies, arrearages, and disconnections. He said this improves CEI South revenues and customer satisfaction in the long run.

iv. Industrial Group's Position. Industrial Group witness York agreed with CEI South's allocation of production costs on the basis of a 4CP demand as being consistent with CEI South's historic practice, cost-causation and sound ratemaking. For transmission costs, she disagreed with CEI South's proposal to deviate from its established method of allocating by shifting to a 12CP basis. Instead, CEI South should continue in this case to allocate transmission costs on a 4CP basis, as it has historically. In addition, she claimed that CEI South's ACOSS does not accurately measure its cost of providing service to each customer class, due to an inaccurate classification and allocation of distribution costs. Indeed, CEI South's classification of distribution cost in its ACOSS does not follow CEI South's own accurate stated policy on the proper classification of distribution costs. She agreed that a significant portion of distribution system costs are incurred simply to connect customers to the system, regardless of electric demand, but stated CEI South's ACOSS ignores this reality. Specifically, she testified CEI South's ACOSS fails to classify a portion of costs included in the FERC Accounts 364, 365, 367, and 368 as customer related. Instead, CEI South classifies and allocates these costs on only demand and, thus, does not properly allocate these costs across rate classes. She also proposed that CEI South's FAC should be modified to recognize the capacity component of renewable resource costs. Renewable resources contribute to the MISO resource adequacy requirements. The capacity component of renewable resource costs should be allocated across rate classes using the production demand allocator established in CEI South's most recent rate case, and the renewable resource capacity costs should be recovered from LP, BAMP, and HLF customers using a demand charge. IG. Ex. 2 at 3-4.

She testified that the change from 4CP allocation of transmission costs is not supported based on CEI South's monthly system demands. CEI South has not identified any material change in system characteristics or operational circumstances since its last rate case to justify the proposed change in allocation methodology. The transmission system must be sized to be able to deliver power from the production resources to the distribution delivery point in all hours of the year, including the peak hour. Hence, the amount of transmission capacity needed to reliably deliver power to the distribution delivery point is based on the coincident peak hour demands. Also,

transmission capacity should be allocated in a similar manner as production capacity because they are interdependent. IG Ex. 2 at 9.

As to distribution costs, she testified that CEI South separates distribution costs in FERC Accounts 364 (Poles, Towers and Fixtures), 365 (Overhead Conductors and Devices), and 367 (Underground Conductors and Devices) between primary and secondary distribution voltages. Primary distribution voltages range from 600 volts ("V") to 12.5 kilovolts ("kV"), while secondary voltages are less than 600 V. CEI South allocates primary voltage distribution costs to all customer classes, but does not allocate secondary voltage distribution costs to customer classes that do not take service from secondary voltage distribution infrastructure, such as the LP and HLF classes. CEI South classifies the costs in FERC Accounts 364, 365, and 367 as entirely demand-related, rather than a combination of demand- and customer-related. She testified that CEI South's approach of allocating such costs only on demand fails to recognize that there is a utility cost simply to connect each customer to the grid.

Ms. York testified that classifying a portion of distribution costs in these accounts as customer-related is common and widely accepted in the industry and is supported by the NARUC Manual. She noted that Chapter 6 of the NARUC Manual discusses the classification and allocation of distribution costs. In this chapter, the NARUC Manual describes methods for classifying distribution costs in Accounts 364 through 368 and classification methods containing both customer and demand components. None are shown as demand only. Multiple methods for determining the demand and energy classification are discussed, such as "Minimum Size Method" and "Zero Intercept Method," yet none yield results of zero cost being classified as customer-related for these accounts. In addition to the wide acceptance in the industry and inclusion in the NARUC Manual, Ms. York explained that it requires little more than common sense to understand that some portion of the installation of poles, conductors, underground conduit and conductors, and line transformers are undertaken simply to connect customers to the grid, even though their demands may be very small, well below the capacity of the minimum sized facilities needed to serve them. The aggregate demand level of customers certainly affects the sizing of these distribution facilities (over and above the minimum levels), but that does not in any way nullify the fact that a portion of the investment is in the minimum system and caused by the existence of the customers. IG Ex. 2 at 10-11. She sponsored her own MSS, where she estimated the customer component of the distribution costs based on a Minimum Size approach. CEI South provided information on the replacement cost and quantity of the assets included in FERC Accounts 364, 365 and 367. Her analysis is contained in Attachment JAY-2. These customer percentages were significantly higher than the customer-related portion of costs in Account 368 developed by CEI South using CEI South's MSS. To be conservative, she applied the lower customer component of 56%, as calculated by CEI South for FERC Account 368, to FERC Accounts 364, 365, and 367.

v. <u>SABIC's Position</u>. SABIC witness Coyle proposed that the share of CEI South's transmission costs that should be collected through Backup Transmission Service rates should be derived using probability-adjusted calculation of Backup Service demand. She also claimed that proxy capacity costs used to determine Backup Generation Capacity rates should be increased by no more than 7% for administrative and general expenses, rather than the 10% proposed by CEI South. Consistent with CEI South's redesign of Rate BAMP, production-related rate adjustment mechanisms should no longer apply to Backup Generation Service. She agreed with witness York that demand-related transmission costs should be allocated to customer classes

using a 4CP allocator, consistent with the quantitative evidence presented by CEI South and Commission decisions in past cases. She reviewed CEI South's load profile, applied the FERC tests for 12CP, and concluded that CEI South's system did not warrant the use of 12CP and that the FERC tests could not be satisfied. SABIC Ex. 1 at 31.

vi. Cross-Answering Testimony. CAC witness Barnes objected to witness York's and witness Coyle's proposal to use a 4CP allocation method for transmission service. He claimed the 12CP method provides a "somewhat more balanced allocation regime." He also continued to state that the Commission should adopt the POD allocation method for renewable resources included in the FAC in light of the issue regarding renewable resource cost allocation in the FAC raised by witness York. He recommended the Commission reject witness Coyle's proposal to revise the methodology under which BAMP customers are charged for Backup Transmission Service because it amounts to a collateral attack on the known terms of the BAMP tariff and would result in unreasonable cost-shifting to non-BAMP customers. Further, he testified the Commission should reject witness Coyle's proposal to modify the BAMP tariff to eliminate the applicability of cost trackers associated with legacy generation costs because doing so would absolve BAMP customers from paying their fair share of costs caused by their historic use of those generation resources. He also opposed witness York's MSS proposal for many of the same reasons that he had opposed witness Taylor's MSS. Finally, he opposed witness Dismukes's proposed customer charge in favor of his own proposed customer charge. CAC Ex. 5 at 3-4.

IG witness York testified that other parties had allowed concerns over affordability to the residential class to influence their recommendations concerning cost allocation, in deviation from the purpose of a COSS to determine cost-causation. IG Ex. 3 at 5. She opposed witness Dismukes's production split between demand and energy and use of the P&A approach. She further opposed witness Barnes's use of the POD method for production plant. She noted that neither witness cited any prior Commission electric orders adopting either the P&A or POD allocation methods. She opposed witness Inskeep's proposed Affordable Power Rider as not being based on cost causation. She also rejected witness Barnes' recommendation to allocate CCR costs within the ECA Tracker based on energy.

vii. CEI South's Rebuttal. Witness Taylor presented an updated COSS based upon CEI South's rebuttal revenue requirement. In addition, he corrected the allocation to 4CP for a few accounts as identified by witness Coyle. Further, he corrected an error identified by witness York that the original study did not allocate transformers based upon CEI South's MSS. Pet. Ex. 18-R at 6.

As to the recommended changes proposed by witnesses Dismukes and Barnes, Mr. Taylor noted that neither of them had demonstrated a change in the operational characteristics of CEI South's system warranting a change in allocation of production costs. CEI South remains a predominantly summer peaking system. In his opinion, there have not been enough changes in the system planning requirements nor the operations of the system resources that would give rise to even consider the radical changes in allocation methodology they recommend. Pet. Ex. 18-R at 9. What drives the selection of a resource is the need to meet an identified resource adequacy at a reasonable cost. The fact that resources may also provide an energy benefit is secondary and does not change that the resource was added to supply capacity. He cited a series of Commission orders rejecting proposals to use an energy component in the classification of production plant.

He opposed witnesses Coyle and York's proposals to use 4CP for transmission plant. He claimed that the transmission system and production plant are not planned in the same manner. Pet. Ex. 18-R at 19.

As to distribution plant and the MSS, he agreed in principle with witness York's proposal to include additional accounts in the MSS, but indicated CEI South's proposal was to use the MSS only for transformers, consistent with the last case. He presented the results of his ACOSS using the broader MSS recommended by witness York. It would produce a significantly greater allocation of costs to the residential class. Pet. Ex. 18-R at 22-23.

As to witness Barnes's recommendations regarding energy efficiency programs, Mr. Taylor testified CEI South agreed to move DSM-related costs to the tracker. For the remaining expenses in Accounts 911 and 912, Mr. Taylor disagreed with Mr. Barnes's recommendation because Mr. Barnes had not presented evidence substantiating his view that expenses in these accounts correlate with revenue per class. Pet. Ex. 18-R at 24.

He rejected Mr. Barnes's approach with respect to Section 24 contracts. Mr. Taylor testified that the treatment of these customers in the ACOSS aligns with the standard approach in base rate proceedings, distributing the costs and revenues across all customer classes. He noted that CEI South is bound by contractual commitments that were approved by the Commission in docketed proceedings. Pet. Ex. 18-R at 25.

Mr. Taylor discussed witness Barnes's recommendations regarding allocation for the CECA, agreeing with Mr. Barnes that the allocation should be the same as is used for production plant. Given that he recommends 4CP for production, he opposed the recommendation to use POD. Mr. Taylor responded to witness Barnes's recommended rate impact mitigation mechanism by identifying that the CEI South proposed increase for the residential class based on the rebuttal ACOSS is 1.22 times the overall system increase.

With respect to customer charges, witness Taylor disagreed with the recommendations of Dismukes and Barnes. Pet. Ex. 18-R at 32-34. Regarding the impact on low-income customers, he noted that low income customers are often higher use customers who are negatively impacted by recovery of fixed costs through volumetric charges. As to the TDSIC as a fixed customer charge, Mr. Taylor disagreed with witness Dismukes and Barnes on multiple issues, including that rolling the TDSIC customer charge into base rates is in line with the findings of the ACOSS model. Mr. Taylor stated that this alignment indicates that when costs are integrated into base rates, the recovery of TDSIC fixed charges corresponds more closely with customer-related costs. This facilitates a better alignment of the type of cost recovery, specifically customer related costs. Based on the various customer charge analyses presented in this instant proceeding he recommended maintaining the TDSIC rate design and continuing with established practices. *Id.* at 39.

Mr. Rice testified that the affordability pillar concerns retail electric utility service being "affordable and competitive across residential, commercial, and industrial customer classes." He noted that if affordability meant producing rates that were affordable for all customers, utilities would need legislative guidance and authority not only on how to design programs aimed at assisting those who are most financially disadvantaged but also to address some of the heavier burdens they bear that are unrelated to the electric bill. Pet. Ex. 19-R at 4. He testified that, rather

than Mr. Inskeep's proposed Affordable Power Rider, CEI South is in the process of converting the Share the Warmth program back to a bill assistance program, which will also benefit customers that fall into the Asset Limited, Income Constrained ("ALICE") classification. He stated what is or is not affordable is going to be different for different customers and that CEI South does not know the income of individual customers, the level of assistance that they may receive outside of LIHEAP, or the number of people in the household. Even Census Median Household Income does not present the full picture, as it does not, among other things, include non-cash benefits, such as food stamps, health benefits, or subsidized housing. He also introduced the "Relative Importance" of electricity to affordability. Using the costs of goods and services from the November 2022 Consumer Price Index ("CPI") for the U.S. Midwest Region, he noted the Electricity Relative Importance value constitutes 2.428% of the total CPI for the US and 2.255% for the CPI in the Midwest Region. Mr. Rice testified that a low Relative Importance value attributed to electricity indicates the presence of other factors possessing superior Relative Importance values, exerting a more substantial influence on affordability, particularly in the context of a general increase in the CPI. For instance, while electricity costs may contribute to overall expenses, items such as housing, transportation, and healthcare often command higher Relative Importance values within the CPI basket. Mr. Rice explained that this underscores the complexity of affordability dynamics, in which the relationships of various economic factors dictate the true impact on consumers' financial well-being. Therefore, he opined that while electricity costs remain a component of concern, a holistic understanding of the broader economic landscape is essential for effective mitigation strategies.

Mr. Rice rebutted Ms. Coyle's testimony on the BAMP rate. He summarized her position. First, SABIC believes that transmission service should be charged based on the Forced Outage Rate ("FOR") of its generating unit with what it calls "probability adjusted demand." In other words, SABIC has proposed dividing its transmission demand billing determinant by the number of days in the year and multiplying it by a FOR of 5%. SABIC would like to spread the cost difference ($3,889,940) to all other customer classes. Second, SABIC took issue with adding a 10% A&G cost to the MISO CONE for firm backup service and proposed that CEI South include a 7% A&G adder for backup power. SABIC's proposal allocates costs based on A&G Production costs only of a labor nature. Third, SABIC did not agree with being charged for CEI South production rate riders, specific to CEI South's generation fleet for Backup Power. He explained this issue was raised by SABIC during discovery, and CEI South agreed. As such, Mr. Rice made corrections to Attachments MAR-1 and MAR-2, the proposed tariff, to remove the reference to the DSMA, CECA, ECA, SCP, SRR, SAC, and RCRA appendices applying to backup service. SABIC agreed that it should be charged for transmission riders, TDSIC and MCRA, but disagreed on utilizing 12CP allocations for MCRA and proposed 4CP. Finally, SABIC raised a concern of their increase relative to the overall increase CEI South has proposed. He responded by claiming that SABIC was asking for essentially an interruptible transmission rate for firm service. Pet. Ex. 19-R at 42-48.

viii. <u>Settlement</u>. Mr. Taylor described how the Settlement Agreement addressed the cost of service and rate design issues in dispute. He sponsored the updated ACOSS and rate design schedules based upon the terms of the Settlement. He testified that the main issues in dispute among the parties were the allocation of production plant (with CEI South and Industrial Group's proposal of 4CP and OUCC and CAC using the P&A and POD methods, respectively, which allocate a portion of fixed production costs based on energy); allocation of transmission

plant (with CEI South, the OUCC, and the CAC proposing 12CP and industrial customers advocating to retain the existing 4CP), and allocation of distribution plant (with CEI South utilizing a more limited MSS based upon the last case, with the Industrial Group advocating a more comprehensive MSS, and the CAC and OUCC eschewing the MSS altogether). He explained that the Settlement Agreement uses the 4CP for production related demand costs. He added that transmission costs are allocated based upon the 4CP as well and distribution plant would be allocated based upon CEI South's more limited MSS. He stated that all these allocation methods are consistent with the allocation used in CEI South's last rate case. Mr. Taylor explained the resolution was reasonable and favorable to the residential customer class. He presented tables in Tables JDT-S1 and JDT-S2 demonstrating that the move to 4CP on transmission resulted in only a 0.3% higher allocation for the residential class; however, use of the more robust MSS (which will not be used under the Settlement), would have resulted in the allocation of 7.7% more for residential customers. Pet. Ex. 18-S at 4-6. Notably, Mr. Taylor had not disagreed with the concept of Ms. York's more robust MSS study in his rebuttal testimony. In fact, he had specifically agreed with it but noted that CEI South wished to stay with the more limited methodology used in the prior case. Pet. Ex. 18-R at 22-23.

As to revenue allocation, the Settling Parties agreed to a conceptually similar approach to that presented by CEI South's rebuttal filing in terms of revenue increase distribution as proportion to the total requested increase. Additionally, the Settling Parties stipulated and agreed, among other things, that: (1) no class will receive a rate decrease as a result of the rates implemented pursuant to this Settlement Agreement; (2) no class will receive a rate increase that is higher than what CEI South proposed in its rebuttal position in this Cause; and (3) other than water heating as explained later, no class will receive a rate increase greater than 1.35 times the system average. The Water Heating Service ("Rate B") schedule's revenues were increased by 1.5 times the system increase, which moved them closer to their cost to serve but not completely, which would have required an increase over two times the system increase. There are no proposed changes to the Street Lighting Service ("Rate SL") and Outdoor Lighting Service ("Rate OL") in alignment with CEI South's rebuttal. A moderate increase of 3.62% for High Load Factor Service ("Rate HLF") revenue was agreed upon, compared to the 5.1% increase to that rate class proposed on rebuttal. The remaining rate classes, Residential ("Rate RS"), Small General Service ("Rate SGS"), Demand General Service ("Rate DGS"), and Large Power Service ("Rate LP"), targeted revenues proportionately below their cost to serve. He testified the settled revenue allocation is as follows:

Customer Classes	Settlement ACOSS			Rebuttal ACOSS		
	Current Revenues	Settled Revenue Change	Percentage Change	Current Revenues	Proposed Revenue Change	Percentage Change
Residential (RS)	$ 319,622,569	$ 46,840,706	14.7%	$ 319,953,137	$ 62,331,515	19.5%
Water Heating (B)	1,759,173	291,642	16.6%	1,763,253	421,785	23.9%
Small General Service (SGS)	14,704,649	1,070,331	7.3%	14,759,589	1,855,123	12.6%
Demand General Service (DGS)	207,073,126	17,955,496	8.7%	207,394,694	27,473,132	13.2%
Large Power Service (LP)	167,222,380	13,539,857	8.1%	166,529,378	22,927,545	13.8%
High Load Factor Service (HLF)	8,607,350	311,586	3.6%	8,601,285	436,596	5.1%
Outdoor Lighting (OL)	1,836,828	-	0.0%	1,832,443	-	0.0%
Street Lighting (SL)	3,096,774	-	0.0%	3,089,124	-	0.0%
Total Base Rate Margin	**$ 723,922,849**	**$ 80,009,617**	**11.1%**	**$ 723,922,906**	**$ 115,445,697**	**15.9%**

Pet. Ex. 18-S at 6-8.

Mr. Rice stated that the Settlement provided for minimal increases to the customer charge, and he explained that this would take the customer charges back to their level prior to the repeal of the utility receipts tax. Pet. Ex. 19-S at 22.

As to the BAMP rate, Mr. Taylor explained that the settlement resolves the disputes between SABIC and CEI South. The Settling Parties agreed on modification of the BAMP rate. Utilizing CEI South's proposed methodology to determine a cost-based Backup Transmission rate for the BAMP tariff, under the settlement revenue requirement, the BAMP Backup Transmission rate would be $0.22561. Mr. Taylor stated that the Settlement Agreement sets the BAMP Backup Transmission rate at $0.21322, which represents 95% of this cost-based rate. Mr. Taylor elaborated on cross-examination that this was a considerably higher rate than would have resulted under witness Coyle's recommendation. Mr. Rice added that the Settlement provides CEI South will evaluate the reasonableness of moving the BAMP rate towards parity with FERC Attachment O price and hold discussions with SABIC in advance of CEI South's next base rate case to determine the appropriate, cost-of service-based Backup Service Transmission Rate. Pet. Ex. 19-S at 22-23.

As to CAC's request for the study of a multi-family rate, Mr. Rice testified that CEI South does not currently have a reliable way to assess whether a home is a multi-family or single-family home, providing as example that over the years, customers remodel homes, convert single family homes to duplexes and vice versa, or add lofts and in-law suites to garages. He added that CEI South currently does not have reliable data on what premises are multi- or single family today; and the new billing system does not contain a field for this information. He explained that, in the spirit of compromise and with the customers' interests top of mind, the Settling Parties stipulated and agreed that CEI South will collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. CEI South will also, in advance of its next rate case, offer to meet to discuss methodology and share initial results of its analysis with any interested party to this Cause. Pet. Ex. 19-S at 20-21.

IG witness York testified that the resolution of cost of service and rate design issues represents a reasonable resolution of the issues in dispute and is further consistent with the approved cost of service methodology that has been in place for CEI South for decades. IG Ex. 5 at 2-4.

ix. Settlement Opposition. CAC witness Inskeep opposed the rate design in the Settlement Agreement because it did not adopt his proposed Affordable Power Rider. CAC Ex. 6 at 19. Witness Barnes claimed that the Settlement assigns a greater portion of the revenue increase to the residential class than under CEI South's direct or rebuttal submission. CAC Ex. 7 at 6. He objected to the use of the 4CP for transmission costs and criticized the limitation of 1.35 times system average as not being a mitigation constraint but rather a result of the other revenue allocation parameters. He was critical of the Settlement for not addressing his concerns about Special Contract customers having cost trackers zeroed out without a corresponding increase to contract rates. He continued his recommendation for use of POD for production, CECA, and FAC, and energy and 4CP for ECA. He objected to exempting BAMP customers from production-related cost trackers He claimed that this provision would allow BAMP customers to be exempt from the Brown Securitization riders, which he claimed to violate the statute. He objected to providing a discount to BAMP customers in the rate for transmission service because SABIC had

agreed to a cost-based rate when it elected to take BAMP service.

OUCC witness Dismukes had several similar objections to those raised by witness Barnes. He reiterated his concerns over allocation of production costs, restating his preferred allocation methodology set forth in his direct testimony. Pub. Ex. 12-S at 8-17. As to transmission plant allocation, he objected to using the 4CP method and argued that the originally proposed 12CP method was appropriate. He also objected to the use of CEI South's MSS for purposes of determining customer costs of the distribution system. He claimed the mitigation caps on revenue allocation increases were inconsistent with gradualism, and that the increase for any single customer class should be limited to 1.15 times the system average. As to rate design, he objected that the Settlement Agreement does not address the recovery of monthly TDSIC costs through fixed monthly charges, and he continued to recommend his proposed customer charges set forth in direct.

x. **Settlement Rebuttal.** Mr. Taylor testified that ultimately, OUCC witness Dismukes and CAC witness Barnes ignored the fact that the system must be built to meet a maximum demand, or peak load. He stated CEI South could not provide reliable service if it chose to only build capacity to support 90% of its peak load and customers expect to have access to electricity as reasonably close to 100% of the time as possible, necessitating the requirement of CEI South to build and invest in capital assets to meet this maximum demand to be placed on the system. Therefore, he opined the best method to accurately account for the respective customer classes' contribution to the need for the production assets is based on a demand-related allocation factor. That is, the demand a respective customer class places on the system at the time when the most capacity is needed. To that same end, the cost of the production assets is fixed in nature. There is no variability in their cost as they require large initial cash outlays. He stated demand is the correct measure of deriving the allocation of production assets to the customer classes. Pet. Ex. 18-SR at 3-4. Further, he testified as to why a change in the production plant allocation is not warranted at this time, stating there is no demonstrable evidence that CEI South's system has drastically changed from prior cases where its production assets were allocated on a demand basis.

As to the use of 4CP for transmission plant, Mr. Taylor testified CEI South's last rate case relied on the use of a 4CP allocation factor for transmission costs, whereas CEI South proposed in this case to move to a 12CP allocation. The continued use of the 4CP, rather than CEI South-proposed 12CP, was a settlement concession that conformed to the historical methodology approved for CEI South in prior rate cases. He noted that continuing to use a 4CP, rather than the proposed 12CP, only added approximately $1 million in costs or 0.3% to the residential class from what CEI South proposed in rebuttal testimony. By contrast, he explained the Industrial Group agreed not to use its MSS for distribution plant beyond transformers as proposed by witness York, which, if adopted, would have added $27 million or 7.7% to the residential allocation. This concession ($27 million) by the Industrial Group had far greater impact to the benefit of residential customers than retaining the 4CP for transmission was a detriment ($1 million). Pet. Ex. 18-SR at 6-7.

Mr. Taylor further supported the modest increase to the customer charge and he responded to the objections by witnesses Dismukes and Barnes regarding recovery of the TDSIC as a fixed charge. He reiterated his rebuttal testimony providing the reasons for why the OUCC's and CAC's recommendation to the TDSIC should be rejected. He stated the TDSIC is recovering fixed cost

of transmission, distribution and storage, so it makes sense to recover the costs through a fixed charge. He opined that it is sound rate design practice to create this matching to the type of underlying cost. Furthermore, CEI South is proposing a TDSIC in a manner for which the Commission has currently approved. Pet. Ex. 18-SR at 10.

Witness Rice responded to Mr. Barnes's allegation that BAMP customers could illegally bypass the securitization charge. He explained that securitization charges are charged to BAMP customers today based on their auxiliary load, and in the proposed tariff, this is the base component of the rate. He further explained that the BAMP Base is the amount of power that a BAMP customer uses above and beyond what is covered by the customer's generating unit. The Securitization of Coal Plant is not applicable to the backup rate, which is supplied by the system when the BAMP customer's generator trips offline, not necessarily by CEI South's generators. He noted during a backup event, BAMP customers will be charged LMP for energy and CONE with overheads for capacity and no minimum charge is necessary for BAMP customers, as suggested by CAC. He claimed the Commission dismissed the same argument that customers would bypass the securitization charge in Cause No. 45722. Pet. Ex. 19-SR at 23.

Mr. Rice also responded to Mr. Inskeep's criticism that the Settlement Agreement does not contain his proposed Affordable Power Rider. He explained why no such rate was in the Settlement. The only occasion where the Commission considered a universal affordability tariff like that proposed by the CAC is the Indiana American Water decision in Cause No. 45870. That was a proposal under a statute that specifically allows for low-income programs (applicable only to water and wastewater). The Commission rejected the proposal and specifically noted its "role in addressing [affordability] is not to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer." Separately, the only electric case where a utility made a similar proposal advocated by the CAC here is Northern Indiana Public Service Company, Cause No. 45772. Under NIPSCO's proposal, all customers would pay a monthly charge that would fund reduced electric bills for low-income customers. In that case, OUCC witness Paronish opposed the proposal and specifically testified "NIPSCO's low-income program proposal is essentially a tax, better left for the legislature to address." So unless there has been a recent change, he explained that he does not see how the CAC's proposed Affordable Power Rider could have been a term in a unanimous settlement. And even if such a term were included, he was uncertain whether it would be approved by the Commission. Pet. Ex. 19-SR at 5-6 and Attachment MAR-SR1.

Witness York rebutted the proposals by witness Dismukes and witness Barnes to include a substantial energy-based component in the allocation of production related costs as being contrary to cost causation principles, established Commission practice, and the longstanding regulatory treatment for CEI South's system specifically. IG Ex. 7 at 3. She pointed out the use of 4CP instead of 12CP was also consistent with the approved approach for CEI South's system dating back to the 1970s. In addition, she emphasized the significance of the Industrial Group's settlement concession not to utilize the MSS to apply a customer component to additional FERC accounts, which would have a much greater impact on residential rates.

Ms. York further rebutted the suggestions by witness Dismukes and witness Barnes advocating for greater mitigation for the benefit of the residential class. IG Ex. 7 at 5-6. She testified that mitigation measures are appropriate where strict adherence to cost of service would

lead to major disparities in impact between classes, but it is important to recognize that basing rates on cost causation is a fundamental ratemaking principle. She noted CEI South's case-in-chief applied to 1.5 times system average parameter to limit the increase to the Water Heating class, but under the settlement the revenue spread falls within a tighter 1.35 times system-average tolerance. She described the OUCC and CAC positions as closer to an across-the-board approach, in derogation of cost of service results.

Regarding affordability, Ms. York noted the statutory affordability pillar applies across all rate classes and is not solely for the protection of the residential class. She further stated that rates must reflect the other four statutory pillars as well as affordability. She testified that the Settlement reasonably addresses affordability by reducing the proposed revenue increase by $38 million, removing most of CEI South's proposed increase to monthly customer charges, and instituting a number of customer protection provisions. IG Ex. 7 at 6-7.

Witness Coyle also rebutted the contentions regarding the BAMP terms. She explained BAMP customers have three components of service under the BAMP tariff: Base, Backup, and Maintenance Service. Base and Maintenance Service are both charged at the customer's Otherwise Applicable Rate Schedule and the BAMP customer is responsible for paying all trackers that apply to those rates. She explained that this means that all energy that is served as part of the Base and Maintenance Service are subject to all the trackers of CEI South, including the production related trackers. She stated that the only sales that are not subject to production-related trackers for the BAMP class is the energy that is delivered during a Backup Event when the customer-owned generator unexpectedly trips off-line. She noted that over the last three years SABIC experienced a Forced Outage Rate (FOR) between 1.3% and 2.1%, equating to Backup Events that are less than 8 days a year worth of energy at reduced level of capacity. In 2023, this resulted in less than $20,000 of associated revenues that CEI South would no longer collect from SABIC under the Settlement Agreement. Mr. Barnes' concerns regarding the potential impact to other customers are overstated considering the small amount of revenue at issue. She also responded to the allegation regarding alleged avoidance of the Securitization tariff. She explained that the BAMP tariff does subject customers in this class to a minimum bill provision, and payment of the securitization charges, as part of its Base and Maintenance Service. SABIC Ex. 2 at 4-5.

She also responded to the allegation from Mr. Barnes that the BAMP rate was less than cost, stating Backup Service customers are required to pay for transmission service at all hours for its full contracted load, even if its customer-owned generator is serving its load. SABIC's position in direct testimony was that Backup Service customers should pay based on its use of the transmission system; since Backup Service is different than full service customers, she proposed a probability weighted approach to ensure Backup Transmission Service charges contributed to the recovery of transmission costs. She noted the Settlement Agreement represents a compromise between CEI South and SABIC on this point and results in SABIC still paying higher than CEI South's FERC transmission rates, and the FERC rates represent the cost of transmission service for all other CEI South customers. She stated that the FERC transmission rate for CEI South for the year 2024 is $4.608/kW-month, which utilizes a forward-looking calculation that is equivalent to the estimated cost of service for the full year 2024 and includes prior period true-ups. The transmission cost of service agreed to in the Settlement agreement is above and beyond this value at $7.209/kW-month. SABIC Ex. 2 at 6-10.

xi. Commission Discussion and Findings. The Settlement Agreement resolves the disputed issues regarding cost of service and rate design among the Settling Parties. As explained below, we find that the resolution of these issues is balanced and achieves a fair result that is consistent with the objectives of achieving rates that are affordable and competitive across the rate class and with the public interest. We will set forth our findings on the individual issues in dispute below.

1. Production Costs. The dispute over the allocation of production costs was whether fixed production costs should be allocated on the basis of demand (either the 4CP or 12CP) or whether some portion of such costs should be allocated based on energy, through the CAC's proposed POD or the OUCC's proposed P&A. The Settlement continues with the allocation based on 4CP that has been in place for CEI South for many decades. We have long recognized that we are reticent to make significant changes in cost allocation. *CEI South,* Cause No. 43839, 289 PUR4th 9 (IURC 4/27/2011), 2011 WL 1690057. Just as in the last case, CEI South's system does not pass the three FERC tests which guide us as to whether the 12CP would be appropriate, and there has been nothing to show that CEI South's system demonstrates anything other than a summer peak. Furthermore, the OUCC and CAC are advocating a much more dramatic change – not a change between 4CP and 12CP but rather a change to a methodology that allocates most of CEI South's fixed production costs based upon energy. We have consistently rejected such proposals and concluded repeatedly that fixed production costs should be allocated based on demand, including for CEI South specifically. *See CEI South*, Cause No. 43839, at 58-65; *see also Duke Energy Indiana,* Cause No. 45253 (June 29, 2020), at 120. We do not find any change in circumstances that would support a departure from that established principle here.

2. Transmission Costs. CEI South initially proposed the use of 12CP to allocate for transmission costs, which is different from the allocation approved in its most recent case, and the OUCC and CAC supported that proposed change. IG and SABIC advocated for continued use of 4CP, which is the method used in the last case. Switching from 4CP to 12CP would have the effect of allocating 0.3% less, approximately $1 million in cost, to the residential class. The Settlement provides for a 4CP allocation for transmission costs, consistent with the last rate case.

We note that the use of 12CP, as proposed by CEI South before the Settlement was reached, better aligns with the MISO construct. While consistency is an important consideration, the passage of time since 2011 and treatment of other MISO utilities under the Commission's jurisdiction supports CEI South's proposal to use 12CP. By contrast, the use of 4CP, as proposed in the Settlement, favors large users such as the Settling Parties. After reviewing the evidence of record, the Settlement Agreement, and the revenue allocation adjustments directed in this Order, we accept the Settlement Agreement's 4CP allocation for transmission.

3. Distribution Costs. The limited MSS proposed by CEI South was opposed by multiple parties. However, none of the other parties demonstrated that the MSS approved in CEI South's last rate case has become unreasonable due to time or other factors. Accordingly, the Settlement Agreement's treatment of distribution cost allocation remains reasonable, and we approve it.

4. Accounts 911-912. After CEI South's agreement to keep DSM cost recovery out of base rates, the amount that remains in these accounts is slightly more than $1 million. We do not find that allocating them as customer-related or based upon total revenues makes a material enough overall difference to change our view of the Settlement. We accept witness Taylor's proposal to allocate these costs as customer related.

5. Section 24 Contracts. There are two issues with Section 24 contracts. The first is how such costs and revenues should be addressed in the preparation of a cost of service study. We find witness Taylor is correct that his study addresses such costs and revenues consistently with past practice and with the standard for actually approving these contracts in the first place. Section 24 contracts are approved in docketed cases, and we require evidence demonstrating: (1) the contract is necessary to attract or retain load; and (2) the cost recovery through the contract is sufficient to pay at least the marginal costs of service plus some recovery of fixed costs. *CEI South,* Cause No. 45773 (Feb. 8, 2023), at 5. This means all other customers benefit from approval of the contract because the fixed cost recovery (and therefore rates) will be lower than it would be had the contract not been approved. *See Local Union 204 v. Public Serv. Co.*, 524 N.E.2d 318, 319 (Ind. 1988). The other issue is CAC's objection that the Section 24 base rates are not being increased when trackers paid by Section 24 customers are zeroed out. This contention fails to recognize that these are contractual arrangements that we have already approved. To do as the CAC suggests would be to modify those previously approved contracts which we had already found were necessary to attract or retain the load. This would deviate from the approved terms and would have a chilling effect on economic development, and we decline to take this step.

6. Customer Charge and TDSIC as Fixed Residential Charge. Much of the dispute over the customer charge in base rates has been resolved by the agreement to an extremely limited increase (back to the level before the repeal of the Utility Receipts Tax). We reject the arguments from the CAC and the OUCC that the fixed charge should only include metering and billing costs. This is inconsistent with our prior findings. *See IPL*, Cause Nos. 44575 and 44602, at 72. Furthermore, we are persuaded by witness Taylor's evidence that frequently low-income customers are harmed by recovery of fixed costs through a volumetric charge. We are further persuaded that the TDSIC distribution costs should continue to be recovered through a fixed charge. These are fixed costs, and recovery through a volumetric charge would send inefficient price signals and would work to the detriment of those low-income customers who are higher volume users.

7. Affordable Power Rider. CAC witness Inskeep's proposal for an Affordable Power Rider presents a novel approach to affordability. As we have said previously, however, responding to a proposal for some form of low-income rates in the context of filing rebuttal testimony in a base rate case is not how such a program should be developed and presented to the Commission. *IPL,* pp. 67-68. There are many details that would need to be worked out to design and present a low-income program. *See Indiana American Water Co.*, Cause No. 45870, (Feb. 14, 2024), at 122-125. As we found in connection with a NIPSCO proposal, the development of a low-income program that could be considered and ultimately approved by this Commission would greatly benefit from consensus among the stakeholders. *Northern Ind. Pub. Serv. Co.*, Cause No. 44688 (July 18, 2016), at 90.

8. Trackers.

A. MCRA. CEI South's proposal was to allocate the MCRA in the same manner as transmission costs. Based on the evidence of record, we approve the allocation based upon 4CP. We reject the CAC's argument otherwise.

B. ECA. With respect to the recovery of CCR remediation costs through the ECA, the CAC contends that since coal ash is generated through the production of energy, the costs of remediation should be based upon energy. We note in CEI South's most recent coal ash pond compliance case, we explained that there are two methods of recovery of the costs of CCR. One is through federal mandate proceedings; the other and more traditional method is to treat CCR costs as cost of removal – debiting Account 108 as the costs are incurred and reflecting projected and past costs (though the debit to Account 108) in the calculation of depreciation accrual rates. *CEI South*, Cause No. 45903, at 10-11. There is no dispute that depreciation expense and accumulated depreciation should be allocated the same as the underlying plant. Pet. Ex. 18 at 15. Thus, if CCR costs were recovered through this more traditional method, they would not be recovered on an energy basis. We fail to see how the method of recovery (ECA or base rates) could impact cost causation. As such, we reject the CAC's proposal to allocate the CCR costs recovered through the ECA on an energy basis.

C. CECA. Given our approval of the 4CP for production-related costs, we reject the CAC's proposal to allocate the CECA on the POD methodology.

D. FAC. Two FAC proposals were made that are either moot or have been withdrawn. Mr. Rice noted in his direct testimony CEI South's proposed allocation of the pipeline demand costs that were the subject of Cause No. 45564-S1. Since the Commission resolved the rate design issues in the FAC related to this subject in that subdocket, the issue in this rate case is now moot. In addition, the IG requested that the FAC should be modified to recognize the capacity component of renewable resource costs. That request has been withdrawn as a result of the Settlement.

E. Revenue Allocation. The only material dispute over revenue allocation was the mitigation factor to put on the rate increases for individual classes. Other than water heating, the Settlement caps the increase at 1.35 times the system average. The OUCC proposed to limit any class increase to 1.15 times the system average, while the CAC proposed 1.20 times the system average.

After reviewing the evidence of record, we reject the Settlement Agreement's proposal to cap the increase (for all classes other than water heating) at 1.35 times the system average and accept the OUCC's proposal to limit any class increase to 1.15 times the system average, to minimize rate shock to consumers. The high volume of consumer comments received in this case, in addition to the nine-hour field hearing held in Evansville on February 29, 2024, indicates how significant of a concern affordability is to CEI South's residential customers, a concern we take very seriously.

The Settling Parties' agreement to cap the increase at 1.35 times the system average results in an increase to residential customer rates of 14.66%, or $46.8 million. Adopting the OUCC's position of 1.15 times the system average reduces this residential rate increase to 12.71%, or $40.6 million, saving residential ratepayers $6.2 million.

On rebuttal, CEI South identified a 1.22 times the system average overall increase for the residential class. While we find above that the choice of 4CP over 12CP is acceptable in the context of the overall settlement, this choice is nonetheless a revenue requirement disadvantage to the residential class. The Settlement Agreement's rate increase cap at 1.35 times the system average highlights the impact of this disadvantage. Affordability is a key consideration across all customer classes, and the desire to provide affordability across the board supports a revenue requirement increase that is as evenly borne as practical, while considering any subsidies that may be identified by the ACOSS. The ACOSS in this proceeding identifies that the interclass subsidies are materially different than those in recent ACOSS seen in other cases. *See e.g., Duke Energy Ind., Inc.*, Cause No. 46038 (Jan. 29, 2025). Accordingly, we find that limiting the residential class increase to 1.15 times the system average is consistent with affordability across all classes in the context of reasonably allocating CEI South's authorized revenue requirement increase.

F. BAMP. Before the Settlement Agreement, there was considerable dispute between CEI South and SABIC regarding the BAMP rate. We find that the Settlement, which produces a rate that is 95% of the cost of BAMP service as calculated by CEI South is a reasonable resolution of that dispute. As noted, under Ms. Coyle's presentation, the cost of service would be much lower. We reject CAC's argument that the BAMP rate allows a bypass of the Securitization Charge. Securitization Charges are to be "payable by all customers and customer classes." Ind. Code § 8-1-40.5-12(b). There is no requirement that each individual rate paid by a customer is subject to the Securitization Charge. It is undisputed that SABIC is subject to and cannot bypass the Securitization Charge and so we reject CAC's argument otherwise.

N. Miscellaneous Fees and Charges.

i. CAC's Position. CAC witness Inskeep made several recommendations regarding miscellaneous charges and fees. He requested that CEI South's late payment charge be eliminated. He recommended that reconnection charges be eliminated or reduced. Finally, he recommended that per-transaction charges assessed by third parties for processing payments be eliminated for the customer by rolling the costs into CEI South's revenue requirement. CAC Ex. 2 at 10. He noted CEI South is proposing to reduce its reconnection charge, and to reduce it $5 if the proposed ARP that would allow remote disconnection is approved. He further objected to the higher reconnection charge for after-hours reconnection. CAC Ex. 1 at 79-80. The convenience fees he was referencing were credit card fees, kiosk payments, plus other fees associated with walk-ins at local businesses. The total amount of such fees during the base year was $810,740, and Mr. Inskeep recommended that this amount be included in the revenue requirement. CAC Ex. 2 at 82. Finally, he noted that 170 IAC 4-1-13(c) allows a utility to assess a late payment charge but it is not required to do so. He recommended that the Commission order CEI South to eliminate or reduce late payment charges. CAC Ex. 2 at 82.

ii. CEI South's Rebuttal. CEI South witness Folz testified that there are costs incurred with reconnection and even though they will be less with remote disconnection, there are still costs. Pet. Ex. 5-R at 13. Mr. Rice noted that this Commission has twice previously rejected the proposal to eliminate the imposition of third-party convenience fees by including such costs in the revenue requirement. Pet. Ex. 19-R at 53.

iii. Settlement Opposition. Mr. Inskeep objected to the Settlement Agreement because it does not adopt his proposal for convenience fees. He also objected that the late payment fee was only to be waived once per year and upon request. He further continued to object to the imposition of any reconnection fee with remote disconnection. CAC Ex. 4 at 22.

iv. Commission Discussion and Findings. We find the Settlement Agreement strikes the appropriate balance in addressing the miscellaneous charges discussed by Mr. Inskeep. For the majority of CEI South's residential customer base, this issue has become largely moot from our approval of the ARP. The fee for reconnection is $3. Despite Mr. Inskeep's protestations, there are administrative tasks as explained by witness Folz to perform a reconnection. The cost is not zero. As to Mr. Inskeep's position on convenience fees, we have twice rejected similar proposals and see no reason to change our view today.[23] Finally, our promulgated rules allow electric utilities to impose a fee for late payment and provides for the calculation. 170 IAC 4-1-13(c). After reviewing the evidence of record, we find that no compelling reason exists to impose on CEI South any further restrictions on late payment fees than those to which it has voluntarily agreed in the Settlement Agreement.

8. Overall Reasonableness of the Settlement Agreement. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co*., 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy*, 664 N.E.2d 401,406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement. *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co*., 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this cause sufficiently supports the conclusions that it is reasonable, just, and consistent with the purpose of Ind. Code § 8-1-2-1 *et seq.*, and that such agreement serves the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement. All parties had an opportunity to participate in and monitor the settlement negotiations. Because the Settlement Agreement is not unanimous, we must address the outstanding concerns raised by the non-settling parties that have

[23] *Indiana American Water Co.*, Cause No. 45870 (Feb. 14, 2024); *Duke Energy Indiana*, Cause No. 45253 (June 29, 2020).

not been addressed elsewhere in this order. The OUCC and CAC voiced concerns related to affordability and reliability in support of their opposition to the Settlement Agreement. As discussed below, we find the evidence of record supports approval of the Settlement Agreement as a reasonable resolution of the issues affecting each of these concerns.

A. OUCC and CAC Position. In addition to the specific issues raised and discussed in detail above, the OUCC and CAC also challenged CEI South's proposed rate increase, as modified by the Settlement Agreement, on the basis of affordability. They also claimed that CEI South has shortcomings in reliability.

In defining affordability, OUCC witness Dismukes discussed the concept of energy burden, referring to the amount of household income that is used to pay for one's electric bill. He stated energy burden becomes unaffordable when the percentage of income spent on energy exceeds 6%.[24] He presented an analysis of residential Energy Affordability Index estimates at both the 15th and 20th income percentiles. In his testimony in opposition to the Settlement, Dr. Dismukes disagreed with CEI South's claims that its rates are below the 6% affordability threshold he presented in his direct testimony. Pub. Ex. 12-S at 5-8. He said CEI South's analysis was flawed insofar as it assesses the affordability of CEI South's rates to the median household instead of examining affordability for low- and moderate-income households. He presented an updated analysis using the 15th and 20th percentile of household incomes in each of the seven counties CEI South operates in. His updated analysis showed that for households earning at the 15th percentile, CEI South's rates currently exceed or will exceed the 6% affordability level in all but one county and for households in the 20th percentile income level the rates currently exceed or will exceed the 6% energy burden in three of the counties. He characterized the 6% threshold as representing a level of "extreme financial burden."

CAC witness Inskeep criticized CEI South for not having performed a bill affordability analysis. CAC Ex. 2 at 18. He initially recommended the Commission adopt the following in the name of affordability: dismissal of the case, a mandated freeze or curtailment on spending and investments, a management audit, disallowance of a return of or on plant that is not in the public interest or resulting in just and reasonable rates, additional adjustments to remove a portion of management employee compensation, and additional downward adjustments to ROE. He claimed the considerations CEI South described to address affordability do not actually help customer affordability or reflect misleading framing by CEI South. He also said even if they were valid affordability considerations, they were not sufficient to address affordability. He presented his own analysis and concluded many of CEI South's customers who are at or near the Federal poverty level have electricity burdens well above 6% and even higher energy burdens. He said even the median household in Evansville would exceed the threshold for a high energy burden after giving effect to CEI South's initial proposed rate increase. He proposed an Affordable Power Rider to assist low-income customers. In his testimony in opposition to the Settlement, Mr. Inskeep updated his energy burden analysis to reflect the impact of the Settlement Agreement and to update CEI South gas rates for current rates in effect as of July 2024. While median households in Evansville

[24] Dr. Dismukes cites Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011 and "understanding Energy Affordability" ACEEE, 2015, page 2. Pub. Ex. 12 at 8 and n.9.

under his revised analysis have an energy burden of nearly 6%, low-income households continue to have energy burdens higher than the 6% threshold. CAC Ex. 6 at 7-8.

OUCC witness Eckert claimed that CEI South has not shown improved reliability over the last five years. Pub. Ex. 1 at 16-17. CAC witness Inskeep claimed CEI South's reliability has gotten worse over time, despite significant investments through its approved TDSIC plans. CAC Ex. 2 at 42.

B. <u>CEI South's Position</u>. Mr. Leger described the many actions CEI South has taken for affordability purposes, beginning with securitization and including several affordability considerations incorporated into its requested relief in this Cause. Pet. Ex. 1 at 14-15. He also stated CEI South partners with a variety of organizations to offer programs to assist qualifying individuals. He explained CEI South offers customers the ability to set a preferred billing date if a customer prefers receiving their bill at a particular time of the month. CEI South also offers budget billing to reduce large bill increases during periods of higher electric use. Payment plans are also available to CEI South customers individually if they fall behind on bill payments. Income eligible customers may also apply for the Energy Assistance Program through their local Community Action Agency. Additionally he stated, CEI South partnered with the City of Evansville, local assistance agencies, and township trustee offices to host a series of access to service fairs throughout the winter season. Participants can speak one-on-one with a customer service representative for bill assistance and general questions about their bill or service.

Mr. Rice presented direct testimony showing that since CEI South's last rate case decided in 2011, CEI South has endeavored to keep customer bills from rising too quickly, even with the addition of rate adjustment mechanisms. He showed that customer bills have remained relatively flat, below inflation levels since 2011. Pet. Ex. 19 at 4. He noted the significant positive impact CEI South's pursuit of securitization has had on affordability for customers.

On rebuttal, Mr. Leger took issues with Mr. Inskeep's insinuation that CEI South's rate case disregards affordability. He noted that Mr. Rice presents a compound annual growth rate calculation highlighting the fact that CEI South has grown residential bills at less than 0.5% per year on average in that timeframe, which is far less than any other utility in the State of Indiana, thereby highlighting CEI South's commitment to affordability for its customers. Pet. Ex. 1-R at 3-4. Mr. Rice responded to the affordability arguments raised by the parties as well as concerns voiced at the field hearing in both his rebuttal and his settlement rebuttal. He described the difficulties inherent in addressing affordability, which does not lend itself to the same examination through modeling, spreadsheets, and statutory parameters as the other four pillars. Pet. Ex. 19-R at 3.

In his Settlement rebuttal, CEI South witness Rice reiterated that the affordability pillar is concerned with retail electric utility service being "affordable and competitive across residential, commercial, and industrial classes." Pet. Ex. 19-SR at 7. He explained all customer classes saw a drop in the proposed increase because of the Settlement Agreement. Mr. Rice testified that all Indiana electric public utilities are in the midst of significant generation transition, causing significant upward pressure on rates well into the future as none of them has completed the transition to cleaner resources. Mr. Rice presented a comparison to other electric utilities in the State based on the IURC's 2024 Residential Bill Survey, showing CEI South's residential electric

bill is not the highest in the state and that between 2011 and 2024, CEI South's rates have increased the least among its peers in terms of dollars, percentage change, and rate of change. He explained it also does not fully reflect the effects of the recent I&M rate case order, nor does it reflect the outcome in the pending Duke Energy Indiana rate case or the termination of temporary credits providing refunds resulting from appeals of Commission orders. He stated that at this point it would be incorrect to imply that following approval of the Settlement Agreement in this case that CEI South's rates will be out of line when compared to other utilities in Indiana. His analysis showed a 2.1% compound average growth rate between rate cases, which is a strong demonstration of affordability and illustrates how prudent CEI South has been in making investment decisions and managing necessary expenses on behalf of its customers to provide safe and reliable service since that time.

Regarding the energy burden of the electric portion for CEI South customers, Mr. Rice presented evidence that, at settled rates, the energy burden for the average CEI South customer in Vanderburgh County has dropped. Moreover, incomes have risen in Vanderburgh County and the City of Evansville with inflation, and should continue to do so, helping to dampen the effect of necessary rate increases. Mr. Rice responded to Mr. Inskeep's updated analysis as well. He stated it is important to reiterate that none of the parties know the income of individual customers, the level of assistance that they may receive, or the number of people in the household. He explained it is also important to note that a family of three with a yearly income of $48,064 or less in the past 12 months is likely to qualify for Energy Assistance through the Community Action Program of Evansville. Specifically, 150% of poverty is a level the federal government and state government have recognized as having affordability challenges. Mr. Rice noted that Dr. Dismukes's updated affordability analysis now shows the 20th percentile household income in the total CEI South service territory is currently under the 6% threshold that he once called "affordable," and it remains under the 6% threshold in 2026 at 5.8%. He explained OUCC witness Dismukes's analysis now shows that customers with a 15th percentile household income in the total CEI South service territory have energy burdens of 7.3%. Mr. Rice testified that he still believes that affordability is difficult to measure and dependent on an individual customer's circumstances. Nevertheless, he stated he stands behind the methodology CEI South presented in rebuttal and settlement as a reasonable view of affordability.

CEI South witness Rawlinson provided testimony explaining that Mr. Eckert has not appropriately correlated TDSIC investment impacts to CEI South's reliability indices, explaining that TDSIC investments do not directly target all outage causes and Mr. Eckert's analysis does not account for external factors such as weather. Pet. Ex. 4-R at 4-5. Moreover, without the investments CEI South made in its first TDSIC Plan (Cause No. 44910) and the investments currently planned in CEI South's second TDSIC Plan (Cause No. 45894), Mr. Rawlinson stated CEI South's reliability performance would have declined. He described CEI South's experience as a result of a severe weather event on April 2, 2024 involving multiple tornados. He said the investments CEI South made through its TDSIC Plans reduced the time required to restore service to CEI South's customers. In Settlement rebuttal, Mr. Rice reiterated that CEI South's capital investments cannot control the weather or prevent a tree from falling into the line or prevent someone from driving into the utility's poles. Mr. Eckert's and Mr. Inskeep's selective use of different time periods do not change Mr. Rawlinson's findings that without these investments, CEI South's reliability would suffer. Pet. Ex. 19-SR, Attachment MAR-SR2 at 1.

C. Commission Discussion and Findings. This case offers the opportunity for the Commission to address the myriad concerns over affordability we have heard throughout this case. Our approval of the Settlement Agreement, which substantially reduces the requested relief in service of affordability, while upholding the tenets of reliability, resiliency, stability and environmental sustainability, represents the constant balancing this Commission has been charged to perform by the Indiana General Assembly.

While arguments were raised by the OUCC and CAC claiming CEI South has not shown improvements in reliability, the record reflects that Petitioner's investments in its transmission and distribution system have been critical to maintaining reliability, particularly when events outside of CEI South's control occur, such as extreme weather events like those experienced in CEI South's service territory in April 2024. The appropriate benchmark must consider these unique events. CEI South's TDSIC investments have improved reliability, all else being equal.

The record reflects efforts undertaken by CEI South to tackle the problem of affordability for its customers. Pet. Ex. 1 at 4; Pet. Ex. 19 at 4-9. These include a multi-phase approach to rate implementation to achieve gradualism in rate increases, a settled ROE considerably below that recommended by CEI South's expert, utilization of the Average Service Life depreciation rates lowering the revenue requirement by approximately $12.5 million despite CEI South's expert's recommendation to use the Equal Life Group, extended amortization periods for recovery of the 20% deferred from TDSIC and ECA and the proposal that 100% of sales margins from the Wholesale Power Market off system sales be credited to customers, and the proposed interim phases when Posey Solar and the CT Project are placed in service, creating savings from avoided incremental PISCC and deferred depreciation. Pet. Ex. 1 at 4, 15; Pet. Ex. 19 at 4-9. Moreover, Petitioner was involved in advocating for legislation authorizing the first ever utility asset securitization in Indiana, allowing for the issuance of securitization bonds at a lower long-term debt cost for the remaining value of the now retired A.B. Brown coal units 1 and 2 for net present value savings of $53 million versus traditional ratemaking. Pet. Ex. 1 at 14; Pet. Ex. 19 at 4-5.

All of these efforts culminated in a Settlement, albeit non-unanimous, that saw a $35 million further decrease in CEI South's request coupled with concessions on numerous other issues including lowering the fixed residential customer charge from approximately $23 to the pre-IURT repeal level of $11, elimination of pre-test year Phase 1 rates, and reducing or eliminating reconnection and late payment charges in certain circumstances. Pet. Ex. 19-SR at 6. The Settlement Agreement also incorporates several customer protection terms that had been acceptable to the OUCC and CAC in other settlements and approved by the Commission as in the public interest. The evidence also reflects that CEI South's rates since its last general rate case have grown at a much slower pace than those of its peers, and the proposed rates from Settlement are in line with where other electric utilities in the state currently are or are likely headed in the near term. Despite CEI South's rate mitigation efforts and the Settling Parties' compromise on issues benefiting residential customers, the resulting proposed rate increase is still being opposed by the OUCC and CAC.

The OUCC and the CAC challenged the Settlement Agreement largely on the basis that the Settling Parties (other than the Petitioner) are large-usage customers and therefore, they contend, the Settlement Agreement does not benefit other customer classes. As discussed in Paragraph 7.M (Cost of Service and Rate Design; Multi-Family Rates; BAMP), we do not accept

this characterization. With the totality of the evidence in mind, we find that the terms of the Settlement, with the modification to the revenue allocation discussed above to further address affordability by limiting the residential customer class increase given the Settling Parties' agreement to use 4CP, are reasonable and beneficial in the provision of electric service to all CEI South ratepayers. This Commission has not lost sight of the testimony of hundreds of witnesses at the public field hearings and recognizes that even moderated rate increases can be difficult on customers. As Mr. Gorman testified, as to revenue issues, the Industrial Group and SABIC had every motivation and made every effort to obtain as favorable an outcome as possible, because the cost of electricity is a large component of their cost of doing business. The negotiated revenue concessions operate to the benefit of all rate classes, not just industrial customers. Notably, the settled result, at $80.0 million, is significantly below the Industrial Group's litigation position. The $80.0 million is closer to the OUCC's litigation position than CEI South's rebuttal case, reflecting a concession on CEI South's part that crosses the midpoint of the range of potential litigation outcomes. IG Ex. 6 at 6; Pet. Ex. 19-SR at 3. While the Commission appreciates that affordability will remain a concern for CEI South's customers, this is not a reason to entirely reject the Settlement Agreement which substantially reduces the impact of CEI South's requested relief for all customers. We recognize that our role in addressing affordability cannot be "to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer." *Indiana-American Water Co.*, Cause No. 45870 (Feb. 14, 2024), at 105.

D. Ultimate Findings Approving Settlement. We are not persuaded by either the OUCC or the CAC that the Settlement Agreement should not be found to be in the public interest. We have recited the benefits flowing to all customers from the terms of the Settlement Agreement. When taken as a whole, the Settlement as modified herein is a reasonable resolution to the issues raised in this proceeding and represents a fair balance between the needs of CEI South and the interests of customers. The Settlement Agreement as modified results in a reasonable revenue increase which reflects a fair return of and on capital investment made by CEI South if the utility is operated efficiently and enables CEI South to continue to provide reliable service to its customers on a sound financial foundation.

Based upon our review of the record, the Commission finds that the Settlement Agreement is within the range of potential outcomes and as modified represents a fair, just, and reasonable resolution of the issues within the guardrails of the Five Pillars statutory construct. The Commission further finds and concludes that the Settlement as modified herein is reasonable, supported by substantial evidence, and in the public interest. Accordingly, the Settlement Agreement is approved, with the exception of the revenue allocation, as discussed above.

9. Overall Authorized Increase. Having found, based on the evidence of record, that the Settlement Agreement should be approved with modification. The proposed revenue increase is based upon a projected test year ending net original cost rate base of $2,769,851,666 as shown on Appendix A to the Settlement Agreement (Schedule B-1 of Petitioner's Exhibit No. 21-S), as follows:

Rate Base as of December 31, 2025

1	Plant In Service	$	3,903,197,879
2	Reserve for Accumulated Depreciation	$	(1,227,581,792)
3	Net Plant in Service	$	2,675,616,087
4	Other Items:		
5	Fuel Stock	$	8,990,701
6	Utility Material & Supplies	$	41,360,961
7	Allowance Inventory	$	-
8	Stores Expense	$	311,332
9	PISCC - AMI	$	10,585,830
10	PISCC - TDSIC 1.0	$	16,517,144
11	PISCC - TDSIC 2.0	$	5,433,980
12	PISCC - CECA	$	2,963,459
13	PISCC - ECA	$	2,863,643
14	PISCC - ECA FB Culley East Ash Pond	$	2,712,341
15	PISCC - CT	$	2,496,186
	Jurisdictional Rate Base	$	2,769,851,666

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 6.77%, as shown on Appendix A to the Settlement Agreement (Schedule D-1 of Petitioner's Exhibit No. 21-S), as follows:

Capital Structure as of December 31, 2025

	Class of Capital	Amount ($000)	Percent	Cost	Weighted Cost
1	Long-Term Debt	$ 1,294,210	39.49%	5.12%	2.02%
2	Preferred Stock	$ -	0.00%	0.00%	0.00%
3	Common Equity	$ 1,582,041	48.28%	9.80%	4.73%
4	Cost Free Capital	$ 390,113	11.90%	0.00%	0.00%
5	Other Capital	$ 10,754	0.33%	5.87%	0.02%
	Total Capital	$ 3,277,119	100.00%		6.77%

We therefore find that CEI South should be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $80,009,617, total base rate revenue of $803,932,466, and total net operating income of $187,518,958, as shown on Appendix A to the Settlement Agreement (Schedule A-1 of Petitioner's Exhibit No. 21-S), as follows:

1	Original Cost Rate Base	$	2,769,851,666
2	Weighted Average Cost of Capital		6.77%
3	Net Operating Income Required	$	187,518,958
4	Net Operating Income at Pro forma Present Rates	$	117,233,544
5	Net Revenue Increase Required	$	70,285,414
6	Gross Revenue Conversion Factor		1.3370172
7	Gross Revenue Increase Required	$	93,972,808
8	Less: Fuel & Purchased Power Expense Reduction	$	(13,963,191)
9	Recommended Gross Revenue Increase Required Less Fuel & Purchased Power Expense Reduction	$	80,009,617

The rate increase authorized herein should be implemented in multiple steps as delineated in Paragraph 7.B (Phased Rate Implementation) above.

Section B.15.b of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed and supported by CEI South's case-in-chief, as modified in its rebuttal testimony. This includes all the relief summarized in Paragraphs 7 (Settlement) and 8 (Overall Reasonableness of the Settlement Agreement) of this Order, which has not otherwise been modified by the Settlement Agreement. The Commission finds Section B.15.b of the Settlement Agreement to be reasonable and it is approved with the entirety of the Settlement Agreement.

10. Effect of Settlement Agreement. The Settlement Agreement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the Settlement Agreement or of this order, we find our approval herein should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (March 19, 1997).

11. Confidentiality. CEI South filed motions for protection and nondisclosure of confidential and proprietary information on December 5, 2023, March 28, 2024, and April 4, 2024, April 9, 2024. The OUCC filed a motion for protection and nondisclosure of confidential and proprietary information on March 12, 2024. The Industrial Group filed motions for protection and nondisclosure of confidential and proprietary information on March 12, 2024 and March 14, 2024. Each motion was supported by affidavits showing certain documents to be submitted to the Commission contain confidential trade secrets as defined under Ind. Code § 23-2-3-2. Docket entries were issued on each of these motions finding such information to be entitled to confidential treatment on a preliminarily basis, after which the information was submitted under seal. The

Commission finds all such information granted preliminary confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

12. OUCC's Motion to Strike. On April 22, 2024, the OUCC filed a Motion to Strike certain rebuttal testimony and attachments filed by Petitioner as inadmissible hearsay that falls within no exception. Petitioner filed a response to the Motion to Strike on April 25, 2024, arguing that the identified reference to testimony in another rate case was not offered for the truth of the matter asserted. The OUCC filed a reply in support of the Motion to Strike on April 29, 2024, reiterating the arguments made in the Motion to Strike.

After reviewing the Motion to Strike, Response, and Reply, we deny the Motion to Strike. As the OUCC itself notes, the Commission may rely on hearsay, though it may not use it as the sole basis for its decision. As should be clear from this Order, the evidence that is the subject of the Motion to Strike was not used as the sole basis for our decision in this Cause, so this issue is moot.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement, a copy of which is attached to this order, is approved in its entirety except as noted in this Order.

2. There shall be a cap limiting any class rate increase (other than for water heating customers) to 1.15 times the system average.

3. Petitioner's ARP for waiver from 170 IAC 4-1-16(f) for remote disconnections as modified pursuant to Sections B.9 and B.10 of the Settlement Agreement is approved as described in Findings Paragraph 7.K (ARP for Remote Disconnection).

4. Petitioner is authorized to increase its rates and charges for electric utility service in multiple steps as described in Findings Paragraph 7.B (Phased Rate Implementation).

5. New depreciation rates applicable to CEI South's common and electric plant are approved as explained in Findings Paragraph 7.F (Depreciation Rates and Amortization).

6. Petitioner shall file under this Cause for approval by the Commission's Energy Division the new schedules of rates and charges along with its revised tariff consistent with the Settlement Agreement and the rates and charges approved in this order.

7. The rates and charges for Steps 1 and 2 shall be implemented upon approval of the filed tariffs on a service-rendered basis.

8. Petitioner shall certify its net plant, original cost rate base, and capital structure on December 31, 2024 (Settlement Phase 1) and December 31, 2025 (Settlement Phase 2) and calculate the resulting rates and charges, which shall be made effective upon filing and approval of the Commission's Energy Division in accordance with the findings herein, subject to being

contested and trued-up consistent with the Settlement Agreement.

9. To the extent that either Posey Solar or the CT Project is not completely in service as of December 31, 2024 but is in service before December 31, 2025, Petitioner is authorized to implement additional interim phases to its increase as described above (Phased Rate Implementation).

10. Petitioner's proposed CPP Pilot, Rider ADR, and Rider GE are approved as contemplated by the Settlement Agreement.

11. Petitioner is directed to file under this Cause all information required by the Settlement Agreement.

12. The information filed in this Cause pursuant to motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

13. This order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: FEB 03 2025

I hereby certify that the above is a true and correct copy of the order as approved.

Regina K. Joyner Digitally signed by Regina K. Joyner Date: 2025.02.03 13:08:55 -05'00' **on behalf of**

Dana Kosco
Secretary of the Commission

OFFICIAL
EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT.	)	**CAUSE NO. 45990**

IURC JOINT - Settling Parties
EXHIBIT No. 1
9-10-24 LR
DATE REPORTER

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement (the "Settlement Agreement") is entered into by and among Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South" or the "Company"), the CenterPoint Energy Indiana South Industrial Group[1] ("Industrial Group") and SABIC Innovative

[1] The Industrial Group is a collection of industrial energy consumers, to include the following: Consolidated Grain & Barge; CountryMark Refining and Logistics, LLC; Marathon Petroleum Company; and Toyota Motor Manufacturing of Indiana, Inc.

Plastics Mt. Vernon, LLC ("SABIC") (collectively, the "Settling Parties"). The Settling Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth in this Settlement Agreement represent a fair, just, and reasonable resolution of all matters raised in this proceeding, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order without modification or further condition that is unacceptable to any Settling Party. The Settling Parties agree that this Settlement Agreement resolves all disputes, claims and issues arising from the electric rate case proceeding currently pending in Cause No. 45990 as between the Settling Parties. The Settling Parties agree that matters for which CEI South requested relief in this Cause as adjusted on rebuttal that are not addressed herein but were expressly supported by CEI South's evidence should be granted as proposed, without waiving the right of any party to litigate such issues in future proceedings.

A. Background.

1. CEI South's Current Rates and Charges.

a. Base Rates and Charges. CEI South's existing base rates and charges for electric utility service were established in its thirty-day filing #50171, effective June 1, 2018, pursuant to the Commission's February 16, 2018 Order in Cause No. 45032, its investigation into the impacts on Indiana utilities and customers resulting from the December 22, 2017 Tax Cuts and Jobs Act of 2017 ("TCJA"), as further reduced in Petitioner's 30-day filing #50548, effective July 1, 2022, to give effect to the repeal of the Utility Receipts Tax. The rates approved effective June 1, 2018 and July 1, 2022, reduced

CEI South's existing base rates and charges for electric utility service established in its most recent retail base rate case order issued on April 27, 2011, in Cause No. 43839.

b. FAC. Pursuant to Ind. Code § 8-1-2-42(d), CEI South files a quarterly Fuel Adjustment Clause ("FAC") proceeding in Cause No. 38708 FAC XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs.

c. DSMA. CEI South recovers demand side management costs, including costs associated with the direct load control inspection and maintenance program, performance incentives, and lost margins, through its Demand Side Management Adjustment ("DSMA") filed annually in Cause No. 43405 DSMA XX.

d. CECA. CEI South recovers, through its Clean Energy Cost Adjustment ("CECA") filed annually in Cause No. 44909 CECA XX, eligible costs of approved clean energy projects under Ind. Code ch. 8-1-8.8, including (a) engineering and project management, management and administration, permitting, contractor site preparation, equipment, and installation costs during construction; and (b) depreciation expense, post-in-service carrying costs ("PISCC"), taxes, and operation and maintenance ("O&M") expense once the projects are placed in service. CEI South's current CECA mechanism includes a component to pass back credits resulting from the Inflation Reduction Act ("IRA"). In this Cause, CEI South proposed to remove this component from the CECA mechanism and include it in a separate Tax Adjustment Rider ("TAR"). In addition, CEI South uses the CECA mechanism to pass on to customers net revenues from the sale of renewable energy credits ("RECs") related to CEI South's various renewable energy projects.

e. ECA. CEI South files annual Environmental Cost Adjustment ("ECA") proceedings in Cause No. 45052 ECA XX to effectuate timely recovery of 80% of its federally mandated costs (as defined by Ind. Code § 8-1-8.4-2) attributable to the following five compliance projects: (1) federally mandated requirements related to CEI South's Culley Unit 3 generating station (Culley 3 Project); (2) clean coal technology projects at CEI South's Culley Unit 3 and Warrick Unit 4 (collectively the MATS Projects); (3) federally mandated requirements to close CEI South's A.B. Brown ash pond (Brown Pond Project); (4) federally mandated compliance projects including a dry fly ash loading facility (Dry Ash Compliance Project) and federally mandated lined ponds at the A.B. Brown and F.B. Culley generating stations to handle coal-pile runoff, flue gas desulfurization wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's coal combustion residuals ("CCR") rules (Pond Compliance Project) (collectively, CCR Compliance Projects); and (5) federally mandated requirements required to close by removal ("CBR") CEI South's F.B. Culley east ash pond (the "CBR Project").[2]

f. MCRA. CEI South files annual Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") proceedings in Cause No. 43354 MCRA XX to recover costs associated with non-fuel-related MISO Day 1, Day 2, and Ancillary Services Market costs. CEI South proposed updates for the MCRA in this Cause as described in the direct testimony of Matthew A. Rice.

[2] CEI South's request for a Certificate of Public Convenience and Necessity for the CBR Project was pending when this Cause was filed but has since been approved by the Commission's February 7, 2024 Order in Cause No. 45903.

g. RCRA. CEI South files annual Reliability Cost and Revenue Adjustment ("RCRA") proceedings in Cause No. 43406 RCRA XX to track the differences between certain actual costs and revenues and the amounts of those costs and revenues included in CEI South's base rates. RCRA cost and revenue components include the non-fuel component of purchased power, cost of Environmental Emission Allowances ("EEAs"), Interruptible Sales billing credits, the retail sharing portion of Wholesale Power marketing margins, the margin from Municipal Wholesale Sales, and the retail portion of the margin from EEA sales (net of cost). CEI South has proposed updates for the RCRA in this Cause as described in the direct testimony of Matthew A. Rice.

h. TDSIC. Pursuant to the Commission's September 20, 2017 Order in Cause No. 44910, CEI South files a semi-annual proceeding in Cause No. 44910 TDSIC XX to recover 80% of approved capital expenditures and transmission, distribution, and storage system improvements ("TDSIC") costs incurred in connection with CEI South's TDSIC Projects through its TDSIC Rider. CEI South's current TDSIC mechanism includes a component to pass back credits resulting from changes in the federal tax rates under the TCJA. CEI South has proposed in this Cause to remove this component from the TDSIC mechanism and include it in the TAR. The TDSIC Plan approved in Cause No. 44910 expired December 31, 2023, and CEI South's new TDSIC Plan was approved in Cause No. 45894 on December 27, 2023.

i. Securitization. As a result of the Commission's financing order dated January 4, 2023, in Cause No. 45722, CEI South was authorized to implement, collect, and receive Securitization Charges associated with the securitization of A.B. Brown Units 1 and 2 pursuant to its Securitization of Coal Plants Tariff. Pursuant to that financing

order, the accumulated deferred income taxes ("ADIT") associated with the retiring A.B. Brown Units 1 and 2 are segregated from all other ADIT and not included in the calculation of Petitioner's capital structure or otherwise used in finding CEI South's authorized return in future rate cases. The financing order also established a Securitization ADIT Credit tariff to provide an annual credit to customers for the ADIT associated with A.B. Brown Units 1 and 2. In addition, the financing order required that the excess ADIT associated with A.B. Brown Units 1 and 2 be amortized and returned to customers over the life of the related Securitization Bonds. The excess accumulated deferred income taxes ("EADIT") resulting from the TCJA is being flowed back to customers via the TDSIC. As described below, the Company is proposing to continue to flow back this EADIT over the life of the bonds but through the new TAR instead of the TDSIC. The Securitization Rate Reduction ("SRR") tariff was a temporary rider established in Cause No. 45722 to provide customers with a credit for A.B. Brown Net Plant. CEI South proposes to zero out the SRR tariff in customer rates in this case (subject to variances), as the A.B. Brown Units 1 and 2 will no longer be included in base rates.

j. Depreciation and Accrual Rates. Petitioner's current electric depreciation rates were approved by the Commission's Order in Cause No. 43111 on August 15, 2007, and subsequently re-authorized (with a modification to the depreciation rate applicable to the Blackfoot landfill gas generating station) in Cause No. 43839 (April 27, 2011). Petitioner's current common plant depreciation rates were approved by the Commission's Order in Cause No. 45447 on October 6, 2021. Depreciation rates for Petitioner's CTs and Posey Solar were approved by the Commission's Orders in Cause No. 45564 on June 28, 2022, and Cause No. 45847 on September 6, 2023, respectively.

2. Status of Pending Electric Base Rate Case. On December 5, 2023, CEI South filed with the Commission its Verified Petition for General Rate Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and Alternative Regulatory Plan under Ind. Code ch. 8-1-2.5 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") in this Cause. CEI South also filed its prepared testimony and exhibits constituting its case-in-chief on that date. CEI South proposed a three-phase rate implementation, with potential interim phases as described in the direct testimony of CEI South Witness Behme. By Docket Entry issued December 28, 2023, as amended on January 17, 2024, the Commission established the procedural schedule in this case as well as the forward-looking test year for determining Petitioner's projected operating revenues, expenses, and operating income as the 12-month period ending December 31, 2025. The January 17, 2024 Docket Entry also established the rate base cutoff date at the end of the test year and associated rate base cutoff dates for each step of CEI South's proposed three-phase increase.

On March 12, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") and intervenors filed their respective cases-in-chief. CEI South filed its rebuttal testimony and evidence, and the Industrial Group and Citizens Action Coalition of Indiana, Inc. ("CAC") filed cross-answering testimony on April 9, 2024.

3. Summary of CEI South Requested Relief. CEI South's total proposed rate increase as set forth in its case-in-chief was $118,757,693, and after rebuttal was $115,445,697, which is approximately 15.95% from pro forma revenues at the rates that would be in effect had this case not been filed. CEI South is also seeking approval of new electric and common plant depreciation rates in this Cause, based on the study

sponsored by John R. Spanos except that the rates for Petitioner's CTs and Posey Solar shall remain unchanged from what was approved in Cause Nos. 45564 and 45847, respectively. CEI South also proposed a new Tax Adjustment Rider to include (i) the passback of EADIT to customers which is currently being passed back through CEI South's TDSIC pursuant to the settlement approved in Cause No. 45032 S21, (ii) the effects of Production Tax Credits ("PTCs") resulting from the IRA that are not reflected in base rates, which is currently authorized to be reflected in CEI South's CECA filings, and (iii) the new corporate alternative minimum tax ("CAMT") established under the IRA. CEI South also proposed a new Green Energy Rider to allow eligible customers to purchase up to 85% of the RECs that are received for generation produced by CEI South's renewable generating resources, a new Rider ADR to allow customers to partner with an aggregator to successfully lower load during MISO events, and a critical peak pricing ("CPP") pilot program to explore the potential use of time of use ("TOU") rates to help manage peak loads during hours of highest usage. CEI South sought authorization to establish a regulatory asset to reflect amounts not already included in base rates that are incurred for third-party cloud computing arrangements ("CCAs"). Finally, CEI South included a request for approval of an Alternative Regulatory Plan ("ARP") to grant CEI South a waiver from the requirements of 170 IAC 4-1-16(f) and allow for remote disconnection and reconnections.

B. Settlement Terms and Conditions.

1. Phased Base Rate Increases.

a. Settlement Phase 1. The Settling Parties agree that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to

increase its base rates and charges for electric utility service in two steps at a defined point in time as described in this Settlement Agreement. The first change in rates will be implemented pursuant to the process described below and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of December 31, 2024 subject to the Net Original Cost Rate Base Cap described in Paragraph B.3.a below ("Settlement Phase 1"). Following issuance of a Final Order in this Cause approving this Settlement, Settlement Phase 1 rates will go into effect after the beginning of the test year and upon the effective date of the Commission's approval of the Settlement Phase 1 compliance filing (currently anticipated to be on or around March 1, 2025) for services-rendered after that effective date. Settlement Phase 1 rates will be implemented on an interim-subject-to-refund basis pending a 60-day period for the parties to submit objections to the compliance filing. CEI South shall submit a certification of its actual utility plant in service and actual capital structure as part of its compliance filing. The compliance filing will calculate rates for the applicable phase based upon these certifications, subject to the Net Original Cost Rate Base Cap. If necessary to resolve any objections, the Commission shall schedule a hearing. However, within a week of CEI South's compliance filing, a technical conference may be held at the request of either a party or Commission staff to allow for further discussion in determining whether CEI South's filing complies with the Order in this Cause and to determine what additional information, if any, should be provided for the Settlement Phase 2 compliance filing. .

b. Settlement Phase 2. The second defined change in rates will be implemented pursuant to the process described above and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as

of the end of the test year (December 31, 2025), subject to the Net Original Cost Rate Base Cap described in Paragraph B.3.a below ("Settlement Phase 2"). Settlement Phase 2 rates will go into effect upon the effective date of the Commission's approval of the Settlement Phase 2 compliance filing (currently anticipated to be on or around March 1, 2026) for services-rendered after that effective date. Settlement Phase 2 rates will be implemented on an interim-subject-to-refund basis pending a 60-day review using the process described above.

c. Interim Phases. The Settling Parties agree CEI South should be authorized to implement interim rate increase steps after the Posey Solar and the CT Projects are placed in service as described by CEI South Witness Behme. Based upon projected in-service dates of May 2025 for Posey Solar Project and July 2025 for the CT Project, this results in a projected reduction to proposed rate base as reflected in Paragraph B.3.a.iii. The actual reduction to rate base and the Net Original Cost Rate Base Cap will be based upon the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps.

2. Revenue Requirement and Net Operating Income.

a. Revenue Requirement. The Settling Parties agree that CEI South's base rates will be designed to produce total pro forma operating revenues of $803,932,466. This represents an overall net revenue increase (net of the reduction to revenues from the stipulated fuel and purchased power expense reduction set forth in Paragraphs B.5.a and B.5.c, when compared to revenues from rates that would be in effect without filing this case, of $80,009,617, which is a decrease of $38,748,076 from the amount requested by CEI South in its case-in-chief and a decrease of $35,436,080 from the amount

requested on rebuttal. Appendix A, attached hereto and incorporated by reference, includes schedules supporting the calculation of CEI South's revenue requirement as of December 31, 2024 and December 31, 2025. Petitioner's Exhibit 20-S, filed with the Commission contemporaneously herewith, contains the updated Revenue Requirement Model reflecting the terms of this Stipulation and Settlement Agreement.

b. Net Operating Income. The Settling Parties agree that CEI South's Revenue Requirement as stipulated in Paragraph B.2.a results in an authorized net operating income ("NOI") of $187,518,958.

3. Original Cost Rate Base, Capital Structure and Fair Return.

a. Original Cost Rate Base. The Settling Parties agree that CEI South's original cost rate base on which it should be permitted to earn a return shall be the actual net original cost rate base as of December 31, 2024 (for Settlement Phase 1 as defined in Paragraph B.1.a above) and December 31, 2025 (for Settlement Phase 2 as defined in Paragraph B.1.b above); *provided, however*, that net original cost rate base at either Settlement Phase 1 or Settlement Phase 2 shall not exceed the forecasted end-of-test-year net original cost rate base of $2,769,851,666, as adjusted for the actual reduction to forecasted post-in-service carrying charges and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar (the "Net Original Cost Rate Base Cap"), which reflects the following stipulated modifications to CEI South's forecasted rate base at rebuttal:

i. Reduction to coal inventory of an additional $2,949,966 as proposed by OUCC Witness Eckert.

ii. Removal of $212,036 in additional net investment in the Urban Living Research Center, as recommended by OUCC Witness Armstrong.

iii. Reduction for avoided PISCC and deferred depreciation in conjunction with the stipulations set forth in Paragraph B.1.c above regarding interim phases of rates.

b. Other Rate Base Items.

i. CEI South stipulates and confirms that the amounts reflected in the table below related to land acquisition and identified in the pre-filed testimony of OUCC Witness Armstrong are not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates:

Table B.3.b.i

Work Order Number	SAP Order	Work Order Description	Total	FERC Account
17410001022013		Future Use Land 8520 Welborn	$ 269,295.15	340.1 Land
17434301022011		Land for Future Use	$ 1,098,217.72	340.1 Land
18410001022011		2018 Smith Diamond Rd - Land	$ 161,154.79	340.1 Land
19410001022012	**13101475**	ABB Land Purchase 2019	$ 273,551.34	310.1 Land
20410001022011	**13102434**	2020 Land Purchase - AB Brown	$ 341,647.36	310.1 Land
Grand Total			**$ 2,143,866.36**	

ii. CEI South stipulates and confirms that the amounts related to the Culley Unit 3 Natural Gas conversion and identified in the confidential pre-filed testimony of OUCC Witness

Krieger and confidential rebuttal testimony of F. Shane Bradford will not be included in rate base in this Cause, but will instead be addressed as part of Petitioner's later anticipated proposed certificate of public convenience and necessity ("CPCN") proceeding related to said conversion.

c. Capital Structure. The Settling Parties agree that CEI South's authorized Return on Equity should be 9.80%. Based on the following capital structure as of the end of the test year, the 9.80% ROE and the cost of debt and zero cost capital as agreed, the overall weighted average cost of capital is computed as follows:

Table B.3.c

Class of Capital	Reference	Amount ($000)	Percent	Cost	Weighted Cost
Long-Term Debt	SCH D-2	$ 1,294,210	39.49%	5.12%	2.02%
Preferred Stock	SCH D-3	$ -	0.00%	0.00%	0.00%
Common Equity	SCH D-4	$ 1,582,041	48.28%	9.80%	4.73%
Cost Free Capital	SCH D-5	$ 390,113	11.90%	0.00%	0.00%
Other Capital	SCH D-5	$ 10,754	0.33%	5.87%	0.02%
Total Capital	Sum of Lines 1 - 5	$ 3,277,119	100.00%		6.77%

d. Fair Return. The Settling Parties stipulate and agree that the agreed weighted cost of capital times the stipulated net original cost rate base yields a fair return on the fair value of rate base for purposes of this case. Accordingly, the Settling Parties agree that CEI South should be authorized a fair return of $187,518,958 yielding an overall return for earnings test purposes of 6.77% based upon the stipulated net original cost rate base, capital structure and ROE as set forth above in this Section B.3.

4. Depreciation and Amortization Expense.

a. Depreciation Expense. The Settling Parties stipulate that the depreciation accrual rates recommended by OUCC Witness David J. Garrett as presented in Public's Exhibit No. 11, Attachment DJG-5, should be approved and used in the determination of net plant in service values for calculation of Settlement Phase 1 and Settlement Phase 2 rates, *except* the depreciation rates for the CT Project and Posey Solar shall remain unchanged from those approved in their respective CPCN proceedings.

b. Amortization Expense.

i. The Settling Parties agree to the amortization of Indiana state excess accumulated deferred income taxes ("Indiana state EADIT") over three years as proposed by OUCC Witness Stull and Industrial Group Witness Gorman, except that Witness Stull's recommendation to impose carrying charges should be rejected. CEI South's proposal is to reflect all refunds of EADIT through the TAR; therefore, this stipulated term does not affect the revenue requirement.

ii. If not already addressed by an intervening base rate case order before expiration of various amortization periods, CEI South agrees to file a revised tariff to remove the annual amortization amount from base rates upon each such expiration, unless a new general rate case petition is pending at that time.

5. Pro Forma Revenues and Expenses.

a. Base Cost of Fuel. The Settling Parties agree that the forecasted base cost of fuel included in the test year revenue requirement shall be reduced by $8,175,808 as recommended by OUCC Witness Eckert.

b. Interruptible Sales Billing Credits. The Settling Parties agree that CEI South's proposal to include $725,000 in interruptible sales billing credits shall be rejected, as recommended by OUCC Witness Lantrip. Any actual interruptible sales billing credits shall be reflected in the RCRA.

c. Capacity Purchase Costs. The Settling Parties agree that the forecasted capacity purchase costs included in the test year revenue requirement shall be reduced by $5,000,000.

d. Operations & Maintenance Expense. The Settling Parties stipulate to a reduction to CEI South's total forecasted level of Operations & Maintenance ("O&M") expense presented in its case-in-chief of $1,350,000. The Settling Parties further agree to include $813,540 related to cloud computing arrangements ("CCAs") in forecasted test year O&M expense for purposes of the revenue requirement.

6. Accounting Treatment for Cloud Computing Costs. Subject to the stipulation and agreement set forth in Paragraph B.5.d above with respect to CCAs, CEI South agrees to withdraw its request for creation of a regulatory asset for post-test year cloud computing costs; *provided*, *however*, that such withdrawal is without prejudice, and CEI South reserves its rights with respect, to filing for such relief in a separate docketed proceeding.

7. Proposed Riders.

a. Critical Peak Pricing Pilot, Rider ADR, and Green Energy Rider. The Settling Parties stipulate and agree that CEI South's Critical Peak Pricing Pilot, Rider ADR, and Green Energy Rider should be approved as proposed by CEI South. CEI South commits to providing all parties to this Cause a copy of the contract with the demand response aggregator after it has been signed.

b. Tax Adjustment Rider. The Settling Parties stipulate and agree that while the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase 1 and Settlement Phase 2 rates, respectively, CEI South shall withdraw its request to include future Corporate Alternative Minimum Tax ("CAMT") effects in its Tax Adjustment Rider ("TAR").

8. Other Tariff Matters.

a. IC and IO Riders. CEI South agrees to continue conversations with interested stakeholders regarding changes to its Interruptible Contract ("IC") and Interruptible Option ("IO") riders related to Demand Response.

b. Limitation of Liability. CEI South agrees to adopt and incorporate the changes to its limitation of liability provision in its tariff as recommended by IG Witness Gorman and modified by CEI South Witness Rice on rebuttal.

9. Alternative Regulatory Plan for Remote Disconnection ("ARP"). CEI South agrees to incorporate the protections contained in the rebuttal testimony of CEI South witness Folz and Paragraph B.10 below. The Settling Parties stipulate the approval of the ARP, as modified pursuant to this Paragraph B.9, will be left to the Commission's discretion and determination.

10. Customer Protection Provisions.

a. LIHEAP Customer Deposits. If an applicant for residential service or current residential customer is qualified by the applicable LIHEAP-affiliate community action agency to participate in the Low Income Home Energy Assistance Program ("LIHEAP Qualified Participant"), the residential deposit amount will be limited to $50.00. LIHEAP qualification can be from the current heating season or one-year prior heating season.

b. Residential Late Payment Charge. CEI South agrees that, following EIP implementation, once per calendar year, upon request by a residential customer, CEI South will waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of the net amount of the next succeeding month's bill.

c. LIHEAP Qualified Participants- Fees; Reporting.

i. CEI South agrees that, following EIP implementation, once per calendar year, the Company will waive the manual disconnection and manual or, subject to approval of the ARP by the Commission, remote reconnection fees of a LIHEAP Qualified Participant.

ii. CEI South agrees to report data on LIHEAP Qualified Participants consistent with the type of data that CEI South reported in Cause No. 45830 and currently reports pursuant to the agreement with the OUCC as a result of Cause No. 45736. CEI South will include this data in its annual Collaboration Report resulting from Cause No. 45564. Specifically, CEI South agrees to provide:

1. Number of residential accounts receiving assistance under the LIHEAP program. For purposes of this reporting, LIHEAP is defined as assistance provided by Community Action Program ("CAP") agencies and/or CenterPoint Energy Indiana's Universal Service Program (USP).
2. Number of LIHEAP accounts that are past due where "past due" is defined as accounts that are any number of days past due.
3. Total dollars owed with respect to LIHEAP accounts that are in arrears.

d. Disconnections/Reconnections.

i. Remote Disconnection/Reconnection. CEI South agrees that if its ARP for remote disconnections/reconnections is approved by the Commission:

1. CEI South will provide at least thirty (30) days advance notice to customers before implementing the remote disconnection/reconnection proposal.
2. The fee for remote disconnection shall remain $0, consistent with CEI South's case-in-chief; and the fee for remote reconnection shall be reduced from $5 to $3.
3. For LIHEAP Qualified Participants, CEI South will waive, once per calendar year per customer, the after-hours remote reconnection charge set forth in CEI South's tariff as $54.19.

4. If a residential customer is designated as "Medical Need" or "Life Support", does not have an AMI meter, or has not provided a phone number or email address, CEI South will make an on-premises visit on the day of disconnect. As specified in CEI South's case-in-chief, Medical Need and Life Support Customers will be excluded from remote disconnection.

ii. Disconnection Service Hours for Non-Payment. CEI South agrees not to disconnect service for non-payment for any residential customer on Fridays, Saturdays, Sundays, and the following Holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Friday after Thanksgiving Day, December 24, and Christmas Day.

iii. Medical Need or Life Support Customers. CEI South agrees to increase the current protection from disconnection for Medical Need (10 days) or Life Support (20 days) to 30 days for both categories. Before any disconnection of a LIHEAP Qualified Participant designated as Medical Need or Life Support, CEI South will place a collection call to such customer that prompts the customer to contact CEI South to establish an installment plan.

11. Multi-Family Data Collection & Analysis. CEI South agrees to collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. In advance of its next rate case, CEI South will offer to

meet to discuss methodology and share initial results of its analysis with any interested party to this Cause.

12. Customer Bill Transparency. CEI South agrees to provide more transparency on its customer bills for CEI South customers as soon as practicable after issuance of a final order and after implementation of EIP, to include additional line items that break out the following:

- Service Charge
- Variable charges (charges tied to usage)
- FAC
- Sales Tax
- Total

CEI South will provide a copy of these changes to all parties to this Cause prior to implementation.

13. Cost of Service - Cost Allocation and Revenue Distribution.

The Settling Parties agree to use CEI South's cost of service study as modified herein and revenue allocation also as described herein. The agreed upon cost of service study and the revenue allocation for purposes of designing rates are depicted in the schedules attached hereto as Appendix B and incorporated by reference. Pursuant to Ind. Code § 8-1-39-9, future TDSIC allocators are based on the proposed revenue allocation by rate class (*i.e.*, the mitigated allocation of the allocated cost of service study revenue) and presented in Appendix B.

a. Generation and Transmission costs will be allocated using the 4CP methodology as in the last general rate case and the allocators from CEI South's testimony in this Cause No. 45990. These allocators will continue to be used in various tracker filings, subject to Commission determinations in particular proceedings.

b. Customer costs will be determined based upon the minimum system study prepared by CEI South Witness Taylor, also consistent with the methodology used in the last general rate case.

c. The Settling Parties stipulate and agree that:

i. No class will receive a rate decrease as a result of the rates implemented pursuant to this Stipulation and Settlement Agreement.

ii. No class will receive a rate increase that is higher than what CEI South proposed in its rebuttal position in this Cause.

iii. Other than water heating, no class will receive a rate increase greater than 1.35x the system average. Water heating will receive a rate increase of 1.5x the system average, as proposed in CEI South's direct and rebuttal positions.

14. Rate Design. The Settling Parties stipulate and agree to set the customer charges (i.e., the fixed portion of the bill) for each class at the level prior to the repeal of the Utility Receipts Tax. For clarification, the customer charge stipulated to in this agreement does not include the fixed portion of TDSIC recovery. The stipulated customer charges are as set forth below:

Rate Schedule	Customer Charge
RS	$11.00
B	$5.00
SGS	$11.00

DGS-1	$15.00
DGS-2	$35.00
DGS-3	$75.00
OSS	$15.00
LP	$150.00

15. Other Disputed Items.

a. BAMP Rates. CEI South agrees to evaluate the reasonableness of moving the Backup Service Transmission Rate towards parity with FERC Attachment O price and hold discussions with SABIC in advance of CEI South's next base rate case to determine the appropriate, cost-of-service-based Backup Service Transmission Rate.

b. All Other Items. The Settling Parties stipulate and agree that all other disputed items not expressly delineated herein shall be resolved as proposed in CEI South's case-in-chief, as modified by its rebuttal position where applicable, to the extent expressly supported in CEI South's evidence and without waiving the right of any party to litigate such issues in future proceedings.

C. Effect of Settlement and Procedural Matters.

1. Scope and Effect of Settlement.

a. Neither the making of this Settlement Agreement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. Neither the making of this Settlement Agreement, nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

b. This Settlement Agreement shall not constitute nor be cited as precedent by any person or deemed an admission by any Settling Party in any other

proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. This Settlement Agreement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceedings.

c. The Settling Parties' entry into this Settlement Agreement shall not be construed as a limitation on any position they may take or relief they may seek in other pending or future Commission proceedings not specifically addressed in this Settlement Agreement.

2. Authority to Enter Settlement. The undersigned have represented and agreed that they are fully authorized to execute this Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby, subject to the agreement of the Settling Parties on the provisions contained herein.

3. Privileged Settlement Communications. The communications and discussions during the negotiations and conferences have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are privileged. All prior drafts of this Settlement Agreement and any settlement proposals and counterproposals also are or relate to offers of settlement and are privileged.

4. Conditions of Settlement. This Settlement Agreement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party.

5. Evidence in Support of Settlement. CEI South, the Industrial Group and SABIC shall offer their respective direct and rebuttal testimonies and supplemental testimony supporting the Commission's approval of this Settlement Agreement and will request that the Commission issue a Final Order incorporating the agreed proposed language of the Settling Parties and accepting and approving the same in accordance with its terms without any modification. Such supportive testimony will be offered into evidence without objection by any Settling Party. The Settling Parties hereby waive cross-examination of each other's witnesses.

6. Commission Approval. The Settling Parties will support this Settlement Agreement before the Commission and request that the Commission accept and approve the Settlement Agreement. This Settlement Agreement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party. If the Commission does not approve the Settlement Agreement in its entirety, the Settlement Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Settlement Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

7. Proposed Order. The Settling Parties will work together to prepare an agreed upon proposed order to be submitted in this Cause. The Settling Parties will request Commission acceptance and approval of this Settlement Agreement in its

entirety, without any change or condition that is unacceptable to any party to this Settlement Agreement.

8. Publicity. The Settling Parties also will work cooperatively on news releases or other announcements to the public about this Settlement Agreement.

9. Waiver of Opposition. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement Agreement in its entirety without changes or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically and exclusively implementing the provisions hereof) and shall not oppose this Settlement Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

Accepted and Agreed on this 20th day of May, 2024.

(signature page follows)

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:_____
Printed Name: Richard C. Leger

CEI South Industrial Group

By:_____
Printed Name:

SABIC Innovative Plastics Mt. Vernon LLC

By:_____
Printed Name:

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:_____
Printed Name:

CEI South Industrial Group

By: Todd A. Richardson
Printed Name: Todd A. Richardson

SABIC Innovative Plastics Mt. Vernon LLC

By:_____
Printed Name:

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:_____
Printed Name:

CEI South Industrial Group

By:_____
Printed Name:

SABIC Innovative Plastics Mt. Vernon LLC

By:_____
Printed Name: Nikki Shoultz

CEI SOUTH
CAUSE NO. 45990
PET'S EX. NO. 20-S
CURRENT AND ADJUSTED PRO FORMA INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2025

SCHEDULE C-1.1a
WITNESS RESPONSIBLE:
C. M. BEHME / S. E. GRAY

Line	Description	Test Year Unadjusted (A)	Pro Forma Adjustments (B)	Pro Forma at Present Rates (C)	Increase (D)		Pro Forma at Proposed Rates (E)
1	OPERATING REVENUES						
2	Base Revenue and Riders	$ 721,683,471	$ 2,239,378	$ 723,922,849	$ 80,009,617		$ 803,932,466
3	Total Operating Revenues	$ 721,683,471	2,239,378	$ 723,922,849	$ 80,009,617	(A)	$ 803,932,466
4							
5	FUEL AND PURCHASED POWER						
6	Fuel	$ 274,718,361	$ (14,525,860)	$ 260,192,501	$ (13,963,191)		$ 246,229,310
7	Total Fuel and Purchased Power Expense	$ 274,718,361	(14,525,860)	$ 260,192,501	$ (13,963,191)		$ 246,229,310
8							
9	MARGIN	$ 446,965,110	$ 16,765,238	$ 463,730,348	$ 93,972,808		$ 557,703,156
10							
11	OPERATING EXPENSES						
12	Steam Power Generation Expense	$ 44,521,454	(14,049,267)	$ 30,472,187	$ -		$ 30,472,187
13	Other Power Generation Expense	15,150,128	13,825	15,163,953	-		15,163,953
14	Other Power Supply Expense	670,659	-	670,659	-		670,659
15	Transmission Expense	23,817,994	195,902	24,013,896	-		24,013,896
16	Distribution Expense	23,077,201	(143,586)	22,933,615	-		22,933,615
17	Customer Accounts Expense	3,678,296	(20,197)	3,658,099	-		3,658,099
18	Customer Service & Information Expense	14,853,347	(13,673,275)	1,180,073	-		1,180,073
19	Sales Expense	-	-	-	-		-
20	Administrative & General Expense	52,414,815	(3,028,251)	49,386,564	419,833		49,806,398
21	Total Operation & Maintenance Expense	$ 178,183,894	$ (30,704,849)	$ 147,479,045	$ 419,833		$ 147,898,878
22							
23	Total Operating Expense	$ 178,183,894	$ (30,704,849)	$ 147,479,045	$ 419,833		$ 147,898,878
24							
25	Depreciation Expense	$ 116,624,348	$ 21,004,605	$ 137,628,953	$ -		$ 137,628,953
26	Amortization Expense	4,145,539	30,029,706	34,175,245	-		34,175,245
27	Total Depreciation and Amortization Expense	$ 120,769,887	$ 51,034,311	$ 171,804,198	$ -		$ 171,804,198
28							
29	Taxes Other Than Income Taxes						
30	Property Taxes	$ 15,550,000	$ (6,033,137)	$ 9,516,863	$ -		$ 9,516,863
31	Other Taxes	2,838,115	(54,904)	2,783,210	-		2,783,210
32	Total Taxes Other Than Income Taxes	$ 18,388,115	(6,088,042)	$ 12,300,073	$ -		$ 12,300,073
33							
34	Income Taxes						
35	State Income Taxes	$ 1,011,151	$ (1,011,151)	$ (0)	$ 4,584,096		$ 4,584,096
36	Deferred Income Taxes - State	3,522,567	396,825	$ 3,919,391			3,919,391
37	Federal Income Taxes	4,063,651	7,260,802	$ 11,324,453	18,683,465		30,007,918
38	Deferred Income Taxes - Federal	10,978,418	(11,308,773)	$ (330,355)	-		(330,355)
39	Total Income Tax Expense	$ 19,575,787	$ (4,662,298)	$ 14,913,489	$ 23,267,560		$ 38,181,049
40							
41	Investment Tax Credits						
42	Investment Tax Credit Adjustments	$ -	$ -	$ -	$ -		$ -
43	Total Investment Tax Credits	$ -	-	$ -	$ -		$ -
44							
45	Total Operating Expenses and Taxes	$ 336,917,682	$ 9,579,123	$ 346,496,805	$ 23,687,393		$ 370,184,198
46							
47	Net Operating Income	$ 110,047,428	$ 7,186,115	$ 117,233,543	$ 70,285,414		$ 187,518,958

Note
(A) Net increase to gross revenue equals $80,009,617 reflects base revenue increase of $93,972,808 less fuel and purchased power costs of $13,963,191.

INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 45990

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH

Petitioner's Exhibit No. 18-S, Attachment JDT-S2

ALLOCATED COST OF SERVICE STUDY
TEST YEAR
ENDED DECEMBER 31, 2025

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

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I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South," "CEIS," or "the Company") based on the Test Year ended December 31, 2025 ("TY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section, CEI South's Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of the COSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the COSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of the electric plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of electric services: demand, energy/commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Energy/Commodity-related costs are variable costs that vary with the quantity of electricity used. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. They are allocated directly to the customers of a particular class of service.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be assigned directly to a particular customer class, including plant investments and associated expenses. All the remaining costs that cannot be directly attributable to a specific group of customers are allocated using allocation factors.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of John D. Taylor. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of working capital, income taxes, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each

customer class; and calculates unit costs by function for customer, energy/commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per kilowatt hour, per kilowatt of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. CEI SOUTH's COST OF SERVICE PROCEDURES

1. Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four basic functions and the associated sub-functions are shown in the table below:

Function	Sub-Function
Generation	Production
	Fuel Expenses
	Variable Production Cost
Transmission	Transmission
Distribution	Substation
	Dist Primary
	Dist Secondary
	Transformation
Customer	Onsite & Metering
	Lighting Plant
	Customer Accounts & Service

CEIS's assigned functional categories are presented on Schedule 4.

2. Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs

The table below shows how each of the functional and sub-functional costs was classified:

Function	Cost Classification		
	Demand	Energy	Customer
Production	x	x	
Transmission	x		
Substation	x		
Distribution Primary	x		
Distribution Secondary	x		
Transformation	x		x
Onsite & Metering			x
Lighting Plant			x
Customer Accounts & Service			x
Fuel Expenses		x	
VPC		x	

CEI South's assigned classification categories are presented on Schedule 4.

As shown in the table above, transformers are classified as demand and customer related using Minimum System Study. The Minimum System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table below shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Transformers and Transformer	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56%	44%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56%	44%
Total	**56,994**	**$218,276,204**		**$122,315,833**	**56%**	**44%**

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate

costs among various customer classes. CEIS's assigned Allocation Factors are presented on Schedule 4.

3.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

Rate Schedule	**COSS Customer Class**
Residential (RS)	Residential (RS)
Water Heating (B)	Water Heating (B)
Small General Service (SGS)	Small General Service (SGS)
Demand General Service (DGS)	Demand General Service (DGS)
Off-Season Service (OSS)	Demand General Service (DGS)
Large Power Service (LP)	Large Power Service (LP)
High Load Factor Service (HLF)	High Load Factor Service (HLF)
Outdoor Lighting (OL)	Outdoor Lighting (OL)
Street Lighting (SL)	Street Lighting (SL)

3.2. External Allocation Factors

CEI South's External Allocation Factors are presented on Schedule 5. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

ENERGY/COMMODITY AND REVENUE ALLOCATION FACTORS

Costs classified as Energy are allocated among customer classes based on the kilowatt-hour (kWh) sales for the test year.

REV	The factor directly assigns Current Annualized Revenues Less Fuel Cost Revenues to customer classes.
REV_ENERGY	The factor directly assigns total Fuel Cost Revenue to customer classes.
REV_RIDER	This factor directly assigns all rider revenues (TDSIC, CECA, etc.) less fuel cost revenue to customer classes.
ENERGY	This represents test year kWh consumption for each customer class.
REV_LATE_FEE	The factor directly assigns late fees revenue to customer classes.
REV_FORFEITED	This factor directly assigns forfeited discounts for each customer class.
REV_RECONNECT	The factor directly assigns reconnect charge revenue to each customer class.
REV_NFS	This factor directly assigns returned check charge revenue to each customer class.
REV_MISC	The factor directly assigns miscellaneous revenues collected through the customer classes.
REV_VP	The factor directly assigns variable production revenue through the customer classes.

REV_PROPOSED_VP	The factor directly assigns variable production revenues to customer classes.

CUSTOMER ALLOCATION FACTORS

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUST	The factor is based on the average number of customers per customer class.
CUST_BILL	This factor is based on the number of customer bills per customer class.
CUST_PRI	The factor is based on the average number of customers per customer class using the Primary System.
CUST_SEC	The factor is based on the average number of customers per customer class using the Secondary System.
MTRS	The factor is based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost (including labor and overhead) was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the customer count for each customer class.
SERV	The analysis relies upon the data contained in the Company's property records which provide an inventory of the average number of service wires by customer class. Additionally, current unit costs per foot by service wire type and design (underground or overhead) were provided by the Company. The method employed to develop the service allocator was similar to that used for the meter allocator.
STREET-LIGHT	The factor is based on the average number of company-owned streetlights.
OUTDOOR-LIGHT	The factor exists to directly assign costs to the Outdoor Lighting class in ACOSS.
MTR_READ	Account 902 Meter Reading Expenses The factor is based on the special study of 902 sub-accounts.
UNCOLL	Account 904 Uncollectible Accounts. The factor is based on three-year average distribution-related write-offs by rate class.

DEMAND ALLOCATION FACTORS

NCP_SEC	Non-Coincident Peak Demand_Secondary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the secondary distribution system.

NCP_PRI	Non-Coincident Peak Demand_Primary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the primary distribution system.
12CP_DEMAND	The Twelve Monthly Coincident Peak Factor is based on the twelve months of average system peak responsibility of coincidental class demand.
4CP_DEMAND	The Four Monthly Coincident Peak Factor is based on the average of four peak months of system peak responsibility of coincidental class demand.

3.3. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated costs. The Internal Allocation Factors are provided in Schedule 5 and described below.

INT_TOTAL_PLANT	Plant Total - The factor is based on the allocated total plant balance by customer class.
INT_RATEBASE	Total Rate Base – The factor is based on the derived rate base by customer class.
INT_DIST_OPS	Distribution related Operation Expense subtotal – The factor is based on the customer class allocated Distribution-related Operation Expenses.
INT_DIST_MAINT	Distribution related Maintenance Expense subtotal – The factor is based on the customer class allocated Distribution-related Maintenance Expenses.
INT_361-364	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 361 "Structures and improvements", 362 "Station Equipment", 363 "Storage battery equipment", 364 "Poles, Towers and Fixtures" plant balances by customer class.
INT_364	FERC 364 "Poles, Towers and Fixtures" - The factor is based on the allocated plant balance of FERC Account 364.
INT_365	FERC 365 "Overhead Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 365.
INT_367	FERC 367 "Underground Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 367.
INT_368	FERC 368 "Transformers and Transformer Installations" - The factor is based on the allocated plant balance of FERC Account 368.
INT_STNS,POLES,LINES	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 362 "Station Equipment", 364 "Poles, Towers and Fixtures", and 365 "Overhead Conductors and Devices" plant balances by customer class.

INT_LABOR	Total Labor Expense – The factor is based on the total customer class allocated labor-related expenses.
INT_REVREQ	Total Revenue Requirement – The factor is based on the derived revenue requirement by customer class.
INT_GENPT	General Plant – The factor is based on the allocated total General Plant balance by customer class.
INT_DIST (60%)_TRANSM (40%)_PLANT	Factor calculated by taking 60% of the allocated total Distribution plant balance and 40% of the allocated total Transmission plant balance by customer class.

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 1 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Rate Base**									
2	Plant in Service	$ 3,903,197,879	$ 1,920,914,445	$ 11,376,172	$ 82,940,564	$ 1,099,503,552	$ 729,052,713	$ 25,156,856	$ 8,449,008	$ 25,804,568
3	Accumulated Reserve	(1,227,581,792)	(619,904,244)	(4,619,659)	(30,261,189)	(331,812,514)	(215,381,920)	(7,552,197)	(3,671,412)	(14,378,656)
4	Other Rate Base Items	94,235,578	47,763,533	401,553	2,251,817	24,854,181	17,737,370	759,288	124,888	342,949
5	**Total Rate Base**	**$ 2,769,851,666**	**$ 1,348,773,734**	**$ 7,158,066**	**$ 54,931,192**	**$ 792,545,219**	**$ 531,408,163**	**$ 18,363,947**	**$ 4,902,484**	**$ 11,768,861**
6	**Margin at Current Rates**									
7	Base Rate Revenue	$ 267,328,652	$ 132,139,577	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
8	Rider Revenue	99,379,048	49,842,143	487,680	2,724,122	29,673,721	15,662,293	814,423	29,159	145,507
9	Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
10	Special Contract Revenue	47,294,984	21,131,238	127,061	912,170	13,281,362	11,061,526	535,090	76,509	170,028
11	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
12	Sale for Resale and Transmission Revenue	23,370,420	10,667,078	64,873	459,181	6,550,173	5,261,659	245,488	36,796	85,171
13	**Total Margin at Current Rates**	**$ 463,730,348**	**$ 224,268,083**	**$ 1,268,276**	**$ 10,507,207**	**$ 132,744,161**	**$ 87,398,250**	**$ 3,880,638**	**$ 1,346,017**	**$ 2,317,715**
14	Fuel Cost Revenue	207,300,587	75,970,833	391,108	3,344,186	59,219,378	63,597,486	3,765,866	391,039	620,692
15	Fuel Cost Revenue_Special Contract	52,891,914	19,383,654	99,790	853,256	15,109,587	16,226,644	960,846	99,772	158,367
15	**Total Revenue at Current Rates**	**$ 723,922,849**	**$ 319,622,569**	**$ 1,759,173**	**$ 14,704,649**	**$ 207,073,126**	**$ 167,222,380**	**$ 8,607,350**	**$ 1,836,828**	**$ 3,096,774**
16	**Expenses at Current Rates**									
17	Fuel Cost	$ 260,192,502	$ 95,354,486	$ 490,897	$ 4,197,442	$ 74,328,965	$ 79,824,130	$ 4,726,711	$ 490,811	$ 779,059
18	Variable Production Cost	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
19	O&M and A&G Expenses	129,424,237	69,018,775	585,070	3,147,651	33,501,407	21,928,446	883,572	27,335	331,981
20	Depreciation and Amortization Expense	171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259
21	Taxes Other Than Income	12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
22	Deferred Taxes	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
23	Current Income Tax	11,324,453	4,926,195	6,721	272,806	3,649,891	2,169,906	121,948	82,678	94,310
24	**Total Expenses at Current Rates**	**$ 606,689,307**	**$ 268,625,380**	**$ 1,689,599**	**$ 11,880,498**	**$ 169,288,554**	**$ 144,758,980**	**$ 7,344,917**	**$ 980,926**	**$ 2,120,452**
25	**Operating Income at Current Rates**	**$ 117,233,543**	**$ 50,997,189**	**$ 69,574**	**$ 2,824,151**	**$ 37,784,572**	**$ 22,463,400**	**$ 1,262,433**	**$ 855,901**	**$ 976,322**
26	Current Rate of Return	4.23%	3.78%	0.97%	5.14%	4.77%	4.23%	6.87%	17.46%	8.30%
27	Relative Rate of Return	1.00	0.89	0.23	1.21	1.13	1.00	1.62	4.12	1.96
28	Current Revenue to Cost Ratio	0.90	0.87	0.79	0.93	0.92	0.92	1.02	1.45	1.06
29	Current Parity Ratio	1.00	0.97	0.88	1.03	1.02	1.03	1.13	1.61	1.17
30	**Current Revenue at Equal Rates of Return**									
31	Current Rate of Return	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%
32	Current Operating Income at Equal ROR	$ 117,233,543	$ 57,086,639	$ 302,964	$ 2,324,954	$ 33,544,354	$ 22,491,768	$ 777,251	$ 207,497	$ 498,115
33	Current Income Taxes - Equal ROR	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
34	Expenses before Income Tax - Equal ROR	595,364,854	263,110,960	1,660,333	11,655,913	166,048,257	142,586,334	7,269,837	960,883	2,072,336
35	**Revenue at Equal Rates of Return**	**$ 723,922,849**	**$ 325,712,019**	**$ 1,992,563**	**$ 14,205,452**	**$ 202,832,908**	**$ 167,250,748**	**$ 8,122,168**	**$ 1,188,423**	**$ 2,618,568**

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 1 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
36	**Revenue Requirement at Equal Rates of Return**									
37	Required Return	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
38	Required Operating Income	$ 187,518,958	$ 91,311,982	$ 484,601	$ 3,718,842	$ 53,655,311	$ 35,976,333	$ 1,243,239	$ 331,898	$ 796,752
39	**Expenses at Required Return**									
40	Fuel Cost	$ 246,229,310	$ 90,237,302	$ 464,553	$ 3,972,187	$ 70,340,112	$ 75,540,380	$ 4,473,053	$ 464,471	$ 737,251
41	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
42	O&M and A&G Expenses	139,203,623	72,577,728	603,790	3,305,972	36,298,202	24,946,614	1,061,394	46,894	363,028
43	Depreciation and Amortization Expense	171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259
44	Taxes Other Than Income	12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
45	Deferred Taxes	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
46	Current Income Tax	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
47	Gross-up Income Tax	23,267,560	11,330,092	60,130	461,438	6,657,611	4,463,983	154,263	41,182	98,862
48	Gross-up Other Expenses	419,833	204,437	1,085	8,326	120,128	80,547	2,783	743	1,784
49	**Total Expenses at Required Return**	$ 616,413,508	$ 275,630,950	$ 1,747,014	$ 12,076,786	$ 171,667,846	$ 145,022,500	$ 7,201,438	$ 933,878	$ 2,133,096
50	Under Equal Rates of Return									
51	**Total Revenue Requirement at Equal Rates of Re**	$ 803,932,466	$ 366,942,931	$ 2,231,616	$ 15,795,627	$ 225,323,157	$ 180,998,832	$ 8,444,677	$ 1,265,777	$ 2,929,848
52	**Total Revenue (Deficiency)/Surplus**	$ (80,009,617)	$ (47,320,362)	$ (472,442)	$ (1,090,978)	$ (18,250,031)	$ (13,776,453)	$ 162,673	$ 571,051	$ 166,926
53	**Percent Change at Equal Rates of Return**	11.05%	14.81%	26.86%	7.42%	8.81%	8.24%	-1.89%	-31.09%	-5.39%
54	LESS:									
55	Fuel Cost Revenue	260,192,502	95,354,486	490,897	4,197,442	74,328,965	79,824,130	4,726,711	490,811	779,059
56	Decrease in Fuel Cost Revenue	(13,963,192)	(5,117,184)	(26,344)	(225,255)	(3,988,853)	(4,283,750)	(253,658)	(26,339)	(41,808)
57	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
58	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
59	Special Contract Revenue	38,066,775	17,375,009	105,669	747,934	10,669,212	8,570,424	399,861	59,935	138,730
60	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
61	Sale for Resale and Transmission Revenue	30,482,048	13,913,074	84,614	598,910	8,543,393	6,862,784	320,190	47,993	111,089
62	**Total Base Rate Margin Requirement at Equal Ra**	$ 472,576,476	$ 238,488,452	$ 1,537,399	$ 10,176,410	$ 131,153,232	$ 85,661,879	$ 3,011,962	$ 661,531	$ 1,885,610

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 1 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
63	Under Proposed Revenues									
64	**Total Proposed Revenue Increase/(Decrease)**	$ 80,009,617	$ 46,840,706	$ 291,642	$ 1,070,331	$ 17,955,496	$ 13,539,857	$ 311,586	$ -	$ -
65	**Total Proposed Revenue**	$ 803,932,466	$ 366,463,275	$ 2,050,815	$ 15,774,980	$ 225,028,622	$ 180,762,236	$ 8,918,936	$ 1,836,828	$ 3,096,774
66	LESS:									
67	Fuel Cost Revenue	246,229,310	90,237,302	464,553	3,972,187	70,340,112	75,540,380	4,473,053	464,471	737,251
68	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
69	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
70	Special Contract Revenue	38,066,775	17,375,009	105,669	747,934	10,669,212	8,570,424	399,861	59,935	138,730
71	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
72	Sale for Resale and Transmission Revenue	30,482,048	13,913,074	84,614	598,910	8,543,393	6,862,784	320,190	47,993	111,089
73	**Total Base Rate Margin as Proposed**	**472,576,476**	**238,008,796**	**1,356,598**	**10,155,762**	**130,858,697**	**85,425,283**	**3,486,220**	**1,232,583**	**2,052,536**
74	Percent Margin Change	17.25%	20.89%	23.00%	10.19%	13.53%	15.49%	8.03%	0.00%	0.00%
75	**Operating Income at Proposed Rates**									
76	Gross-up Other Expenses	419,833	245,786	1,530	5,616	94,218	71,047	1,635	-	-
77	Operating Income Prior to Taxes	$ 222,110,971	$ 107,635,488	$ 392,751	$ 4,386,926	$ 63,284,593	$ 42,385,865	$ 1,947,990	$ 964,918	$ 1,112,440
78	Income Taxes	34,592,013	16,763,369	61,168	683,229	9,856,071	6,601,261	303,384	150,278	173,254
79	**Total Operating Income at Proposed Rates**	$ 187,518,958	$ 90,872,118	$ 331,583	$ 3,703,698	$ 53,428,522	$ 35,784,604	$ 1,644,606	$ 814,640	$ 939,186
80	Proposed Rate of Return	6.77%	6.74%	4.63%	6.74%	6.74%	6.73%	8.96%	16.62%	7.98%
81	Relative Rate of Return	1.00	1.00	0.68	1.00	1.00	0.99	1.32	2.45	1.18
82	Proposed Revenue to Cost Ratio	1.00	1.00	0.92	1.00	1.00	1.00	1.06	1.45	1.06
83	Proposed Parity Ratio	1.00	1.00	0.92	1.00	1.00	1.00	1.06	1.45	1.06
84	Class (Subsidies)/Excesses at Current Rates (at equal 4.23% ROR)	$ -	$ (6,089,450)	$ (233,390)	$ 499,197	$ 4,240,218	$ (28,368)	$ 485,181	$ 648,404	$ 478,207
85	Class (Subsidies)/Excesses at Proposed Rates	$ -	$ (479,656)	$ (180,800)	$ (20,648)	$ (294,535)	$ (236,596)	$ 474,259	$ 571,051	$ 166,926
86	Dollar Value of Change in Subsidies	$ -	$ 5,609,794	$ 52,589	$ (519,845)	$ (4,534,754)	$ (208,228)	$ (10,922)	$ (77,353)	$ (311,281)
87	Percent Change in Subsidies		-92%	-23%	-104%	-107%	734%	-2%	-12%	-65%

Cause No. 45990
CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Functional Rate Base**									
2	**Production**									
3	Demand	$ 1,323,048,488	$ 602,181,695	$ 2,035,043	$ 22,336,433	$ 396,173,274	$ 286,853,492	$ 13,468,551	$ -	$ -
4	Energy	$ 8,990,701	$ 3,223,242	$ 16,954	$ 143,387	$ 2,541,688	$ 2,845,268	$ 174,329	$ 17,715	$ 28,118
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 1,332,039,189	$ 605,404,937	$ 2,051,998	$ 22,479,821	$ 398,714,962	$ 289,698,760	$ 13,642,879	$ 17,715	$ 28,118
7	**Transmission**									
8	Demand	$ 446,145,668	$ 203,061,911	$ 686,238	$ 7,532,077	$ 133,593,736	$ 96,729,972	$ 4,541,735	$ -	$ -
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 446,145,668	$ 203,061,911	$ 686,238	$ 7,532,077	$ 133,593,736	$ 96,729,972	$ 4,541,735	$ -	$ -
12	**Substation**									
13	Demand	$ 222,157,224	$ 109,738,272	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,948	$ 24,187	$ 460,625	$ 731,145
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 222,157,224	$ 109,738,272	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,948	$ 24,187	$ 460,625	$ 731,145
17	**Dist Primary**									
18	Demand	$ 481,469,100	$ 237,449,082	$ 1,014,422	$ 8,432,560	$ 136,073,813	$ 95,798,250	$ 149,412	$ 986,190	$ 1,565,371
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 481,469,100	$ 237,449,082	$ 1,014,422	$ 8,432,560	$ 136,073,813	$ 95,798,250	$ 149,412	$ 986,190	$ 1,565,371
22	**Dist Secondary**									
23	Demand	$ 122,983,800	$ 75,355,932	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 122,983,800	$ 75,355,932	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
27	**Transformation**									
28	Demand	$ 22,803,498	$ 11,273,912	$ 48,155	$ 399,571	$ 6,444,244	$ 4,514,485	$ -	$ 47,591	$ 75,540
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 29,066,466	$ 24,891,405	$ 599,934	$ 1,850,775	$ 1,724,352	$ -	$ -	$ -	$ -
31	Subtotal	$ 51,869,964	$ 36,165,316	$ 648,089	$ 2,250,346	$ 8,168,597	$ 4,514,485	$ -	$ 47,591	$ 75,540

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Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
32	**Onsite & Metering**									
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 89,519,390	$ 72,011,953	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
36	Subtotal	$ 89,519,390	$ 72,011,953	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
37	**Lighting Plant**									
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
41	Subtotal	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
42	**Customer Accounts & Service**									
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Customer	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
46	Subtotal	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
47	**Total**									
48	Demand	$ 2,618,607,778	$ 1,239,060,803	$ 4,574,492	$ 45,263,492	$ 778,880,477	$ 527,955,146	$ 18,183,885	$ 1,812,507	$ 2,876,976
49	Energy	$ 8,990,701	$ 3,223,242	$ 16,954	$ 143,387	$ 2,541,688	$ 2,845,268	$ 174,329	$ 17,715	$ 28,118
50	Customer	$ 142,253,186	$ 106,489,689	$ 2,566,619	$ 9,524,312	$ 11,123,054	$ 607,749	$ 5,733	$ 3,072,263	$ 8,863,767
51	**TOTAL RATE BASE**	$ 2,769,851,666	$ 1,348,773,734	$ 7,158,066	$ 54,931,192	$ 792,545,219	$ 531,408,163	$ 18,363,947	$ 4,902,484	$ 11,768,861

52 **Functional Revenue Requirement**

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
53	**Production**									
54	Demand	$ 273,209,008	$ 124,350,290	$ 420,236	$ 4,612,465	$ 81,809,630	$ 59,235,137	$ 2,781,251	$ -	$ -
55	Energy	$ 723,660	$ 259,438	$ 1,365	$ 11,541	$ 204,580	$ 229,015	$ 14,032	$ 1,426	$ 2,263
56	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	Subtotal	$ 273,932,668	$ 124,609,728	$ 421,600	$ 4,624,006	$ 82,014,210	$ 59,464,152	$ 2,795,282	$ 1,426	$ 2,263
58	**Transmission**									
59	Demand	$ 85,499,091	$ 38,914,664	$ 131,510	$ 1,443,443	$ 25,601,824	$ 18,537,274	$ 870,375	$ -	$ -
60	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Subtotal	$ 85,499,091	$ 38,914,664	$ 131,510	$ 1,443,443	$ 25,601,824	$ 18,537,274	$ 870,375	$ -	$ -
63	**Substation**									
64	Demand	$ 25,791,481	$ 12,677,309	$ 54,174	$ 451,435	$ 7,290,050	$ 5,166,502	$ 18,817	$ 51,480	$ 81,714
65	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Subtotal	$ 25,791,481	$ 12,677,309	$ 54,174	$ 451,435	$ 7,290,050	$ 5,166,502	$ 18,817	$ 51,480	$ 81,714

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Line	Description	TOTAL	Residential (R5)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
68	**Dist Primary**									
69	Demand	$ 92,126,969	$ 45,040,419	$ 192,551	$ 1,610,907	$ 26,044,620	$ 18,653,579	$ 129,094	$ 176,169	$ 279,631
70	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Subtotal	$ 92,126,969	$ 45,040,419	$ 192,551	$ 1,610,907	$ 26,044,620	$ 18,653,579	$ 129,094	$ 176,169	$ 279,631
73	**Dist Secondary**									
74	Demand	$ 19,676,111	$ 12,056,155	$ 51,496	$ 427,295	$ 7,009,491	$ -	$ -	$ 50,893	$ 80,782
75	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	Subtotal	$ 19,676,111	$ 12,056,155	$ 51,496	$ 427,295	$ 7,009,491	$ -	$ -	$ 50,893	$ 80,782
78	**Transformation**									
79	Demand	$ 3,052,724	$ 1,509,248	$ 6,447	$ 53,491	$ 862,696	$ 604,358	$ -	$ 6,371	$ 10,113
80	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ 3,891,153	$ 3,332,234	$ 80,314	$ 247,765	$ 230,840	$ -	$ -	$ -	$ -
82	Subtotal	$ 6,943,876	$ 4,841,482	$ 86,760	$ 301,256	$ 1,093,537	$ 604,358	$ -	$ 6,371	$ 10,113
83	**Onsite & Metering**									
84	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 35,321,723	$ 28,891,585	$ 696,346	$ 2,471,403	$ 3,232,265	$ 29,842	$ 282	$ -	$ -
87	Subtotal	$ 35,321,723	$ 28,891,585	$ 696,346	$ 2,471,403	$ 3,232,265	$ 29,842	$ 282	$ -	$ -
88	**Lighting Plant**									
89	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Customer	$ 2,209,879	$ -	$ -	$ -	$ -	$ -	$ -	$ 498,522	$ 1,711,357
92	Subtotal	$ 2,209,879	$ -	$ -	$ -	$ -	$ -	$ -	$ 498,522	$ 1,711,357
93	**Customer Accounts & Service**									
94	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Customer	$ 7,925,936	$ 6,682,183	$ 116,886	$ 360,591	$ 338,231	$ 423,416	$ 3,994	$ -	$ 635
97	Subtotal	$ 7,925,936	$ 6,682,183	$ 116,886	$ 360,591	$ 338,231	$ 423,416	$ 3,994	$ -	$ 635
98	**Total**									
99	Demand	$ 499,355,383	$ 234,548,085	$ 856,413	$ 8,599,035	$ 148,618,311	$ 102,196,850	$ 3,799,537	$ 284,913	$ 452,240
100	Energy	$ 723,660	$ 259,438	$ 1,365	$ 11,541	$ 204,580	$ 229,015	$ 14,032	$ 1,426	$ 2,263
101	Customer	$ 49,348,691	$ 38,906,001	$ 893,546	$ 3,079,759	$ 3,801,336	$ 453,258	$ 4,276	$ 498,522	$ 1,711,993
	TOTAL REVENUE REQUIREMENT AT EQUAL	$ 549,427,734	$ 273,713,524	$ 1,751,324	$ 11,690,335	$ 152,624,228	$ 102,879,123	$ 3,817,844	$ 784,861	$ 2,166,495
102	**RATES OF RETURN**									
103	Demand	90.89%	85.69%	48.90%	73.56%	97.38%	99.34%	99.52%	36.30%	20.87%
104	Energy	0.13%	0.09%	0.08%	0.10%	0.13%	0.22%	0.37%	0.18%	0.10%
105	Customer	8.98%	14.21%	51.02%	26.34%	2.49%	0.44%	0.11%	63.52%	79.02%

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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
106	**Unit Costs**									
107	**Production**									
108	Demand	$ -	$ -	$ -	$ -	$ 25.09	$ 21.92	$ 28.58	$ -	$ -
109	Energy	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
110	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	**Transmission**									
112	Demand	$ -	$ -	$ -	$ -	$ 7.85	$ 6.86	$ 8.94	$ -	$ -
113	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	**Substation**									
116	Demand	$ -	$ -	$ -	$ -	$ 2.24	$ 1.91	$ 0.19	$ -	$ -
117	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	**Dist Primary**									
120	Demand	$ -	$ -	$ -	$ -	$ 7.99	$ 6.90	$ 1.33	$ -	$ -
121	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	**Dist Secondary**									
124	Demand	$ -	$ -	$ -	$ -	$ 2.15	$ -	$ -	$ -	$ -
125	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
127	**Transformation**									
128	Demand	$ -	$ -	$ -	$ -	$ 0.26	$ 0.22	$ -	$ -	$ -
129	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	Customer	$ 2.08	$ 2.08	$ 2.08	$ 2.08	$ 2.06	$ -	$ -	$ -	$ -
131	**Onsite & Metering**									
132	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
133	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
134	Customer	$ 18.85	$ 18.02	$ 18.02	$ 20.74	$ 28.91	$ 23.46	$ 23.46	$ -	$ -
135	**Lighting Plant**									
136	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	Customer	$ 1.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,505.95
139	**Total**									
140	Energy	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002
141	Customer (per cust month)	$ 26.33	$ 24.27	$ 23.13	$ 25.84	$ 34.00	$ 356.33	$ 356.33	$ -	$ 7,508.74
142	Onsite and Customer Services	$ 3.26	$ 20.10	$ 20.10	$ 22.81	$ 30.98	$ 23.46	$ 23.46	$ -	$ -
143	Demand & Customer (per cust month)	$ 292.79	$ 170.60	$ 45.30	$ 97.99	$ 1,363.40	$ 80,699.77	$ 316,984.39	$ -	$ 9,492.25
144	Demand		$ -	$ -	$ -	$ 45.58	$ 37.81	$ 39.04	$ -	$ -
145	**BILLING DETERMINANTS**									
146	Demand		0	0	0	3,260,842	2,702,812	97,323	0	0
147	Energy	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
148	Customers (Number of Bills)	1,874,048	1,602,925	38,634	119,184	111,793	1,272	12	0	228

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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**RATE BASE**										
2	**Plant in Service**										
3	**Intangible Plant**										
4	Organization	301	12,151	6,459	65	323	3,064	2,101	93	2	44
5	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
6	Miscellaneous Intangible Plant	303	198,547,734	105,538,977	1,069,960	5,273,049	50,062,369	34,326,702	1,527,001	32,757	716,918
7	Subtotal - Intangible Plant		198,559,885	105,545,436	1,070,025	5,273,372	50,065,433	34,328,803	1,527,095	32,759	716,962
8	**Steam Production Plant**										
9	Land and Land Rights	310	1,976,433	899,568	3,040	33,367	591,823	428,516	20,120	-	-
10	Structures and Improvements	311	96,772,607	44,045,772	148,851	1,633,768	28,977,563	20,981,514	985,139	-	-
11	Boiler Plant Equipment	312	$69,693,573	259,294,383	876,273	9,617,881	170,588,886	123,516,706	5,799,445	-	-
12	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
13	Turbogenerator Units	314	48,177,832	21,928,001	74,105	813,365	14,426,357	10,445,558	490,447	-	-
14	Accessory Electric Equipment	315	33,226,393	15,122,897	51,107	560,946	9,949,302	7,203,898	338,243	-	-
15	Miscellaneous Power Plant Equipment	316	24,639,884	11,214,772	37,900	415,984	7,378,160	5,342,236	250,832	-	-
16	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
17	Subtotal - Steam Production Plant		774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	-	-
18	**Other Production Plant**										
19	Land and Land Rights	340	389,504	177,282	599	6,576	116,633	84,449	3,965	-	-
20	Structures and Improvements	341	2,271,907	1,034,052	3,495	38,356	680,299	492,578	23,128	-	-
21	Fuel Holders, Producers and Accessories	342	4,101,467	1,866,771	6,309	69,243	1,228,142	889,249	41,753	-	-
22	Prime Movers	343	48,262,971	21,966,752	74,236	814,802	14,451,851	10,464,017	491,314	-	-
23	Generators	344	17,496,247	7,963,366	26,912	295,381	5,239,071	3,793,406	178,111	-	-
24	Accessory Electric Equipment	345	5,263,501	2,395,667	8,096	88,861	1,576,101	1,141,193	53,582	-	-
25	Miscellaneous Power Plant Equipment	346	777,314,426	353,792,414	1,195,624	13,123,050	232,758,817	168,531,508	7,913,012	-	-
26	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
27	Subtotal - Other Production Plant		855,100,022	389,196,303	1,315,270	14,436,270	256,050,915	185,396,401	8,704,865	-	-
28	**Transmission Plant**										
29	Land and Land Rights	350	19,334,962	8,800,252	29,740	326,423	5,789,656	4,192,062	196,829	-	-
30	Structures and Improvements	352	6,442,051	2,932,081	9,909	108,758	1,929,006	1,396,717	65,580	-	-
31	Station Equipment	353	196,875,807	89,607,455	302,824	3,323,766	58,952,437	42,685,142	2,004,183	-	-
32	Towers and Fixtures	354	4,622,707	2,104,012	7,110	78,043	1,384,222	1,002,261	47,059	-	-
33	Poles and Fixtures	355	237,797,966	108,233,057	365,768	4,014,636	71,206,157	51,557,579	2,420,768	-	-
34	Overhead Conductors and Devices	356	106,793,870	48,606,921	164,265	1,802,953	31,978,327	23,154,249	1,087,155	-	-
35	Underground Conduit	357	1,180,974	537,517	1,817	19,938	353,630	256,050	12,022	-	-
36	Underground Conductors and Devices	358	1,356,646	617,473	2,087	22,904	406,234	294,138	13,811	-	-
37	Road and Trails	359	-	-	-	-	-	-	-	-	-
38	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
39	Subtotal - Transmission Plant		574,404,982	261,438,767	883,519	9,697,421	171,999,669	124,538,198	5,847,407	-	-

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40	**Distribution Plant**										
41	Land and land rights	360	3,081,457	1,554,237	6,639	55,085	889,974	558,546	-	6,561	10,414
42	Structures and improvements	361	1,539,531	780,794	3,335	27,673	447,304	271,897	-	3,296	5,232
43	Station equipment	362	259,931,734	128,508,679	548,906	4,554,612	73,456,434	51,459,558	-	542,476	861,068
44	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
45	Poles, Towers and Fixtures - PRI DEM	364	250,802,380	123,995,182	529,627	4,394,644	70,876,489	49,652,190	-	523,423	830,825
46	Poles, Towers and Fixtures - PRI CUST	364	-	-	-	-	-	-	-	-	-
47	Poles, Towers and Fixtures - SEC DEM	364	47,052,112	28,830,267	123,144	1,021,804	16,762,020	-	-	121,702	193,176
48	Poles, Towers and Fixtures - SEC CUST	364	-	-	-	-	-	-	-	-	-
49	Overhead Conductors and Devices - PRI DEM	365	265,280,976	131,153,312	560,202	4,648,343	74,968,125	52,518,566	-	553,640	878,788
50	Overhead Conductors and Devices - PRI CUST	365	-	-	-	-	-	-	-	-	-
51	Overhead Conductors and Devices - SEC DEM	365	46,814,290	28,684,546	122,522	1,016,639	16,677,297	-	-	121,087	192,200
52	Overhead Conductors and Devices - SEC CUST	365	-	-	-	-	-	-	-	-	-
53	Underground conduit	366	47,676,074	25,658,238	109,595	909,381	14,772,313	5,946,313	-	108,312	171,922
54	Underground Conductors and Devices - PRI DEM	367	104,053,705	51,443,523	219,733	1,823,264	29,405,467	20,599,861	-	217,160	344,695
55	Underground Conductors and Devices - PRI CUST	367	-	-	-	-	-	-	-	-	-
56	Underground Conductors and Devices - SEC DEM	367	61,110,906	37,444,519	159,939	1,327,111	21,770,376	-	-	158,065	250,896
57	Underground Conductors and Devices - SEC CUST	367	-	-	-	-	-	-	-	-	-
58	Transformers and Transformer Installations - DEM	368	45,332,193	22,411,962	95,729	794,326	12,810,830	8,974,567	-	94,608	150,171
59	Transformers and Transformer Installations - CUST	368	57,782,655	49,482,846	1,192,638	3,679,247	3,427,924	-	-	-	-
60	Services	369	103,266,723	78,847,006	1,900,374	10,461,700	11,948,298	108,324	1,022	-	-
61	Meters	370	26,328,799	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
62	Installations on customers premises	371	5,941,020	-	-	-	-	-	-	5,941,020	-
63	Street lighting and signal systems	373	20,653,277	-	-	-	-	-	-	-	20,653,277
64	Subtotal - Distribution Plant		1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
65	**General Plant**										
66	Land and Land Rights	389	2,309,376	1,227,560	12,445	61,333	582,292	399,266	17,761	381	8,339
67	Structures and Improvements	390	56,222,863	29,885,526	302,981	1,493,172	14,176,186	9,720,310	432,402	9,276	203,010
68	Office Furniture and Equipment	391	23,986,173	12,749,962	129,260	637,027	6,047,939	4,146,943	184,474	3,957	86,610
69	Transportation Equipment	392	25,161,795	13,374,870	135,595	668,249	6,344,364	4,350,195	193,516	4,151	90,854
70	Stores Equipment	393	688,773	366,120	3,712	18,292	173,669	119,081	5,297	114	2,487
71	Tools, Shop and Garage Equipment	394	9,246,944	4,915,256	49,831	245,581	2,331,550	1,598,694	71,117	1,526	33,389
72	Laboratory Equipment	395	1,859,238	988,287	10,019	49,378	468,793	321,442	14,299	307	6,713
73	Power Operated Equipment	396	5,812,993	3,089,924	31,326	154,382	1,465,704	1,005,002	44,707	959	20,990
74	Communication Equipment	397	22,869,808	12,156,553	123,244	607,378	5,766,456	3,953,936	175,888	3,773	82,579
75	Miscellaneous Equipment	398	2,761,879	1,468,090	14,884	73,350	696,388	477,498	21,241	456	9,973
76	Miscellaneous Equipment-DLC	398	3,078,597	1,401,214	4,735	51,975	921,854	667,478	31,340	-	-
77	Subtotal - General Plant		153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
78	**Total Plant in Service**		3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568

CenterPoint Energy Indiana
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Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
79	**Accumulated Depreciation & Amortization**										
80	**Intangible Plant**										
81	Organization	301	-	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
82	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303	(120,558,306)	(64,083,332)	(649,680)	(3,201,799)	(30,397,901)	(20,843,195)	(927,196)	(19,890)	(435,313)
84	Subtotal - Intangible Plant		(120,558,306)	(64,083,332)	(649,680)	(3,201,799)	(30,397,901)	(20,843,195)	(927,196)	(19,890)	(435,313)
				-	-	-	-	-	-	-	-
85	Steam Production Plant			-	-	-	-	-	-	-	-
86	Land and Land Rights	310	142,880	65,032	220	2,412	42,784	30,978	1,455	-	-
87	Structures and Improvements	311	(46,698,062)	(21,254,488)	(71,828)	(788,382)	(13,983,255)	(10,124,725)	(475,383)	-	-
88	Boiler Plant Equipment	312	(264,424,780)	(120,352,174)	(406,724)	(4,464,165)	(79,179,283)	(57,330,606)	(2,691,828)	-	-
89	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
90	Turbogenerator Units	314	(36,101,462)	(16,431,476)	(55,529)	(609,485)	(10,810,212)	(7,827,249)	(367,511)	-	-
91	Accessory Electric Equipment	315	(3,420,234)	(1,556,710)	(5,261)	(57,742)	(1,024,154)	(741,550)	(34,818)	-	-
92	Miscellaneous Power Plant Equipment	316	(8,721,704)	(3,969,659)	(13,415)	(147,245)	(2,611,625)	(1,890,975)	(88,786)	-	-
93	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
94	Subtotal - Steam Production Plant		(359,223,363)	(163,499,475)	(552,538)	(6,064,607)	(107,565,745)	(77,884,127)	(3,656,871)	-	-
				-	-	-	-	-	-	-	-
95	Other Production Plant			-	-	-	-	-	-	-	-
96	Land and Land Rights	340	38,004	17,297	58	642	11,380	8,240	387	-	-
97	Structures and Improvements	341	(2,231,173)	(1,015,512)	(3,432)	(37,668)	(668,102)	(483,746)	(22,713)	-	-
98	Fuel Holders, Producers and Accessories	342	(4,631,843)	(2,108,170)	(7,124)	(78,197)	(1,386,958)	(1,004,242)	(47,152)	-	-
99	Prime Movers	343	(42,171,802)	(19,194,374)	(64,866)	(711,968)	(12,627,913)	(9,143,375)	(429,306)	-	-
100	Generators	344	(13,256,606)	(6,033,706)	(20,391)	(223,805)	(3,969,554)	(2,874,198)	(134,951)	-	-
101	Accessory Electric Equipment	345	(4,116,286)	(1,873,516)	(6,331)	(69,493)	(1,232,580)	(892,462)	(41,904)	-	-
102	Miscellaneous Power Plant Equipment	346	(16,512,384)	(7,515,564)	(25,398)	(278,771)	(4,944,464)	(3,580,092)	(168,095)	-	-
103	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
104	Subtotal - Other Production Plant		(82,882,091)	(37,723,544)	(127,485)	(1,399,261)	(24,818,190)	(17,969,876)	(843,734)	-	-
				-	-	-	-	-	-	-	-
105	Transmission Plant			-	-	-	-	-	-	-	-
106	Land and Land Rights	350	(4,213,024)	(1,917,546)	(6,480)	(71,127)	(1,261,547)	(913,436)	(42,888)	-	-
107	Structures and Improvements	352	(2,543,412)	(1,157,626)	(3,912)	(42,939)	(761,598)	(551,443)	(25,892)	-	-
108	Station Equipment	353	(55,183,260)	(25,116,501)	(84,880)	(931,634)	(16,524,060)	(11,964,422)	(561,762)	-	-
109	Towers and Fixtures	354	(5,214,294)	(2,373,271)	(8,020)	(88,031)	(1,561,367)	(1,130,524)	(53,081)	-	-
110	Poles and Fixtures	355	(55,473,356)	(25,248,538)	(85,326)	(936,532)	(16,610,926)	(12,027,319)	(564,715)	-	-
111	Overhead Conductors and Devices	356	(27,944,809)	(12,718,999)	(42,983)	(471,780)	(8,367,786)	(6,058,785)	(284,476)	-	-
112	Underground Conduit	357	(968,589)	(440,850)	(1,490)	(16,352)	(290,034)	(210,002)	(9,860)	-	-
113	Underground Conductors and Devices	358	(1,294,260)	(589,079)	(1,991)	(21,850)	(387,553)	(280,612)	(13,175)	-	-
114	Road and Trails	359	-	-	-	-	-	-	-	-	-
115	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
116	Subtotal - Transmission Plant		(152,835,002)	(69,562,409)	(235,083)	(2,580,245)	(45,764,871)	(33,136,544)	(1,555,851)	-	-

CenterPoint Energy Indiana
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				-	-	-	-	-	-	-	-
117	Distribution Plant			-	-	-	-	-	-	-	-
118	Land and land rights	360	(20,815)	(10,499)	(45)	(372)	(6,012)	(3,773)	-	(44)	(70)
119	Structures and improvements	361	(897,293)	(455,074)	(1,944)	(16,129)	(260,705)	(158,471)	-	(1,921)	(3,049)
120	Station equipment	362	(44,601,013)	(22,050,471)	(94,185)	(781,514)	(12,604,199)	(8,829,812)	-	(93,082)	(147,748)
121	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364	(90,761,034)	(46,568,362)	(198,910)	(1,650,478)	(26,704,857)	(15,129,817)	-	(196,580)	(312,030)
123	Overhead Conductors and Devices	365	(91,322,510)	(46,770,316)	(199,773)	(1,657,636)	(26,816,459)	(15,367,510)	-	(197,432)	(313,383)
124	Underground conduit	366	(18,345,845)	(9,873,340)	(42,173)	(349,931)	(5,684,415)	(2,288,153)	-	(41,679)	(66,156)
125	Underground Conductors and Devices	367	(51,477,871)	(27,704,283)	(118,335)	(981,897)	(15,950,290)	(6,420,486)	-	(116,949)	(185,632)
126	Transformers and Transformer Installations	368	(52,561,797)	(36,647,684)	(656,733)	(2,280,361)	(8,277,548)	(4,574,699)	-	(48,226)	(76,548)
127	Services	369	(71,529,816)	(54,614,998)	(1,316,333)	(7,246,511)	(8,276,234)	(75,033)	(708)	-	-
128	Meters	370	(2,976,324)	(2,465,507)	(59,424)	(190,394)	(258,578)	(2,398)	(23)	-	-
129	Installations on customers premises	371	(2,944,632)	-	-	-	-	-	-	(2,944,632)	-
130	Street lighting and signal systems	373	(12,598,490)	-	-	-	-	-	-	-	(12,598,490)
131	Subtotal - Distribution Plant		(440,037,441)	(247,160,534)	(2,687,853)	(15,155,224)	(104,839,296)	(52,850,152)	(730)	(3,640,545)	(13,703,106)
				-	-	-	-	-	-	-	-
132	General Plant			-	-	-	-	-	-	-	-
133	Land and Land Rights	389	(22,147)	(11,772)	(119)	(588)	(5,584)	(3,829)	(170)	(4)	(80)
134	Structures and Improvements	390	(17,518,991)	(9,312,302)	(94,409)	(465,271)	(4,417,286)	(3,028,839)	(134,736)	(2,890)	(63,258)
135	Office Furniture and Equipment	391	(15,258,932)	(8,110,957)	(82,229)	(405,248)	(3,847,429)	(2,638,100)	(117,354)	(2,517)	(55,097)
136	Transportation Equipment	392	(16,726,737)	(8,891,175)	(90,139)	(444,230)	(4,217,525)	(2,891,867)	(128,643)	(2,760)	(60,397)
137	Stores Equipment	393	(574,962)	(305,624)	(3,098)	(15,270)	(144,972)	(99,404)	(4,422)	(95)	(2,076)
138	Tools, Shop and Garage Equipment	394	(2,180,271)	(1,158,933)	(11,749)	(57,904)	(549,739)	(376,945)	(16,768)	(360)	(7,873)
139	Laboratory Equipment	395	(1,935,880)	(1,029,026)	(10,432)	(51,413)	(488,118)	(334,692)	(14,889)	(319)	(6,990)
140	Power Operated Equipment	396	(2,361,451)	(1,255,240)	(12,726)	(62,716)	(595,423)	(408,269)	(18,162)	(390)	(8,527)
141	Communication Equipment	397	(9,472,725)	(5,035,271)	(51,048)	(251,578)	(2,388,479)	(1,637,729)	(72,853)	(1,563)	(34,204)
142	Miscellaneous Equipment	398	(480,682)	(255,509)	(2,590)	(12,766)	(121,200)	(83,105)	(3,697)	(79)	(1,736)
143	Miscellaneous Equipment-DLC	398	(5,512,812)	(2,509,141)	(8,480)	(93,070)	(1,650,755)	(1,195,247)	(56,120)	-	-
144	Subtotal - General Plant		(72,045,589)	(37,874,949)	(367,020)	(1,860,054)	(18,426,511)	(12,698,026)	(567,814)	(10,977)	(240,237)
				-	-	-	-	-	-	-	-
145	**Total Accumulated Depreciation & Amortization**		(1,227,581,792)	(619,904,244)	(4,619,659)	(30,261,189)	(331,812,514)	(215,381,920)	(7,552,197)	(3,671,412)	(14,378,656)
146	**Other Rate Base Items**										
147	Fuel Stock & Expense	151	8,990,701	3,223,242	16,954	143,387	2,541,688	2,845,268	174,329	17,715	28,118
148	Materials and Supplies (Generation Inventory)	154	41,360,961	18,825,322	63,619	698,279	12,385,115	8,967,575	421,052	-	-
149	Allowance Inventory	158	-	-	-	-	-	-	-	-	-
150	Stores Expense	163	311,332	153,218	907	6,616	87,700	58,152	2,007	674	2,058
151	PISCC - AMI	182.3	10,585,830	9,054,353	218,228	673,227	631,482	7,185	68	-	1,288
152	PISCC - ECA	182.3	5,575,984	2,537,893	8,577	94,137	1,669,671	1,208,943	56,763	-	-
153	PISCC - CECA	182.3	2,963,459	1,348,810	4,558	50,031	887,377	642,515	30,168	-	-
154	PISCC - TDSIC	182.3	21,951,124	11,484,563	84,869	543,999	5,903,691	3,466,528	49,491	106,499	311,485
155	PISCC - CT	182.3	2,496,186	1,136,132	3,840	42,142	747,457	541,204	25,411	-	-
156	Total Other Rate Base Items		94,235,578	47,763,533	401,553	2,251,817	24,854,181	17,737,370	759,288	124,888	342,949
157	**TOTAL RATE BASE**		2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861

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158	**OPERATION AND MAINTENANCE EXPENSE**										
159	**Generation Production, Transmission, and Distribution Expense**										
160	**Steam Power Generation Operation Expenses**										
161	Operation Supervision and Engineering	500	743,496	338,400	1,144	12,552	222,632	161,199	7,569	-	-
162	Fuel	501	246,229,310	90,237,302	464,553	3,972,187	70,340,112	75,540,380	4,473,053	464,471	737,251
163	Fuel (Operation Related Expenses)	501	2,240,456	1,019,737	3,446	37,825	670,882	485,759	22,808	-	-
164	Steam Expenses	502	1,969,108	896,234	3,029	33,244	589,629	426,927	20,045	-	-
165	Steam Expenses - VPC	502	7,310,722	2,643,303	13,904	117,588	2,083,840	2,278,647	135,853	14,527	23,059
166	Electric Expenses	505	1,348,774	613,890	2,075	22,771	403,876	292,431	13,730	-	-
167	Electric Expenses - VPC	505	165,000	59,658	314	2,654	47,031	51,428	3,066	328	520
168	Miscellaneous Steam Power Expenses	506	2,163,147	984,550	3,327	36,519	647,732	468,997	22,021	-	-
169	Miscellaneous Steam Power Expenses - VPC	506	299,500	108,289	570	4,817	85,369	93,350	5,566	595	945
170	Rents	507	-	-	-	-	-	-	-	-	-
171	Allowances	509	-	-	-	-	-	-	-	-	-
172	Subtotal - Steam Power Generation Operation Expenses		262,469,512	96,901,364	492,361	4,240,157	75,091,104	79,799,118	4,703,711	479,922	761,775
173	**Steam Power Generation Maintenance Expenses**										
174	Maintenance Supervision and Engineering	510	492,730	224,265	758	8,319	147,543	106,830	5,016	-	-
175	Maintenance of Structures	511	1,494,465	680,202	2,299	25,230	447,502	324,019	15,214	-	-
176	Maintenance of Boiler Plant	512	6,725,481	3,061,083	10,345	113,543	2,013,876	1,458,169	68,465	-	-
177	Maintenance of Boiler Plant-VPC	512	500,200	180,855	951	8,045	142,576	155,905	9,295	994	1,578
178	Maintenance of Electric Plant	513	3,512,286	1,598,607	5,402	59,296	1,051,718	761,508	35,755	-	-
179	Maintenance of Miscellaneous Steam Plant	514	1,506,822	685,825	2,318	25,439	451,202	326,698	15,339	-	-
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984	6,430,837	22,073	239,873	4,254,418	3,133,128	149,084	994	1,578
181	**Other Power Generation Operation Expenses**										
182	Operations Supervision and Engineering	546	20,563	9,359	32	347	6,157	4,458	209	-	-
183	Generation Expenses	548	5,608,351	2,552,625	8,626	94,683	1,679,363	1,215,961	57,093	-	-
184	Miscellaneous Other Power Generation Expenses	549	917,282	417,498	1,411	15,486	274,671	198,878	9,338	-	-
185	Subtotal - Other Power Generation Operation Expenses		6,546,196	2,979,482	10,069	110,516	1,960,191	1,419,297	66,640	-	-
186	**Other Power Generation Maintenance Expenses**										
187	Maintenance Supervision and Engineering	551	1	0	0	0	0	0	0	-	-
188	Maintenance of Structures	552	15,000	6,827	23	253	4,492	3,252	153	-	-
189	Maintenance of Generating and Electric Plant	553	8,602,756	3,915,519	13,232	145,236	2,576,007	1,865,185	87,576	-	-
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756	3,922,347	13,255	145,490	2,580,499	1,868,438	87,728	-	-
191	**Other Power Supply Expenses**										
192	System Control and Load Dispatching	556	670,659	305,248	1,032	11,322	200,822	145,407	6,827	-	-
193	All Other Expenses - Fixed	557	-	-	-	-	-	-	-	-	-
194	All Other Expenses - Variable	557	-	-	-	-	-	-	-	-	-
195	Subtotal - Other Power Supply Expenses		670,659	305,248	1,032	11,322	200,822	145,407	6,827	-	-

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196	**Transmission Operation Expenses**										
197	Operation Supervision and Engineering	560	419,171	190,784	645	7,077	125,516	90,881	4,267	-	-
198	Load Dispatching	561	19,910,336	9,062,132	30,625	336,137	5,961,946	4,316,810	202,686	-	-
199	Station Expenses	562	111,914	50,937	172	1,889	33,512	24,264	1,139	-	-
200	Overhead Line Expenses	563	(118)	(54)	(0)	(2)	(35)	(26)	(1)	-	-
201	Underground Line Expenses	564	-	-	-	-	-	-	-	-	-
202	Transmission of Electricity by Others	565	-	-	-	-	-	-	-	-	-
203	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-	-
204	Rents	567	-	-	-	-	-	-	-	-	-
205	Subtotal - Transmission Operation Expenses		20,441,303	9,303,800	31,442	345,101	6,120,938	4,431,931	208,091	-	-
206	**Transmission Maintenance Expenses**										
207	Maintenance Supervision and Engineering	568	388,095	176,640	597	6,552	116,211	84,144	3,951	-	-
208	Maintenance of Structures	569	2,371,329	1,079,304	3,647	40,034	710,070	514,134	24,140	-	-
209	Maintenance of Station Equipment	570	233,432	106,246	359	3,941	69,899	50,611	2,376	-	-
210	Maintenance of Overhead Lines	571	579,737	263,866	892	9,787	173,596	125,694	5,902	-	-
211	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-	-
212	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-	-
213	Subtotal - Transmission Maintenance Expenses		3,572,594	1,626,056	5,495	60,314	1,069,776	774,583	36,369	-	-
214	**Distribution Operation Expenses**										
215	Operation Supervision and Engineering	580	1,941,263	1,445,917	31,150	104,467	251,537	102,206	5,474	198	315
216	Load Dispatching	581	256,022	113,552	489	4,399	72,599	61,352	3,319	120	191
217	Station Expenses	582	64,922	28,795	124	1,116	18,410	15,558	842	31	48
218	Overhead Line Expenses	583	-	-	-	-	-	-	-	-	-
219	Underground Line Expenses	584	-	-	-	-	-	-	-	-	-
220	Street Lighting and Signal System Expenses	585	-	-	-	-	-	-	-	-	-
221	Meter Expenses	586	1,157,573	958,903	23,112	74,049	100,568	933	9	-	-
222	Customer Installations Expenses	587	-	-	-	-	-	-	-	-	-
223	Miscellaneous Distribution Expenses	588	7,696,359	5,732,504	123,499	414,170	997,246	405,206	21,703	786	1,247
224	Rents	589	-	-	-	-	-	-	-	-	-
225	Subtotal - Distribution Operation Expenses		11,116,139	8,279,669	178,374	598,200	1,440,359	585,254	31,346	1,135	1,801
226	**Distribution Maintenance Expenses**										
227	Maintenance Supervision and Engineering	590	203,910	100,991	432	3,632	58,962	36,297	466	376	2,755
228	Maintenance of Structures	591	1,112,625	493,475	2,126	19,119	315,503	266,624	14,423	523	831
229	Maintenance of Station Equipment	592	815,274	361,593	1,558	14,009	231,185	195,369	10,569	383	609
230	Maintenance of Overhead Lines	593	8,631,137	4,420,389	18,881	156,668	2,534,496	1,452,425	-	18,660	29,619
231	Maintenance of Underground Lines	594	267,725	144,084	615	5,107	82,954	33,392	-	608	965
232	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-
233	Maintenance of Street Lighting and Signal Systems	596	115,832	-	-	-	-	-	-	-	115,832
234	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-
235	Maintenance of Miscellaneous Distribution Plant	598	670,972	332,312	1,421	11,951	194,017	119,435	1,532	1,237	9,066
236	Subtotal - Distribution Maintenance Expenses		11,817,475	5,852,843	25,034	210,485	3,417,117	2,103,541	26,990	21,788	159,677
237	**Total Generation Production, Transmission, and Distribution Ex**		47,618,170	25,367,617	241,377	1,225,424	12,249,012	8,040,715	309,623	22,923	161,478

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238	**Customer Accounts, Service, and Sales Expense**										
239	**Customer Account**										
240	Supervision	901	-	-	-	-	-	-	-	-	-
241	Meter Reading Expenses	902	152,498	-	-	-	-	151,073	1,425	-	-
242	Customer Billing and Accounting	903	1,155,579	988,399	23,822	73,491	68,934	784	7	-	141
243	Uncollectible Accounts	904	2,279,803	2,215,142	9,222	28,448	26,684	304	3	-	-
244	Misc. Customer Accounts Expenses	905	70,218	60,060	1,448	4,466	4,189	48	0	-	9
245	Subtotal - Customer Account		3,658,099	3,263,601	34,492	106,405	99,807	152,209	1,436	-	149
				60,060	1,448	4,466	4,189	48	0	-	9
246	**Customer Service & Information Expenses**			3,263,601	34,492	106,405	99,807	152,209	1,436	-	149
247	Supervision	907	-	-	-	-	-	-	-	-	-
248	Customer Assistance	908	14,596	12,484	301	928	871	10	0	-	2
249	Informational and Instructional Advertising	909	-	-	-	-	-	-	-	-	-
250	Miscellaneous Customer Service and Informational	910	329	281	7	21	20	0	0	-	0
251	Subtotal - Customer Service & Information Expenses		14,925	12,766	308	949	890	10	0	-	2
				281	7	21	20	0	0	-	0
252	**Sales Expenses**			12,766	308	949	890	10	0	-	2
253	Supervision	911	1,139,859	974,953	23,498	72,492	67,997	774	7	-	139
254	Demonstrating and Selling Expenses	912	25,289	21,630	521	1,608	1,509	17	0	-	3
255	Advertising Expenses	913	-	-	-	-	-	-	-	-	-
256	Miscellaneous Sales Expenses	916	-	-	-	-	-	-	-	-	-
257	Subtotal - Sales Expenses		1,165,148	996,583	24,020	74,100	69,505	791	7	-	142
				-	-	-	-	-	-	-	-
258	**Total Customer Accounts, Service, and Sales Expense**		4,838,172	4,272,949	58,819	181,454	170,203	153,010	1,443	-	293
259	**Administrative and General Expenses**										
260	Administrative and General Salaries	920	20,391,648	10,839,276	109,889	541,563	5,141,606	3,525,490	156,829	3,364	73,630
261	Office Supplies and Expenses	921	2,742,248	1,457,655	14,778	72,829	691,438	474,104	21,090	452	9,902
262	Administrative Expenses Transferred - Company	922	-	-	-	-	-	-	-	-	-
263	Outside Services Employed	923	340,000	180,729	1,832	9,030	85,729	58,782	2,615	56	1,228
264	Property Insurance	924	2,276,531	1,120,369	6,635	48,375	641,283	425,218	14,673	4,928	15,050
265	Injuries and Damages	925	4,009,520	2,131,279	21,607	106,485	1,010,971	693,202	30,837	662	14,478
266	Employee Pensions and Benefits	926	8,123,484	4,318,076	43,777	215,744	2,048,278	1,404,460	62,477	1,340	29,332
267	Regulatory Commission Expenses	928	414,956	202,062	1,072	8,229	118,732	79,611	2,751	734	1,763
268	General Advertising Expenses	930.1	(835)	(406)	(2)	(17)	(239)	(160)	(6)	(1)	(4)
269	Miscellaneous General Expense	930.2	5,306,182	2,611,377	15,465	112,753	1,494,714	991,107	34,199	11,486	35,080
270	Rents	931	4,626,382	2,459,175	24,931	122,868	1,166,509	799,850	35,581	763	16,705
271	Maintenance of General Plant	935	1,156,447	612,948	6,143	30,489	292,683	200,952	8,952	187	4,092
272	Total Administrative and General Expenses		49,386,564	25,932,540	246,128	1,268,349	12,691,704	8,652,617	369,997	23,972	201,257
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		393,708,355	165,807,136	1,084,082	7,411,264	108,997,131	103,066,324	5,688,227	527,810	1,126,381

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274	**Adjustments, Depreciation and Amortization Expense**										
275	**Depreciation Expense**										
276	**Intangible Plant**			1,598,607	5,402	59,296	1,051,718	761,508	35,755	-	-
277	Organization	301	-	685,825	2,318	25,439	451,202	326,698	15,339	-	-
278	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303	18,385,082	9,772,676	99,076	488,273	4,635,665	3,178,577	141,397	3,033	66,385
280	Subtotal - Intangible Plant		18,385,082	9,772,676	99,076	488,273	4,635,665	3,178,577	141,397	3,033	66,385
				-	-	-	-	-	-	-	-
281	**Other Production Plant**			-	-	-	-	-	-	-	-
282	Land and Land Rights	310	-	-	-	-	-	-	-	-	-
283	Structures and Improvements	311	5,712,146	2,599,867	8,786	96,436	1,710,443	1,238,465	58,149	-	-
284	Boiler Plant Equipment	312	21,729,351	9,890,051	33,423	366,847	6,506,631	4,711,196	221,203	-	-
285	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
286	Turbogenerator Units	314	998,400	454,419	1,536	16,856	298,961	216,466	10,164	-	-
287	Accessory Electric Equipment	315	1,970,549	896,890	3,031	33,268	590,061	427,240	20,060	-	-
288	Miscellaneous Power Plant Equipment	316	1,231,001	560,287	1,893	20,782	368,611	266,897	12,532	-	-
289	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
290	Subtotal - Other Production Plant		31,641,447	14,401,513	48,669	534,188	9,474,706	6,860,262	322,108	-	-
				-	-	-	-	-	-	-	-
291	**Other Production Plant**			-	-	-	-	-	-	-	-
292	Land and Land Rights	340	-	-	-	-	-	-	-	-	-
293	Structures and Improvements	341	76,322	34,738	117	1,289	22,854	16,548	777	-	-
294	Fuel Holders, Producers and Accessories	342	70,847	32,246	109	1,196	21,214	15,360	721	-	-
295	Prime Movers	343	842,977	383,678	1,297	14,232	252,421	182,768	8,581	-	-
296	Generators	344	553,653	251,994	852	9,347	165,786	120,039	5,636	-	-
297	Accessory Electric Equipment	345	137,601	62,629	212	2,323	41,203	29,834	1,401	-	-
298	Miscellaneous Power Plant Equipment	346	24,331,594	11,074,455	37,426	410,779	7,285,846	5,275,394	247,694	-	-
299	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
300	Subtotal - Other Production Plant		26,012,993	11,839,739	40,012	439,166	7,789,324	5,639,943	264,811	-	-
				-	-	-	-	-	-	-	-
301	**Other Production Plant**			-	-	-	-	-	-	-	-
302	Land and Land Rights	350	143,300	65,223	220	2,419	42,910	31,069	1,459	-	-
303	Structures and Improvements	352	91,477	41,636	141	1,544	27,392	19,833	931	-	-
304	Station Equipment	353	3,139,593	1,428,977	4,829	53,004	940,119	680,703	31,961	-	-
305	Towers and Fixtures	354	17,043	7,757	26	288	5,103	3,695	173	-	-
306	Poles and Fixtures	355	5,951,193	2,708,668	9,154	100,471	1,782,024	1,290,293	60,583	-	-
307	Overhead Conductors and Devices	356	2,833,897	1,289,840	4,359	47,843	848,581	614,424	28,849	-	-
308	Underground Conduit	357	14,054	6,396	22	237	4,208	3,047	143	-	-
309	Underground Conductors and Devices	358	9,361	4,261	14	158	2,803	2,030	95	-	-
310	Road and Trails	359	-	-	-	-	-	-	-	-	-
311	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
312	Subtotal - Other Production Plant		12,199,918	5,552,757	18,765	205,966	3,653,140	2,645,095	124,194	-	-

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				-	-	-	-	-	-	-	-
313	**Distribution Plant**			-	-	-	-	-	-	-	-
314	Land and land rights	360	1,177	593	3	21	340	213	-	3	4
315	Structures and improvements	361	19,706	9,994	43	354	5,725	3,480	-	42	67
316	Station equipment	362	4,013,204	1,984,104	8,475	70,321	1,134,127	794,507	-	8,376	13,294
317	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364	15,005,586	7,699,180	32,886	272,875	4,415,133	2,501,423	-	32,501	51,588
319	Overhead Conductors and Devices	365	13,295,258	6,809,093	29,084	241,328	3,904,095	2,237,291	-	28,743	45,624
320	Underground conduit	366	1,015,632	546,591	2,335	19,372	314,691	126,673	-	2,307	3,662
321	Underground Conductors and Devices	367	2,912,001	1,567,176	6,694	55,544	902,276	363,194	-	6,616	10,501
322	Transformers and Transformer Installations	368	1,749,229	1,219,616	21,856	75,889	275,473	152,244	-	1,605	2,547
323	Services	369	1,993,032	1,521,735	36,677	201,909	230,600	2,091	20	-	-
324	Meters	370	1,852,884	1,534,879	36,994	118,528	160,975	1,493	14	-	-
325	Installations on customers premises	371	192,489	-	-	-	-	-	-	192,489	-
326	Street lighting and signal systems	373	431,653	-	-	-	-	-	-	-	431,653
327	Subtotal - Distribution Plant		42,481,852	22,892,963	175,045	1,056,142	11,343,436	6,182,610	34	272,681	558,942
				-	-	-	-	-	-	-	-
328	**General Plant**			-	-	-	-	-	-	-	-
329	Land and Land Rights	389	-	-	-	-	-	-	-	-	-
330	Structures and Improvements	390	1,139,965	605,954	6,143	30,275	287,434	197,087	8,767	188	4,116
331	Office Furniture and Equipment	391	1,445,296	768,254	7,789	38,384	364,421	249,876	11,116	238	5,219
332	Transportation Equipment	392	1,805,524	959,735	9,730	47,951	455,250	312,155	13,886	298	6,519
333	Stores Equipment	393	22,940	12,194	124	609	5,784	3,966	176	4	83
334	Tools, Shop and Garage Equipment	394	369,878	196,610	1,993	9,823	93,262	63,948	2,845	61	1,336
335	Laboratory Equipment	395	92,074	48,943	496	2,445	23,216	15,919	708	15	332
336	Power Operated Equipment	396	245,204	130,340	1,321	6,512	61,827	42,393	1,886	40	885
337	Communication Equipment	397	1,505,059	800,021	8,111	39,972	379,490	260,208	11,575	248	5,434
338	Miscellaneous Equipment	398	127,525	67,787	687	3,387	32,155	22,048	981	21	460
339	Miscellaneous Equipment-DLC	398	154,194	70,181	237	2,603	46,172	33,431	1,570	-	-
340	Subtotal - General Plant		6,907,660	3,660,018	36,631	181,962	1,749,009	1,201,031	53,510	1,114	24,385
				-	-	-	-	-	-	-	-
341	**Amortization Expense**			-	-	-	-	-	-	-	-
342	Regulatory Amortization - TDISC	407.4	7,935,299	4,151,652	30,680	196,655	2,134,175	1,253,145	17,891	38,499	112,601
343	Regulatory Amortization - CECA	407.4	167,953	76,443	258	2,835	50,292	36,414	1,710	-	-
344	Regulatory Amortization - ECA	407.4	24,657,372	11,222,732	37,927	416,279	7,383,397	5,346,027	251,010	-	-
345	Regulatory Amortization - AMI	407.4	1,643,527	1,405,754	33,882	104,523	98,042	1,116	11	-	200
346	Regulatory Amortization - CT	407.4	118,495	53,933	182	2,001	35,482	25,691	1,206	-	-
347	Pro Forma Amortization Expense - Deferred Medicare Tax Liat	407.4	(347,401)	(184,663)	(1,872)	(9,226)	(87,595)	(60,062)	(2,672)	(57)	(1,254)
348	Subtotal - Amortization Expense		34,175,245	16,725,851	101,057	713,067	9,613,793	6,602,331	269,156	38,442	111,547
349	**Total Adjustments, Depreciation and Amortization Expense**		171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259

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350	**Taxes**										
351	**Taxes Other Than Income Taxes**										
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	4,683,616	27,738	202,227	2,680,834	1,777,592	61,338	20,601	62,917
353	Taxes Other Than Income Taxes - Payroll	408.1	2,783,210	1,479,429	14,999	73,917	701,766	481,186	21,405	459	10,050
354	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
355	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
356	Investment Tax Credits		-	-	-	-	-	-	-	-	-
357	Subtotal - Taxes Other Than Income Taxes		12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
358	**Income Taxes**										
359	State Income Tax	409.01	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
360	Federal Income Tax	409	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
361	Deferred Federal & State Income Taxes	410	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
362	Subtotal - Income Taxes		14,913,489	7,280,723	39,726	300,849	4,251,303	2,843,018	98,212	27,813	71,844
363	**Total Taxes**		27,213,562	13,443,767	82,462	576,994	7,633,903	5,101,797	180,956	48,872	144,811
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**										
365	**Test Year Expenses at Current Rates**		592,726,115	264,096,421	1,685,800	11,607,022	164,890,107	140,477,970	7,044,392	891,953	2,032,451
366	**Return on Rate Base**		187,518,958	91,311,982	484,601	3,718,842	53,655,311	35,976,333	1,243,239	331,898	796,752
367	**Gross Up Items**			-	-	-	-	-	-	-	-
368	Gross-up State Income Tax		4,584,096	2,232,216	11,847	90,911	1,311,660	879,479	30,392	8,114	19,477
369	Gross-up Federal Income Tax		18,683,465	9,097,876	48,283	370,527	5,345,951	3,584,504	123,870	33,069	79,384
370	Gross-up IURC Assessment		137,915	67,157	356	2,735	39,462	26,460	914	244	586
371	Gross-up Bad Debts		281,918	137,280	729	5,591	80,666	54,087	1,869	499	1,198
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848

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373	**INTERNAL ALLOCATION FACTORS**										
374	INT_STEAM_PROD_PT		774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	0	0
375	INT_OTHER_PROD_PT		855,100,022	389,196,303	1,315,270	14,436,270	256,050,915	185,396,401	8,704,865	0	0
376	INT_TRANSMISSION_PT		574,404,982	261,438,767	883,519	9,697,421	171,999,669	124,538,198	5,847,407	0	0
377	INT_DIST_PLANT		1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
378	INT_TOTAL_PLANT		3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568
379	INT_RATEBASE		2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861
380	INT_TRANS_OPS		20,022,132	9,113,015	30,797	338,025	5,995,422	4,341,049	203,824	0	0
381	INT_TRANS_MAINT		3,184,499	1,449,416	4,898	53,762	953,566	690,439	32,418	0	0
382	INT_DIST_OPS		1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
383	INT_DIST_MAINT		10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
384	INT_361-364		559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	0	1,190,898	1,890,300
385	INT_364		297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	0	645,125	1,024,001
386	INT_365		312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	0	674,727	1,070,988
387	INT_367		165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	0	375,225	595,591
388	INT_368		103,114,848	71,894,808	1,288,367	4,473,573	16,238,754	8,974,567	0	94,608	150,171
389	INT_STNS,POLES,LINES		869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	0	1,862,328	2,956,056
390	INT_T&D_OH_CNDT		418,889,136	208,444,779	846,989	7,467,935	123,623,748	75,672,815	1,087,155	674,727	1,070,988
391	INT_LABOR		25,452,949	13,529,634	137,164	675,982	6,417,776	4,400,533	195,755	4,199	91,906
392	INT_REVREQ		803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848
393	INT_GENPT		153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
394	INT_TOTAL_PLANT_EXCL INT		3,704,637,994	1,815,369,009	10,306,146	77,667,192	1,049,438,120	694,723,910	23,629,762	8,416,249	25,087,606
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691	542,938,618	4,012,238	25,717,812	279,100,017	163,881,902	2,339,696	5,034,810	14,725,598
397	Operating Revenue										
398	Base Rate Revenue		267,328,652	132,139,577	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
399	Fuel Cost Revenue		207,300,587	75,970,833	391,108	3,344,186	59,219,378	63,597,486	3,765,866	391,039	620,692
400	Special Contract Revenue		30,156,859	13,764,647	83,712	592,521	8,452,251	6,789,571	316,774	47,481	109,904
401	Non-Firm Revenue		14,611,626	6,669,258	40,560	287,089	4,095,291	3,289,688	153,484	23,006	53,251
402	Forfeited Discounts		2,551,683	1,142,913	6,208	53,353	735,598	566,346	29,022	6,886	11,357
403	Reconnect Charge		237,837	226,325	1,642	5,065	4,751	54	1	-	-
404	Returned Check Charge		104,726	99,263	779	2,403	2,254	26	0	-	-
405	Securitization Fees		245,725	112,157	682	4,828	68,871	55,323	2,581	387	896
406	Interdepartmental Sales		100,367	45,811	279	1,972	28,130	22,597	1,054	158	366
407	Rent From Property		5,062,099	2,310,519	14,052	99,460	1,418,786	1,139,690	53,173	7,970	18,448
408	LRAM Incentive		-	-	-	-	-	-	-	-	-
409	Rider Revenue		99,379,048	49,842,143	487,680	2,724,122	29,673,721	15,662,293	814,423	29,159	145,507
410	Rider Revenue_Special Contract		12,267,532	5,599,331	34,053	241,032	3,438,298	2,761,935	128,861	19,315	44,708
411	Variable Production Revenue_Special Contract		4,870,592	1,767,260	9,296	78,617	1,390,814	1,510,021	89,455	9,713	15,417
412	Variable Production Revenue		18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
413	Transmission Revenue		8,758,794	3,997,820	24,313	172,092	2,454,882	1,971,971	92,004	13,791	31,921
414	Fuel Cost Revenue_Special Contract		52,891,914	19,383,654	99,790	853,256	15,109,587	16,226,644	960,846	99,772	158,367
415	Total Operating Revenue		723,922,849	319,622,569	1,759,173	14,704,649	207,073,126	167,222,380	8,607,350	1836827.708	3096774.211
416	NET INCOME AT CURRENT RATES		131,196,735	55,526,149	73,374	3,097,628	42,183,019	26,744,410	1,562,958	944,875	1,064,323

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	12,151	INT_LABOR					
5	Franchises and Consents	302.0	0						
6	Miscellaneous Intangible Plant	303.0	198,547,734	INT_LABOR					
7	Subtotal - Intangible Plant		198,559,885						
8	**Steam Production Plant**								
9	Land and Land Rights	310.0	1,976,433		PRODUCTION	DEMAND	4CP_Demand		
10	Structures and Improvements	311.0	96,772,607		PRODUCTION	DEMAND	4CP_Demand		
11	Boiler Plant Equipment	312.0	569,693,573		PRODUCTION	DEMAND	4CP_Demand		
12	Engines and Engine Driven Generators	313.0	0		PRODUCTION	DEMAND	4CP_Demand		
13	Turbogenerator Units	314.0	48,177,832		PRODUCTION	DEMAND	4CP_Demand		
14	Accessory Electric Equipment	315.0	33,226,393		PRODUCTION	DEMAND	4CP_Demand		
15	Miscellaneous Power Plant Equipment	316.0	24,639,884		PRODUCTION	DEMAND	4CP_Demand		
16	Asset Retirement Costs for Steam Production	317.0	0		PRODUCTION	DEMAND	4CP_Demand		
17	Subtotal - Steam Production Plant		774,486,722						
18	**Other Production Plant**								
19	Land and Land Rights	340.0	389,504		PRODUCTION	DEMAND	4CP_Demand		
20	Structures and Improvements	341.0	2,271,907		PRODUCTION	DEMAND	4CP_Demand		
21	Fuel Holders, Producers and Accessories	342.0	4,101,467		PRODUCTION	DEMAND	4CP_Demand		
22	Prime Movers	343.0	48,262,971		PRODUCTION	DEMAND	4CP_Demand		
23	Generators	344.0	17,496,247		PRODUCTION	DEMAND	4CP_Demand		
24	Accessory Electric Equipment	345.0	5,263,501		PRODUCTION	DEMAND	4CP_Demand		
25	Miscellaneous Power Plant Equipment	346.0	777,314,426		PRODUCTION	DEMAND	4CP_Demand		
26	Asset Retirement Costs for Other Production	347.0	0		PRODUCTION	DEMAND	4CP_Demand		
27	Subtotal - Other Production Plant		855,100,022						
28	**Transmission Plant**								
29	Land and Land Rights	350.0	19,334,962		TRANSMISSION	DEMAND	4CP_Demand		
30	Structures and Improvements	352.0	6,442,051		TRANSMISSION	DEMAND	4CP_Demand		
31	Station Equipment	353.0	196,875,807		TRANSMISSION	DEMAND	4CP_Demand		
32	Towers and Fixtures	354.0	4,622,707		TRANSMISSION	DEMAND	4CP_Demand		
33	Poles and Fixtures	355.0	237,797,966		TRANSMISSION	DEMAND	4CP_Demand		
34	Overhead Conductors and Devices	356.0	106,793,870		TRANSMISSION	DEMAND	4CP_Demand		
35	Underground Conduit	357.0	1,180,974		TRANSMISSION	DEMAND	4CP_Demand		
36	Underground Conductors and Devices	358.0	1,356,646		TRANSMISSION	DEMAND	4CP_Demand		
37	Road and Trails	359.0	0		TRANSMISSION	DEMAND	4CP_Demand		
38	ARO for Transmission Plant	359.1	0		TRANSMISSION	DEMAND	4CP_Demand		
39	Subtotal - Transmission Plant		574,404,982						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
40	**Distribution Plant**								
41	Land and land rights	360.0	3,081,457	INT_361-364					
42	Structures and Improvements	361.0	1,539,531	INT_STNS,POLES,LINES					
43	Station equipment	362.0	259,931,734		SUBSTATION	DEMAND	NCP_PRI		
44	Storage battery equipment	363.0	0						
45	Poles, Towers and Fixtures - PRI DEM	364.0	250,802,380		DIST PRIMARY	DEMAND	NCP_PRI		
46	Poles, Towers and Fixtures - PRI CUST	364.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
47	Poles, Towers and Fixtures - SEC DEM	364.0	47,052,112		DIST SECONDARY	DEMAND	NCP_SEC		
48	Poles, Towers and Fixtures - SEC CUST	364.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
49	Overhead Conductors and Devices - PRI DEM	365.0	265,280,976		DIST PRIMARY	DEMAND	NCP_PRI		
50	Overhead Conductors and Devices - PRI CUST	365.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
51	Overhead Conductors and Devices - SEC DEM	365.0	46,814,290		DIST SECONDARY	DEMAND	NCP_SEC		
52	Overhead Conductors and Devices - SEC CUST	365.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
53	Underground conduit	366.0	47,676,074	INT_367					
54	Underground Conductors and Devices - PRI DEM	367.0	104,053,705		DIST PRIMARY	DEMAND	NCP_PRI		
55	Underground Conductors and Devices - PRI CUST	367.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
56	Underground Conductors and Devices - SEC DEM	367.0	61,110,906		DIST SECONDARY	DEMAND	NCP_SEC		
57	Underground Conductors and Devices - SEC CUST	367.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
58	Transformers and Transformer Installations - DEM	368.0	45,332,193		TRANSFORMATION	DEMAND	NCP_PRI		
59	Transformers and Transformer Installations - CUST	368.0	57,782,655		TRANSFORMATION	CUSTOMER			CUST_SEC
60	Services	369.0	103,266,723		ONSITE & METERING	CUSTOMER			SERV
61	Meters	370.0	26,328,799		ONSITE & METERING	CUSTOMER			MTRS
62	Installations on customers premises	371.0	5,941,020		LIGHTING PLANT	CUSTOMER			OUTDOOR-LIGHT
63	Street lighting and signal systems	373.0	20,653,277		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
64	Subtotal - Distribution Plant		1,346,647,831						
65	**General Plant**								
66	Land and Land Rights	389.0	2,309,376	INT_LABOR					
67	Structures and Improvements	390.0	56,222,863	INT_LABOR					
68	Office Furniture and Equipment	391.0	23,986,173	INT_LABOR					
69	Transportation Equipment	392.0	25,161,795	INT_LABOR					
70	Stores Equipment	393.0	688,773	INT_LABOR					
71	Tools, Shop and Garage Equipment	394.0	9,246,944	INT_LABOR					
72	Laboratory Equipment	395.0	1,859,238	INT_LABOR					
73	Power Operated Equipment	396.0	5,812,993	INT_LABOR					
74	Communication Equipment	397.0	22,869,808	INT_LABOR					
75	Miscellaneous Equipment	398.0	2,761,879	INT_LABOR					
76	Miscellaneous Equipment-DLC	398.0	3,078,597		PRODUCTION	DEMAND	4CP_Demand		
77	Subtotal - General Plant		153,998,437						
78	**Total Plant in Service**		3,903,197,879						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
79	**Accumulated Depreciation & Amortization**								
80	**Intangible Plant**								
81	Organization	301.0	0	INT_LABOR	-	-	-	-	-
82	Franchises and Consents	302.0	0	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303.0	(120,558,306)	INT_LABOR	-	-	-	-	-
84	Subtotal - Intangible Plant		(120,558,306)						
85	**Steam Production Plant**								
86	Land and Land Rights	310.0	142,880	-	PRODUCTION	DEMAND	4CP_Demand	-	-
87	Structures and Improvements	311.0	(46,698,062)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
88	Boiler Plant Equipment	312.0	(264,424,780)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
89	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
90	Turbogenerator Units	314.0	(36,101,462)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
91	Accessory Electric Equipment	315.0	(3,420,234)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
92	Miscellaneous Power Plant Equipment	316.0	(8,721,704)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
93	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
94	Subtotal - Steam Production Plant		(359,223,363)						
95	**Other Production Plant**								
96	Land and Land Rights	340.0	38,004	-	PRODUCTION	DEMAND	4CP_Demand	-	-
97	Structures and Improvements	341.0	(2,231,173)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
98	Fuel Holders, Producers and Accessories	342.0	(4,631,843)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
99	Prime Movers	343.0	(42,171,802)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
100	Generators	344.0	(13,256,606)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
101	Accessory Electric Equipment	345.0	(4,116,286)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
102	Miscellaneous Power Plant Equipment	346.0	(16,512,384)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
103	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
104	Subtotal - Other Production Plant		(82,882,091)						
105	**Transmission Plant**								
106	Land and Land Rights	350.0	(4,213,024)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
107	Structures and Improvements	352.0	(2,543,412)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
108	Station Equipment	353.0	(55,183,260)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
109	Towers and Fixtures	354.0	(5,214,294)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
110	Poles and Fixtures	355.0	(55,473,356)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
111	Overhead Conductors and Devices	356.0	(27,944,809)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
112	Underground Conduit	357.0	(968,589)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
113	Underground Conductors and Devices	358.0	(1,294,260)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
114	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
115	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
116	Subtotal - Transmission Plant		(152,835,002)						

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Petitioner's Exhibit No. 18-S, Attachment JDT-52: Allocated Cost of Service Study
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
117	**Distribution Plant**								
118	Land and land rights	360.0	(20,815)	INT_361-364	-	-	-	-	-
119	Structures and improvements	361.0	(897,293)	INT_STNS,POLES,LINES	-	-	-	-	-
120	Station equipment	362.0	(44,601,013)	-	SUBSTATION	DEMAND	NCP_PRI	-	-
121	Storage battery equipment	363.0	0	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364.0	(90,761,034)	INT_364					
123	Overhead Conductors and Devices	365.0	(91,322,510)	INT_365					
124	Underground conduit	366.0	(18,345,845)	INT_367	-	-	-	-	-
125	Underground Conductors and Devices	367.0	(51,477,871)	INT_367					
126	Transformers and Transformer Installations	368.0	(52,561,797)	INT_368					
127	Services	369.0	(71,529,816)	-	ONSITE & METERING	CUSTOMER	-	-	SERV
128	Meters	370.0	(2,976,324)	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
129	Installations on customers premises	371.0	(2,944,632)	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
130	Street lighting and signal systems	373.0	(12,598,490)	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
131	Subtotal - Distribution Plant		(440,037,441)						
132	**General Plant**								
133	Land and Land Rights	389.0	(22,147)	INT_LABOR	-	-	-	-	-
134	Structures and Improvements	390.0	(17,518,991)	INT_LABOR	-	-	-	-	-
135	Office Furniture and Equipment	391.0	(15,258,932)	INT_LABOR	-	-	-	-	-
136	Transportation Equipment	392.0	(16,726,737)	INT_LABOR	-	-	-	-	-
137	Stores Equipment	393.0	(574,962)	INT_LABOR	-	-	-	-	-
138	Tools, Shop and Garage Equipment	394.0	(2,180,271)	INT_LABOR	-	-	-	-	-
139	Laboratory Equipment	395.0	(1,935,880)	INT_LABOR	-	-	-	-	-
140	Power Operated Equipment	396.0	(2,361,451)	INT_LABOR	-	-	-	-	-
141	Communication Equipment	397.0	(9,472,725)	INT_LABOR	-	-	-	-	-
142	Miscellaneous Equipment	398.0	(480,682)	INT_LABOR	-	-	-	-	-
143	Miscellaneous Equipment-DLC	398.0	(5,512,812)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
144	Subtotal - General Plant		(72,045,589)						
145	**Total Accumulated Depreciation & Amortization**		(1,227,581,792)						
146	**Other Rate Base Items**								
147	Fuel Stock & Expense	151.0	8,990,701		PRODUCTION	ENERGY		ENERGY	
148	Materials and Supplies (Generation Inventory)	154.0	41,360,961		PRODUCTION	DEMAND	4CP_Demand		
149	Allowance Inventory	158.0	0		PRODUCTION	DEMAND	4CP_Demand		
150	Stores Expense	163.0	311,332	INT_TOTAL_PLANT					
151	PISCC - AMI	182.3	10,585,830		CUST ACCTS & SRVC	CUSTOMER			CUST
152	PISCC - ECA	182.3	5,575,984		PRODUCTION	DEMAND	4CP_Demand		
153	PISCC - CECA	182.3	2,963,459		PRODUCTION	DEMAND	4CP_Demand		
154	PISCC - TDSIC	182.3	21,951,124	ST (60%)_TRANSM (40%)_PLANT					
155	PISCC - CT	182.3	2,496,186		PRODUCTION	DEMAND	4CP_Demand		
156	**Total Other Rate Base Items**		94,235,578						
157	**TOTAL RATE BASE**		2,769,851,666						

Northern Indiana
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
158	**OPERATION AND MAINTENANCE EXPENSE**								
159	**Generation Production, Transmission, and Distribution Expense**								
160	**Steam Power Generation Operation Expenses**								
161	Operation Supervision and Engineering	500.0	743,496		PRODUCTION	DEMAND	4CP_Demand		
162	Fuel	501.0	246,229,310		FUEL EXPENSES	ENERGY		REV_ENERGY	
163	Fuel (Operation Related Expenses)	501.0	2,240,456		PRODUCTION	DEMAND	4CP_Demand		
164	Steam Expenses	502.0	1,969,108		PRODUCTION	DEMAND	4CP_Demand		
165	Steam Expenses - VPC	502.0	7,310,722		VPC	ENERGY		REV_PROPOSED_VP	
166	Electric Expenses	505.0	1,348,774		PRODUCTION	DEMAND	4CP_Demand		
167	Electric Expenses - VPC	505.0	165,000		VPC	ENERGY		REV_PROPOSED_VP	
168	Miscellaneous Steam Power Expenses	506.0	2,163,147		PRODUCTION	DEMAND	4CP_Demand		
169	Miscellaneous Steam Power Expenses - VPC	506.0	299,500		VPC	ENERGY		REV_PROPOSED_VP	
170	Rents	507.0	0		PRODUCTION	DEMAND	4CP_Demand		
171	Allowances	509.0	0		PRODUCTION	DEMAND	4CP_Demand		
172	Subtotal - Steam Power Generation Operation Expenses		262,469,512						
173	**Steam Power Generation Maintenance Expenses**								
174	Maintenance Supervision and Engineering	510.0	492,730		PRODUCTION	DEMAND	4CP_Demand		
175	Maintenance of Structures	511.0	1,494,465		PRODUCTION	DEMAND	4CP_Demand		
176	Maintenance of Boiler Plant	512.0	6,725,481		PRODUCTION	DEMAND	4CP_Demand		
177	Maintenance of Boiler Plant-VPC	512.0	500,200		VPC	ENERGY		REV_PROPOSED_VP	
178	Maintenance of Electric Plant	513.0	3,512,286		PRODUCTION	DEMAND	4CP_Demand		
179	Maintenance of Miscellaneous Steam Plant	514.0	1,506,822		PRODUCTION	DEMAND	4CP_Demand		
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984						
181	**Other Power Generation Operation Expenses**								
182	Operations Supervision and Engineering	546.0	20,563		PRODUCTION	DEMAND	4CP_Demand		
183	Generation Expenses	548.0	5,608,351		PRODUCTION	DEMAND	4CP_Demand		
184	Miscellaneous Other Power Generation Expenses	549.0	917,282		PRODUCTION	DEMAND	4CP_Demand		
185	Subtotal - Other Power Generation Operation Expenses		6,546,196						
186	**Other Power Generation Maintenance Expenses**								
187	Maintenance Supervision and Engineering	551.0	1		PRODUCTION	DEMAND	4CP_Demand		
188	Maintenance of Structures	552.0	15,000		PRODUCTION	DEMAND	4CP_Demand		
189	Maintenance of Generating and Electric Plant	553.0	8,602,756		PRODUCTION	DEMAND	4CP_Demand		
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756						
191	**Other Power Supply Expenses**								
192	System Control and Load Dispatching	556.0	670,659		PRODUCTION	DEMAND	4CP_Demand		
193	All Other Expenses - Fixed	557.0	0						
194	All Other Expenses - Variable	557.0	0						
195	Subtotal - Other Power Supply Expenses		670,659						

Indiana Michigan Power Company Indiana
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
196	**Transmission Operation Expenses**								
197	Operation Supervision and Engineering	560.0	419,171		TRANSMISSION	DEMAND	4CP_Demand		
198	Load Dispatching	561.0	19,910,336		TRANSMISSION	DEMAND	4CP_Demand		
199	Station Expenses	562.0	111,914		TRANSMISSION	DEMAND	4CP_Demand		
200	Overhead Line Expenses	563.0	(118)		TRANSMISSION	DEMAND	4CP_Demand		
201	Underground Line Expenses	564.0	0						
202	Transmission of Electricity by Others	565.0	0						
203	Miscellaneous Transmission Expenses	566.0	0						
204	Rents	567.0	0						
205	Subtotal - Transmission Operation Expenses		20,441,303						
206	**Transmission Maintenance Expenses**								
207	Maintenance Supervision and Engineering	568.0	388,095		TRANSMISSION	DEMAND	4CP_Demand		
208	Maintenance of Structures	569.0	2,371,329		TRANSMISSION	DEMAND	4CP_Demand		
209	Maintenance of Station Equipment	570.0	233,432		TRANSMISSION	DEMAND	4CP_Demand		
210	Maintenance of Overhead Lines	571.0	579,737		TRANSMISSION	DEMAND	4CP_Demand		
211	Maintenance of Underground Lines	572.0	0						
212	Maintenance of Miscellaneous Transmission Plant	573.0	0						
213	Subtotal - Transmission Maintenance Expenses		3,572,594						
214	**Distribution Operation Expenses**								
215	Operation Supervision and Engineering	580.0	1,941,263	INT_DIST_OPS					
216	Load Dispatching	581.0	256,022		DIST PRIMARY	DEMAND	12CP_Demand		
217	Station Expenses	582.0	64,922		SUBSTATION	DEMAND	12CP_Demand		
218	Overhead Line Expenses	583.0	0	INT_365					
219	Underground Line Expenses	584.0	0	INT_367					
220	Street Lighting and Signal System Expenses	585.0	0		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
221	Meter Expenses	586.0	1,157,573		ONSITE & METERING	CUSTOMER			MTRS
222	Customer Installations Expenses	587.0	0		ONSITE & METERING	CUSTOMER			MTRS
223	Miscellaneous Distribution Expenses	588.0	7,696,359	INT_DIST_OPS					
224	Rents	589.0	0	INT_DIST_OPS					
225	Subtotal - Distribution Operation Expenses		11,116,139						
226	**Distribution Maintenance Expenses**								
227	Maintenance Supervision and Engineering	590.0	203,910	INT_DIST_MAINT					
228	Maintenance of Structures	591.0	1,112,625		DIST PRIMARY	DEMAND	12CP_Demand		
229	Maintenance of Station Equipment	592.0	815,274		DIST PRIMARY	DEMAND	12CP_Demand		
230	Maintenance of Overhead Lines	593.0	8,631,137	INT_365					
231	Maintenance of Underground Lines	594.0	267,725	INT_367					
232	Maintenance of Line Transformers	595.0	0						
233	Maintenance of Street Lighting and Signal Systems	596.0	115,832		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
234	Maintenance of Meters	597.0	0		ONSITE & METERING	CUSTOMER			MTRS
235	Maintenance of Miscellaneous Distribution Plant	598.0	670,972	INT_DIST_MAINT					
236	Subtotal - Distribution Maintenance Expenses		11,817,475						
237	**Total Generation Production, Transmission, and Distribution Expense**		47,618,170						

Northern Indiana Public Service Company Indiana
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
238	**Customer Accounts, Service, and Sales Expense**								
239	**Customer Account**								
240	Supervision	901.0	0						
241	Meter Reading Expenses	902.0	152,498		CUST ACCTS & SRVC	CUSTOMER			MTR_READ
242	Customer Billing and Accounting	903.0	1,155,579		CUST ACCTS & SRVC	CUSTOMER			CUST
243	Uncollectible Accounts	904.0	2,279,803		CUST ACCTS & SRVC	CUSTOMER			UNCOLL
244	Misc. Customer Accounts Expenses	905.0	70,218		CUST ACCTS & SRVC	CUSTOMER			CUST
245	Subtotal - Customer Account		3,658,099						
246	**Customer Service & Information Expenses**								
247	Supervision	907.0	0						
248	Customer Assistance	908.0	14,596		CUST ACCTS & SRVC	CUSTOMER			CUST
249	Informational and Instructional Advertising	909.0	0						
250	Miscellaneous Customer Service and Informational	910.0	329		CUST ACCTS & SRVC	CUSTOMER			CUST
251	Subtotal - Customer Service & Information Expenses		14,925						
252	**Sales Expenses**								
253	Supervision	911.0	1,139,859		CUST ACCTS & SRVC	CUSTOMER			CUST
254	Demonstrating and Selling Expenses	912.0	25,289		CUST ACCTS & SRVC	CUSTOMER			CUST
255	Advertising Expenses	913.0	0						
256	Miscellaneous Sales Expenses	916.0	0						
257	Subtotal - Sales Expenses		1,165,148						
258	**Total Customer Accounts, Service, and Sales Expense**		4,838,172						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
259	**Administrative and General Expenses**								
260	Administrative and General Salaries	920.0	20,391,648	INT_LABOR					
261	Office Supplies and Expenses	921.0	2,742,248	INT_LABOR					
262	Administrative Expenses Transferred - Company	922.0	0						
263	Outside Services Employed	923.0	340,000	INT_LABOR					
264	Property Insurance	924.0	2,276,531	INT_TOTAL_PLANT					
265	Injuries and Damages	925.0	4,009,520	INT_LABOR					
266	Employee Pensions and Benefits	926.0	8,123,484	INT_LABOR					
267	Regulatory Commission Expenses	928.0	414,956	INT_RATEBASE					
268	General Advertising Expenses	930.1	(835)	INT_RATEBASE					
269	Miscellaneous General Expense	930.2	5,306,182	INT_TOTAL_PLANT					
270	Rents	931.0	4,626,382	INT_LABOR					
271	Maintenance of General Plant	935.0	1,156,447	INT_GENPT					
272	**Total Administrative and General Expenses**		49,386,564						
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		393,708,355						
274	**Adjustments, Depreciation and Amortization Expense**								
275	**Depreciation Expense**								
276	**Intangible Plant**								
277	Organization	301.0	0	INT_LABOR	-	-	-	-	-
278	Franchises and Consents	302.0	0	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303.0	18,385,082	INT_LABOR	-	-	-	-	-
280	Subtotal - Intangible Plant		18,385,082						
281	**Other Production Plant**								
282	Land and Land Rights	310.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
283	Structures and Improvements	311.0	5,712,146	-	PRODUCTION	DEMAND	4CP_Demand	-	-
284	Boiler Plant Equipment	312.0	21,729,351	-	PRODUCTION	DEMAND	4CP_Demand	-	-
285	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
286	Turbogenerator Units	314.0	998,400	-	PRODUCTION	DEMAND	4CP_Demand	-	-
287	Accessory Electric Equipment	315.0	1,970,549	-	PRODUCTION	DEMAND	4CP_Demand	-	-
288	Miscellaneous Power Plant Equipment	316.0	1,231,001	-	PRODUCTION	DEMAND	4CP_Demand	-	-
289	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
290	Subtotal - Other Production Plant		31,641,447						
291	**Other Production Plant**								
292	Land and Land Rights	340.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
293	Structures and Improvements	341.0	76,322	-	PRODUCTION	DEMAND	4CP_Demand	-	-
294	Fuel Holders, Producers and Accessories	342.0	70,847	-	PRODUCTION	DEMAND	4CP_Demand	-	-
295	Prime Movers	343.0	842,977	-	PRODUCTION	DEMAND	4CP_Demand	-	-
296	Generators	344.0	553,653	-	PRODUCTION	DEMAND	4CP_Demand	-	-
297	Accessory Electric Equipment	345.0	137,601	-	PRODUCTION	DEMAND	4CP_Demand	-	-
298	Miscellaneous Power Plant Equipment	346.0	24,331,594	-	PRODUCTION	DEMAND	4CP_Demand	-	-
299	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
300	Subtotal - Other Production Plant		26,012,993						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
301	**Other Production Plant**								
302	Land and Land Rights	350.0	143,300	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
303	Structures and Improvements	352.0	91,477	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
304	Station Equipment	353.0	3,139,593	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
305	Towers and Fixtures	354.0	17,043	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
306	Poles and Fixtures	355.0	5,951,193	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
307	Overhead Conductors and Devices	356.0	2,833,897	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
308	Underground Conduit	357.0	14,054	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
309	Underground Conductors and Devices	358.0	9,361	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
310	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
311	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
312	Subtotal - Other Production Plant		12,199,918						
313	**Distribution Plant**								
314	Land and land rights	360.0	1,177	INT_361-364	-	-	-	-	-
315	Structures and improvements	361.0	19,706	INT_STNS,POLES,LINES	-	-	-	-	-
316	Station equipment	362.0	4,013,204	-	SUBSTATION	DEMAND	NCP_PRI	-	-
317	Storage battery equipment	363.0	0	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364.0	15,005,586	INT_364	-	-	-	-	-
319	Overhead Conductors and Devices	365.0	13,295,258	INT_365	-	-	-	-	-
320	Underground conduit	366.0	1,015,632	INT_367	-	-	-	-	-
321	Underground Conductors and Devices	367.0	2,912,001	INT_367	-	-	-	-	-
322	Transformers and Transformer Installations	368.0	1,749,229	INT_368	-	-	-	-	-
323	Services	369.0	1,993,032	-	ONSITE & METERING	CUSTOMER	-	-	SERV
324	Meters	370.0	1,852,884	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
325	Installations on customers premises	371.0	192,489	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
326	Street lighting and signal systems	373.0	431,653	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
327	Subtotal - Distribution Plant		42,481,852						
328	**General Plant**								
329	Land and Land Rights	389.0	0	INT_LABOR	-	-	-	-	-
330	Structures and Improvements	390.0	1,139,965	INT_LABOR	-	-	-	-	-
331	Office Furniture and Equipment	391.0	1,445,296	INT_LABOR	-	-	-	-	-
332	Transportation Equipment	392.0	1,805,524	INT_LABOR	-	-	-	-	-
333	Stores Equipment	393.0	22,940	INT_LABOR	-	-	-	-	-
334	Tools, Shop and Garage Equipment	394.0	369,878	INT_LABOR	-	-	-	-	-
335	Laboratory Equipment	395.0	92,074	INT_LABOR	-	-	-	-	-
336	Power Operated Equipment	396.0	245,204	INT_LABOR	-	-	-	-	-
337	Communication Equipment	397.0	1,505,059	INT_LABOR	-	-	-	-	-
338	Miscellaneous Equipment	398.0	127,525	INT_LABOR	-	-	-	-	-
339	Miscellaneous Equipment-DLC	398.0	154,194	-	PRODUCTION	DEMAND	4CP_Demand	-	-
340	Subtotal - General Plant		6,907,660						

Northern Indiana Public Service Company Indiana
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
341	**Amortization Expense**								
342	Regulatory Amortization - TDISC	407.4	7,935,299	ST (60%)_TRANSM (40%)_PLANT					
343	Regulatory Amortization - CECA	407.4	167,953		PRODUCTION	DEMAND	4CP_Demand		
344	Regulatory Amortization - ECA	407.4	24,657,372		PRODUCTION	DEMAND	4CP_Demand		
345	Regulatory Amortization - AMI	407.4	1,643,527		CUST ACCTS & SRVC	CUSTOMER			CUST
346	Regulatory Amortization - CT	407.4	118,495		PRODUCTION	DEMAND	4CP_Demand		
347	Pro Forma Amortization Expense - Deferred Medicare Tax Liability	407.4	(347,401)	INT_LABOR					
348	Subtotal - Amortization Expense		34,175,245						
349	**Total Adjustments, Depreciation and Amortization Expense**		171,804,198						
350	**Taxes**								
351	**Taxes Other Than Income Taxes**								
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	INT_TOTAL_PLANT					
353	Taxes Other Than Income Taxes - Payroll	408.1	2,783,210	INT_LABOR					
354	Taxes Other Than Income Taxes - Other	408.0	0						
355	Taxes Other Than Income Taxes - Other	408.0	0						
356	Investment Tax Credits		0	INT_RATEBASE					
357	Subtotal - Taxes Other Than Income Taxes		12,300,073						
358	**Income Taxes**								
359	State Income Tax	409.0	(0)	INT_RATEBASE					
360	Federal Income Tax	409.0	11,324,453	INT_RATEBASE					
361	Deferred Federal & State Income Taxes	410.0	3,589,036	INT_TOTAL_PLANT					
362	Subtotal - Income Taxes		14,913,489						
363	**Total Taxes**		27,213,562						
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
365	**Test Year Expenses at Current Rates**		592,726,115	n/a	n/a	n/a	n/a	n/a	n/a
366	**Return on Rate Base**		187,518,958	INT_RATEBASE					
367	**Gross Up Items**								
368	Gross-up State Income Tax		4,584,096	INT_RATEBASE					
369	Gross-up Federal Income Tax		18,683,465	INT_RATEBASE					
370	Gross-up IURC Assessment		137,915	INT_RATEBASE					
371	Gross-up Bad Debts		281,918	INT_RATEBASE					
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**803,932,466**						

Duke Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
373	**INTERNAL ALLOCATION FACTORS**								
				Occurrences					
374	INT_STEAM_PROD_PT		774,486,722	0					
375	INT_OTHER_PROD_PT		855,100,022	0					
376	INT_TRANSMISSION_PT		574,404,982	0					
377	INT_DIST_PLANT		1,346,647,831	0					
378	INT_TOTAL_PLANT		3,903,197,879	5					
379	INT_RATEBASE		2,769,851,666	10					
380	INT_TRANS_OP5		20,022,132	0					
381	INT_TRANS_MAINT		3,184,499	0					
382	INT_DIST_OPS		1,478,517	3					
383	INT_DIST_MAINT		10,942,593	2					
384	INT_361-364		559,325,756	3					
385	INT_364		297,854,492	2					
386	INT_365		312,095,266	4					
387	INT_367		165,164,611	7					
388	INT_368		103,114,848	2					
389	INT_STNS,POLES,LINES		869,881,492	3					
390	INT_T&D_OH_CNDT		418,889,136	0					
391	INT_LABOR		25,452,949	44					
392	INT_REVREQ		803,932,466	0					
393	INT_GENPT		153,998,437	1					
394	INT_TOTAL_PLANT_EXCL INT		3,704,637,994	0					
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691	2					

Northern Indiana Public Service Company Indiana
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
397	**Operating Revenue**			**Revenue/Margin Allocation Factor**	**Revenue Category**				
398	Base Rate Revenue		267,328,652	REV	Base Rate Revenue				
399	Fuel Cost Revenue		207,300,587	REV_ENERGY	Fuel Cost Revenue				
400	Special Contract Revenue		30,156,859	INT_REVREQ	Special Contract Revenue				
401	Non-Firm Revenue		14,611,626	INT_REVREQ	Sale for Resale and Transmission Revenue				
402	Forfeited Discounts		2,551,683	REV_FORFEITED	Other Revenue				
403	Reconnect Charge		237,837	REV_RECONNECT	Other Revenue				
404	Returned Check Charge		104,726	REV_NFS	Other Revenue				
405	Securitization Fees		245,725	INT_REVREQ	Other Revenue				
406	Interdepartmental Sales		100,367	INT_REVREQ	Other Revenue				
407	Rent From Property		5,062,099	INT_REVREQ	Other Revenue				
408	LRAM Incentive		0	INT_REVREQ	Other Revenue				
409	Rider Revenue		99,379,048	REV_RIDER	Rider Revenue				
410	Rider Revenue_Special Contract		12,267,532	INT_REVREQ	Special Contract Revenue				
411	Variable Production Revenue_Special Contract		4,870,592	REV_VP	Special Contract Revenue				
412	Variable Production Revenue		18,054,808	REV_VP	Variable Production Revenue				
413	Transmission Revenue		8,758,794	INT_REVREQ	Sale for Resale and Transmission Revenue				
414	Fuel Cost Revenue_Special Contract		52,891,914	REV_ENERGY	Fuel Cost Revenue_Special Contract				
415	**Total Operating Revenue**		723,922,849						
416	**NET INCOME AT CURRENT RATES**		131,196,735						
417	**EARNINGS (DEFICIENCY)/SURPLUS**		(56,322,223)						
418	**REQUIRED INCOME INCREASE/(DECREASE)**		56,322,223						
419	**REVENUE GROSS-UP**		23,687,393						
420	**REQUIRED REVENUE INCREASE/(DECREASE)**		80,009,617						

Duke Energy Indiana
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Schedule 5 - Allocation Factors (External, Functionalization & Classification, and Internal)

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Allocation Factor Basis**									
2	INT_STEAM_PROD_PT	774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	-	-
3	INT_OTHER_PROD_PT	855,100,022	389,196,303	1,315,270	14,436,270	256,050,915	185,396,401	8,704,865	-	-
4	INT_TRANSMISSION_PT	574,404,982	261,438,767	883,519	9,697,421	171,999,669	124,538,198	5,847,407	-	-
5	INT_DIST_PLANT	1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
6	INT_TOTAL_PLANT	3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568
7	INT_RATEBASE	2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861
8	INT_TRANS_OPS	20,022,132	9,113,015	30,797	338,025	5,995,422	4,341,049	203,824	-	-
9	INT_TRANS_MAINT	3,184,499	1,449,416	4,898	53,762	953,566	690,439	32,418	-	-
10	INT_DIST_OPS	1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
11	INT_DIST_MAINT	10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
12	INT_361-364	559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	-	1,190,898	1,890,300
13	INT_364	297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	-	645,125	1,024,001
14	INT_365	312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	-	674,727	1,070,988
15	INT_367	165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	-	375,225	595,591
16	INT_368	103,114,848	71,894,808	1,288,367	4,473,573	16,238,754	8,974,567	-	94,608	150,171
17	INT_STNS,POLES,LINES	869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	-	1,862,328	2,956,056
18	INT_T&D_OH_CNDT	418,889,136	208,444,779	846,989	7,467,935	123,623,748	75,672,815	1,087,155	674,727	1,070,988
19	INT_LABOR	2545294946%	1352963438%	13716416%	67598180%	641777630%	440053284%	19575488%	419932%	9190578%
20	INT_REVREQ	803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848
21	INT_GENPT	153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
22	INT_TOTAL_PLANT_EXCL INT	3,704,637,994	1,815,369,009	10,306,146	77,667,192	1,049,438,120	694,723,910	23,629,762	8,416,249	25,087,606
23	INT_DIST (60%)_TRANSM (40%)_PLA	1,037,750,691	542,938,618	4,012,238	25,717,812	279,100,017	163,881,902	2,339,696	5,034,810	14,725,598
24	**Allocation Factor %**									
25	INT_STEAM_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
26	INT_OTHER_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
27	INT_TRANSMISSION_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
28	INT_DIST_PLANT	100.0%	54.3%	0.5%	2.7%	26.0%	14.1%	0.0%	0.6%	1.8%
29	INT_TOTAL_PLANT	100.0%	49.2%	0.3%	2.1%	28.2%	18.7%	0.6%	0.2%	0.7%
30	INT_RATEBASE	100.0%	48.7%	0.3%	2.0%	28.6%	19.2%	0.7%	0.2%	0.4%
31	INT_TRANS_OPS	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
32	INT_TRANS_MAINT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
33	INT_DIST_OPS	100.0%	74.5%	1.6%	5.4%	13.0%	5.3%	0.3%	0.0%	0.0%
34	INT_DIST_MAINT	100.0%	49.5%	0.2%	1.8%	28.9%	17.8%	0.2%	0.2%	1.4%
35	INT_361-364	100.0%	50.4%	0.2%	1.8%	28.9%	18.1%	0.0%	0.2%	0.3%
36	INT_364	100.0%	51.3%	0.2%	1.8%	29.4%	16.7%	0.0%	0.2%	0.3%
37	INT_365	100.0%	51.2%	0.2%	1.8%	29.4%	16.8%	0.0%	0.2%	0.3%
38	INT_367	100.0%	53.8%	0.2%	1.9%	31.0%	12.5%	0.0%	0.2%	0.4%
39	INT_368	100.0%	69.7%	1.2%	4.3%	15.7%	8.7%	0.0%	0.1%	0.1%
40	INT_STNS,POLES,LINES	100.0%	50.7%	0.2%	1.8%	29.1%	17.7%	0.0%	0.2%	0.3%
41	INT_T&D_OH_CNDT	100.0%	49.8%	0.2%	1.8%	29.5%	18.1%	0.3%	0.2%	0.3%
42	INT_LABOR	100.0%	53.2%	0.5%	2.7%	25.2%	17.3%	0.8%	0.0%	0.4%
43	INT_REVREQ	100.0%	45.6%	0.3%	2.0%	28.0%	22.5%	1.1%	0.2%	0.4%
44	INT_GENPT	100.0%	53.0%	0.5%	2.6%	25.3%	17.4%	0.8%	0.0%	0.4%
45	INT_TOTAL_PLANT_EXCL INT	100.0%	49.0%	0.3%	2.1%	28.3%	18.8%	0.6%	0.2%	0.7%
46	INT_DIST (60%)_TRANSM (40%)_PLANT	100.0%	52.3%	0.4%	2.5%	26.9%	15.8%	0.2%	0.5%	1.4%

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	CUSTOMER EXTERNAL ALLOCATORS										
1	**CUST**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers	156,171	133,577	3,219	9,932	9,316	106	1	-	19
2	**CUST-BILL**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers Bills	1,873,820	1,602,925	38,634	119,184	111,793	1,272	12		
3	**CUST_PRI**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number of Customers Using Primary System	156,146	133,577	3,219	9,932	9,316	101	-		
4	**CUST_SEC**		100.0%	85.6%	2.1%	6.4%	5.9%	0.0%	0.0%	0.0%	0.0%
		Number of Customers Using Secondary System	155,982	133,577	3,219	9,932	9,254	-	-		
5	**MTRS**		100.0%	82.8%	2.0%	6.4%	8.7%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.04	1.50	1.23	1.23		
		Relative Cost	161,252	133,577	3,219	10,315	14,009	130	1		
6	**SERV**		100.0%	76.4%	1.8%	10.1%	11.6%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.78	2.17	1.73	1.73		
		Relative Cost	174,947	133,577	3,219	17,723	20,242	184	2		
7	**STREET-LIGHT**		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
		Street Lights	1	-	-	-	-	-	-	-	1
8	**OUTDOOR-LIGHT**		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
		Outdoor Lighting	1	-	-	-	-	-	-	1	-
9	**MTR_READ**		100.0%	0.0%	0.0%	0.0%	0.0%	99.1%	0.9%	0.0%	0.0%
		ACCT - 902_Meter reading expenses	107					106	1		
10	**UNCOLL**		100.0%	97.2%	0.4%	1.2%	1.2%	0.0%	0.0%	0.0%	0.0%
		ACCT - 904_Uncollectible accounts	(2,385,325)	(2,317,672)	(9,648)	(29,765)	(27,919)	(318)	(3)	-	-

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	ENERGY AND REVENUE EXTERNAL ALLOCATORS										
11	**REV**		100.0%	49.4%	0.2%	2.2%	28.4%	18.0%	0.7%	0.4%	0.7%
		Total Revenue_Less Fuel Cost	267,328,655	132,139,578	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
12	**REV_ENERGY**		100.0%	36.65%	0.19%	1.61%	28.57%	30.68%	1.82%	0.19%	0.30%
		Total Fuel Cost Revenue	195,282,190	71,566,370	368,433	3,150,305	55,786,093	59,910,377	3,547,537	368,368	584,707
13	**REV_RIDER**		100.0%	50.2%	0.5%	2.7%	29.9%	15.8%	0.8%	0.0%	0.1%
		Total Rider	99,379,046	49,842,142	487,680	2,724,122	29,673,720	15,662,292	814,423	29,159	145,507
14	**ENERGY**		100.0%	35.9%	0.2%	1.6%	28.3%	31.6%	1.9%	0.2%	0.3%
		kWh Sales	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
15	**REV_LATE_FEE**		100.0%	65.2%	5.0%	15.3%	14.4%	0.2%	0.0%	0.0%	0.0%
		Late Payment Fees	2,138,215	1,393,541	106,202	327,629	307,313	3,497	33	-	-
16	**REV_FORFEITED**		100.0%	44.8%	0.2%	2.1%	28.8%	22.2%	1.1%	0.3%	0.4%
		Forfeited Discounts	2,182,387	977,503	5,310	45,631	629,137	484,381	24,822	5,889	9,713
17	**REV_RECONNECT**		100.0%	95.2%	0.7%	2.1%	2.0%	0.0%	0.0%	0.0%	0.0%
		Reconnection Charge Revenue	51,711	49,208	357	1,101	1,033	12	0	-	-
18	**REV_NFS**		100.0%	94.8%	0.7%	2.3%	2.2%	0.0%	0.0%	0.0%	0.0%
		Returned Check Charge Revenue	152,777	144,808	1,137	3,506	3,289	37	0	-	-
19	**REV_MISC**		100.0%	56.7%	2.5%	8.4%	20.8%	10.8%	0.5%	0.1%	0.2%
		Total Misc Revenue	4,525,089	2,565,060	113,005	377,868	940,772	487,926	24,855	5,889	9,713
20	**REV_VP**		100.0%	36.3%	0.2%	1.6%	28.6%	31.0%	1.8%	0.2%	0.3%
		Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
21	**REV_PROPOSED_VP**		100.0%	36.2%	0.2%	1.6%	28.5%	31.2%	1.9%	0.2%	0.3%
		Proposed Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule S - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	DEMAND ALLOCATORS										
22	NCP_SEC		100.0%	61.3%	0.3%	2.2%	35.6%	0.0%	0.0%	0.3%	0.4%
		Non-Coincident Peak Demand_Secondary (kW)	739,741	453,262	1,936	16,065	263,528	-	-	1,913	3,037
23	NCP_PRI		100.0%	49.4%	0.2%	1.8%	28.3%	19.8%	0.0%	0.2%	0.3%
		Non-Coincident Peak Demand_Primary (kW)	916,803	453,262	1,936	16,065	259,087	181,503	-	1,913	3,037
24	DEM_UNIT										
		Demand kW	8	1	1	1	1	1	1	1	1
25	12CP_Demand		100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
		12_Coincident Peak Demand	678,015	300,715	1,296	11,651	192,262	162,477	8,789	319	506
26	4CP_Demand		100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
		4_Coincident Peak Demand	854,192	388,783	1,314	14,421	255,779	185,199	8,696	-	-

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - Functionalization Summary

	Replacement Costs	% of Total
Poles Primary	$ 158,125,353	84%
Poles Secondary	$ 29,665,316	16%
	$ 187,790,669	100%

	Replacement Costs	% of Total
Overhead Primary	$ 263,915,794	85%
Overhead Secondary	$ 46,061,696	15%
	$ 309,977,490	100%

	Replacement Costs	% of Total
Underground Primary	$ 134,491,649	63%
Underground Secondary	$ 77,557,582	37%
	$ 212,049,231	100%

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - Transformer Classification Summary

Transformers and Transformer Installations	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56.03%	43.97%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56.05%	43.95%
Total	**56,994**	**$ 218,276,204**	**$ -**	**$ 122,315,833**	**56.04%**	**43.96%**
					Rounded	**44.00%**

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S3: Revenue Apportionment
Schedule 1 - Proposed Revenue Apportionment

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	Total Revenue at Current Rates	$ 723,922,849	$ 319,622,569	$ 1,759,173	$ 14,704,649	$ 207,073,126	$ 167,222,380	$ 8,607,350	$ 1,836,828	$ 3,096,774
2	Total Revenue Requirement at Equal Rates of Return	$ 803,932,466	$ 366,942,931	$ 2,231,616	$ 15,795,627	$ 225,323,157	$ 180,998,832	$ 8,444,677	$ 1,265,777	$ 2,929,848
3	Total Revenue (Deficiency)/Surplus	$ (80,009,617)	$ (47,320,362)	$ (472,442)	$ (1,090,978)	$ (18,250,031)	$ (13,776,453)	$ 162,673	$ 571,051	$ 166,926
4	Percent Change at Equal Rates of Return	11.05%	14.81%	26.86%	7.42%	8.81%	8.24%	-1.89%	-31.09%	-5.39%
5	Multiple of system average increase required for parity	1.00	1.34	2.43	0.67	0.80	0.75	(0.17)	(2.81)	(0.49)
6	**Proposed Multiple of system average increase**	**1.00**	**1.34**	**1.50**	**0.67**	**0.80**	**0.75**	**-0.17**	**0.00**	**0.00**
7	Target Percentage Increase	11.05%	14.81%	16.58%	7.42%	8.81%	8.24%	3.62%	0.00%	0.00%
8	Targeted Increase	$ 81,041,052	$ 47,320,362	$ 291,642	$ 1,090,978	$ 18,250,031	$ 13,776,453	$ 311,586	$ -	$ -
9	Targeted Revenue	$ 804,963,901	$ 366,942,931	$ 2,050,815	$ 15,795,627	$ 225,323,157	$ 180,998,832	$ 8,918,936	$ 1,836,828	$ 3,096,774
10	*Include in Allocation of Delta*		*yes*	*no*	*yes*	*yes*	*yes*	*no*	*no*	*no*
11	Allocation of Delta	$ (1,031,435)	$ (479,656)	$ -	$ (20,648)	$ (294,535)	$ (236,596)	$ -	$ -	$ -
12	**Proposed Increase/ (Decrease)**	**$ 80,009,617**	**$ 46,840,706**	**$ 291,642**	**$ 1,070,331**	**$ 17,955,496**	**$ 13,539,857**	**$ 311,586**	**$ -**	**$ -**
13	Resulting Increase %	11.05%	14.66%	16.58%	7.28%	8.67%	8.10%	3.62%	0.00%	0.00%
14	Multiple of System Increase		1.33	1.50	0.66	0.78	0.73	0.33	-	-
15	**Proposed Revenue**	**$ 803,932,466**	**$ 366,463,275**	**$ 2,050,815**	**$ 15,774,980**	**$ 225,028,622**	**$ 180,762,236**	**$ 8,918,936**	**$ 1,836,828**	**$ 3,096,774**
16	Proposed Rate of Return	6.77%	6.74%	4.63%	6.74%	6.74%	6.73%	8.96%	16.62%	7.98%
17	Proposed Revenue to Cost Ratio	1.000	0.999	0.919	0.999	0.999	0.999	1.056	1.451	1.057
18	Current Parity Ratio	1.000	0.967	0.875	1.034	1.021	1.026	1.132	1.612	1.174

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 1-Energy Allocation

Line	Customer Classes	Energy Usage	Resulting % Allocation
1	Residential (RS)	1,399,798,865	28.11%
2	Water Heating (B)	7,362,997	0.15%
3	Small General Service (SGS)	62,270,627	1.25%
4	Demand General Service (DGS)	1,022,639,369	20.54%
5	Off Season Service (OSS)	81,172,214	1.63%
6	Large Power Service (LP)[1]	2,310,836,770	46.41%
7	High Load Factor Service (HLF)	75,708,000	1.52%
8	Outdoor Lighting (OL)	7,693,136	0.15%
9	Street Lighting (SL)	12,211,243	0.25%
10	**Total**	**4,979,693,220**	

[1] Includes BAMP-Base

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 2-TDSIC Allocation

Line	Customer Classes	Transmission Allocation %	Distribution Allocation %	EADIT Credit Allocation %
1	Residential (RS)	33.34%	54.27%	46.32%
2	Water Heating (B)	0.08%	0.38%	0.26%
3	Small General Service (SGS)	1.12%	2.50%	1.98%
4	Demand General Service (DGS)	22.80%	24.34%	23.75%
5	Off Season Service (OSS)	1.75%	1.87%	1.82%
6	Large Power Service (LP)/BAMP	39.35%	15.45%	24.52%
7	High Load Factor Service (HLF)	1.57%	0.16%	0.70%
8	Outdoor Lighting (OL)/Street Lighting (SL)	0.00%	1.03%	0.64%
9	**Total**	**100%**	**100%**	**100%**

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 3-Production Allocation

Line	Customer Classes	4CP for Trackers	Resulting % Allocation
1	Residential (RS)	388,783	38.31%
2	Water Heating (B)	1,314	0.13%
3	Small General Service (SGS)	14,421	1.42%
4	Demand General Service (DGS)	240,623	23.71%
5	Off Season Service (OSS)	15,156	1.49%
6	Large Power Service (LP)[1]	345,822	34.08%
7	High Load Factor Service (HLF)	8,696	0.86%
8	Outdoor Lighting (OL)	-	0.00%
9	Street Lighting (SL)	-	0.00%
10	**Total**	**1,014,814**	

[1] Includes BAMP-Base

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 4-Rate Base Allocation

Line	Customer Classes	Production Rate Base	Transmission Rate Base	All Other Rate Base	Total Rate Base	Resulting % Allocation
1	Residential (RS)	$ 510,313,916	$ 163,955,223	$ 540,306,886	$ 1,214,576,026	43.85%
2	Water Heating (B)	$ 1,724,581	$ 706,511	$ 4,419,830	$ 6,850,921	0.25%
3	Small General Service (SGS)	$ 18,928,826	$ 6,352,183	$ 24,919,294	$ 50,200,304	1.81%
4	Demand General Service (DGS)	$ 315,840,232	$ 96,769,742	$ 260,236,520	$ 672,846,494	24.29%
5	Off Season Service (OSS)	$ 19,893,546	$ 8,055,053		$ 27,948,599	1.01%
6	Large Power Service (LP)	$ 435,127,133	$ 157,588,857	$ 144,979,431	$ 737,695,421	26.63%
7	BAMP-Base	$ 18,797,144	$ 7,476,221		$ 26,273,365	0.95%
8	High Load Factor Service (HLF)	$ 11,413,812	$ 4,792,035	$ 179,333	$ 16,385,180	0.59%
9	Outdoor Lighting (OL)	$ -	$ 173,866	$ 4,884,770	$ 5,058,636	0.18%
10	Street Lighting (SL)	$ -	$ 275,976	$ 11,740,743	$ 12,016,719	0.43%
11	**Total**	**$ 1,332,039,189**	**$ 446,145,668**	**$ 991,666,808**	**$ 2,769,851,666**	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 127
Chrissy Behme Testimony

CAUSE NO. 45990

FILED
December 5 2023
INDIANA UTILITY
REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

DIRECT TESTIMONY
OF
CHRISSY M. BEHME
MANAGER, REGULATORY REPORTING

ON

REVENUE REQUIREMENT, PHASE-IN, ACCOUNTING REQUESTS, AND CAUSE NO. 45564 S1 ISSUES

SPONSORING PETITIONER'S EXHIBIT NO. 2 (PUBLIC),
ATTACHMENTS CMB-1 THROUGH CMB-5

DIRECT TESTIMONY OF CHRISSY M. BEHME

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chrissy M. Behme. My business address is 211 NW Riverside Drive, Evansville, IN 47708.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by CenterPoint Energy Service Company, LLC ("Service Company"), a wholly owned subsidiary of CenterPoint Energy, Inc. The Service Company provides centralized support services to CenterPoint Energy, Inc.'s operating units, one of which is Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South", "Petitioner", or "Company").

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting testimony on behalf of CEI South.

Q. WHAT IS YOUR ROLE WITH RESPECT TO PETITIONER CEI SOUTH?

A. I am Manager, Regulatory Reporting.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Evansville in 2015 with a Bachelor of Science in Accounting. I joined CenterPoint Energy, Inc. in 2014 as an Accounting Analyst and have held various accounting and reporting positions with increasing responsibility with Petitioner[1] or one of its affiliates since that time. Those positions include Senior Accounting Analyst, Senior External Reporting and Accounting Research Analyst, Senior Utility Accounting Analyst, and Lead Regulatory Reporting Analyst. In October 2021, I was promoted to my current role as Manager, Regulatory Reporting and have been supporting CEI South since that time.

[1] For the sake of clarity, my testimony refers to CEI South, even though in certain situations, I may be referring to Southern Indiana Gas and Electric Company operating under a prior assumed business name.

Q. WHAT ARE YOUR PRESENT DUTIES AND RESPONSIBILITIES AS MANAGER, REGULATORY REPORTING?

A. I am responsible for the financial analysis for CenterPoint Energy Inc.'s regulated utility operations covering Indiana and Ohio. These duties include preparation of accounting exhibits submitted in various regulatory proceedings for these operations, including CEI South.

Q. ARE YOU FAMILIAR WITH THE BOOKS, RECORDS, AND ACCOUNTING PROCEDURES OF CEI SOUTH?

A. Yes, I am.

Q. ARE CEI SOUTH'S BOOKS AND RECORDS MAINTAINED IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") UNIFORM SYSTEM OF ACCOUNTS ("USOA") AND GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes.

Q. HAVE YOU EVER TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION")?

A. Yes. I have testified before the Commission on behalf of CEI South in its Gas Cost Adjustment ("GCA") proceeding, Cause No. 37366; its Fuel Adjustment Clause ("FAC") proceeding, Cause No. 38708; its Environmental Cost Adjustment ("ECA") proceeding, Cause No. 45052; its Clean Energy Cost Adjustment ("CECA") proceeding, Cause No. 44909; its Electric Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") proceeding, Cause No. 44910; and its Compliance and System Improvement Adjustment ("CSIA") proceeding, Cause No. 45612. I have also testified on behalf of CEI South in support of its request for a certificate of public convenience and necessity ("CPCN") in Cause No. 45836, Cause No. 45847, and Cause No. 45903; its request to enter into certain amendments to Power Purchase Agreements ("PPAs") in Cause No. 45839; and its request for an for the 2024 – 2028 Electric TDSIC Plan in Cause No. 45894 (the "45894 TDSIC" or "2024 – 2028 TDSIC Plan"). In addition, I have testified before the Commission on behalf of Indiana Gas Company, Inc. d/b/a CenterPoint Energy Indiana North ("CEI North") in its GCA proceeding, Cause No. 37394 and its CSIA proceeding, Cause No. 45611.

II. PURPOSE & SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present: (i) the financial and accounting data in support of CEI South's revenue requirement; (ii) an explanation of the Company's forecasted 2025 test year for ratemaking purposes; (iii) the proposed update process for the phase-in of rates; (iv) the pro forma adjustments to the test year; (v) the determination of rate base; (vi) certain elements of the capital structure presented by Petitioner's Witness Brett A. Jerasa; (vii) CEI South's request for deferred accounting treatment for future cloud-based technologies and the Critical Peak Pricing ("CPP") Pilot Program; and (viii) potential impacts on this case from the pending subdocket in Cause No. 45564 S1.

Q. ARE YOU SPONSORING ANY OF THE REVENUE REQUIREMENT SCHEDULES PROVIDED IN PETITIONER'S EXHIBIT NO. 20 IN THIS PROCEEDING?

A. Yes. Within the financial schedules included in Petitioner's Exhibit No. 20, I am specifically sponsoring or co-sponsoring the revenue requirement and supporting calculations within **Schedules A** (Revenue Increase and Financial Summary), **Schedules B** (Rate Base), and **Schedules C** (Income Statement and Adjustments). Petitioner's Witness Jerasa will sponsor and support **Schedules D** (Capital Structure). Petitioner's Witnesses John D. Taylor and Matthew A. Rice will sponsor and support respective portions of the **Schedules E** (Revenue Proof and Bill Impacts). Through my testimony, I will refer to Petitioner's Exhibit No. 20 based on these Schedule references.

Q. HAS CEI SOUTH INCLUDED THESE FINANCIAL EXHIBITS IN THEIR NATIVE FORMAT WITHIN THE DOCUMENT SUBMITTED TO THE COMMISSION IN THIS PROCEEDING?

A. Yes.

Q. HAS CEI SOUTH ALSO INCLUDED WORKPAPERS IN THEIR NATIVE FORMAT SUPPORTING THESE SCHEDULES WITHIN THE DOCUMENTS SUBMITTED TO THE COMMISSION?

A. Yes. The Revenue Requirement files, including the workpapers, are contained in a single Excel workbook, which is marked as Petitioner's Exhibit No. 20. For simplicity,

printed pages of selected individual worksheets from Petitioner's Exhibit No. 20 are included as Petitioner's Exhibit No. 21.

Q. ARE YOU SPONSORING ANY ATTACHMENTS OR SCHEDULES IN THIS PROCEEDING?

A. Yes. In addition to the schedules described earlier in my testimony, I am sponsoring the following attachments:

- Petitioner's Exhibit No. 2, **Attachment CMB-1:** CEI South Balance Sheet as of December 31, 2021 and December 31, 2022
- Petitioner's Exhibit No. 2, **Attachment CMB-2:** CEI South Income Statement for the twelve months ended December 31, 2021 and December 31, 2022
- Petitioner's Exhibit No. 2, **Attachment CMB-3:** CEI South Statement of Cash Flows for the twelve months ended December 31, 2021 and December 31, 2022
- Petitioner's Exhibit No. 2, **Attachment CMB-4:** Phase 1 Revenue Requirement
- Petitioner's Exhibit No. 2, **Attachment CMB-5:** Phase 2 Exemplar Revenue Requirement

Q. WERE THESE ATTACHMENTS OR SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. REVENUE REQUIREMENT

Q. WHAT IS THE REVENUE INCREASE REQUESTED BY CEI SOUTH?

A. As reflected on **Schedule A-1**, the Company seeks a total revenue increase of $118,757,693 utilizing the calendar year 2025 as the forecasted test year, with rate base and capital structure balances forecasted as of December 31, 2025. This is necessary to allow the Company the opportunity to earn a fair and reasonable return on its investment at a proposed return on equity of 10.40%. The return on equity is set forth in the capital structure (**Schedule D-1**) sponsored by Petitioner's Witness Jerasa.

Q. WHY IS CEI SOUTH SEEKING RATE RELIEF IN THIS PROCEEDING?

A. In Cause No. 44910, the Company sought and received Commission approval under Ind. Code ch. 8-1-39 (the "TDSIC Statute") of a seven-year TDSIC plan, which started

in 2017 and completes in 2023 (the "44910 TDSIC Plan" or "2017 – 2023 TDSIC Plan"). The TDSIC Statute requires that the Company file a base rate case prior to the completion of a seven-year plan, which, for the Company, is before the end of 2023.

In addition, **Schedule A-1** demonstrates there is a financial need that currently exists. Petitioner's Exhibit No. 20 demonstrates that rate base is forecasted to grow by more than 50% from December 31, 2023 to the end of the test year, and this is largely driven by the placement in service of new generation for which the Commission has issued a certificate of public convenience and necessity ("CPCN"). In addition, it has been well over a decade since the Company last filed a petition seeking a general increase in rates and charges. Petitioner's Witness Rice explains that over the past sixteen years between test years and rate base cutoff periods between rate cases, the Company has proactively taken measures that have allowed us to delay a general rate case. Nevertheless, CEI South's current rates are simply insufficient.

Q. WHAT IS THE RATE OF RETURN FOR THE TEST YEAR, ABSENT RATE RELIEF AS PROPOSED IN THIS PROCEEDING?

A. Without a base rate case, the Company is forecasting a rate of return of 3.91% for calendar year 2025. This compares to the proposed rate of return of 7.06%.

IV. TEST YEAR

Q. WHAT IS THE HISTORIC BASE PERIOD AND THE FORWARD-LOOKING TEST YEAR USED IN SUPPORT OF THE COMPANY'S RATE CASE?

A. The Company's historic base period is the twelve months ended December 31, 2022. This represents the most recent financial data available included in the FERC Form 1 that was submitted to the Commission for 2022. The Company's forward-looking test year is the forecasted twelve months ending December 31, 2025.

Q. IS 2025 APPROPRIATE FOR THE FORWARD-LOOKING TEST YEAR?

A. Yes. This is a twelve-month period beginning not later than 24 months after the date the petition in this case has been filed. The year ending December 31, 2025, with appropriate adjustments, is an appropriate test year since it is representative of the ongoing operations and economic conditions.

The testimony of Petitioner's Witness Stephanie E. Gray will support the 2025 forecasting process in further detail and support the 2025 forecasted net operating income statement (including both revenues and operating expenses). Petitioner's Witnesses Stephen R. Rawlinson, F. Shane Bradford, and Ronald W. Bahr will support the capital expenditure forecast. I am sponsoring the forecasted and adjusted rate base (**Schedule B**) and adjusted net operating income statement at present and proposed rates (**Schedule C**), both of which are derived from these 2025 forecasts.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED REVENUE REQUIREMENT?

A. As discussed in further detail by Petitioner's Witness Gray, CEI South developed the 2025 forecasted data with input provided by operations and allocated costs discussed by Petitioner's Witness Christopher G. Wood. Workpapers in support of the forecasted data are part of Petitioner's Exhibit No. 20. The forecasted data begins with the end of the historic base period and forecasts across the bridge periods (calendar years 2023 and 2024) and then on through the future test year (calendar year 2025). The forecast data components were classified within the appropriate FERC USoA for presentation within the revenue requirement schedules. Petitioner's Witness Gray supports the unadjusted test year levels for all income statement components. These are presented by FERC account monthly in **Schedule C-1.1** in Petitioner's Exhibit No. 20. Later in my testimony, I will discuss and sponsor necessary adjustments to the forecasted amounts.

Q. DOES THE COMPANY PROPOSE TO PHASE IN RATES FOLLOWING THE ISSUANCE OF AN ORDER IN THIS CAUSE?

A. Yes. The Company proposes that the rates should be set in a minimum of three phases.

Q. PLEASE DESCRIBE PHASE 1.

A. Upon issuance of an Order in this Cause, the Company proposes to implement rates under Phase 1 based on the actual rate base and capital structure as of December 31, 2023. As described below, revenues and O&M expense will be updated to November 2024, rather than the beginning of the test year.

Q. PLEASE DESCRIBE PHASE 2.

A. For Phase 2, the Company proposes to reflect most of the pro forma test year results of operations, updated to reflect the actual rate base and capital structure as of the December 31, 2024. We will implement rates as soon as possible following the beginning of the test year.

Q. PLEASE DESCRIBE PHASE 3.

A. For Phase 3, the Company proposes to update to reflect the fully adjusted test year and the actual rate base and capital structure as of the end of the test year. Phase 3 will be implemented as soon as possible following the end of the test year.

Q. HAS THIS THREE-PHASE APPROACH BEEN PROPOSED IN INDIANA GENERAL RATE CASES?

A. Yes. It is modeled after the approach proposed by Indiana American Water Company in Cause No. 45870.

Q. WHAT PROCESS DO YOU PROPOSE FOR THE PHASE 1 IMPLEMENTATION?

A. Phase 1 will take effect as soon as possible following issuance of the Order in this Cause and the Company's submission of the tariff and any required compliance filing. Phase 1 rates will be based upon the actual capital structure and rate base as of December 31, 2023. The Company has included a forecast of this information in its case-in-chief filed with the petition (the petition and case-in-chief were filed in December 2023). Actual data will be submitted at the time Petitioner files rebuttal. As I will explain later, pro forma results of operations at present and proposed rates will be based upon the test year data, but the operating expenses in Phase 1 will begin with November 2024 for the twelve-month period. In addition, as I will explain later, certain revenue and expense adjustments will not be included or will not be included at the full amount at Phase 1 because the changes for which these adjustments are made will not occur until the test year. A presentation of the Phase 1 revenue requirement is set forth in **Attachment CMB-4**, which I will explain later in my testimony. Other than the findings that are contained in the Commission's Final Order in this Cause, all of the information that is necessary to calculate Phase 1 rates will be available before the evidentiary hearing. Accordingly, there should not be a need to build in a post-order review process for Phase 1 as there will be with later phases.

Q. WHAT PROCESS DO YOU PROPOSE FOR THE PHASE 2 UPDATE?

A. Phase 2 rates shall be implemented as soon as possible after January 1, 2025 and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2024. Phase 2 rates should be subject to refund during the review period described below in the event the Commission determines that less than the certified amount of plant additions was placed in service as of that date. Prior to implementation of Phase 2 rates, CEI South will certify the net original cost rate base and the actual capital structure as of December 31, 2024 and calculate the Phase 2 rates using those certified figures. CEI South will provide its certification to all parties to this proceeding. Other parties to this proceeding should be provided up to 60 days to verify or state any objection to the net plant in service numbers from those which CEI South certifies. A hearing should be convened, as necessary, to resolve any objections, and rates should be trued up, with carrying charges at the weighted average cost of capital, retroactive to the date Phase 2 rates were submitted. Pro forma results of operations for purposes of Phase 2 rates should reflect the adjusted test year results of operations except there are certain revenue and expense adjustments that will not have been fully reflected by the beginning of the test year. Accordingly, we will modify some of the adjustments, as I will explain later in my testimony. **Attachment CMB-5** is an example of what the Phase 2 rate implementation would be, using the currently forecasted rate base and capital structure as of the beginning of the test year. I will explain this Attachment in further detail later in my testimony. Actual Phase 2 rates will be based upon the beginning-of-test-year submission.

Q. WHAT PROCESS DO YOU PROPOSE FOR THE PHASE 3 UPDATE?

A. The same process as with Phase 2, except using the end of test year rate base and capital structure. In addition, the pro forma results of operations will be based upon the fully adjusted test year presented in Petitioner's Exhibit No. 20.

Q. ARE THERE ANY INTERIM STEPS TO THE THREE-PHASE INCREASE YOU HAVE DESCRIBED?

A. Yes, up to three additional interim steps between Phases 2 and 3. The Company has been authorized to accrue post-in-service carrying costs ("PISCC") for each of the combustion turbines ("CTs") approved in Cause No. 45564 and the Posey Solar project approved in Cause No. 45847. The CTs and Posey Solar are both projected to

be placed in service during mid-test year. If the PISCC on these projects continues to accrue until the end of the test year, rate base and Phase 3 rates will be higher than if these projects were reflected in rates at an earlier time. As such, CEI South would propose to implement interim steps to reflect the additional after-tax return and depreciation expense on each of these projects (each CT, in the event there is a delay in implementation between the two, and Posey Solar) using the capital structure in effect at the beginning of the test year and used for Phase 2. These interim steps would take effect upon filing of a certification in this Cause that the plant in question is in service. For GAAP purposes, prioritization of recovery upon implementation of each interim step should mirror what presently occurs in various rider filings, with the first dollars recovered collecting the PISCC (both debt and equity) related to these investments. The same interim-subject-to-refund basis as for Phases 2 and 3 would apply, with the same time period for other parties to raise objections. Because the number and timing of interim steps is dependent on the actual in-service dates, one cannot reliably predict precisely how many interim steps there will be, when they will occur, the overall increase at each step, or the overall ultimate reduction in Phase 3 rates from using interim steps. As such, the overall revenue requirement in Petitioner's Exhibit No. 20 is presented as if there were no interim steps.

V. REVENUE REQUIREMENT SCHEDULES

Q. PLEASE GENERALLY DESCRIBE THE STRUCTURE OF THE REVENUE REQUIREMENT SCHEDULES AND WORKPAPERS INCLUDED IN PETITIONER'S EXHIBIT NO. 20.

A. The revenue requirement schedules support the proposed final rates at Phase 3. The Company has included within Petitioner's Exhibit No. 20 all of its revenue requirement schedules and associated workpapers in native format, with printed copies of the schedules referenced below in Petitioner's Exhibit No. 21. As previously explained, these calculations are organized by schedule to differentiate the components and more clearly explain each of the factors utilized to derive the proposed revenue requirement and revenue increase.

- **A Schedules** – Revenue Increase and Financial Summary, including the gross revenue conversion factor support.
- **B Schedules** – Rate Base, and all components with pro forma adjustments.

- **C Schedules** – Income Statement and all pro forma adjustments.
- **D Schedules** – Capital Structure and Weighted Average Cost of Capital.
- **E Schedules** – Revenue Proof and Bill Impacts, referred to as the "Revenue Model."

VI. A SCHEDULES

Q. PLEASE DESCRIBE SCHEDULE A-1.

A. **Schedule A-1** is the overall financial summary including rate base, operating income, rate of return, and the proposed revenue increase. As indicated on this summary schedule and as I explained previously, the forecasted rate of return on a pro forma basis for calendar year 2025 without a general rate case is 3.91%, which is significantly below the level required to provide CEI South with a fair and reasonable return as recommended by Petitioner's Witnesses Jerasa and Bulkley.

Q. PLEASE EXPLAIN THE CALCULATION OF THE REVENUE DEFICIENCY FOR THE FORWARD-LOOKING TEST YEAR OF DECEMBER 31, 2025.

A. The revenue deficiency is determined by multiplying the test year ending rate base of $2,820,468,760 by the proposed rate of return (equal to the weighted average cost of capital) of 7.06% to arrive at the required operating income of $199,125,094. The difference between the required operating income and the pro forma operating income without this rate case results in the operating income deficiency of $88,822,861. The operating income deficiency is multiplied by the Gross Revenue Conversion Factor ("GRCF") to arrive at the revenue deficiency of $118,757,693.

Q. IS THE PRO FORMA NET OPERATING INCOME WITHOUT THIS RATE CASE THE SAME THING AS THE PRO FORMA NET OPERATING INCOME AT THE RATES THAT ARE IN EFFECT AS OF THE DATE THE PETITION WAS FILED IN THIS CASE?

A. No. CEI South believes that what matters most to customers is how much rates will change as a result of this case. The need for a rate increase is primarily driven by the increase in rate base, and a significant amount of that rate base increase is related to TDSIC and federal mandate projects that have already been reviewed and approved by the Commission and would be reflected in rates even without this case. This means

that an average customer's rates would increase to reflect cost recovery associated with these approved projects even if this case had not been filed. The unadjusted test year revenues reflect these increases that would naturally occur between now and the end of the test year had this case not been filed. As such, the pro forma net operating income without this rate case uses the rates that would be in effect based upon a December 31, 2025 rider cutoff had this case not been filed. Those are not the same rates that are in effect in December 2023. While the schedules will refer to this as the pro forma "present rates," that language means the pro forma results at the rates that would presently be in effect without this case.[2] This is the same presentation that the Company used in its most recent gas base rate case, Cause No. 45447.

Q. PLEASE DESCRIBE THE GRCF THAT IS SHOWN ON SCHEDULE A-2.

A. **Schedule A-2** presents the calculated GRCF of 1.3370172 which is used to determine the overall revenue increase on **Schedule A-1**. The GRCF uses the current statutory federal income tax rate of 21% and the statutory Indiana State Tax Rate of 4.90% effective July 1, 2021. The GRCF calculates the incremental gross revenue required to generate the incremental dollar of net operating income accounting for the effects of taxes, IURC fees, and uncollectible accounts.

Q. HOW DID THE COMPANY DETERMINE THE UNCOLLECTIBLE EXPENSE (OR BAD DEBT) RATE USED IN THE CURRENT PROCEEDING?

A. The uncollectible expense rate of 0.300% as depicted in the GRCF was determined based on the ratio of the three-year (2020 – 2022) average of (1) bad debt charge offs, net of collections, to (2) total revenues.

[2] At the time of filing the Petition in this Cause, CEI South has proceedings pending in Cause Nos. 45894 and 45903. The revenue requirement model filed with the Petition assumes that CEI South's relief in those Causes will be granted. To the extent the Commission's Final Order in those Causes differs from that proposed by CEI South, CEI South will update Petitioner's Exhibit No. 20 and Petitioner's Exhibit No. 21 to reflect the result of any changes. Orders in these cases could affect the total cost recovery under the 45894 TDSIC Plan as well as the timing of recovery. It could also affect the method of recovery of ash pond remediation costs pending in Cause No. 45903.

VII. B SCHEDULES

Q. PLEASE DESCRIBE THE COMPONENTS OF SCHEDULES B, RATE BASE.

A. The purpose of the B Schedules is to present the forecasted rate base as of December 31, 2025. The rate base summary is shown on **Schedule B-1**, reflecting the total rate base forecasted of $2,820,468,760. This schedule includes various components from other B Schedules, as referenced on **Schedule B-1**. The supporting schedule references are: **B-2**, plant in service; **B-3**, reserve for accumulated depreciation; and **B-4**, other rate base components, which include fuel stock, utility materials and supplies, material storeroom expense, allowance inventory, and regulatory assets related to PISCC for capital expenditure programs that will have been approved.

Q. PLEASE DESCRIBE GENERALLY HOW RATE BASE IS CALCULATED FOR THIS PROCEEDING.

A. CEI South began with the actual rate base as of December 31, 2022. As described in the testimony of Petitioner's Witnesses Gray, Rawlinson, Bradford, and Bahr, the Company has forecasted capital expenditures for calendar years 2023, 2024, and 2025 as part of its capital investment planning process. As associated investments are placed in service, these expenditures, along with the estimated accumulated depreciation, have been included as net utility plant in service in the Company's December 31, 2025 forecasted rate base balance. As I discuss in greater detail later in my testimony, for other rate base components included in working capital, the Company has either maintained the actual December 31, 2022 balances or forecasted the balances based on activity during the 2023, 2024, and 2025 periods.

Q. PLEASE DESCRIBE SCHEDULE B-1.1.

A. **Schedule B-1.1** presents a roll-forward of the rate base as determined in the Company's last rate case to the amounts forecasted in this proceeding, by FERC major class of plant. The schedule starts with the comparison of the last authorized rate base in Cause No. 43839, as of June 30, 2009, to the rate base as of December 31, 2025, noting the changes over this sixteen-year period. Petitioner's Witnesses Rawlinson, Bradford, and Bahr discuss in greater detail in their testimony the activity that comprises the material changes in gross plant since 2009.

From the actual December 31, 2022 balances, the 2023 activity is added in Column D of **Schedule B-1.1** to calculate the December 31, 2023 rate base balance. The 2023 capital investment plan is supported by Petitioner's Witnesses Rawlinson, Bradford, and Bahr. The Company has taken these capital expenditures and determined the estimated activity that will be placed in service during calendar year 2023, using the same information that supports the calculation of forecasted depreciation expense as discussed in greater detail by Petitioner's Witness Gray. The difference between the activity included in rate base in 2023 and the capital investment plan dollars supported by Petitioner's Witnesses Rawlinson, Bradford, and Bahr is the exclusion of any year-end 2023 construction work in progress ("CWIP") activity, which is not included in rate base at Phase 1 in this proceeding. The estimated Phase 1 rate base amount, as of December 31, 2023 in Column E, is forecasted to be $1,827,211,874.

The same process is followed for 2024 capital investment plan activity. Activity for 2024 is included in Column F to forecast the December 31, 2024 rate base balance. The estimated Phase 2 rate base amount, as of December 31, 2024 in Column G, is forecasted to be $1,930,379,152. Following the same process, 2025 capital investment plan activity is included in Column H to forecast the December 31, 2025 rate base balance. The estimated Phase 3 rate base amount, as of December 31, 2025 in Column I, is forecasted to be $2,820,468,760, as used within the revenue requirement schedules to determine the requested increase in this proceeding.

Later in my testimony, I will discuss adjustments that have been included in the forecasted December 31, 2025 rate base. These adjustments have been captured in the forecasted periods.

Q. PETITIONER'S WITNESS BRADFORD DESCRIBES IN HIS TESTIMONY THE RETIREMENT OF WARRICK UNIT 4. IS THAT RETIREMENT REFLECTED IN YOUR B SCHEDULES?

A. Yes. As Petitioner's Witness Bradford notes, Warrick Unit 4 has been jointly owned and operated by Alcoa Power Generating Inc. ("Alcoa") and CEI South since 1968 pursuant to a Joint Operating Agreement ("JOA"). That original agreement had an operating term of [redacted]. An Amendment to the JOA for Warrick Unit 4 was executed in 2017 (the "2017 Amendment"). Under the 2017 Amendment, [redacted]

[redacted]The term of the 2017 Amendment continued until December 31, 2023 and thereafter until terminated by written notice by either party. [redacted] provided timely written notice to terminate, which now triggers a process [redacted] As a result of this sequence of events, the unit is no longer used and useful as of December 31, 2023 and is being retired from the books and records as of that date. This is considered a normal retirement, and the B Schedules reflect the journal entries prescribed by the FERC Uniform System of Accounts to reflect the retirement – debiting Account 108 and crediting Utility Plant in Service for the original cost. As I noted, there is a process under the 2017 Amendment [redacted] If and when there is a final agreement with Alcoa, the Company expects it will need to file a proceeding with the Commission.

Q. IS ALL OF THE PLANT IN SERVICE INCLUDED IN RATE BASE USED AND USEFUL IN PROVIDING UTILITY SERVICE?

A. The plant in service as of December 31, 2022 is rendering service to CEI South's customers receiving service subject to the Commission's jurisdiction and is used and useful in that regard. The plant in service in the forward-looking test year is anticipated to be used and useful to render service to the Company's customers. The phase-in process that I have described previously will provide assurance that only plant that is placed in service will be reflected in rates.

Q. PLEASE DESCRIBE SCHEDULES B-2 AND B-2.1?

A. **Schedule B-2** presents the gross plant in service forecasted for December 31, 2025 by major FERC class of plant. **Schedule B-2.1** is the supporting detail for this schedule, subdividing the class of plant by account and sub-account.

Q. HAS CEI SOUTH PROPOSED ADJUSTMENTS TO THE FORECASTED RATE BASE AS OF DECEMBER 31, 2025?

A. Yes. On **Schedule B-2 and B-2.1**, specifically in the "Adjustments" column, gross plant in service forecasted as of December 31, 2025 includes three primary adjustments. The adjustments have both gross plant and accumulated reserve

impacts. The first adjustment relates to the Midcontinent Independent System Operator ("MISO") Regional Expansion Criteria and Benefit ("RECB"). The second adjustment relates to a 50 MW Solar Farm in Troy, Indiana ("Troy Solar").[3] The third adjustment relates to a 130 MW solar farm in Pike County, Indiana ("Crosstrack Solar").[4]

Q. PLEASE DESCRIBE THE ADJUSTMENT ASSOCIATED WITH MISO RECB INVESTMENTS.

A. This adjustment reflects the removal of the utility plant in service and associated accumulated depreciation of RECB transmission plant in service. Pursuant to the Commission's Order in Cause No. 43111, CEI South has treated MISO-approved RECB investments as FERC jurisdictional. This accounting treatment was affirmed in CEI South's following base rate case, Cause No. 43839. As a result of this treatment, CEI South has removed the revenues, operating expenses, and associated rate base related to these investments, and treated them as non-jurisdictional. CEI South continues this accounting practice of treating RECB projects as non-jurisdictional and recovery is handled outside of base rate cases.

Q. PLEASE DESCRIBE THE ADJUSTMENT ASSOCIATED WITH TROY SOLAR.

A. This adjustment reflects the removal of the utility plant in service and associated accumulated depreciation of the assets associated with Troy Solar. CEI South was granted authority to recover the costs of Troy Solar using a levelized rate through the CECA annual tracker. As part of the settlement agreement in Cause No. 45086, the Order states that the project will be excluded from the calculation of the Company's electric revenue requirement in each rate case over the life of the project. Specifically, as it pertains to this adjustment, the Order states that the project will be excluded from rate base in such future base rate cases.

Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO CROSSTRACK SOLAR PROJECT.

A. This adjustment reflects the removal of the utility plant in service and associated accumulated depreciation of the assets associated with Crosstrack Solar. CEI South was granted authority to recover the costs of Crosstrack Solar using a levelized rate

[3] IURC Cause No. 45086, March 20, 2019.
[4] IURC Cause No. 45754, January 1, 2023.

through the CECA annual tracker. The unadjusted forecast assumes that Crosstrack Solar would be placed in service during the test year as was detailed in Cause No. 45754. Similar to the way CEI South accounts for Troy Solar, per the Final Order in Cause No. 45754, when completed CEI South would have excluded Crosstrack Solar from rate base in future base rate cases. Petitioner's Exhibit No. 20 has been prepared based upon that assumption; therefore, the net book value of the assets have been excluded from rate base. As it is, CEI South [redacted] Crosstrack Solar and its commercial operation date has been updated to 2026, which is beyond the test year in this Cause. While the schedules may reflect adjustments for Crosstrack Solar as a levelized rate (similar to Troy Solar), none of the costs associated with Crosstrack Solar should be included because it is beyond the test year.

Q. PLEASE DESCRIBE SCHEDULES B-3 AND B-3.1.

A. **Schedule B-3** is the accumulated depreciation and amortization balances by FERC account and subaccount, forecasted as of December 31, 2025. **Schedule B-3.1** summarizes the corresponding adjustments for the test year, discussed earlier in my testimony, to the accumulated depreciation reserve by FERC account. Each of these adjustments to gross plant in service also carried with it a corresponding adjustment to the accumulated reserve account. The net impact of each is summarized in the table below:

Table CMB-1 – Net Plant Adjustments

Description	Gross Plant In Service (Schedule B-2.1)	Accumulated Depreciation Reserve (Schedule B-3.1)	Net Adjustments to Rate Base
MISO RECB	$(162,709,742)	$52,120,703	$(110,589,039)
Troy Solar	$(97,671,665)	$14,193,921	$(83,477,744)
Crosstrack Solar	$(291,140,060)	$2,079,572	$(289,060,488)
Total	$(551,521,467)	$68,394,196	$(483,127,271)

Q. WILL CEI SOUTH BE PROPOSING NEW DEPRECIATION RATES IN THE PROCEEDING?

A. Yes. CEI South is proposing new depreciation rates effective upon an order in this proceeding. The "Depreciation Study" and the proposed depreciation rates are

supported by the testimony of Petitioner's Witness Spanos. CEI South included the annualized depreciation expense based on December 31, 2025 plant in service balances in its revenue requirement schedules. The new depreciation accrual rates are forecasted to take effect in Phase 1, and the forecasted net original cost rate bases for Phases 2 and 3 reflect an effective date of the new depreciation rates in approximately November 2024. As explained by CEI South Witness Richard C. Leger, in an effort to mitigate the rate impact of the requests in this case, CEI South is not seeking to implement the depreciation rates for the new combustion turbines and Posey Solar that are recommended by Mr. Spanos. Instead, we are proposing to continue to use the depreciation rates for these projects that were approved in Cause Nos. 45564 and 45847. Depreciation rates for these generating stations will be reviewed on the next occasion that CEI South conducts a depreciation study for its electric plant.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. **Schedule B-3.2** presents the calculation of the pro forma level of depreciation expense, by FERC account and subaccount, using the forecasted and adjusted December 31, 2025 gross plant in service and current approved depreciation rates, as compared to those depreciation rates proposed by Petitioner's Witness Spanos. This schedule shows that the current approved depreciation rates would result in annual depreciation on forecasted gross plant in service of $122.478 million, whereas the proposed depreciation rates applied to the same asset base would produce annual depreciation of $143.047 million.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. **Schedule B-4** presents the other rate base component items, forecasted as of December 31, 2025. Within this schedule, there are eleven specific items included in rate base as working capital components.

The first four components are: (1) fuel stock; (2) utility materials and supplies; (3) storeroom expenses associated with the materials and supplies; and (4) allowance inventory. Each balance noted on Workpaper WPB-4.1 reflects a thirteen-month average of the actual balances for CEI South for the monthly periods ended December 31, 2022, with the exception of fuel stock and utility materials and supplies. Fuel stock and utility materials and supplies were adjusted to reflect the retirement of A.B. Brown

and Warrick Unit 4, as detailed in Workpapers WPB-4.1a and WPB-4.1b. The Company does not generally forecast these balances as part of its forecasting process, so the Company has maintained the actual, historical balances as the basis for inclusion in rate base in this proceeding.

The remaining seven components are regulatory assets associated with the deferral of PISCC associated with projects or programs forecasted to be approved as of December 31, 2025. The first regulatory asset is related to the Company's Advanced Metering Infrastructure ("AMI") project. The accounting treatment for this deferral was approved in Cause No. 44910. The second regulatory asset is related to the Company's initial TDSIC plan. The accounting treatment for this PISCC deferral was originally approved in Cause No. 44910, with amounts approved in subsequent TDSIC proceedings. The third regulatory asset is related to the Company's second TDSIC plan.[5] The accounting treatment for this PISCC deferral has been sought in Cause No. 45894. The fourth regulatory asset is related to the Company's annual CECA proceeding.[6] The accounting treatment for this PISCC deferral was originally approved in Cause No. 44909, with amounts approved in subsequent CECA proceedings. The fifth regulatory asset is related to the Company's annual ECA proceeding. The accounting treatment for this PISCC deferral was originally approved in Cause No. 45052, with amounts approved in subsequent ECA proceedings. The sixth regulatory asset is related to the PISCC associated with the F.B. Culley East Ash Pond Closure. The accounting treatment for this deferral has been sought in Cause No. 45903. It includes the PISCC that is forecasted to accrue after the completion of the project and before the commencement of recovery through the ECA, as I explained in my direct and rebuttal testimony in that Cause.[7] The seventh regulatory asset is related to the PISCC associated with the natural gas Combustion Turbines ("CTs"). The accounting treatment for this deferral was originally approved in Cause No. 45564.[8]

[5] See note 2, supra.
[6] In addition to the PISCC deferral originally approved in Cause No. 44909 and amounts separately approved in subsequent CECA proceedings, this regulatory asset also includes PISCC associated with Posey Solar, approved in Cause No. 45847.
[7] See note 2, supra.
[8] To the extent the proposed additional interim phases are granted, the forecasted level of PISCC associated with the CTs and Posey Solar will be reduced. It will only be the actual amount that is accrued for purposes of the implementation of Phase 3 rates.

VIII. C SCHEDULES

Q. PLEASE DESCRIBE THE COMPONENTS OF SCHEDULES C, INCOME STATEMENT AND ADJUSTMENTS.

A. The C Schedules present the calculation of CEI South's operating income for the test year, adjusted to capture items that were not within the 2025 forecast.

Q. PLEASE DESCRIBE SCHEDULE C-1.

A. **Schedule C-1** is the pro forma income statement showing adjusted revenues and expenses under what would be the present customer rates without this case and the impact of the proposed revenue increase. This schedule shows that under the rates without this case, the Company's pro forma rate of return forecasted for 2025 is 3.91%. The revenue increase calculated within **Schedule E-4** is based on the rates submitted as part of CEI South's proposed tariff supported by Petitioner's Witnesses Taylor and Rice. By adjusting the current adjusted operating income statement by the impact of the proposed rates, this schedule shows that the Company's rate of return will increase to 7.06%, which is the requested Rate of Return reflected on **Schedule D-1** and discussed by Petitioner's Witness Jerasa.

Q. PLEASE DESCRIBE SCHEDULE C-1.1.

A. **Schedule C-1.1** presents a more detailed view of the pro forma income statement, through net operating income, for the twelve months ended December 31, 2025. Column A presents the unadjusted income statement, by FERC Account, for the 2025 forecast as supported by Petitioner's Witness Gray. Column B summarizes the pro forma adjustments required to the test year. These pro forma adjustments are detailed within the various **C-3 Schedules** I will discuss later in my testimony. These adjustments are numbered sequentially starting with **Schedule C-3.1** and presented by FERC Account, shown on the far-left side of **Schedule C-1.1**. Column C then represents the pro forma income statement at present rates. Column D captures the revenue increase, as noted on **Schedule C-1**, to arrive at the pro forma at proposed rates income statement presented in Column E. The version of **Schedule C-1.1** in native format as presented in Petitioner's Exhibit No. 20 can be expanded to show the breakdown of the Test Year Unadjusted column on a monthly basis.

Q. IN YOUR OPINION, DOES SCHEDULE C-1.1, COLUMN E ACCURATELY REFLECT CEI SOUTH'S PROJECTED OPERATING RESULTS DURING THE TEST YEAR, WITH APPROPRIATE ADJUSTMENTS?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE C1.1a.

A. **Schedule C-1.1a** presents a summarized view of the pro forma income statement, through net operating income, for the twelve months ended December 31, 2025. Column A presents the unadjusted income statement for 2025 forecasted as supported by Petitioner's Witness Gray. Column B summarizes the pro forma adjustments required to the test year. Column C then represents the pro forma income statement at the rates that would be in effect without this case. Column D captures the revenue increase, as noted on **Schedule C-1**, to arrive at the pro forma at proposed rates income statement presented in Column E.

Q. PLEASE DESCRIBE SCHEDULE C-2.

A. **Schedule C-2** reflects the Company's operating income for the test year, the twelve months ended December 31, 2025, adjusted for several items as identified in **Schedule C-3** (Summary of Adjustments to Operating Income). These adjustments will be discussed later in my testimony.

Q. PLEASE DESCRIBE SCHEDULE C-2.1.

A. **Schedule C-2.1** provides the detail of the revenue and expenses for the test year, by account in accordance with FERC USoA. The detail provided on this schedule represents the test year amounts and is unadjusted, as supported by Petitioner's Witness Gray.

Q. PLEASE DESCRIBE SCHEDULE C-3.

A. The amounts as indicated on **Schedule C-3** represent a summary of the adjustments which are detailed on **Schedules C-3.1** through **C-3.39**. The adjustments are necessary to reflect the annual effect of expenses and revenues for ratemaking purposes and establish test year expense and revenue levels appropriate for ratemaking purposes.

Q. PLEASE DESCRIBE SCHEDULES C-3.1 THROUGH C-3.12.

A. **Schedules C-3.1** through **C-3.12** are pro forma adjustments to the Company's test year gross revenues and represent an overall net increase in test year revenues.

Q. HAS CEI SOUTH PROVIDED DETAILED CALCULATIONS SUPPORTING THE DETERMINATION OF THE PRO FORMA LEVEL OF OPERATING REVENUES WITHIN THE DOCUMENTS SUBMITTED IN THIS PROCEEDING?

A. Yes. The Company has included as workpapers documents that support these adjustments, and specifically support for the amount ultimately utilized on **Schedule E-4.1** for the Revenue Proof, which is supported by Petitioner's Witness Taylor. These workpapers, referred to below as the "Revenue Model" provide detailed calculations of the test year and pro forma level of operating revenues by Rate Schedule.

Q. PLEASE DESCRIBE SCHEDULE C-3.1.

A. **Schedule C-3.1** reflects the change to operating revenues to remove revenues from the forecast to match contracts in place that have been approved pursuant to Ind. Code § 8-1-2-24.

Q. PLEASE DESCRIBE SCHEDULE C-3.2.

A. **Schedule C-3.2** reflects adjustments associated with the TDSIC rider related to the 2017 – 2023 TDSIC Plan under Cause No. 44910 (the "44910 TDSIC" or "2017 – 2023 TDSIC Plan") and the 2024 – 2028 TDSIC Plan under Cause No. 45894 (the "45894 TDSIC" or "2024 – 2028 TDSIC Plan"). The 2025 forecast includes 100% of the 44910 TDSIC revenues but present rates only allow for the collection of 80% of the revenue requirement associated with the approved 44910 TDSIC investments. The 2025 forecast includes the recognition of this deferral authority, and includes the deferred amount forecasted; however, this amount should be removed from the test year operating revenues as present rates and charges do not include recovery of this balance. This adjustment removes the remaining 20% deferred for recovery. Note that the annual amortization of the 20% that will have been deferred up to the anticipated order date in this Cause is reflected in **Schedule C-3.21**. Additionally, this adjustment annualizes the level of 45894 TDSIC recovery that would be reflected in the TDSIC based upon a December 31, 2025 cutoff. Finally, the 2025 forecast includes recovery of 100% of the 45894 TDSIC costs based upon a December 31, 2025 cutoff. The rider allows for only the collection of 80% of the revenue requirement associated with the

approved 45894 TDSIC investments. The remaining 20% is deferred for recovery. The 2025 forecast includes the recognition of this deferral authority and includes the deferred amount forecasted; however, this amount should be removed from the test year operating revenues as present rates and charges do not include recovery of this balance.

Q. PLEASE DESCRIBE SCHEDULE C-3.3.

A. **Schedule C-3.3** reflects the change in operating revenues and expenses for annualized CECA revenues and the removal of the levelized rate projects, Troy Solar and Crosstrack Solar, that are excluded from rate base. In addition, and similar to the TDSIC, this adjustment annualizes revenues in the 2025 forecast for assets in service through December 31, 2025 that are currently recovered through the CECA filing or would have been recovered through the CECA filing absent this base rate case. To clarify, Posey Solar has been authorized for recovery through the CECA to the extent not included in rate base in CEI South's general rate case. As such, had this case not been filed, Posey Solar would be reflected in the CECA and is therefore reflected in pro forma present rate revenues.

Q. PLEASE DESCRIBE SCHEDULE C-3.4.

A. **Schedule C-3.4** reflects adjustments associated with the ECA rider. The 2025 forecast includes 100% of the ECA revenues forecasted through December 31, 2025. This rider, currently authorized under Cause No. 45052, allows for the collection of 80% of the revenue requirement associated with the approved federally mandated projects. The remaining 20% is deferred for recovery within this base rate case in **Schedule C-3.23**. The 2025 forecast includes the recognition of this deferral authority and includes the deferred amount forecasted; however, this amount should be removed from the test year operating revenues as present rates and charges do not include recovery of this balance. This adjustment also annualizes the revenues forecasted to be recovered through the ECA based upon a cutoff at December 31, 2025. The adjustment also reflects a decrease in forecasted O&M recovery, which corresponds to the anticipated proceeds to be received for the sale of ash from the A.B. Brown Ash Pond Project approved in Cause No. 45280.

Q. PLEASE DESCRIBE SCHEDULE C-3.5.

A. **Schedule C-3.5** reflects the change in operating revenues for annualized Demand Side Management Adjustment ("DSMA") revenue and to allocate DSMA Over/Under recoveries to the rate classes from miscellaneous revenues.

Q. PLEASE DESCRIBE SCHEDULE C-3.6.

A. **Schedule C-3.6** reflects an allocation of MISO Cost and Revenue Adjustment ("MCRA") Over/Under recovery to the rate classes from miscellaneous revenues and to match forecasted MCRA revenues with recoverable expenses.

Q. PLEASE DESCRIBE SCHEDULE C-3.7.

A. **Schedule C-3.7** reflects an allocation of Reliability Cost and Revenue Adjustment ("RCRA") Over/Under recovery to the rate classes from miscellaneous revenues and to match forecasted RCRA revenues with recoverable expenses. In addition, this adjustment reflects anticipated purchases of capacity from a demand response aggregator.

Q. PLEASE DESCRIBE SCHEDULE C-3.8.

A. **Schedule C-3.8** reflects adjustments to excess accumulated deferred income tax ("EDIT"). Currently, the Company is returning to customers the EDIT associated with the Tax Cuts and Jobs Act through the TDSIC, pursuant to the Settlement Agreement approved in Cause No. 45032 S21. As explained by Witness Rice, the Company plans to continue to pass back this EDIT per that Settlement Agreement outside of base rates, but now is proposing to do so through the Tax Adjustment Rider ("TAR"). This adjustment increases pro forma revenues by the amount forecasted to be passed back during the test year, as it will not be passed back through base rates but through the TAR. In addition, to avoid passing the amounts back twice, a similar adjustment has been made to remove the pass-back in the calculation of federal income tax.

Q. PLEASE DESCRIBE SCHEDULE C-3.9.

A. This is similar to Adjustment C-3.8. In Cause No. 45722, the Commission approved the issuance of Securitization Bonds. That Order also required that the EDIT associated with A.B. Brown (which was similarly being flowed back to customers through the TDSIC) be amortized and returned to customers over the life of those Securitization Bonds. Effective upon closing of those bonds, the Company filed a

revision to its EDIT credit in the TDSIC to make this change. As such, the EDIT associated with A.B. Brown is being flowed back to customers over the life of the bonds via the TDSIC. The Company will continue to flow back this EDIT over the life of the bonds but is instead proposing to reflect the pass-back through the new TAR. This adjustment removes the forecasted pass-back from base rate revenues, as it will be reflected outside base rates. **Schedule C-3.9** reflects this adjustment.

Q. PLEASE DESCRIBE SCHEDULE C-3.10.

A. **Schedule C-3.10** reflects the change in operating revenues and operating expenses for normalized FAC associated with F.B. Culley 2.

Q. PLEASE DESCRIBE SCHEDULE C-3.11.

A. **Schedule C-3.11** reflects the removal of operating revenues and operating expenses for RECB projects. The revenues and expenses associated with these projects relate to non-jurisdictional transmission projects under the MISO Transmission Expansion Plan ("MTEP") process. The treatment to remove the impact of these projects was established in Cause No. 43111 and affirmed in Cause No. 43839.

Q. PLEASE DESCRIBE SCHEDULE C-3.12.

A. **Schedule C-3.12** reflects the change in operating revenues and operating expenses for various adjustments to Miscellaneous Revenue to synchronize to the forecasted test year revenue.

Q. PLEASE DESCRIBE SCHEDULE C-3.13.

A. **Schedule C-3.13** represents an adjustment of $414,956 to increase test year expenses for the estimated incremental rate case costs associated with this proceeding. Line 1 reflects the total estimated cost of the current proceeding, $2,074,780. Line 2 reflects the amortization period of five years. CEI South has proposed a five–year TDSIC Plan and, upon Commission approval of that Plan, CEI South must file a general rate case before the end of that Plan. That is the basis for the five-year amortization period. Line 3 reflects the annual pro forma amortization. If a rate case is filed before the end of the five year amortization, CEI South would propose to recover the unamortized balance in its next general rate case.

Q. PLEASE DESCRIBE SCHEDULE C-3.14.

A. **Schedule C-3.14** represents the increase in operating expenses of $108,034 associated with the proposed five year amortization of COVID-19 deferred expenses. Pursuant to the Commission's June 29, 2020 Order in Cause No. 45380 following the mandated moratorium on utility disconnections, CEI South established a regulatory asset to track COVID-19 related impacts. In combination with the temporary disconnection moratorium, the Commission's Orders with respect to extended payment plans, deferrals, and other arrangements have resulted in an increase in uncollectible accounts. Since the Commission's authorization to do so in its June 29, 2020 Order in Cause No. 45380, the Company has deferred bad debt expense associated with COVID-19 in a regulatory asset. We have chosen the same amortization period as the life of rates in this Cause.

Q. PLEASE DESCRIBE SCHEDULE C-3.15.

A. **Schedule C-3.15** reflects the pro forma level of IURC Fees and is determined by applying a rate of 0.147% (Line 2) to the adjusted test year operating revenues of $741,397,336 (Line 1). The pro forma increase of $211,836 on Line 5 was calculated as the difference between the pro forma level of IURC assessment fee (Line 3) and the unadjusted test year assessment fee amount (Line 4).

Q. PLEASE DESCRIBE SCHEDULE C-3.16.

A. **Schedule C-3.16** in the amount of $9,946,645 reflects an adjustment to annualize depreciation expense based on plant in service as of December 31, 2025 at the proposed depreciation rates discussed above. This is calculated by taking the annualized depreciation expense of $143,046,671 as shown in **Schedule B-3.2** less the adjustments for TDSIC annualized depreciation expense of $4,004,864 (**Schedule C-3.2**), for CECA annualized depreciation expense of $12,011,430 (**Schedule C-3.3**), for ECA annualized depreciation expense of $459,384 (**Schedule C-3.4**), and the test year depreciation expense of $116,624,348 (**Schedule C-2.1**).

Q. PLEASE DESCRIBE SCHEDULE C-3.17.

A. **Schedule C-3.17** includes expenses associated with Troy Solar and removes them from the revenue requirement calculation. CEI South was granted authority to recover the costs of Troy Solar using a levelized rate through the CECA annual tracker. As part of the Settlement Agreement in Cause No. 45086, the Order states that the project

will be excluded from the calculation of the Company's electric revenue requirement in each rate case over the life of the project.

Q. PLEASE DESCRIBE SCHEDULE C-3.18.

A. **Schedule C-3.18** includes expenses associated with Crosstrack Solar and removes them from the revenue requirement calculation. CEI South was granted authority to recover the costs of Crosstrack Solar using a levelized rate through the CECA annual tracker. The adjustment is shown in this fashion for Crosstrack Solar even though, as I previously explained, Crosstrack Solar is not expected to be in service before the end of the test year.

Q. PLEASE DESCRIBE SCHEDULE C-3.19.

A. **Schedule C-3.19** reflects a pro forma adjustment increase of $38,459 in Vectren Utility Holdings, LLC ("VUH") shared services charges for the test year. The VUH shared services charge represents the centralization of the assets that service multiple utility jurisdictions, and the subsequent charging via a lease or rental charge as operating expense to the utilities. The shared services charge includes depreciation expense, property taxes, and a fair and reasonable return on net plant. The adjusted test year amount of $4,690,415 is based on the allocated share of forecasted plant at December 31, 2025, multiplied by the pre-tax rate of return proposed in this proceeding, with the return on the assets adding to the annual depreciation and property tax expense to determine the total shared services charge. This is consistent with the treatment of these costs in CEI South's most recent gas rate case, Cause No. 45447.

Q. PLEASE DESCRIBE SCHEDULE C-3.20.

A. **Schedule C-3.20** reflects the annual amortization expense associated with the AMI deferrals related to PISCC and deferred depreciation. Per the Final Order in Cause No. 44910 for TDSIC, accounting treatment was approved to accrue PISCC and to defer, without carrying costs, the depreciation associated with the AMI project. The total investment in the AMI project eligible for this deferred accounting authority was capped at $39 million and the total amount of deferred debt related to post-in-service carrying costs would not exceed $12 million. The deferred depreciation and deferred PISCC balance were approved to be recovered over a period of ten years, with the deferred depreciation being without carrying costs, in the Company's next electric rate case. The forecasted December 31, 2025 regulatory asset balance for AMI PISCC

and depreciation is $16,435,272, with the amortization period representing the approved ten years.

Q. PLEASE DESCRIBE SCHEDULE C-3.21.

A. **Schedule C-3.21** reflects the annual amortization expense associated with the regulatory assets for the TDSIC approved in 2017 in Cause No. 44910 (the "44910 TDSIC"), and the TDSIC pending in Cause No. 45894 (the "45894 TDSIC"). Regulatory assets include PISCC and deferred depreciation, and 20% of the revenues. The PISCC and deferred depreciation regulatory assets have an amortization period representing the average remaining asset life of 34 years. The forecasted December 31, 2025 PISCC and deferred depreciation balance for the 44910 TDSIC is $24,003,107 and for the 45894 TDSIC is $7,463,195. In addition to these regulatory assets, the statute requires that the utility recover 80% of its revenues via its approved recovery mechanism, with the remaining amount deferred. The deferred revenues regulatory assets are being amortized over seven years.[9] The total annual amortization expense is $6,965,302 collectively for both TDSIC plans and all regulatory assets including PISCC, deferred depreciation, and the 20% revenue deferral. The deferrals will be updated with each phase and will not be included in the calculation until incurred.

Q. PLEASE DESCRIBE SCHEDULE C-3.22.

A. **Schedule C-3.22** reflects the annual amortization expense associated with the regulatory assets for CECA approved in 2019 in Cause No. 44909. The Company has recorded PISCC and deferred depreciation to regulatory assets, which have an amortization period representing the average remaining asset life of 27 years. In addition, O&M expense was deferred to a regulatory asset, which is proposed to be amortized over seven years. The total annual amortization expense is $994,415 collectively for all regulatory assets including PISCC, deferred depreciation, and O&M expense deferral.

Q. PLEASE DESCRIBE SCHEDULE C-3.23.

A. **Schedule C-3.23** reflects the annual amortization expense associated with the regulatory assets for ECA approved in 2019 in Cause No. 45052. The Company has

[9] See note 2, supra.

recorded PISCC and deferred depreciation to regulatory assets, which have an amortization period representing the average remaining asset life of 23 years. In addition to these regulatory assets, the statute requires that the utility recover 80% of its revenues via its approved recovery mechanism, with the remaining amount deferred. The deferred revenues regulatory asset is being amortized over seven years. Finally, O&M expense has been deferred as well and the regulatory asset is also being amortized over seven years. The total annual amortization expense is $15,911,386 collectively for all regulatory assets including PISCC, deferred depreciation, 20% revenue deferral, and O&M expense deferral.

Q. PLEASE DESCRIBE SCHEDULE C-3.24.

A. This is amortization of the PISCC that will accrue to a regulatory asset after completion of the F.B. Culley East Ash Pond project at issue in Cause No. 45903.[10] Total forecasted PISCC deferral is $2,712,341 with an amortization period of seven years estimating amortization expense to be $387,477 annually.

Q. YOU MENTIONED PREVIOUSLY THAT IN CAUSE NO. 45903 THERE WAS AN ISSUE CONCERNING THE PROPER METHOD OF RECOVERY ASSOCIATED WITH THESE ASH POND REMEDIATION COSTS. WHAT IS THAT ISSUE AND HOW COULD IT AFFECT THIS CASE?

A. The Indiana Office of Utility Consumer Counselor ("OUCC") has taken the position that proper accounting for these costs is through traditional cost of removal accounting, with its associated effect on net original cost rate base and the establishment of depreciation rates. While I agree that this is one proper method for recovering these costs, the federal mandate statute is an additional method providing for a timelier recovery. In any event, at the time of filing this case, this issue remains pending. As such, CEI South Witness Spanos has prepared and is sponsoring an alternative calculation of depreciation accrual rates in the event the requested CPCN in Cause No. 45903 is denied or CEI South is not permitted to recover these costs as requested therein.

[10] See note 2, supra.

Q. PLEASE DESCRIBE SCHEDULE C-3.25.

A. **Schedule C-3.25** reflects the annual amortization expense associated with the CT Project deferrals related to PISCC. Per the Final Order in Cause No. 45564, accounting treatment was approved to accrue and defer carrying costs associated with the CT Project. Line 1 represents the forecasted PISCC deferrals as of December 31, 2025. Line 2 represents the amortization period of 29 years based on the approved annual depreciation rate of 3.44%. If the Company's request to implement interim step(s) upon placement in service of the CTs is approved, this adjustment will be reduced accordingly.

Q. PLEASE DESCRIBE SCHEDULE C-3.26.

A. **Schedule C-3.26** reflects a pro forma adjustment decrease of $560,000 to normalize integrated resource planning ("IRP") Expense. Portions of costs incurred during an IRP are deferred and ultimately capitalized to resulting projects pursuant to the FERC USoA. There is a portion of IRP costs that are not eligible for such treatment and are expensed. As discussed by Petitioner's Witness Rice, the expense annually is not the same between 2024 and 2026 and the majority is expected in 2025. Due to this, the pro forma adjustment normalizes the expense for the test year to an adjusted expense on Line 1 of $340,000.

Q. PLEASE DESCRIBE SCHEDULE C-3.27.

A. **Schedule C-3.27** reflects the annualized property tax expense on the forecasted tax basis balance of assets as of December 31, 2025. The detailed pro forma property tax expense calculation is presented in workpapers supporting **Schedule C-3.27** and is calculated in line with the Company's annual property tax return. The resulting calculation yields pro forma property tax expense of $9,516,863, and a total pro forma adjustment of ($9,562,096) to property tax expense. Petitioner's Witness Jennifer K. Story sponsors the pro forma property tax expense.

Q. PLEASE DESCRIBE SCHEDULE C-3.28.

A. **Schedule C-3.28** reflects a pro forma adjustment of $75,808 decrease to test year expense to annualize the level of uncollectible accounts expense to the latest known level. This is calculated by taking the pro forma adjusted operating revenues on Line 1 multiplied by the bad debt write-off percentage of 0.300% as described earlier in my testimony to arrive at the amount of $2,224,192. The amount of $2,300,000 on Line 2

represents the unadjusted test year uncollectible expense, which is removed from the amount on Line 1 to arrive at the adjustment to uncollectible accounts expense.

Q. PLEASE DESCRIBE SCHEDULE C-3.29.

A. **Schedule C-3.29** reflects a pro forma adjustment of $160,653 decrease to test year expenses associated with sponsorships including Indianapolis Colts and Ford Center that should have been recorded below the line.

Q. PLEASE DESCRIBE SCHEDULE C-3.30.

A. **Schedule C-3.30** reflects a pro forma adjustment of $347,401 decrease to test year expense associated with Deferred Medicare Tax Liability, which is sponsored by Petitioner's Witness Story. Line 1 reflects the balance of $1,737,007. Line 2 reflects the amortization period of five years. CEI South has proposed a 5-year TDSIC Plan in Cause No. 45894 and, upon Commission approval of that Plan, CEI South must file a general rate case before the end of that Plan. That is the basis for the five year amortization period. Line 3 reflects the annual pro forma amortization.

Q. PLEASE DESCRIBE SCHEDULE C-3.31.

A. **Schedule C-3.31** reflects a pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with the CT Project, forecasted to be placed in service during the test year.

Q. PLEASE DESCRIBE SCHEDULE C-3.32.

A. **Schedule C-3.32** reflects a pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with Posey Solar, forecasted to be placed in service during the test year.

Q. PLEASE DESCRIBE SCHEDULE C-3.33.

A. **Schedule C-3.33** reflects a pro forma adjustment decrease to test year expense associated with F.B. Culley Unit 2, which is forecasted to retire at the end of the test year. As the unadjusted expense will be incurred throughout the entirety of the test year, this is a Phase 3 adjustment only.

Q. PLEASE DESCRIBE SCHEDULE C-3.34.

A. **Schedule C-3.34** reflects a pro forma adjustment to normalize outage operating expense. The test year includes a major outage. Planned outages do not occur every

year, and so this requires normalization of expense by averaging expense across multiple forecasted years.

Q. PLEASE DESCRIBE SCHEDULE C-3.35.

A. **Schedule C-3.35** reflects a pro forma adjustment increase to test year expenses of $770,000 pertaining to the SAP S/4HANA Transformation Project. Petitioner's Witness Bahr describes the SAP S/4HANA Transformation Project in more detail.

Q. PLEASE DESCRIBE SCHEDULE C-3.36.

A. **Schedule C-3.36** reflects a pro forma adjustment decrease to test year expenses of $1,368,371 pertaining to ash transportation and ash handling operating expenses that should have been deferred to a regulatory asset during the test year.

Q. PLEASE DESCRIBE SCHEDULE C-3.37.

A. **Schedule C-3.37** reflects a pro forma adjustment decrease to test year expenses of $159,143 pertaining to non-recurring miscellaneous forecast adjustments. The pro forma adjustment was made to correct FERC 5930 for distribution programs that should have been capitalized.

Q. PLEASE DESCRIBE SCHEDULES C-3.38 AND C-3.39.

A. **Schedule C-3.38** and **C-3.39** are calculations of the Indiana state and federal income taxes for the pro forma adjusted test year. Indiana state income taxes are calculated in detail on **Schedule C-4**, sponsored by Petitioner's Witness Story. The statutory rate utilized for the Indiana income taxes is 4.90%, which was effective July 1, 2021. Federal income taxes are calculated in detail on **Schedule C-5**, also sponsored by Petitioner's Witness Story. The current statutory rate utilized for the federal income taxes is 21%. The pro forma level of state and federal income tax expense is compared to the test year unadjusted tax expense to determine the required adjustment. As all the adjustments to revenue and operating expenses also include state and federal tax impacts, the net adjustment shown on **Schedule C-3.38** and **C-3.39** excludes all adjustments already reflected to the test year income tax expense.

IX. D SCHEDULES

Q. PLEASE DESCRIBE SCHEDULE D-1.

A. **Schedule D-1** reflects the calculation of the overall rate of return summary which is based on the forecasted capital structure on December 31, 2025. This is sponsored by Petitioner's Witness Jerasa, who also discusses how the forecasted balances for long-term debt and common equity were determined for December 31, 2025.

Q. HAS CEI SOUTH ADJUSTED THE CAPITAL STRUCTURE COMPONENTS?

A. Yes. The Commission issued an Order in Cause No. 45722 (the "45722 Order") that stated the accumulated deferred income tax ("ADIT") associated with the retiring A.B. Brown Units 1 and 2 shall be segregated from all other ADIT and not included in the calculation of capital structure or otherwise be used in finding CEI South's authorized return in future rate cases. Therefore, in compliance with the 45722 Order, the Company has excluded A.B. Brown Securitization ADIT associated with the retiring of A.B. Brown Units 1 and 2. The Company has also excluded Troy Solar and Crosstrack Solar from the capital structure since both solar farms have ratemaking terms using a fixed levelized rate per kWh of produced energy for the life of the investment allowing the Company and customers to benefit from the investment tax credit to offset project costs. The Company has included a prepaid pension asset as a component of the capital structure which is an offset to zero cost capital. This methodology is consistent with previous rulings made by the Commission in CEI South Gas and CEI North's last base rate case proceedings, Cause Nos. 45447 and 45468, respectively. Petitioner's Witness Jerasa discusses in further detail CEI South's proposal to include the prepaid pension asset in the capital structure.

Q. ARE THERE COMPONENTS OF CEI SOUTH'S CAPITAL STRUCTURE THAT HAVE NOT BEEN FORECASTED TO DECEMBER 31, 2025?

A. Yes. On **Schedule D-5** Customer Advances for Construction, Other Post-Employment Benefits ("OPEB"), Prepaid Pension, and Customer Deposits are held constant as of December 31, 2022 with no forecasted assumptions or estimates to include for the forecasted test year for 2025. This is consistent with how the Company currently forecasts, with these items not discretely forecasted for changes on the forecasted balance sheet.

Q. HOW DID THE COMPANY FORECAST THE TEST YEAR BALANCE OF INVESTMENT TAX CREDIT ("ITC")?

A. The Company used the year-end balance as of December 31, 2022 as a starting point then forecasted activity associated with amortizations of the balance through December 31, 2025 to arrive at the forecasted level of ITC included in the capital structure. Petitioner's Witness Story discusses ITC in further detail.

X. RATE PHASE SCHEDULES

Q. YOU PREVIOUSLY REFERENCED ATTACHMENTS CMB-4 AND CMB-5 AS REFLECTING THE ANTICIPATED REVENUE REQUIREMENT AT PHASES 1 AND 2 OF THE PROPOSED RATE PHASE-IN. HOW ARE THESE TWO ATTACHMENTS PREPARED?

A. **Attachments CMB-4** and **CMB-5** are print-outs of the Revenue Requirement model for purposes of Phase 1 (rates upon issuance of the Order in this Cause) and Phase 2 (rates upon beginning of the test year). The Revenue Requirement model at each step is in the same format as Petitioner's Exhibit No. 20. The complete Excel model for Phase 1 and Phase 2 is included in the workpapers. **Attachments CMB-4** and **CMB-5** are **Schedules A-1** (Overall Financial Summary), **Schedule A-2** (Calculation of Gross Revenue Conversion Factor), **Schedule B-1** (Rate Base Summary), **Schedule C-1** (Pro Forma Income Statement), **Schedule C-1.1a** (Current and Adjusted Pro Forma Income Statement), **Schedule C-3** (Summary of Adjustments to Operating Income), and **Schedule D-1** (Rate of Return Summary).

Q. BEGINNING WITH ATTACHMENT CMB-4, CAN YOU BRIEFLY SUMMARIZE HOW THIS DIFFERS FROM WHAT IS SHOWN IN PETITIONER'S EXHIBIT NO. 20?

A. As originally filed, **Attachment CMB-4** is based upon a forecasted rate base and capital structure as of December 31, 2023. Prior to the evidentiary hearing, this Attachment will be updated to the actual rate base and capital structure as of that date. The primary difference between **Attachment CMB-4** and Petitioner's Exhibit No. 20 is to use this December 31, 2023 date for purposes of **Schedule A**. The billing determinants set forth in **Schedule E** of Petitioner's Exhibit No. 20 have not been changed across all three phases. For Phase 1, expenses and the rates used to

forecast revenues have been modified to reflect the state of the forecast that will have occurred by the anticipated date of the Order.

Q. HOW DID YOU DETERMINE WHAT FORECASTED REVENUES AND EXPENSES WILL HAVE OCCURRED BY THE ANTICIPATED DATE OF THE ORDER?

A. The first step is to remove the revenues (and associated expenses) associated with the TDSIC, CECA, and ECA rates using the projected rates for these riders with a December 31, 2025 cutoff. Rates in effect at the time of the order will not have yet reflected these revenues. I have then removed amortization of PISCC and deferred depreciation associated with the CT Project and Posey Solar, because the PISCC accrual and depreciation deferral will not have commenced as of that date. These are Adjustments C-3.22 and C-3.25. In addition, I have removed amortization of the 45894 TDSIC PISCC and deferred depreciation and recovery of 45894 TDSIC deferred revenues. This is Adjustment C-3.21. Further, there will be no O&M associated with the CT Project or Posey Solar until after they have been placed in service, which will not be before the test year. This affects Adjustments C-3.31 and 3.32. Finally, F.B. Culley Unit 2 will still be in service, and so O&M associated with operating that unit will still be incurred. Adjustment C-3.33 has therefore been eliminated. The remainder of the differences from this Attachment and Petitioner's Exhibit No. 20 are to update the remaining forecasted expenses by substituting the monthly November and December 2024 forecast for those months of the test year. As shown on **Attachment CMB-4** and based upon the projection as of the filing of the Petition, the Phase 1 increase is projected to be approximately 6%.

Q. TURNING TO ATTACHMENT CMB-5, CAN YOU EXPLAIN HOW THIS DIFFERS FROM PETITIONER'S EXHIBIT NO. 20?

A. This Attachment represents an example of the anticipated revenue requirement at the beginning of the test year. The actual revenue requirement will be based upon the actual rate base and capital structure as of December 31, 2024. Otherwise, it reflects the full test year except for certain adjustments to the test year that should not be made until the end of the test year, or in Phase 3 rates.

Q. WHAT ARE THOSE ADJUSTMENTS THAT SHOULD NOT BE MADE UNTIL THE END OF THE TEST YEAR?

A. As with Phase 1, the revenues (and expenses) from TDSIC, CECA, and ECA should be stated as of the beginning of the test year cutoff. In addition, there will not yet have been PISCC or deferred depreciation for the CTs or Posey Solar at the beginning of the test year. Accordingly, I have removed Adjustments C-3.22 and C-3.25. Further, I have removed the amortization of PISCC and deferred depreciation associated with the 45894 TDSIC and recovery of the 45894 TDSIC deferred revenue, which is in Adjustment C-3.21. Finally, F.B. Culley Unit 2 will continue to operate the entire test year (it is forecasted to be retired at the end of the test year). I have therefore eliminated Adjustment 3.33, which removes the F.B. Culley Unit 2 O&M. That adjustment will also be made at Phase 3. Based upon the projected data as of the filing of the case-in-chief, the Phase 2 increase is projected to be approximately 2% above Phase 1 levels. The remainder of the increase would then be reflected over the proposed interim steps as the CT Project and Posey Solar are placed in service and then ultimately Phase 3.

XI. CLOUD COMPUTING AND CRITICAL PEAK PRICING ACCOUNTING-RELATED ISSUES

Q. PLEASE EXPLAIN CLOUD COMPUTING AND HOW IT IS BEING USED BY THE COMPANY.

A. Petitioner's Witness Bahr is the Company's subject matter expert regarding what cloud computing is and how it is being used by the Company. To restate the background for purposes of my testimony, he explains the delivery of Information Technology ("IT") products, including servers, storage, databases, networking, and software, over the internet or "cloud." Primarily, CEI South's cloud computing arrangements ("CCAs") are for infrastructure as a service ("IaaS") and software as a service ("SaaS"). This is referred to as the Cloud Acceleration, Transformation, and Optimization ("CATO") program.

Q. ARE IaaS-RELATED COSTS INCURRED UNDER A CCA ELIGIBLE TO BE CAPITALIZED PER GAAP?

A. Yes. Whether or not an IaaS-type CCA may be capitalized pursuant to GAAP requires an evaluation under lease accounting guidance. As such, certain costs may be eligible to be capitalized under GAAP in instances where it can be demonstrated that control exists. Control can take various forms, such as the ability to restrict or dictate the way in which the CCA provider may utilize the underlying infrastructure. For example, control would exist where a server under an IaaS-type CCA was entirely reserved for the service recipient alone or if the service recipient had the ability to require the service be provided using specific assets. For FERC purposes, the IaaS-type CCA would be eligible to be capitalized as a capital lease assuming certain criteria are met. Additionally, certain costs, such as implementation and development costs may be eligible to be capitalized as well.

Q. ARE SaaS-RELATED COSTS INCURRED UNDER A CCA ELIGIBLE TO BE CAPITALIZED PURSUANT TO GAAP?

A. Yes. If the SaaS-type CCA includes an identifiable cost associated with a license, then that cost may be eligible to be capitalized pursuant to GAAP. In making this determination, it must also be demonstrated that: (1) a contractual right to take possession of the software at any time may occur without significant penalty or loss in functionality; and (2) it is feasible to run the software on the company's own hardware or contract with another party to do so. Additionally, certain costs, such as implementation and development costs may be eligible to be capitalized as well. Determining whether a SaaS-type CCA contains a license can be difficult, however, as many of these CCAs do not contain the level of detail necessary to reasonably make that determination. In those situations, none of the costs under the SaaS-type CCA would be capitalized, despite the similarity of the economics between traditional on-premises IT solutions ("On-Prem") and the CCA that would indicate that a capital component would exist.

Q. ARE CLOUD COMPUTING COSTS ELIGIBLE TO BE CAPITALIZED AS RATE BASE FOR RATEMAKING PURPOSES?

A. Yes. Northern Indiana Public Service Company ("NIPSCO") has capitalized cloud computing costs as rate base in Cause No. 45159. As explained by NIPSCO's witness in that Cause, cloud computing is becoming an ever more prevalent approach to IT

solutions, and the regulatory treatment of such costs should not be different than more traditional IT solutions. As such, NIPSCO included in rate base in that Cause its forecast of cloud computing costs. In addition, not all costs of the more traditional IT solutions are eligible to be capitalized pursuant to GAAP, but this Commission has authorized the capitalization of the costs that GAAP would treat as expense for regulatory purposes. This rate base treatment was authorized for Aqua Indiana, Inc. in Cause No. 45675.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ACCOUNTING TREATMENT FOR THIRD-PARTY CCA COSTS.

A. Going forward from the end of the test year in this case, CEI South is proposing to capitalize all cloud computing costs by establishing a deferred regulatory asset to reflect amounts not already included in the Company's base rates that are incurred for third-party CCAs. Amortization of the regulatory asset would begin upon the effective date of rates in CEI South's next rate case and would be amortized over the anticipated life of the rates in that case.

Q. DO THE COMPANY'S REQUESTED RATES IN THIS CASE REFLECT THIS PROPOSED ACCOUNTING TREATMENT?

A. No. The Company has only reflected in rate base the forecasted amounts that are expected to be eligible for capitalization pursuant to GAAP. The remainder of the costs are reflected in the forecasted test year O&M expenses. The Company proposes the deferred accounting treatment on a prospective basis, beginning with the end of the test year, December 31, 2025, and it would apply to the costs in excess of the amount reflected in O&M in this case.

Q. WHAT IS THE BASELINE LEVEL OF THIRD-PARTY CCA COSTS INCLUDED IN THIS CASE, AND HOW WAS THIS AMOUNT CALCULATED?

A. The baseline level of third-party CCA costs expected to be recorded to expense during the test year pursuant to GAAP is $813,540, which the Company proposes to recover through base rates and has included in this case:

Table CMB-2 – CCA Test Year Amounts

CCA Type	Test Year Amount
SaaS	$754,683
IaaS	$58,857

The amounts in the table above represent the Company's unadjusted test year level of expense for CCAs. Eligible CCA costs are recorded either to Work-Breakdown Structure ("WBS") Elements with a specific identifying code, or into a specific cost center. In either case, third-party CCA costs are recorded to specific general ledger accounts designated for CCAs. After the conclusion of the test year, CEI South is proposing to defer 100% of costs that GAAP would treat as expense and that are in excess of these annual levels included in base rates to the regulatory asset.

Q. WHY IS THE COMPANY PROPOSING THIS ACCOUNTING TREATMENT?

A. While the test year level of expense for CCAs is small, there is a high likelihood for increased usage of CCAs over On-Prem in the future as evidenced by the Company's CATO program discussed by Petitioner's Witness Bahr. Further as explained by NIPSCO's witness in Cause No. 45159, it is important that regulatory treatment match the progress of the technology advancement. As I previously mentioned, disparate outcomes between the treatment of comparable On-Prem and CCAs can occur despite similarities in economics. Moreover, due to the nature of SaaS-type CCAs that make it very difficult to determine identifiable license costs, there is also increased potential for CCA costs to be recorded as O&M expense as opposed to capital as would occur with On-Prem. It is for these reasons, that the Company is requesting the accounting treatment described above.

Q. HOW WOULD THE DEFERRED ACCOUNTING WORK UNDER THE PROPOSED CCA REGULATORY ASSET?

A. The proposed deferral would specifically authorize the Company to create a regulatory asset to recover, or regulatory liability to credit, eligible CCA costs as described above. The CCA regulatory asset balance will be adjusted on a monthly basis consistent with actual CCA eligible costs and will be addressed in the Company's next rate case. Because the costs recorded to the regulatory asset represent amounts that would have been capitalized if they were for On-Prem, the Company requests to also defer to the

regulatory asset a return on the balance. The Company would defer a return using the Company's approved pre-tax weighted average cost of capital and would do so until the return on the balance begins to be recovered in rates. This is the equivalent to providing PISCC at the weighted average cost of capital ("WACC") on the regulatory balance. Amortization of the balance would not begin until rates are in effect in the Company's ensuing rate case. This is consistent with the Commission's treatment of On-Prem costs in Cause No. 45675.

Q. WITNESS RICE ALSO MENTIONS AN ACCOUNTING DEFERRAL REQUEST PERTAINING TO THE CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM. CAN YOU EXPLAIN THAT REQUEST?

A. Yes. Petitioner 's Witness Rice describes a proposed pilot program that would allow for more efficient utilization of CEI South's system by allowing customers to manage peak loads. To provide this service and to set up the pilot program, CEI South will incur anticipated costs as set forth in **Table MAR-4** to Petitioner Witness. Rice's testimony. Most of these costs are capital, but a portion are O&M. Most of the expense items are IT costs. CEI South seeks authority to defer to a regulatory asset all of the costs that would otherwise be booked to expense. CEI South seeks to commence amortization of the regulatory asset beginning with the effective date of rates in our next rate case, amortized over the life of rates in that case. Finally, CEI South seeks to include the regulatory asset in rate base upon which it is authorized to earn a return and to accrue PISCC at the WACC,

XII. <u>COSTS THAT ARE SUBJECT TO CAUSE NO. 45564 S1</u>

Q. WHAT IS THE ISSUE PENDING IN CAUSE NO. 45564 S1, AND HOW COULD IT IMPACT THE RELIEF SOUGHT IN THIS CASE?

A. In Cause No. 45564, the Commission issued a CPCN for the CT Project. In that case, the Company requested authority to treat the demand charge for the interstate pipeline as a fuel cost for purposes of the FAC. The 45564 S1 subdocket was created to review and decide the proper method of recovery for the demand charge. It could be recovered through the FAC as proposed by CEI South. It is possible that the cost could be recovered through base rates. The Commission has authorized the deferral of any actual demand costs that are incurred until they are reflected in rates. If the

Commission ultimately approves CEI South's request to recover this cost through the FAC, then there is no impact on the request in this case. If it is to be recovered through base rates, however, then the revenue requirement proposed herein would need to be updated to reflect this cost. Petitioner's Witness Rice has recommended a process that would allow the updating of the revenue requirement for this demand cost and any resulting deferrals in the event it becomes necessary as a result of the subdocket.

XIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

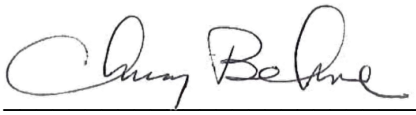
A. Yes, it does.

CAUSE NO. 45990

VERIFICATION

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH



Chrissy M. Behme
Manager, Regulatory Reporting

12/5/2023
Date

Attachments CMB-1 Provided in Native Excel Format

Attachments CMB-2 Provided in Native Excel Format

Attachments CMB-3 Provided in Native Excel Format

Attachments CMB-4 Provided in Native Excel Format

Attachments CMB-5 Provided in Native Excel Format

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 129
Energy Innovation Report

ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

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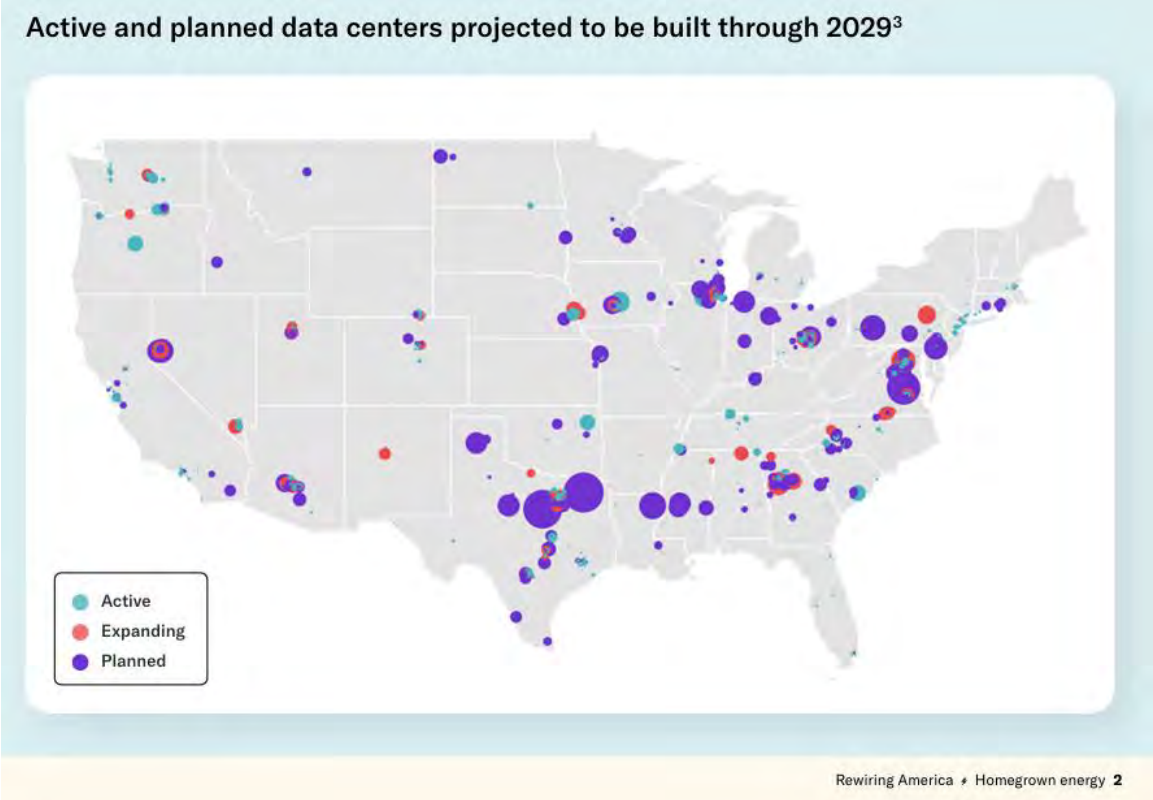
EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

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Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

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- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

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- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to

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outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

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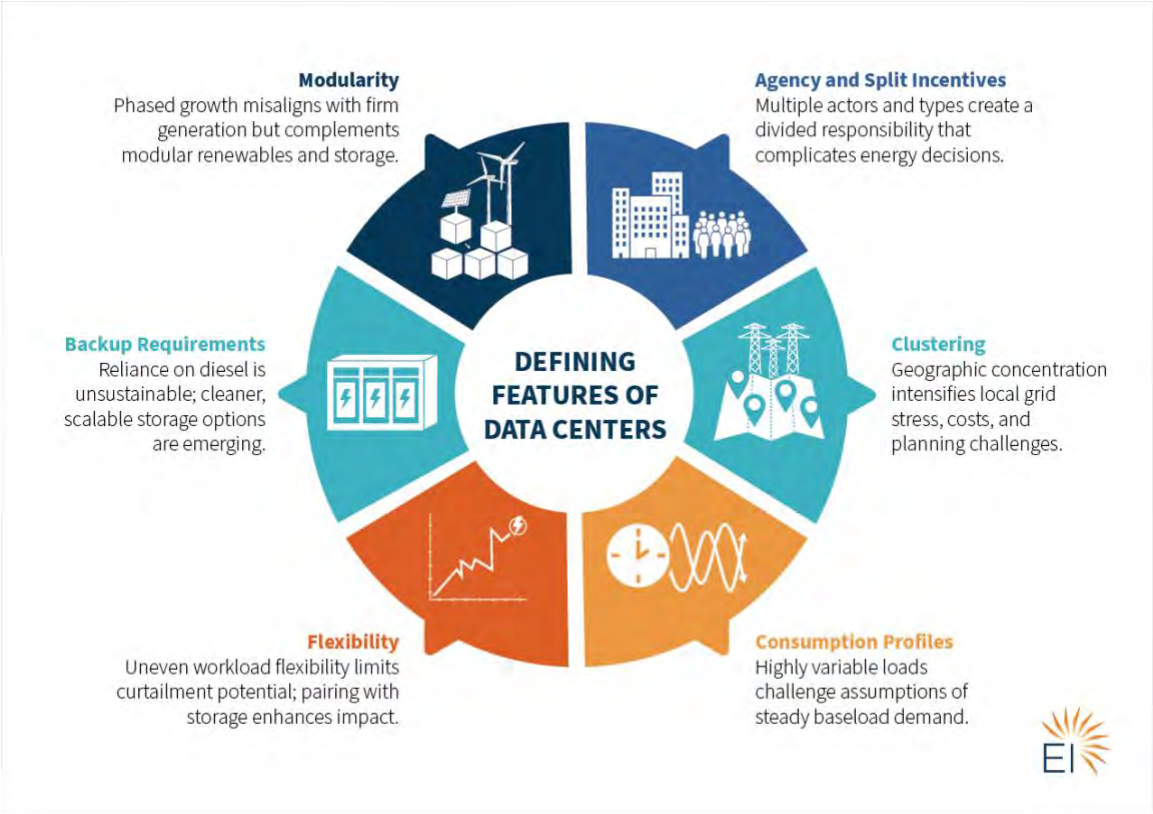
Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.



Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive

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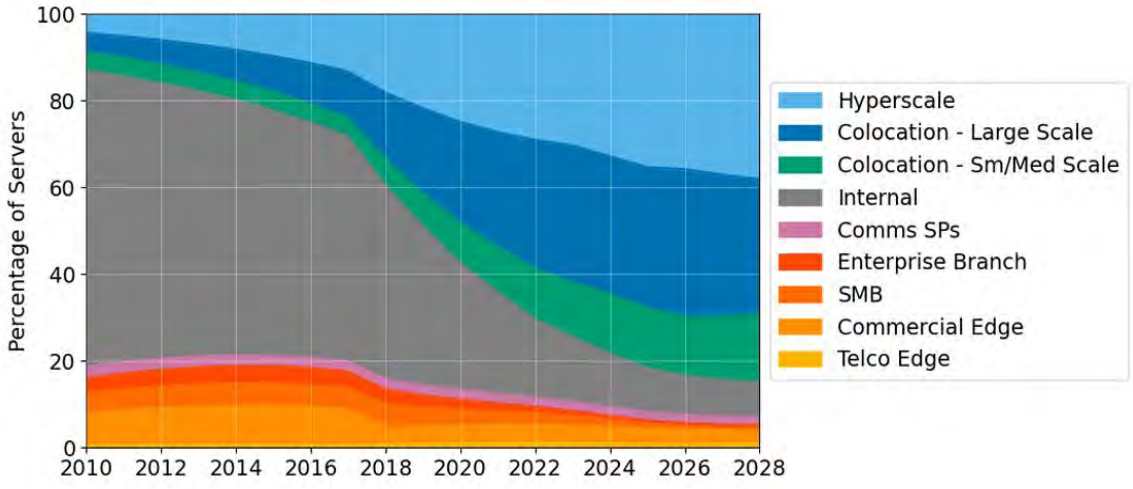
issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

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electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

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investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

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[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

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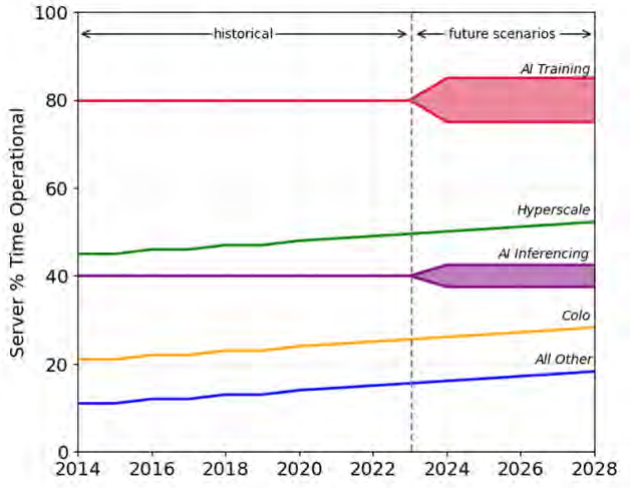
grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.

Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

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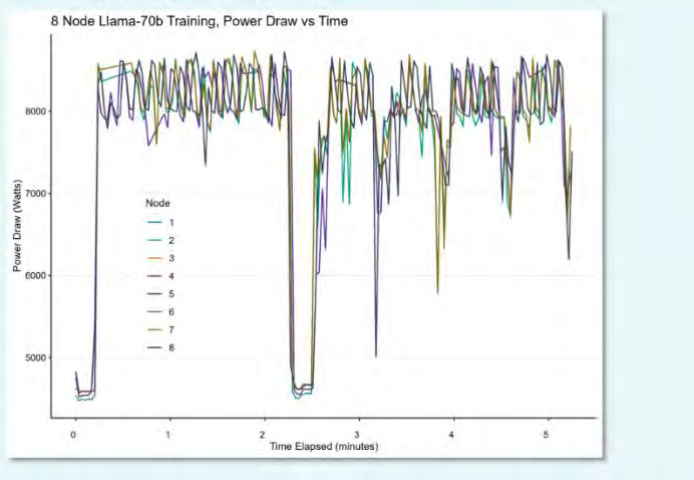
Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.

[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

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AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

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economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery [25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

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Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

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per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report[32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

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When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

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the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

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will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

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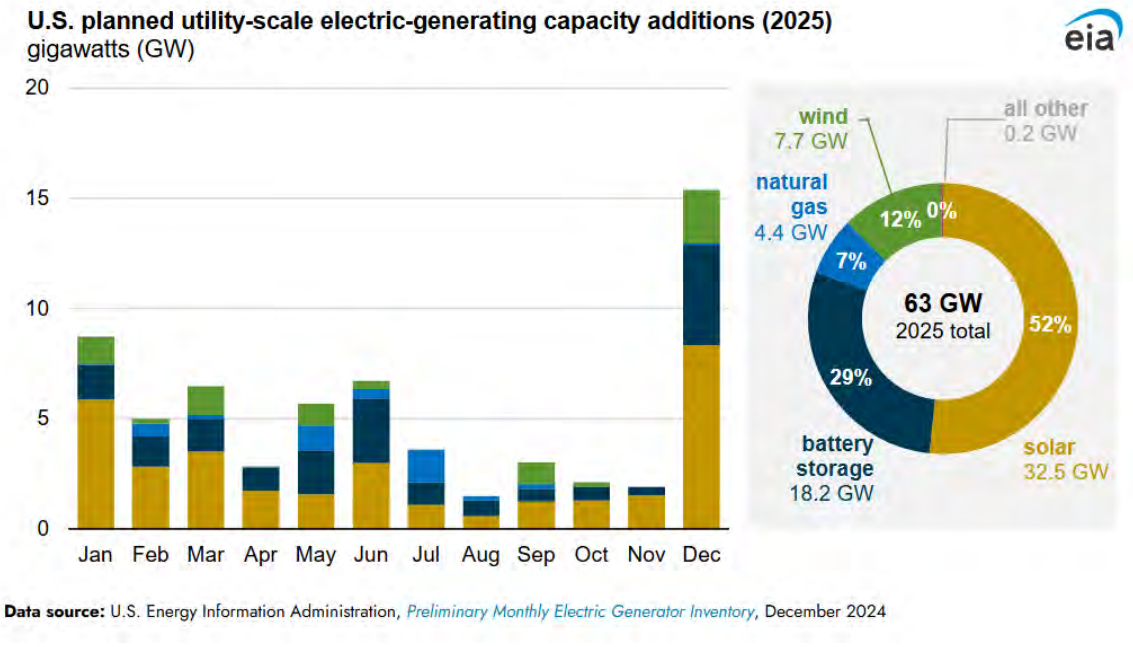
clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Data source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, December 2024

Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

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New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

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Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

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Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called “bridge power”[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

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flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[5960]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

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- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

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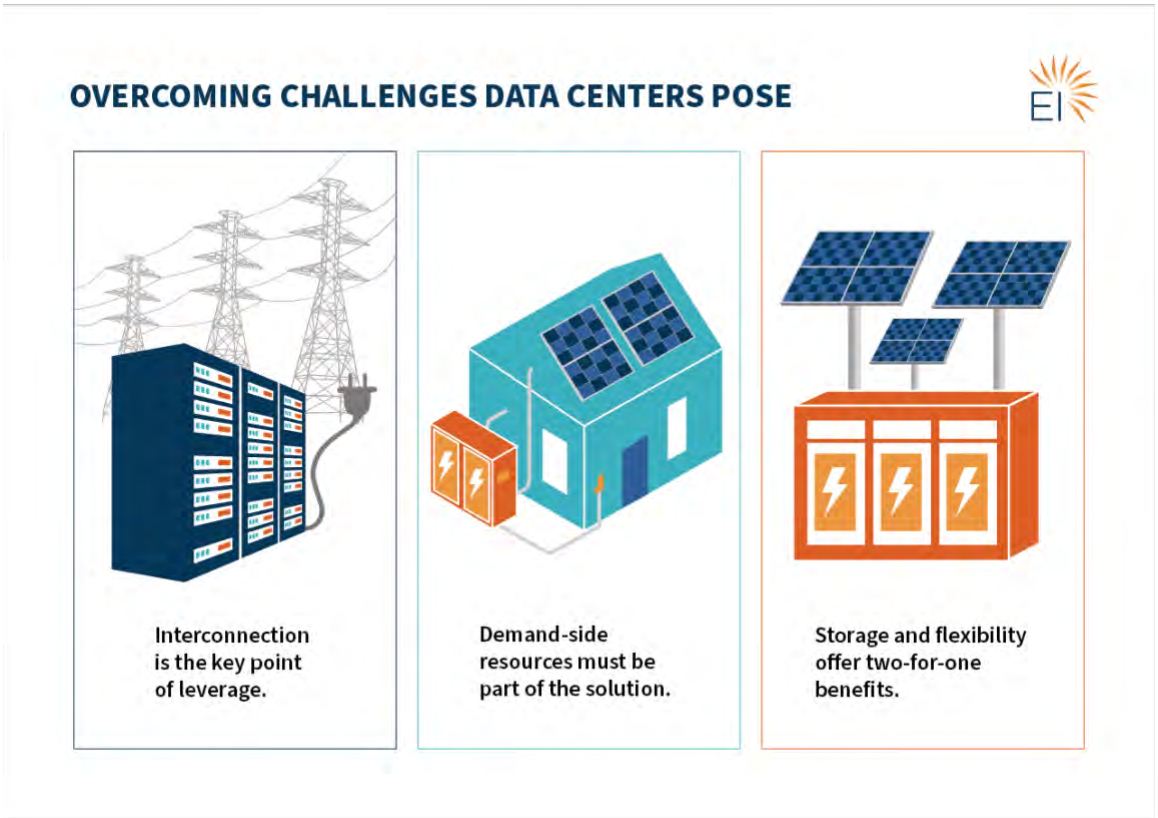
TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

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When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

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Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 130
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 131
Eddystone November Order

Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[7]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[5] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id.*

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[21] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[22]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.

[16] *Id*.

[17] *Id.* at 16, Table 1.

[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

[19] *Id*.

[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[21] *Id.* at 14.

[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").

[23] *Id*. at P 10.

[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[32] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[33]

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[25] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[35] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

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[34] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[35] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[36] *See* Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[37] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy, at 28 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[41] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).
[44] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 132
NIPSCO Rate Case Discovery Responses

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	)	**CAUSE NO. 46120**

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC'S OBJECTIONS AND RESPONSES TO THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S NINTH SET OF DATA REQUESTS

Northern Indiana Public Service Company LLC ("NIPSCO"), pursuant to 170 IAC 1-1.1-16, the discovery provisions of Rules 26 and 37 of the Indiana Rules of Trial Procedure, and the October 9, 2024 docket entry in this Cause, by counsel, hereby submits

the following Objections and Responses to the Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests ("Requests").

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable investigation and search, Petitioner objects on grounds that they seek to impose an undue burden and unreasonable expense and exceed the scope of permissible discovery.

2. To the extent that the Requests seek production of electronically stored information, Petitioner objects to producing such information from sources that are not reasonably accessible because of undue burden or cost.

3. The responses provided to the Requests set forth the information in reasonably complete detail. To the extent that the requesting party contends that a Request calls for more detail, Petitioner objects to the Request on the grounds that it is overly broad, seeks to impose an undue burden and unreasonable expense, and exceeds the scope of permissible discovery.

4. Petitioners objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonably calculated to lead to the discovery of admissible evidence.

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

6. Petitioner objects to the Requests to the extent they are vague and ambiguous and do not provide a reasonable basis from which Petitioner can determine what information is sought.

7. Petitioner objects to the Requests to the extent they seek information that is subject to the attorney/client, work product, settlement negotiation or other applicable privileges.

8. Petitioner objects to the Requests to the extent they purport to require Petitioner to supply information in a format other than that in which Petitioner normally keeps such information.

9. Petitioner objects to the Requests to the extent that they seek production of documents created during an unreasonably long or unlimited period, on the grounds that the Requests are overly broad, seek to impose an undue burden and unreasonable expense, and exceed the scope of permissible discovery.

10. Petitioner objects to the Requests to the extent they request the production of information and documents not presently in Petitioner's possession, custody or control.

11. Petitioner objects to the Requests to the extent they request the production of (a) multiple copies of the same document; (b) additional copies of the same document merely because of immaterial or irrelevant differences; and (c) copies of the same information in multiple formats on the grounds that such Requests are irrelevant, overbroad, unreasonably burdensome, unreasonably cumulative and duplicative, not required by the Commission rules, and inconsistent with practice in Commission proceedings.

12. The responses constitute the corporate responses of Petitioner and contain information gathered from a variety of sources. Petitioner objects to the Requests to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that: (a) they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them; and (b) they seek information that is subject to the attorney/client and work product privileges. Petitioner also objects to the Requests to the extent they request identification of witnesses to be called in Petitioner's case-in-chief or rebuttal who can answer questions regarding the information supplied in the responses on the grounds that: (a) Petitioner is under no obligation to call witnesses

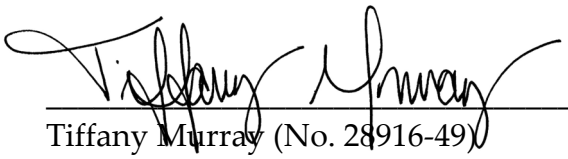
to respond to questions about information provided in discovery; and (b) the Requests seek information subject to the work product privilege.

13. Petitioner assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2).

Without waiving these objections, Petitioner responds to the Requests in the manner set forth in the attached.

Dated this 4th day of November, 2024.

As to objections:



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Attorneys for Petitioner
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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

Adam J. Kashin Matthew Kappus Lorraine Hitz Michael Eckert Indiana Office of Utility Consumer Counselor 115 W. Washington Street, Suite 1500 South Indianapolis, Indiana 46204 akashin@oucc.in.gov mkappus@oucc.in.gov lhitz@oucc.in.gov With a copy to: kremy@oucc.in.gov aparonish@oucc.in.gov carmstrong@oucc.in.gov chewilliams@oucc.in.gov infomgt@oucc.in.gov	Jennifer Washburn Reagan Kurtz Citizens Action Coalition of Indiana, Inc. 1915 West 18th Street, Suite C Indianapolis, Indiana 46202 jwashburn@citact.org With a copy to: rkurtz@citact.org
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A courtesy copy has also been provided by email transmission upon the following:

Barry A. Naum
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Dated this 4th day of November, 2024.

Tiffany Murray

Cause No. 46120
Northern Indiana Public Service Company LLC's
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OUCC Request 9-001:

Please refer to NIPSCO MSFR 0635 providing historical and test year materials and supplies monthly balances.

a. Please provide a detailed breakdown of historical materials and supplies monthly ending balances by subaccount or category for January 2020 through September 2024.
b. Please provide supporting data, calculations, documents, and methodology supporting NIPSCO's forecasted decrease in materials and supplies monthly ending balances from $147,390,643 at the end of November 2025 to $133,826,242 in December 2025 when Schahfer Units 17 and 18 retire.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO is unable to prepare.

Response:

Subject to and without waiving the foregoing general and specific objections, NIPSCO submits the following response.

a. Please see OUCC Request 9-001 Attachment A (2020), OUCC Request 9-001 Attachment B (2021), OUCC Request 9-001 Attachment C (2022), and OUCC Request 9-001 Attachment D (2023). NIPSCO continues to compile information responsive for 2024 and will supplement as soon as the information is available. The support provided in OUCC Request 9-001 Attachments A through D can only capture information available at that specific point in time and does not specifically align with the balances and timing included in NIPSCO MSFR 0635. In addition, this is not a report that NIPSCO runs for every month so the detailed breakdown for February 2023, September 2023, and November 2023 is not available for those periods.
b. Please see Petitioner's Confidential Exhibit No. 18-S2 (Redacted) (p. 689), specifically Workpaper RB 13-S2, page [.4], for support of the referenced amounts as of November 30, 2025 by location. The forecasted balance through November 2025 is held constant to the December 31, 2023 amounts supported in this workpaper, therefore the workpaper amounts are also representative of

the November 30, 2025 forecasted balance requested. Please also see Petitioner's Confidential Exhibit No. 18-S2 (Redacted) (p. 692), specifically Workpaper RB 13-S2, page [.7], for support of the referenced amounts as of December 31, 2025 by location. The reduction is attributed to the removal of the Schahfer Gen Station balance on line 18.

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OUCC Request 9-002:
Please confirm that NIPSCO does not include emission allowance inventory or allowance consumption costs in the test year.
Objections:
Response:
Confirmed. NIPSCO did not include emission allowance inventory or allowance consumption costs in the Forward Test Year.

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OUCC Request 9-003:
If NIPSCO includes emission allowance inventory and/or allowance consumption costs in the test year, please provide the following by allowance type (SO_2, Annual NOx, and Seasonal NOx): a. For the months of January 2020 through September 2024: i. Beginning monthly balances; ii. The number of allowances added or purchased; iii. The value or price of allowances added or purchased; iv. The number and price of emission allowances sold; v. Gains or losses on emission allowances sold; vi. The number and cost of allowances consumed and the associated weighted average inventory cost at which they were charged; and vii. Brokerage fees.
Objections:
Response:
Not applicable. Please see NIPSCO's response to OUCC Request 9-002.

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OUCC Request 9-004:

Please state the total investment cost necessary for NIPSCO to continue operating Schahfer Units 17 and 18 after December 31, 2025.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is vague and ambiguous as the term "investment cost necessary" is undefined such that the nature of information sought is unclear.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is overly broad and unduly burdensome in that this Request is not limited to a specific time.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

The request contains an erroneous premise. NIPSCO cannot operate Schahfer Units 17 and 18 beyond December 31, 2025 and also complete the CT Project, for which a CPCN was approved by the Commission on October 16, 2024 in Cause No. 45947. Completion of the CT Project requires reuse of Schahfer's MISO interconnection rights, and NIPSCO's commitment to MISO to use those interconnection rights for the CT Project is due on December 31, 2024 (12 months before Schahfer's retirement date). NIPSCO has received preapproval of a significant future generation transition decision – to operate a nearly 400MW natural gas peaking unit - and that preapproval relies upon the 2025 retirement of Schahfer Units 17 and 18. Relating specifically to this Cause, because Schahfer's retirement is set to occur by the end of the Future Test Year, NIPSCO's case includes approximately $70 million in *associated reductions* to its proposed revenue requirement that will not be realized if that retirement date did not occur as expected.

The request is also untimely. The economics in support of Schahfer's retirement have been public record since 2018, and the retirement date for Units 17 and 18 has already been delayed once. NIPSCO's 2021 IRP demonstrated that retirement of Units 17 and 18 by *December 31, 2023* was most economic for customers, but NIPSCO made the

decision to delay retirement as a result of disruptions across the renewable industry including the COVID-19 pandemic, Department of Commerce involvement, and international supply chain disruption. This least-cost resource portfolio also included the addition of significant renewable generation, which NIPSCO has now added and is in the process of adding to its portfolio (1950MW in solar, wind, and solar plus storage as of December 31, 2025 (Figure 3 in Witness Cocking's direct testimony)) - as well as retirement of Michigan City Unit 12 by December 31, 2028, and the addition of a thermal peaking resource, which was recently approved by the Commission. Substantial planning and Commission-approved action is underway to execute this transition, as evidenced by the rate base additions proposed in this Cause.

NIPSCO has conducted two analyses since its 2021 IRP that are responsive to this Request – one of which has already been filed with the Commission in Cause No. 45772. Based on his 2022 analysis, NIPSCO Witness Augustine's 45772 testimony concluded that retaining NIPSCO's coal units to 2035 (Portfolio 3) resulted in significantly higher costs than the preferred portfolio from the 2021 IRP. This is because the capital and operating costs of delayed solar and storage projects and the additional solar, storage, and gas peaking capacity in the preferred portfolio from NIPSCO's 2021 IRP (all of which have now been approved by the Commission) were found to be lower than the capital (including mandated environmental technology), O&M, fuel, and emissions costs that would have to be incurred to continue operating the existing coal fleet over the long-term. Mr. Augustine's 2022 analysis filed in Cause No. 45772 is attached as OUCC Request 9-004 Confidential Attachment A.

Since 2022, as noted above, NIPSCO has received approval for a CPCN (Cause No. 45947) to complete the gas CT Project to be located at the site of the soon-to-be retired Schahfer plant. In anticipation of filing this electric rate base rate case, NIPSCO updated certain assumptions from its 2018 IRP with additional information that is now known today to confirm the preferred portfolio remained the least-cost option for customers. This refreshed 2024 analysis, with refreshed assumptions under the 2018 IRP's portfolio construct, is attached as OUCC Request 9-004 Confidential Attachment B.

OUCC Request 9-004 Confidential Attachments A and B reflect estimated costs to continue to operate Schahfer Units 17 and 18 through 2035 (Confidential Attachment A) and in perpetuity (Confidential Attachment B). Those estimated costs are as of a point in time and reflect information known at the time each analysis was conducted. The methodologies associated with these analyses are generally consistent with

NIPSCO's 2018 and 2021 IRPs, which were viewed favorably by stakeholders and the IURC.

Pulled from the 2024 analysis, OUCC Request 9-004 Confidential Attachment C shows NIPSCO's calculation of what it considers a reasonable estimate, based on presently available information, of the total investment cost necessary to operate Schahfer Units 17 and 18 through 2027. This calculation relies on assumptions related to costs to install required environmental controls and to continue the ongoing replacement, repair, and operation of equipment installed when the units were placed in service in the mid 1980s. As discussed below and importantly, this estimate does not incorporate costs associated with the feasibility of reversing course on a long-planned-for plant retirement within the next twelve months without compromising service reliability and the delivery of other generation projects, already found to be reasonable and necessary. For example, by significantly jeopardizing construction of the approved CT Project that provides needed load-following generation, NIPSCO's compliance with now-approved MISO resource adequacy and capacity accreditation rules would be upended. NIPSCO would need to install a wastewater treatment system and convert the Unit 14 and 15 bottom ash handling system by the December 31, 2025 compliance date established in Schahfer's IDEM water permit (National Pollutant Discharge Elimination System ("NPDES") permit), which is not feasible, and which would be required to operate Schahfer Units 17 and 18 *for one day* beyond 2025. Operating Schahfer Units 17 and 18 beyond 2025 would expose NIPSCO to financial risk; NIPSCO has not estimated the cost of that risk but expects it would be substantial.

Based on the above, as shown in OUCC Request 9-004 Confidential Attachment C, NIPSCO calculates that operating Schahfer Units 17 and 18 beyond 2025 would require more than $1 billion of additional investment through 2027.

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OUCC Request 9-005:
Please confirm the estimated annual O&M costs for NIPSCO to continue operating Schafer Units 17 and 18 after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See the "2024 Coal Assumptions" tab in OUCC Request 9-004 Confidential Attachment B.

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OUCC Request 9-006:
Please confirm the estimated cost and lead time needed to install wastewater treatment systems on Schahfer Unit 17 and on Schahfer Unit 18 if these units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004. See OUCC Request 9-006 Confidential Attachment A for NIPSCO's estimate to install a wastewater treatment system on Schahfer Units 17 and 18. NIPSCO estimates it would take approximately three to four years to install a wastewater treatment system on Schahfer Units 17 and 18. It is not feasible to install a wastewater treatment system on Schahfer Units 17 and 18 by the December 31, 2025 compliance date.

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OUCC Request 9-007:
Please confirm the estimated annual O&M cost to operate wastewater treatment systems on Schahfer Units 17 and on Schahfer Unit 18 if they continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's responses to OUCC Request 9-004 and 9-006. See OUCC Request 9-007 Confidential Attachment A.

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OUCC Request 9-008:
Please confirm the estimated cost and lead time necessary to install dry bottom ash handling on Schahfer Unit 17 and on Schahfer Unit 18 if the units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Requests 9-004, 9-010, and 9-011.

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OUCC Request 9-009:
Please confirm the estimated annual O&M cost for the dry bottom ash handling system for Schahfer Units 17 and 18 if the units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-010:
Please confirm whether Schahfer Units 17 and 18 would be able to use the dry bottom ash handling system previously built to serve Schahfer Units 14 and 15. Please explain why or why not.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Yes. See OUCC Request 9-010 Confidential Attachment A.

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OUCC Request 9-011:
If it is possible to use the Schafer Units 14 and 15 dry bottom ash handling system, please confirm the cost and lead time necessary to re-route Schahfer Units 17 and 18's bottom ash wastewater stream to this system.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-010.

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OUCC Request 9-012:
Please confirm whether it is feasible to construct a Coal Combustion Residuals (CCR) Rule-compliant lined surface impoundment to hold Schahfer Units 17 and 18 bottom ash wastewater. Please explain why or why not.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request is vague and ambiguous as the term "feasible" is undefined. For purposes of this Request, NIPSCO interprets "feasible" to mean it is practically capable of being carried out.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: It is not feasible to construct a CCR Rule-compliance lined surface impoundment to hold Schahfer Units 17 and 18 bottom ash wastewater. As described in the Schahfer Waste Disposal Area Part A Demonstration Annual Progress Report dated October 26, 2024:[1] > NIPSCO previously evaluated the feasibility of constructing new alternative CCR and non-CCR waste management options on-Site, even though RMSGS will cease all coal-fired generation in just over one more year (i.e., no later than December 2025). As in 2020 and confirmed in 2022 (Demonstration Addendum 2), due to Site-specific factors (e.g., space limitations, shallow depth to groundwater and thus the inability to reasonably achieve the 40 CFR §257.60(a) five-foot separation from the upper limit of the uppermost aquifer), permitting and/or regulatory hurdles including permit application review timeframes, potential supply chain issues relative to equipment and construction materials availability, and building timeframes, *construction of new alternative management facilities is infeasible*. (emphasis added)

[1] Available at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/nipsco-llc-rmsgs-wda-part-a-demonstration-annual.pdf?sfvrsn=31fae551_3

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OUCC Request 9-013:
Please confirm the estimated cost and lead time necessary to construct a CCR Rule-compliant lined surface impoundment to hold Schahfer Units 17 and 18's bottom ash wastewater.
Objections:
NIPSCO objects to this Request on grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection. See also NIPSCO's response to OUCC Request 9-012.

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OUCC Request 9-014:
Please confirm the estimated annual O&M cost associated with a CCR Rule-compliant lined surface impoundment serving Schahfer Units 17 and 18 if NIPSCO were to continue their operation after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection. See also NIPSCO's response to OUCC Request 9-012.

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OUCC Request 9-015:
Please confirm whether Schahfer Units 17 and 18 currently have dry fly ash handling systems.
Objections:
Response:
Yes. Schahfer Units 17 and 18 currently have dry fly ash handling systems.

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OUCC Request 9-016:
Please confirm the estimated annual disposal cost for CCR material from Schahfer Units 17 and 18 if these units were to continue operating after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-017:
Please confirm the estimated cost lead time necessary to construct and install Selective Catalytic Reduction (SCR) systems on Schahfer Units 17 and 18.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See OUCC Request 9-017 Confidential Attachment A.

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OUCC Request 9-018:
Please confirm the estimated annual O&M cost to operate SCRs on Schahfer Units 17 and 18.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-019:
Please confirm the estimated cost and lead time necessary to convert Schahfer Units 17 and 18 to co-fire on natural gas.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO completed one estimate of the cost to "fully convert" Schahfer Units 17 and 18 to gas-fired units as part of its 2018 IRP for the portfolio titled "6b," which assumed a 2023 conversion of the units to natural gas. The conversion cost and ongoing FOM and CapEx costs are highlighted in the "CapEx" and "FOM" tabs in OUCC Request 9-019 Attachment A. Additional details around the assumptions for these costs can be found in Section 4.10.5 of the 2018 IRP report (pg. 63-64).[1] "Fully converting" to natural gas would not include the costs of coal handling and ash disposal, which would be included in "co-firing" the unit. "Fully converting" assumes a 15% capacity de-rate (when the analysis was conducted in 2018). NIPSCO has not studied the current lead time to convert Schahfer Units 17 and 18 to natural gas.

[1] https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=83256851_16.

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OUCC Request 9-020:
Please confirm the approximate date when Schahfer Units 17 and 18 last had a major turbine overhaul or replacement. Please explain.
Objections:
Response:
The last major turbine overhauls for Units 17 & 18 at Schahfer were: Unit 17 – Fall of 2017 Unit 18 – Fall of 2018

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OUCC Request 9-021:
If Schahfer Units 17 and 18 were to continue to operate after December 31, 2025, please identify the major repairs, maintenance, or replacement of equipment NIPSCO anticipates would need to be completed. Please provide the cost associated with each such project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

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OUCC Request 9-022:
If NIPSCO were to add required environmental controls and investments to continue operating Schahfer Units 17 and 18 after December 31, 2025, please identify the cost NIPSCO anticipates Schahfer Units 17 and 18 would need to be offered into the MISO energy market to break even.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is overly broad and unduly burdensome in that this Request is not limited to a specific time. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's latest dispatch analysis with Schahfer Units 17 and 18 operating beyond 2025 was conducted as part of Mr. Augustine's 2022 analysis included in OUCC Request 9-004 Confidential Attachment A.

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OUCC Request 9-023:
Please provide the last two analyses NIPSCO conducted, including any internal analyses not publicly shared to date, demonstrating whether retiring Schahfer Units 17 and 18 by the end of December 31, 2025, is NIPSCO's most economical option available.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

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Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-024:

Please confirm all additional investments that will be necessary to continue Michigan City Unit 12's operation if it retired January 1, 2032, instead of December 31, 2028. Please also provide the related estimated capital and annual O&M costs associated with each investment.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

NIPSCO last evaluated operation of Michigan City until 2032 in its 2021 IRP (https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=f6ae0251_6). In that analysis, NIPSCO evaluated four different retirement dates for MC12, including 2032, 2028, 2026, and 2024. NIPSCO concluded that earlier retirement continued to show cost savings and that a retirement date between 2026-2028 was preferred (no later than 2028). Please refer to the 2021 IRP pages 214-218: section 9.1.7 "Evaluation of Each Existing Fleet Portfolio – Results" and section 9.1.8 "Existing Fleet Analysis Scorecard Summary" for the details on the portfolios that were analyzed. Portfolio 1 included a 2032 retirement date for Michigan City Unit 12 and had a higher customer cost than portfolios 2, 3, 4, and 6, which all assumed earlier retirement dates for Michigan City Unit 12. The "Retirement CapEx" and "Retirement FOM" tabs of Confidential Appendix D to the 2021 IRP contain the annual capital and FOM projections associated with a 2032 retirement date for Michigan City Unit 12 as of the time of the 2021 analysis.

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No updated analysis has been performed on Michigan City Unit 12 with a specific 2032 retirement date since 2021 IRP.

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OUCC Request 9-025:
Please confirm all additional investments that will be necessary to continue Michigan City Unit 12's operation if Michigan City Unit 12 retired after January 1, 2032, but before January 1, 2039. Please also provide the estimated capital and O&M costs associated with each investment.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO has not evaluated a retirement date for Michigan City 12 after January 1, 2032, but before January 1, 2039. In order to operate Michigan City Unit 12 after 2032 and retire before 2039, NIPSCO would need to retrofit the facility to co-fire with natural gas by 2030 to comply with the EPA Emission Guidelines for Existing Steam Generating Units. NIPSCO has not evaluated the cost of retrofitting the Michigan City facility to co-fire with natural gas.

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OUCC Request 9-026:
Please confirm the estimated cost and lead time necessary to convert Michigan City Unit 12 to co-fire on natural gas if the unit were to continue operation past 2028.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO has not evaluated any costs or lead times associated with converting Unit 12 to run on natural gas or co-fire with coal and natural gas.

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OUCC Request 9-027:
Please confirm the approximate date when Michigan City Unit 12 last had a major turbine overhaul or replacement. Please explain.
Objections:
Response:
The last turbine major overhaul for Unit 12 at Michigan City Generating Station was in the Spring of 2019.

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OUCC Request 9-028:
If Michigan City Unit 12 were to retire January 1, 2032, instead of the end of 2028, please confirm the major repairs, maintenance, or replacement of equipment that would need to be completed. Please provide the cost associated with each such project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Future Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-024.

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OUCC Request 9-029:
If Michigan City Unit 12 were to retire after January 1, 2032, but before January 1, 2039, please confirm the major repairs, maintenance, or replacement of equipment that would need to be completed. Please provide the cost associated with each project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-025.

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OUCC Request 9-030:
Please confirm whether the Schahfer landfill currently has sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2032. If not, please confirm and explain whether it is possible to expand the current landfill and state the expected cost of such an expansion.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
The Schahfer landfill does not have sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2032. Expanding the current landfill could be possible, but no analysis has been performed as to the expected cost of such an expansion.

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OUCC Request 9-031:
Please confirm whether the Schahfer landfill currently has sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2039. If not, please confirm and explain whether it is possible to expand the current landfill and state the expected cost of such an expansion.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: The Schahfer landfill does not have sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2039. Expanding the current landfill could be possible, but no analysis has been performed as to the expected cost of such an expansion.

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OUCC Request 9-032:
Please provide the last two analyses NIPSCO conducted, including any internal analyses not publicly shared, showing whether retiring Michigan City Unit 12 by December 31, 2028, is the most economical option available.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

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OUCC Request 9-033:
Since its previous Integrated Resource Plan (IRP), please confirm whether NIPSCO has analyzed the cost to extend the retirement dates of Schahfer Unit 17, Schahfer Unit 18, and/or Michigan City Unit 12. If so, please provide any and all such analyses.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's responses to OUCC Requests 9-004, 9-023, and 9-032.

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OUCC Request 9-034:
Please confirm whether NIPSCO anticipates significant load growth within the next 10 years from data centers or other large load customers. If yes, please quantify this load growth and the expected annual growth, by year, over the next 10 years.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks publicly available information. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: In its 2024 Integrated Resource Plan ("IRP"), NIPSCO is analyzing five (5) different scenarios that are intended to evaluate various "future states of the world". This includes the "Domestic Resiliency (DR)" scenario, which evaluates high load from new large loads and industrial onshoring MISO-wide, as well as higher electric vehicle penetration. The IRP includes 2,600 MW of data center load in its Reference case portfolios by 2035 (details are listed in the public slides), and it also includes an Emerging High Load sensitivity with 8,600 MW of data center load through 2035 (details are also listed in the public slides). The public stakeholder materials for the 2024 IRP are available online at: https://www.nipsco.com/our-company/about-us/regulatory-information/irp. NIPSCO would specifically direct attention to the following slides: - Stakeholder Meeting #2, slides 17 to 25, 46 to 50, 57 to 60, 133 to 136, - Stakeholder Meeting #3, slides 14 to 15 - Stakeholder Meeting #4, slides 21 to 54 - Stakeholder Meeting #5, slides 64 and 67 to 69 for the high load sensitivity

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The IRP represents a snapshot in time based on what is known today. NIPSCO will continue to evaluate future states of the world, including data center and large load customers, in future IRPs.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 133
Department Press Release on Centralia Order

An official website of the United States government

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025
2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to

ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

“The last administration’s energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won’t let that happen,” said **Energy Secretary Wright**. “The Trump administration will continue taking action to keep America’s coal plants running so we can stop the price spikes and ensure we don’t lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining.”

According to DOE’s Resource Adequacy Report(link is external), blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment(link is external) warns that “extreme winter conditions extending over a wide area could result in electricity supply shortfalls.” With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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Just Launched: A Critical Materials Career Map
December 17, 2025

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Energy Department Grants Woodside Louisiana LNG Project Additional Time to Commence Exports
December 16, 2025

Tags:

- Strengthen Grid Reliability and Security
- Emergency Response

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Whistleblower Protection
Equal Employment Opportunity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 134
MISO Manual on Resource Adequacy

Manual No. 011

Business Practices Manual

RESOURCE ADEQUACY

Disclaimer

This document is prepared for informational purposes only, to support the application of the provisions of the Tariff and the services provided thereunder. MISO may revise or terminate this document at any time at its discretion without notice. While every effort will be made by MISO to update this document and inform its users of changes as soon as practicable, it is the responsibility of the user to ensure use of the most recent version of this document in conjunction with the Tariff and other applicable documents, including, but not limited to, the applicable NERC Standards. Nothing in this document shall be interpreted to contradict, amend, or supersede the Tariff. MISO is not responsible for any reliance on this document by others, or for any errors or omissions or misleading information contained herein. In the event of a conflict between this document, including any definitions, and either the Tariff, NERC Standards, or NERC Glossary, the Tariff, NERC Standards, or NERC Glossary shall prevail. In the event of a conflict between the Tariff and the NERC Standards, or NERC Glossary, the Tariff shall prevail until or unless the Federal Energy Regulatory Commission ("FERC") orders otherwise. Any perceived conflicts or questions should be directed to the Legal Department.

Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-011-r31	Included language related to Final PRMR allocation process in Section 5.6 and other editorial changes Updated PRA Formulations in Appendix M	MISO Staff	FEB-21-2025
BPM-011-r30	Annual Review Complete including UCAP/ISAC ratio related process improvement, GADS events/performance submission, timeline change for multiple process such as state notifying MISO on utilizing their own PRM, full responsibility transactions, confirm/convert SAC etc, edits for RBDC (MRI/RBDC curve development, RBDC opt out process, PRMR determinations for PRA and settlements etc)	MISO Staff	OCT-01-2024
BPM-011-r29	Annual Review Complete. Edits include GVTC test extension updates, 31-day rule and ZRC replacement updates, LMR and ER registration updates, OY CIL CEL removal Appendix K timeline updates and Attachment Y updates to schedule 53 resources and the UCAP/ISAC ratio process and timeline.	N. Przybilla	OCT-01-2023
BPM-011-r28	Clarify and add additional context surrounding ZRC replacement and the 31-day outage rule in section 6.4 while ensuring language is consistent with Module E-1 of the MISO Tariff.	N. Przybilla	May-31-2023
BPM-011-r27	Updates to all sections to facilitate the implementation of seasonal auctions & seasonal accreditation (FERC Docket No. ER22-495). Includes updates from annual BPM review	MISO Staff	October-31-2022
BPM-011 r26	Replacement of 4.2.12 Battery Storage Accreditation with Electric Storage Resource. Add Electric Storage Resource to section 4.2.8. BTMG Qualification Requirements. Update Appx K. Correct Appendix N – Demand and Energy Forecast Characteristics.	M. Guerriero	AUG-15-2022
BPM-011-r25	2021 Annual review complete. Edits include: Hybrid resources, detail added to States establishing PRM, detail for 90/120 day outages, clarification for BTMG wind UCAP, Updated to	MISO Staff	JUL-01-2021

	reference new DSRI tool instead of MCS, updated RAN related LMR accreditation (ER20-1846), new DR Test Deferral process, Battery Storage accreditation, reorganized Appx I XEFORd, added Process Load reporting section, updated App K Timeline.		
BPM-011-r24	2020 Annual review complete. Edits include new Appendix W (DR LOLE), Deliverable ICAP (ER20-1942, ER20-2005), GVTC testing clarification, ZDB example, and other minor clarifications.	G. Alexander	DEC-15-2020
BPM-011-r23	Revisions to address treatment of resources on long term outage which FERC approved under Dock No. ER20-129-000.	T. Bachus	MAR-31-2020
BPM-011-r22	2019 Annual Review Complete. Edits include: general clean up, ER19-2559 (PRA Process Timeline) & ER18-2363 (Locational Filing), web links, ER UCAP intermittent qualification, Appx R CONE calculation, removing Att W (ER19-650 RAN Phase 1 LMR filing) by imbedding language into applicable LMR sections.	E. Thoms	OCT-1-2019
BPM-011-r21	Added LMR Registration FAQ to address ER19-650-000	E. Thoms	FEB-20-2019
BPM-011-r20	Multiple updates. Revisions supporting changes to the out-year transfer study process. Additional revisions to support the Module E-1, Locational Tariff update which created External Resource Zones and several other changes.	M. Sutton	NOV-01-2018
BPM-011-r19	Revisions to Section 4.2.8 clarifying language when a Qualifying Facility participates as a BTMG. Addition of SER Type II resource. Annual Review completed.	J. Harmon	SEP-28-2018
BPM-011-r18	Annual Review Complete Includes revisions to Section 4.2.8.5 clarifying deliverability options for BTMG.	J. Harmon	JAN-22-2018
BPM-011-r17	Annual Review Complete	J. Harmon	AUG-25-2017
BPM-011-r16	Several updates. Updated Wind UCAP values; added section regarding Solar capacity credit; Revised provisions for Zonal Deliverability Benefit; Inclusion of Suspended resources in the PRA; Retail Choice coincident load forecast reporting process. Annual Review completed.	J. Harmon	JUL-15-2016

BPM-011-r15	Annual Review completed. Included Inter-zonal replacement, sub regional constraints in PRA, PRMR and LCR relationship, external resource and host BA qualification requirements, GVTC deferral, and refueling versus repowering. Additions to section 5.2.1 for Local Resource Zone reevaluation process and Generation Limited Transfers	J. Milli / M. Sutton / S. Quadri / J. Cole / R. Westphal	SEP-01-2015
BPM-011-r14	Annual Review completed. Remove netting of Demand Response. Update SFT and Transfer Analysis provisions.	J. Milli	SEP-01-2014
BPM-011-r13	Updated LRZ map, timeline, and added catastrophic outage provisions	C. Clark	JAN-01-2014
BPM-011-r12	Annual review and updated to reflect Tariff orders	C. Clark	AUG-01-2013
BPM-011-r11	Updated to reflect Module E-1-1 Tariff	C. Clark	OCT-01-2012
BPM-011-r10	Updated GVTC language for Hydro and ROR.	C. Clark	SEP-28-2012
BPM-011-r9	Annual Review completed and Updated Registration tables and added new section for qualifying PPAs.	C. Clark	APR-15-2012
BPM-011-r8	MISO Rebranding Changes JUL-19-2011	G. Krebsbach	JUN-13-2011
BPM-011-r8	Annual Review and added Dispatchable Intermittent Resource, minor clarifications	C. Clark	JUN-13-2011
BPM-011-r7	Updated UCAP calculations for plan year 2011/2012, undated must offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications	M. Heraeus / C. Clark	Dec-1-2010
BPM-011-r6	Corrected errors and added “must offer” language and Units with Low Service Hours	M. Heraeus / C. Clark	JUN-1-2010
BPM-011-r5	Corrected errors and inadvertent omissions	M. Heraeus	MAR-3-2010
BPM-011-r4	Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011	K. Larson	DEC-21-2009
TP-BPM-003-r3	Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1.	T. Hillman	JUN-01-2009
TP-BPM-003-r2	Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements	T. Hillman	JUN-01-2009
TP-BPM-003-r1	Revised to reflect Open Access Transmission, Energy and Operating Reserve Markets Tariff for	J Moser	JAN-06-2009

	the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.		
TP-BPM-003	Updated template	J. Moser	APR-01-2008
N/A	Section 3.2.1 Determination of Requirements – Non-valid statements were removed. Section 3.2.3 Default Requirements – Minor revisions were made for clarification. Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification. Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification. Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted. Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 5.5 Financial Transmission Rights – This section was deleted. Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions. Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890. Section 6.1.4 Hubbing Transactions – This section was deleted. Section 8 Data Requirements – Entire section updated to reflect FERC order 890		DEC-12-2007

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1 Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Resource Adequacy Requirements includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. The third section (Section 1.3) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

1.2 Purpose of this Business Practices Manual

This Resource Adequacy Business Practices Manual describes MISO's and other entities' roles and responsibilities related to maintaining Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak Demand requirements plus an appropriate reserve margin.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff, NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines, and standards to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- How is Resource Adequacy determined?
- How do the multiple state jurisdictions relate regarding Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities regarding Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?
- What are the deliverability requirements for Planning Resources?

- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under the changes to Module E-1 of the Tariff?
- What are the procedures for participating in Planning Resource Auctions?
- What are the settlement provisions for the Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

1.3 References

Other reference information related to this document includes:

- MISO BPMs
- MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004
- Federal Energy Regulatory Commission (FERC) Order Nos. 890, Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- LOLE Study Reports
- Wind & Solar Capacity Credit Report
- PowerGADS User's Manual
- CIL/CEL Study Reports

2 Overview of Resource Adequacy

Achieving reliability in bulk electric systems requires, among other things, that the amount of resources exceeds customer Demand by an adequate margin. The margins necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed through the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer Demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance
- Unplanned or forced outages of generating equipment
- Deratings in the capability of Generation Resources and Demand Response Resources
- System effects due to reasonably anticipated variations in weather
- Load Forecast Uncertainty

2.1 Planning Reserve Margin Requirement Overview

Each LSE's total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Coincident Peak Demand forecasts are submitted by LSEs using a 50%/50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the projected peak Demand) which will include distribution losses. An LSE's Initial Planning Reserve Margin Requirement (Initial PRMR) is described in Section 3 (Establishing Initial Planning Reserve Margin Requirements) of this BPM.

2.2 Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency Resources. The relationships and key attributes of the Planning Resource types are as follows:

- Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of the MISO Balancing Authority Area), Electric Storage Resources (ESR), Hybrid Resources, and resources that can be dispatched to reduce Demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market

and are available during Emergencies. Thermal Generation Resources are accredited based on the methodology described in Appendix Y (Schedule 53 Resources). Wind Resources will be accredited based on the ELCC study that MISO conducts. Non-wind intermittent generation resources will be accredited based on historical performance during the critical hours within each Season, where new resources will receive the class average for that resource type until enough historical data is accrued. Non-Schedule 53 Capacity Resources that report to GADS are quantified by applying seasonal forced outage rates to Installed Capacity (ICAP) values to calculate the Seasonal Accredited Capacity (SAC) for the resource.

- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during capacity and transmission Emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service.

A Market Participant (MP) can use Capacity Resources, LMRs, and Energy Efficiency Resources, up to their SAC values, to comply with their Resource Adequacy Requirements via a Fixed Resource Adequacy Plan or Reliability Based Demand Curve Opt Out (RBDC Opt Out) as described in Section 5.3 (Pre-PRA arrangement of capacity scheduling) of this BPM, or through self-scheduling their Zonal Resource Credits in the Planning Resource Auction(s) (PRA) as detailed in Section 5.5.6 (Resource Offers) of this BPM. A Market Participant can also sell ZRCs from Capacity Resources, LMRs, and Energy Efficiency Resources bilaterally before the Planning Resource Auction(s) or offer them in the Planning Resource Auction(s) as described in Section 5.5 (Planning Resource Auction) of this BPM.

MISO will determine Seasonal Accredited Capacity (SAC) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each Season within the Planning Year.

2.3 Resource Adequacy Requirements Overview

Planning Resources that clear the Planning Resource Auction(s) (PRA) or that are designated in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out will be obligated to provide capacity in the Day-Ahead and Real Time Markets (DA/RT) for each Season cleared within the Planning Year unless replaced by another Planning Resource, as per Module E-1 Section 69A.3.1.h. Capacity Replacement Non-Compliance Charge(s) (CRNCC) may be applicable as

per Module E-1 Section 69A.3.1h. Load Serving Entities (LSEs) that serve Load during the Planning Year will be obligated to pay for capacity from Planning Resources in the PRA pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone (LRZ) where the Load is located unless the Planning Resource was designated in a FRAP or RBDC Opt Out.

LSEs that have a Planning Reserve Margin Requirement (PRMR) will be obligated to procure capacity equal to their Final PRMR pursuant to the relevant ACP for the LRZ where they have PRMR unless, and to the extent that the LSE meets its Final PRMR via a FRAP or RBDC Opt Out per Section 5.3 of this BPM, or unless and to the extent that the LSE chooses to reduce its Final PRMR that is cleared in a given auction(s) by electing to pay the Capacity Deficiency Charge per Section 5.7 of this BPM.

2.4 Settlements/Performance Requirements Overview

The seasonal Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be established for each Season of the Planning Year and will be settled based upon the applicable Planning Resource Auction(s) (PRA) clearing price for an LSE's Final Planning Reserve Margin Requirement, unless covered by a FRAP or RBDC Opt Out, or unless the LSE elects to pay the Capacity Deficiency Charge. Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable PRA included on their daily settlement statements for all loads and Planning Resources cleared in a PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA or were used in a FRAP or RBDC Opt Out will have a performance obligation to be available during system Emergencies per section 4.2.7 (Demand Resource Qualification Requirements) iof this BPM.

3 Establishing Initial Seasonal Planning Reserve Margin Requirements

3.1 Overview

The Initial seasonal Planning Reserve Margin Requirement (PRMR) is the number of MWs in ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable Seasons.

The Initial seasonal PRMR is expressed in the following equation per Load Serving Entity (LSE) per Local Resource Zone (LRZ)

$$Initial\ PRMR_{LRZ} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times (1 + PRM_{RTO})]$$

Where attributes are seasonal for the following:
Initial $PRMR_{LRZ}$ = Initial Planning Reserve Margin Requirement per LRZ
$CPDf_{LBA}$ = Coincident Peak Demand forecast per LBA
FRP_{LBA} = Full Responsibility Purchase per LBA
FRS_{LBA} = Full Responsibility Sale per LBA
$TL_{LBA}\%$ = Transmission Loss Percentage of LBA
PRM_{RTO} = Planning Reserve Margin in Unforced Capacity set by LOLE Studies

3.1.1 Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity may perform functions on behalf of the applicable LSE including, but not limited to, submitting the LSE's forecasted CPD forecast or share of CPD forecast.

Each individual LSE is ultimately responsible for conformance with the RAR, even if the LSE enters a contract with a third party acting on its behalf. If requested by MISO, each LSE that contracts with another entity to comply with any part of the Resource Adequacy Requirements must notify MISO of the arrangement. The LSE must provide MISO with the name of the organization representing them, primary and alternate contact information for the individuals representing them, and the scope of responsibilities the contracted entity will provide.

3.1.2 Validation of Firm Transmission Service for Load

Each LSE shall document, as described in Module B – Transmission Service, to MISO that the LSE has obtained sufficient firm Transmission Service to serve its load for each Season in the Planning Year. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement (GFA), when applicable—however, Demand does not require firm MISO Transmission Service when the LSE meets its Initial PRMR using its own Behind-the-Meter Generation (BTMGs), Demand Resources (DRs), and Energy Efficiency Resources, and does not use the MISO Transmission System to serve such Demand.

Additionally, Energy Resource Interconnection Service (ERIS) requires a completed firm Transmission Service Request (TSR) submitted through OASIS OATI that has been approved by the Generation and Interchange team at MISO in order to be considered towards deliverability that is used to convert Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs). This information will be entered into the MECT on the Convert SAC screen by Market Participants (and in the Registrations screen, if applicable).

3.2 Demand and Energy Forecasts

MISO collects a variety of load forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them. Please See Appendix O for the list of parties responsible for reporting Demand and Energy forecasts.

Demand and Energy forecasts that are not subject to retail choice load switching should be reported by the respective LSE. Demand and Energy forecasts that are subject to retail choice load switching should be reported by the respective Electric Distribution Company (EDC). The EDC calculates a Peak Load Contribution (PLC) MW value for each retail choice LSE that represents a share of the EDC's Initial PRMR. If an LSE disagrees with their PLC value calculated by their EDC, the LSE will work with its EDC to revise the PLC prior to the final EDC forecast submission deadline. See Appendix K for all Demand and Energy forecast deadlines.

All Demand (Energy) forecasts must reflect a 50% probability that the Demand (Energy) will not exceed the forecasted Demand (Energy) for the relevant time period. Any manual or ex-post adjustments to the forecasts derived from the LSE's chosen forecasting method that are offered

due to catastrophic event impacts (such as COVID-19) must be supported analytically and quantitatively.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.1 Non-Coincident Peak Demand and Energy for Load Forecasts

Non-Coincident Peak Demand and Energy for Load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

The MISO FTR Administration team uses the Non-Coincident Peak forecast value for the upcoming planning year in the annual Auction Revenue Rights (ARR) allocation process. This forecast should not include transmission losses or Grandfathered Agreements (GFAs) but should include Demand Resources and Behind-The-Meter-Generation (BTMG). Load served by GFAs is reported separately via the same MECT section.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-Coincident Peak Demand forecast and FERC's Form 714 for the Energy for Load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective NERC standards documents, defer to the latter.

The Non-Coincident Peak Demand and Energy for Load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:

Summer: June through August
Fall: September through November
Winter: December through February
Spring: March through May

For seasonal reporting of the Non-Coincident Peak Demand forecast, the single highest peak hour during the Season should be reported in MW. The ARR allocation section of the Non-Coincident Peak Demand Forecast submission screen, should be calculated and submitted on an annual peak for a given Planning Year for use in the FTR annual Auction Revenue Rights process. For Energy for Load forecasts, the summation of each month or season's Energy for load (GWh) should be reported as appropriate.

For all forecasts submitted, each LSE shall ensure that it counts its customer Demand once and only once.

Non-Coincident Peak Demand and Energy for Load forecast must be reported in the MECT by 11:59 pm EST on November 1 prior to the Planning Year.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.2 Coincident Peak Demand Forecast

The seasonal Coincident Peak Demand forecasts (CPD forecast) are used as the basis for determining each LSE's seasonal obligation. The seasonal CPD forecasts shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of Demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing the desired approach to be used by LSEs in preparing the seasonal CPD forecasts, the information required in each annual filing, and the process used in reviewing the CPD Forecasts can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper. This document was written for when LSEs submitted an annual Coincident Peak Forecast, but the same methodology described in the paper can be performed at a seasonal level.

The seasonal CPD forecasts must be provided for each Asset Owner/LBA combination. Providing the CPD forecasts by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the appropriate seasonal Transmission Losses towards the Initial PRMR and Final PRMR calculation. Seasonal Transmission Losses will be made available on the public website by MISO for each LBA. For more information on Transmission Losses see Appendix L.

The CPD forecasts must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecasts are reported differently in non-retail choice and retail choice areas as described in the following subsections.

3.2.3 Forecast Reporting

LSEs with Demand and Energy that are not subject to retail choice load switching are required to provide MISO with Demand and Energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The seasonal CPD forecasts must be reported for each Asset Owner by LBA.

LSEs with Demand and Energy that is subject to retail choice load switching are not required to provide MISO with Demand and Energy forecasts. Electric Distribution Companies (EDCs) are responsible for submitting forecasts in areas that have Demand and Energy that is subject to retail choice load switching.

EDCs are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area provides MISO with a seasonal peak forecasted Demand coincident with MISO's seasonal peak and must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs must provide both MISO and the respective retail choice LSEs with each retail customer's initial seasonal Peak Load Contribution (PLC) in the EDC's service territory no later than 11:59 p.m. EST on December 15 prior to the Planning Year.

All new EDCs are required to work with the MISO Client Services and Readiness department (https://help.misoenergy.org/) to set up access to the MECT tool and identify the relationships between the EDC and the LSEs in the EDC area. A Help Center ticket will need to be created to detail the access and relationship additions for the new EDC. The MISO Client Services and Readiness team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the retail choice load switching program are required to provide the name of the EDC where the commercial pricing node is located.

3.2.3.1 Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any Initial PRMR from Demand left unclaimed by retail choice LSEs in the EDC service territory. The Transmission Provider will work with the POLR and EDC to ensure that the POLR will serve any remaining Demand that is not allocated to LSEs.

3.2.4 Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the Demand and Energy attributed to those wholesale customers in their Demand and Energy forecasts by 11:59 p.m. EST on November 1 prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

Case 1: LSE knows the entity that will serve the wholesale customer next Planning Year:
In this case, the existing LSE is not responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

Case 2: LSE does not know who will serve the wholesale customer next Planning Year:
In this case, the existing LSE is responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the Demand from the old LSE to the new LSE prior to the Planning Resource Auction.

3.2.5 Review of CPD Forecasts

Starting November 1, MISO will begin reviewing all forecasts and a randomly chosen set of supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether the forecast methodology adequately and reasonably forecasts peak Demand, Energy, and/or Demand reduction capability of the submitting entity. The forecast review process will be completed no later than March 1 of each year prior to the annual PRA. If necessary, MISO may develop the required seasonal CPD forecasts for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity or other Market Participants that do not submit CPD forecasts and supporting documentation by the November 1 deadline.

3.3 Full Responsibility Transactions

Full Responsibility Transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of an FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of Demand. As a result, the seasonal obligation (Initial PRMR and Final PRMR) calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for Demand that is not subject to retail choice load switching.

The FRS results in an increase in Demand and FRP results in a decrease in Demand. This can be interpreted as the purchaser paying the seller to take on Demand and its associated seasonal Initial PRMR. This transfer of Demand also results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS is contractually obligated to deliver power and Energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within MISO's Region, sellers are responsible for all of that LSE's Initial PRMR associated with the sale.

  Example:

  Asset Owner MM1:
  Seasonal CPDf = 10 MW
  Seasonal PRM = 6.2%
  Seasonal Transmission Loss % = 2%
  Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
  MM1's Initial PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

  Asset Owner SS2:
  Seasonal CPDf = 20 MW
  Seasonal PRM = 6.2%
  Seasonal Transmission Loss % = 2%
  Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
  SS2's Initial PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

  Asset Owner BB3:
  Seasonal CPDf = 50 MW

Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3's Initial PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

The LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon the ACP for all or part of its load delivered to the purchaser through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated Initial PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted Coincident Peak Demand information for the transferred Demand into the MECT. An MP with a FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. If the seller under an FRP/FRS agreement is not an LSE subject to the MISO Tariff, then the purchaser under an FRP/FRS agreement will remain responsible for any capacity payments associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE subject to the MISO Tariff ("non-jurisdictional"), then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. A purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from their responsibility for any RAR deficiencies associated with the FRP/FRS agreement.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand remains with the original LSE (purchaser). Both the purchasing and selling parties will be required to enter and verify the FRT into the MECT Full Responsibility Transaction screen. The parties must enter an FRT into the MECT along with documentation detailing their contract between the purchasing and selling

parties to enable MISO to track the load and capacity obligations shift. This must be done by the fifth business day of February and the settlement will be between LSEs for all FRTs.

The Initial PRMR cannot be a negative number as a result of the FRT.

3.4 Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process used by MISO to establish the Planning Reserve Margin (PRM) for each Season of the prompt MISO Planning Year. A MISO Planning Year runs from June 1 through May 31.

3.4.1 Determination of Seasonal Planning Reserve Margin

MISO will perform probabilistic analyses annually to establish the system-wide seasonal PRMs. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations. Additionally, MISO will perform probabilistic analyses to establish the seasonal Local Reliability Requirements (LRRs) for each Local Resource Zone. MISO will publish the results by November 1 preceding the applicable Planning Year.

The LOLE study shall be consistent with Good Utility Practice, the reliability requirements of the Regional Entities (RE), and applicable states in the MISO Region. The PRM analyses shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMRs), Intermittent Resources, Energy Efficiency Resources, load forecast uncertainty, and the Transmission System's import and export capabilities with external systems. The seasonal PRMs that are calculated in the LOLE probabilistic modeling software are determined on an ICAP and UCAP basis. The preliminary $PRMR_{ICAP}$ values are the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the UCAP ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total UCAP-rated MW needed, or the preliminary $PRMR_{UCAP}$ Values. PRMR values are finalized after MISO has received the updated LSE-submitted load forecasts on November 1 and validated the load forecasts.

MISO will calculate and publish on its website the estimated seasonal PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

See the Resource Adequacy page on MISO's public website for current and previous LOLE study reports.

3.4.2 LOLE Analysis

MISO will determine the appropriate PRM for each Season of the applicable Planning Year based on the probabilistic analyses of being able to reliably serve MISO's forecasted seasonal Coincident Peak Demand. This probabilistic analysis will utilize a LOLE study which assumes that there are no internal transmission limitations.

MISO's LOLE study will first calculate the annual PRM such that the summation of LOLE across the year is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined through LOLE analyses by either adding a negative output unit with no outage rates, or by adding increments of a positive output combustion turbine (CT) Planning Resource with nominal capacity values that correspond with the most recent annual calculation of Cost of New Entry (CONE) as described in Section 6.3 and that have class average outage rates, until a 0.1 day per year solution is reached.

A minimum of 0.01 day per Season LOLE will be used to calculate the seasonal PRMs and LRRs in Seasons with less than 0.01 day per year LOLE risk upon the annual summation of LOLE reaching the 0.1 day per year reliability criteria.

The LOLE model will initially be run with no adjustments to the capacity. If the LOLE in a given Season is less than the reliability criteria day per year for that Season, a negative output unit with no outage rates will be added until the LOLE reaches the reliability criteria for that Season. This is comparable to adding Coincident Peak Demand. If the LOLE is greater than the reliability criteria, proxy units based on a unit of typical size and outage rates will be added to the model until the LOLE reaches the reliability criteria.

MISO will also determine the Local Reliability Requirement (LRR) for each LRZ consistent with the LOLE achieving 0.1 day per year for each LRZ. The minimum amount of capacity above seasonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system-wide seasonal PRMs. The minimum amount of capacity above the seasonal Zonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the seasonal LRR for each LRZ. When determining LRRs, risk-deficient Seasons will have a minimum reliability criteria of 0.01 LOLE per Season.

3.4.3 Loss of Load Expectation (LOLE) Working Group

MISO establishes seasonal Unforced Capacity requirements applicable in the Planning Resource Auction (PRA) based on LOLE probabilistic analyses conducted by MISO Resource Adequacy and in coordination with members of the LOLE Working Group (LOLEWG). The duties of the working group are to help guide MISO in implementing the study methods outlined in this section. The analyses will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable Regional Entities for reliability and resource adequacy. The LOLEWG will review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analyses, as well as reviewing the results of the LOLE analyses and related sensitivity cases. MISO will be the entity ultimately responsible for conducting the LOLE study and determining the seasonal PRMs, except as set forth in Section 3.4.5.

3.4.4 Generator Outage Data for LOLE Study

The probabilistic study will use a LOLE model capable of sequential Monte Carlo simulation. Primary inputs are the generation data submitted to MISO through the PowerGADS tool and forecasted Demands provided as described above in this Section 3. If applicable to the generator type, Asset Owners are obligated to report outage event data as well as Generator Verification Test Capacity (GVTC) for Generation Resources and External Resources through the PowerGADS tool in the MISO Market Portal. Annualized planned outage rates and seasonal forced outage rates are developed for each applicable resource from the submitted outage event data and, together with the capabilities of each resource, are the key generator inputs to the LOLE model. Outage parameters for the LOLE model are established using outage event data from the past five calendar years, as submitted to PowerGADS.

The LOLE study will account for all system-wide forced outage causes captured in the EFORd metric. The EFORd term is defined as:

> Equivalent Forced Outage Rate while in Demand (EFORd): A measure of the probability that a generating unit will not be available for the applicable Season due to forced outages or forced deratings when there is Demand on the unit to generate.

More information on EFORd calculations can be found in Appendix I of this BPM.

3.4.5 State Authority to Set PRM

The only entity other than MISO that may establish a PRM for any Season during the Planning Year is a state regulatory authority regarding those regulated entities under their jurisdiction. If a state regulatory authority establishes a minimum seasonal PRM for the LSEs under their jurisdiction, then that state-set seasonal PRM would be adopted by MISO for jurisdictional LSEs in such state. Other entities, such as reserve sharing groups or NERC regional entities, do not have the authority to establish a seasonal PRM under Module E-1. MISO will translate any state-set seasonal PRM into the same terms as MISO's seasonal PRM (e.g., utilizing a UCAP basis) to facilitate comparison and compliance with PRMR.

MISO will perform the Loss of Load Expectation (LOLE) study to establish the seasonal PRM and publish the results by November 1 preceding the Planning Year. State regulatory authorities choosing to instead elect a state set seasonal PRM must notify MISO in writing by December 1 for the upcoming PRA. The notice shall be from an authorized representative of the state regulatory authority and include the seasonal PRMs, a list of those LSEs to which the seasonal PRMs apply, and a statement that the entities to which the seasonal PRM applies have been duly notified. In scenarios where an LSE crosses state boundaries and one of the states opts to set its own seasonal PRM, the state regulatory authority must work with the impacted LSEs to submit to MISO the pro-rata distribution of seasonal Coincident Peak Forecasts and seasonal Zonal Coincident Peak Forecasts among the states.

Any disputes regarding the applicability of the seasonal PRM information submitted by a state regulatory authority and an affected entity shall be resolved in accordance with applicable dispute resolution measures established by the state regulatory authority. If the state regulatory authority makes any changes to information initially submitted to MISO as a result of such a dispute, the changed information shall be submitted to MISO by the state regulatory authority on or before December 31. If no such changes are submitted, the original information submitted by the state regulatory authority will be used by MISO.

MISO shall update the MECT with the state-set seasonal PRM by January 31.

4 Qualifying and Quantifying Planning Resources

4.1 Overview

This section identifies the qualification requirements for each type of Planning Resource.

All Planning Resources that qualify will have a SAC value determined by MISO. The benefits of SAC include:

- Fair recognition of the contribution each unit provides towards Resource Adequacy;
- Market signals that will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the SAC value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs.

Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, Electric Storage Resources, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources are resources registered with MISO that permanently reduce electricity Demand. A Hybrid Resource may also qualify as a Planning Resource to the extent that such Hybrid Resource is a Generation Resource or Capacity Resource.

Capacity Resources backed by behind-the-meter-generation that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have SAC MWs calculated based on data submitted by the Asset Owner, as described in the Appendix H - Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources - of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources backed by behind-the-meter-generation that have not provided at least one Season of historical performance data will have their SAC calculated for them after they are registered in MISO's Commercial Model, provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA in which they are physically located. The following table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

	Planning Resource				
	Capacity Resource		Load Modifying Resource		Energy Efficiency Resource
	Generation, ESR, and External	Demand Response Resources	BTMG	Demand Resource	
Capacity Verification	X	X	X	X	X
Must Offer	X	X			
GADS Data Entry	X	X	X		
Must Respond to Emergency Operating Procedures	X	X	X	X	

4.2 Planning Resources

4.2.1 Generation Resource, but not Dispatchable Intermittent Resource or Intermittent Generation

4.2.1.1 *Qualification Requirements*

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within MISO's Region. The deliverability of Generation Resources to Network Load within MISO's Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. Generation Resources that pass the deliverability test receive Network Resource Interconnection Service.
- Generation Resources that do not pass the deliverability test may procure firm Transmission Service (or utilize a GFA) in conjunction with Energy Resource Interconnection Service (ERIS) to meet the deliverability requirements.
    - Firm Transmission Service must either be a Firm Point-to-Point (PTP) Transmission Service Request (TSR) or a Firm Network Integration Transmission Service (NITS) Scheduling Right (SR).
        - NITS SRs should reference the OASIS NITS Application number and Resource Name used in the SR.

  - Firm transmission service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in total or in aggregate and be submitted in the MECT. The resource is only deliverable to the LBA identified in the Firm Transmission study that grants the NITS SR or PTP TSR.
- Generation Resources with ERIS may participate in MISO's Interim Deliverability Study process as described in BPM-015. The following generic parameters apply for the Interim Deliverability Study:
  - MISO may grant conditional NRIS applicable for the next Planning Year
  - MISO may grant conditional ERIS applicable for the next Planning Year
  - MISO may grant conditional External-NRIS (E-NRIS) applicable for the next Planning Year.
  - MISO may implement a Quarterly Operating Limit (QOL) on a portion of a Generation Resource due to transmission study overloads. MW amount subject to QOL can qualify as capacity in the PRA. The MW amount subject to QOL is not required to procure replacement capacity if the QOL is reduced in a subsequent MISO quarterly study.
- Generation Resources with a Provisional Interconnection Agreement are not qualified to participate in the PRA.
- Generation Resources that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.
  - This may include Generation Resources that were issued 'local' NRIS through a Generator Interconnection Agreement consistent with Module E-1 Section 69.3.1.g paragraph v. In such instances, 'local' NRIS is processed in similar fashion as ERIS for the purposes of demonstrating deliverability for participation in the Planning Resource Auction. As with resources with ERIS, firm Transmission Service must be demonstrated to cover the entire auction period for the level of participation desired in order to qualify for participation in the PRA.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Generation Resources greater than or equal to 10 MW (based on Generation Verification Tested Capacity (GVTC)) must submit their Generator Availability Data System (GADS) data (including, but not limited to, NERC GADS) into the MISO PowerGADS database through the MISO Market Portal. Quarterly GADS Event and

Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.

- Generation Resources less than 10 MW based upon GVTC are not required to report their GADS data.
- Generation Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report GADS data each Planning Year.
- The seasonal XEFORd for new Generation Resources in service less than one full Season will be the seasonal EFORd class average for the resource type. A Generation Resource will use the class average value until 3 consecutive seasonal months of data is available. Forced outage rates are used for the capacity accreditation of non-Schedule 53 Generation Resources.
- Generation Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- Generation Resources that are in approved “Suspension” status qualify as a Planning Resource through the ICAP Deferral process.
- If Generation Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date. Generation Resources with approved “Suspension” status must participate as a Planning Resource in the next Planning Year subject to provisions regarding physical withholding in Module D of the Tariff.
- Generation Resources that plan to retire during the Planning Year will be subject to test for Physical Withholding.
- Generation Resources that are or plan to be suspended will be subject to test for Physical Withholding.
- Generation Resources that have been designated as a System Support Resource (SSR) may participate in the PRA.
- Generation Resources must demonstrate capability on an annual basis as described below.
- Generation Resources undergoing conversion to natural gas are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource’s rolling XEFORd.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, ESR, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year must submit their GVTC no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be completed by completing a real power test or based on operational data. The GVTC must be completed during the test period of September 1 through August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and a revised GVTC should be submitted to MISO no later than March 1 prior to the Planning Year. The initial GVTC, even if a Planning Resource is unable to test and the GVTC is 0, must be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to service in MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).
- A real power test is required for Planning Resources in an approved "Suspension" status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item, including timing and cost requirements, when requesting a facility specific reference level.

The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1 prior to the Planning Year unless the GVTC has been deferred via the ICAP Deferral process as described in Section 4.5. See Appendix J **– GVTC Testing Requirements**.

GVTC Test Extension Request

A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC results by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline, estimated seasonally corrected GVTC values, and an expected completion date prior to the upcoming Planning Year. An extension may also be requested for re-testing and submitting after the October 31 deadline. The

estimated seasonally corrected GVTC values are only an estimate to be used in initial SAC posting and the actual test results will be used for the final SAC posting. The Transmission Provider will review each extension request on a case-by-case basis to determine whether to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process. Test results for Approved GVTC Test Extension Requests must be submitted by January 15 prior to the upcoming Planning Year.

Reporting is accomplished through MISO's PowerGADS reporting system as described in the Net Capability Verification Test User Manual.

4.2.1.2 *SAC Determination*

The SAC values for a Generation Resource are based on an evaluation of the type and volume of interconnection service, GVTC values, the XEFORd value of non-Schedule 53 Generation Resources as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources and Appendix I – XEFORd Calculation, and SAC value for Schedule 53 Resources as applicable and described in Appendix Y – SAC Calculations for Schedule 53 Resources.

Generation Resources relying either fully or in part on Energy Resource Interconnection Service (ERIS) coupled with firm Transmission Service to demonstrate deliverability must procure firm Transmission Service up to the Resource's ICAP level in order to receive their full SAC allocation.

If a Generation Resource's procured firm Transmission Service coupled with ERIS is less than the Generation Resource's ICAP value, the SAC allocation would be pro-rated based on Tariff Module E-1 Section 69A.4.5.

The SAC methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit based on its availability, SAC provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average EFORd of all the pooled resources, the generating units with better than average availability will reflect higher values than units with below average availability.

In order for a Generation Resource to convert its entire calculated Total SAC into Zonal Resource Credits, the Generation Resource must be fully deliverable up to its ICAP. Deliverability is determined by any combination as outlined in Module E-1 Section 69A.3.1.g of the Tariff.

If a Generation Resource is not fully deliverable up to its ICAP, the resource will be eligible to convert a value less than the Total SAC into Zonal Resource Credits as outlined in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources, as well as in Appendix Y – SAC Calculations for Schedule 53 Resources.

4.2.1.3 *Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements*

Intermittent Generation and Dispatchable Intermittent Resources are subclasses of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1 Qualification Requirements and the alternate GADS reporting procedure as described below:

For existing Intermittent Generation and Dispatchable Intermittent Resources (eg. run-of-river hydro, solar, biomass), Market Participants must supply MISO with a minimum of one entire Planning Year of hourly net output data for each season in which the resource would be accredited.

For existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind, Market Participants may submit up to three (3) Planning Years of hourly net output data, for a total of 9 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19, and 20 EST for the Winter Season. Seasonal accreditation for existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind is determined as an average of the hourly net output.

For Intermittent Generation and Dispatchable Intermittent Resources classified as run-of-river hydro, Market Participants may submit up to fifteen (15) Planning Years of hourly net

output data, for a total of 45 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16 and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season. Seasonal accreditation for fun-of-river hydro resources is determined as a median of the provided hourly net output.

For resources on qualified extended outage where data does not exist for some or all of the previous historical seasonal months, a minimum of 30 consecutive days' worth of historical net output data during the relevant typical seasonal peak hours, must be provided prior to participating in the PRA.

New Intermittent Generation or Dispatchable Intermittent Resources that do not have a minimum of 30 consecutive days' worth of seasonal historical operating data during the typical seasonal peak hours may participate in the PRA and will receive class average accreditation values if the resource will be in operation by the start of a Season in the applicable Planning Year.

4.2.1.4 *Dispatchable Intermittent Resources and Intermittent Generation Resource - SAC Determination*

The Seasonal Accredited Capacity (SAC) for Intermittent Generation and Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of Interconnection Service. Examples of SAC calculations for these resources can be found in Appendix V – Solar and Run-of-River Hydro Capacity Credit.

Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their SAC values determined based on Interconnection Service volumes and their respective wind capacity credit established via seasonal Effective Load Carry Capacity (ELCC) analyses as described in Appendix A – Wind Capacity Credit.

1.1.1.1.1 4.2.1.5 Wind Capacity Credit

MISO calculates specific wind capacity credit (%) for each wind resource and applies it to its registered maximum capability (MW) in the Commercial Model or its registered Capacity (MW) through the LMR or External Resource registration process. MISO uses historical wind

availability information to calculate a seasonal Effective Load Carrying Capacity (ELCC) to determine a wind capacity credit. Wind capacity credits are determined for each individual wind resource based on its average capacity factor during MISO's top eight (8) coincident peaks that occurred during the Season for the previous three Planning Years.

A new wind resource with no commercial operation history during the Season will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the seasonal Effective Load Carrying Capacity (ELCC) analyses for their initial Planning Year, and thereafter metered data will be used to calculate its future resource-specific wind capacity credit.

If an existing wind resource has no historical metered data available, or was inoperable for a Season, then the existing wind resource will receive a seasonal capacity credit of 0%.

An increase in unit capacity for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the SAC values have been established will require written notification from the Market Participant to a member of the Resource Adequacy department to update the values. This notification is due by March 1 prior to the applicable Planning Year.

BTMG wind will have their SAC values determined from their historical net output during periods of MISO system peak Demand for the three Planning Years prior.

For more information regarding the methodology for calculating wind capacity credits, see Appendix A – Wind Capacity Credit of this BPM and MISO's wesbite (misoenergy.org / Planning / Resource Adequacy / PRA Documents / select the appropriate Planning Year) for the Wind and Solar Capacity Credit Report. Additionally, Appendix H – Seasonal Accredited Capacity (SAC) Calculations for Planning Resources details the determination of convertible SAC using the deliverability-adjusted capacity factor.

1.1.1.1.2 4.2.1.6 Solar Capacity Credit

Solar resources will have their SAC values determined based on the three (3) most recent Planning Years of historical average net output during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season.

Solar resources that have been upgraded or returning from extended outages shall submit all operating data for the prior Season with a minimum of 30 consecutive days to have their capacity registered with MISO.

Solar esources with less than 30 days of metered values would receive seasonal class accreditation for their initial Planning Year in operation. Seasonal class accreditation for a new solar resource in the Summer, Fall, and Spring Seasons is 50% and 5% for the Winter Season. Refer to Appendix V - Solar and Run-of-River Hydro Capacity Credit for additional examples and determination of convertible SAC.

4.2.2 Use Limited Resources

4.2.2.1 *Use Limited Resources – Qualification Requirements*

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously, but are able to operate for a minimum set of consecutive operating hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- Is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates GVTC and submits the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.
    - MISO will consider how the resource has historically operated and any proposed changes in its operation to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources are a subclass of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.

- MISO may qualify a resource classified as a Diversity Contract as a Use Limited Resource seasonally provided the resource meets all of the requirements of both an External and Use Limited Resource.
- Use Limited Resources must demonstrate GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Use Limited Resources with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.2.2 *Use Limited Resources – SAC Determination*

The SAC values for a Use Limited Resource are based on an evaluation of the resource type and volume of Interconnection Service, GVTC value, and XEFORd value of such Use Limited Resource as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources.

In addition, a Use Limited Resource with contract provisions that prevent the resource from meeting its Must Offer requirement will have a decrease in the SAC calculation to the extent that the contract provisions are less than the required Must Offer requirement of 4 hours across the forecasted peak for each day during the registered Season. Use Limited Resources unable to meet the Must Offer requirements will have their SAC prorated relative to the percentage of hours meeting the Must Offer requirement and to the must offer hours for the Season.

4.2.3 External Resources

MPs may register an External Resource by providing the information listed below to MISO Resource Adequacy to qualify such resources as Capacity Resources. External Resources are registered through the MECT tool for each Planning Resource Auction and reviewed and approved by MISO Resource Adequacy staff. An MP that owns an External Resource or contracts for an External Resource through a power purchase agreement (PPA) may register its External Resources. An MP must denote within the registration if the External Resource being registered is a Use Limited Resource. External Resources that are also Use Limited Resources must meet all requirements in Section 4.2.2.1 “Use Limited Resources – Qualification Requirements” and be approved by MISO Resource Adequacy.

An MP must submit the completed registration form for existing External Resources in the MECT by February 1 prior to the upcoming Planning Year. New External Resource registrations

or existing registrations with increased capacity are to be submitted in the MECT by March 1 prior to the upcoming Planning Year. Existing registrations with increased capacity are required to submit the original GVTC by October 31 prior to the upcoming Planning Year. The completed registration form requires the MP to certify that the registration information is accurate and that the qualifying MWs from External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it has been determined whether or not the External Resource qualifies for the applicable Planning Resource Auction, or whether there are any outstanding deficiencies in the registration.

4.2.3.1 *External Balancing Authority Qualification Options*

MISO has established host/external Balancing Authority qualification criteria that applies to Balancing Authorities that could impact Energy schedules associated with qualifying External Resources. The Balancing Authority qualification criteria ensures that Energy schedules corresponding to the qualifying External Resources will only be interrupted in a manner that provides consistency, transparency, and reliability.

An executed PPA or External Resource owned prior to April 3, 2014 will continue to qualify as a Planning Resource for the initial full term of the PPA or ownership of the resource, if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011 between June 1 and September 30.

Resources or PPAs that are submitted to MISO for qualification as External Resources must have their corresponding Energy schedules flow through host/external Balancing Authorities that comply with one of the three options outlined below to qualify.

A. Scheduled Interruption Linked to Performance of a Specific Generator in the External Balancing Authority

In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external Balancing Authority will not interrupt the schedule from the External Resource unless the generator being used to serve a unit-specific sale has a forced or planned outage.

This type of External Resource would be treated similarly to internal generation because those internal resources constitute Capacity Resources, even when they can be interrupted for forced or planned outages. This provision ensures that the generator delivering the Energy in support of the PPA can be specifically identified.

B. Slice-of-System Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

PPA or External Resource fleets in this category will qualify as Planning Resources, so long as the associated capacity schedule only will be curtailed pro-rata, along with load in the source Balancing Authority, and only when the source Balancing Authority is operating under Emergency Procedures.

Under this situation and as an example, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

C. Slice-of-System in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

In addition to the slice-of-system treatment noted in category B above, a slice-of-system PPA or External Resource fleet can qualify as External Resources under this category, and MISO and the external Balancing Authority will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met. This qualification category has several requirements for the host Balancing Authority:

1. It must be in MISO's Reliability Coordination Area.
2. It must share Operating Reserves with the MISO Balancing Authority.
3. It must have a Seams Operating Agreement with MISO containing several features. The Seams Operating Agreement must:
    a. Ensure that the host Balancing Authority has established planning reserve processes and criteria similar to MISO.
    b. Specify the actions that will be taken by both entities, MISO and the host Balancing Authority, during Emergency Procedures prior to implementing Load Shedding.

c. Specify that the host Balancing Authority will submit load estimates to MISO in a similar manner as submitted by other Load Serving Entities under Module E-1, provide generator testing data for all resources used to serve firm requirements of the host Balancing Authority, and provide transparency to such resource plans in the form of a FRAP or RBDC Opt Out, pursuant to Module E-1.

With these requirements in place, when both Balancing Authorities have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

For example, if the load of an external Balancing Authority in capacity emergency is 3,000 MW, and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

4.2.3.2 *External Resources - Qualification Requirements*

The following information will be required to register an External Resource:

- Demonstration of firm Transmission Service from the External Resource to the MISO border, and that;
- Firm Transmission Service has been obtained within MISO to deliver the Capacity Resource MWs seeking to be qualified from the External Resource(s) to the Load Zone CPNode within MISO. The Load Zone CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO's OASIS reservation sinks in for Network Customers, or either;
    - The External Resource has Network Resource Interconnection Service under Attachment X.
    - The External Resource was accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date.
- External Resources may procure firm Transmission Service (or utilize a Grandfathered Agreement) to meet the deliverability requirements.
    - Firm Transmission Service must either be in the form of a firm Point-to-Point (PTP) Transmission Service Request (TSR) or firm Network Integration Transmission Service (NITS) Scheduling Rights (SR).

        - NITS Scheduling Rights should reference the OASIS NITS Application Reference number or Assignment Reference number, and Resource Name of the Scheduling Right.
    - Firm Transmission Service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in aggregate and be submitted in the MECT once approved. The resource is only deliverable to the LBA identified in the firm transmission study that grants the NITS SR or PTP TSR.
- Demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program, is available in the event of an Emergency, and performs an annual GVTC test and reports the data via MISO's PowerGADS (or alternatively, submits a populated Non-GADS Performance Template to the MECT) by October 31 for returning resources and March 1st for new resources.
- External Resources that have been retired prior to the applicable Planning Year will not qualify as a Planning Resource.
- If External Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.
- External Resources greater than or equal to 10 MW based on their GVTC must submit generator availability data to PowerGADS through the MISO Market Portal. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs and does not apply to Intermittent Resources or Intermittent Generation. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must pass Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report such information.
- Border External Resources and Coordinating Owner External Resources will be modeled, for LOLE and PRA purposes, in the LRZ where their firm Transmission Service crosses the MISO border. All remaining External Resources will be modeled in an External Resource Zone based on their associated External Balancing Authority.

- A PPA may qualify as a Planning Resource if it is valid for the entire Season or is unavailable for no greater than thirty-one (31) days in total for each Season it is being used. If an amended PPA or interim operating plan exists for the Season in which the MP seeks capacity credit, this will be used in calculating the capacity value provided the PPA or interim operating plan contains a capacity amount.
- For a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.
- External Resources that are in service and registering as a Planning Resource for the first time must submit GVTC, and if greater than or equal to 10 MW based on GVTC must submit GADS data (if applicable) prior to being approved as a Capacity Resource.
- An External Resource registration needs to point to a Load Zone CPNode. Along with firm Transmission Service, this acts as verification of deliverability to the load being served by the External Resource.
- All External Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31 to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and be corrected to the average temperature of the date and times of MISO's coincident seasonal peaks, measured at or near the generator's location, for the last 5 years, or provide past operational data that meets these requirements to determine its GVTC and submit its GVTC data to MISO's PowerGADS.
    - Resources that do not submit real power tests through GADS must submit a populated Non-GADS Performance Template via MECT as substitute. Existing resources must do this by October 31, while new resources should submit this template by March 1.
- External Resources undergoing gas conversion are not required to submit GVTC prior to returning.
- MPs who register a slice-of-system External Resource are responsible for ensuring proper outage and GVTC data is submitted to MISO through PowerGADS, unless a populated Non-GADS Performance Template is submitted via MECT for the External Resource. This information is due no later than October 31 of the prior Planning Year to qualify as a Planning Resource.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- External Resources that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be met by a real power test or past operational data must be provided during the test period between September 1 and August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC to MISO by March 1. The initial GVTC should be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time and must be submitted to MISO no later than March 1 prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT and must be submitted by March 1 prior to the upcoming Planning Year.
- See Appendix J – GVTC Testing Requirements.
- External Resources with any new or untested additional capacity are eligible for the ICAP Deferral process as described in Section 4.5 ICAP Deferral.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Capacity Verification Manual, which is located on MISO's PowerGADS > Tools > Guide.

4.2.3.3 *Submission of new External Resource Registrations*

A Market Participant must register their new External Resource via the Registrations screen in the MECT by March 1 prior to the Planning Year. To guarantee new resources can be used in an LSE's FRAP or RBDC Opt Out, registrations must be submitted no later than February 15 prior to the Planning Year. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Client Services and Readiness team at MISO Help Center (https://help.misoenergy.org/) to become a Market Participant. The resource information submitted through the Registrations screen will require the Market Participant to

certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F, External Resources, contains the information that must be submitted by an MP through the MECT on the Registrations screen.

4.2.3.4 *Amendments to Accredited External Resource Registration Data*

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by the deadline.

4.2.3.5 *Renewal of External Resource for Subsequent Planning Years*

Renewed External Resource registrations must be submitted by February 1 prior to the upcoming Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an External Resource. MISO will notify the Market Participant within 15 days after the renewed registration form has been submitted as to whether or not the External Resource has been accredited as an External Resource, or whether there are any deficiencies within the registration that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT for use by the MP during the applicable Planning Year.

4.2.3.6 *Review of Power Purchase Agreements*

Market Participants that have entered into power purchase agreement(s) for future Planning Years must provide to MISO the documentation that demonstrates the active power purchase agreement and MISO will make a preliminary determination of whether the agreement(s) would qualify as External Resources from power purchase agreement(s) as set forth in sections 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered conforming. Market Participants must submit this documentation as part of the External Resource registration process and will be reviewed by MISO Resource Adequacy staff.

MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of their agreements will need to follow the procedures

applicable to the planning period for which such External Resource is intended to be relied upon to meet capacity requirements. This includes the provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.3 External Resources, to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term.

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered non-conforming and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;
f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which Energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the MISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

4.2.3.7 *External Resources – SAC Determination*

The Seasonal Accredited Capacity (SAC) for External Resources will be accredited based on seasonal GVTC values and seasonal Transmission Service, and seasonal $XEFORd_d$ (where applicable) values of such External Resources, are based on the methodology documented in

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources. MISO will determine SAC values for External Resources that are Intermittent Generation as described in Section 4.2.1.4 – Dispatchable Intermittent Resources and Intermittent Generation Resource – SAC Determination. External Resources, from PPAs, with varying monthly capacity values will be credited with the monthly capacity value of the contract that corresponds with the seasonal peak Demand month, unless the resource(s) supporting the PPA are considered Intermittent Generation.

4.2.3.8 *Dually Connected Border External Resources*

Border External Resources can have interconnection facilities which connect to multiple LRZs. In those instances, these resources would be modeled in a single Local Resource Zone with which the resource has the greatest connectivity. Connectivity is measured using shift factor analysis that evaluates the generator's impact on flows on the Transmission System. The analysis is performed based on the latest models and input files used in support for the upcoming PRA. The study model is created by ramping the resource up and sinking the output to the MISO footprint. Line loadings in the connected LRZs are compared with those of the base model to determine the impact of the unit. The study will include consideration of tie line flow, impact on historical constraints, and impacts on the connected LRZs as a whole. Results of the analysis will be posted on MISO's website prior to the Planning Resource Auction. Details regarding the resource's impact on individual transmission lines will not be published.

4.2.3.9 *SAC Determination – Fixed Capacity PPA*

Market Participants may register External Resources where the supplier has guaranteed delivery of a fixed MW value of capacity. Market Participants must contact MISO Resource Adequacy for a review of this type of PPA. Subsequent approval of such contracts by MISO results in an accreditation of XEFORd and the SAC will be set equal to the ICAP of the External Resource registered. PPAs backed by an Intermittent Resource do not qualify as this type of PPA.

4.2.3.10 *SAC Determination – Full Requirements PPA*

Market Participants may register External Resources to model a full requirements power purchase agreement with a counterparty. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, applicable Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource's SAC and Must Offer calculations. Market Participants must contact MISO Resource Adequacy for a review of these types of contracts.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left(\frac{ICAP_i\ x\ (1 + PRM_{LRZ})\ x\ (1 + TL_{LBA})}{(1 - XEFORd_i)} \right)$$

Where:
$ICAP_{adjusted}$: PPA Percent x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
PRM_{LRZ}: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in
TL_{LBA}: Transmission Losses for the LBA that the External Resource will be serving load in

4.2.4 DRR Type I and Type II – Qualification Requirements

Demand Response Resources (DRR) Type I and Type II may qualify as Capacity Resources provided that the following criteria are met. (All references to generation availability and testing in this section pertain to DRRs backed by generation.):

- DRR Type I and Type II backed by behind the meter generation (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into the PowerGADS tool through the Market Portal.
- DRR Type I and Type II must demonstrate seasonal capability on an annual basis. Verification of DRR Type I and Type II capability will be in accordance with the guidelines established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.
- DRRs may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.
- DRRs must demonstrate seasonal corrected GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- DRRs with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.4.1 *DRR Type I and Type II – SAC Determination*

MISO will determine the SAC value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and XEFORd values of such generator. If such behind the meter generation facility is interconnected to the Transmission

System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average EFORd of the resource type will be used to calculate the forced outage rate (XEFORd) for the resource.

A XEFORd value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

SAC MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4 – Generation Verification Test Capacity During a Derate.

4.2.5 Load Modifying Resource Obligations and Penalties

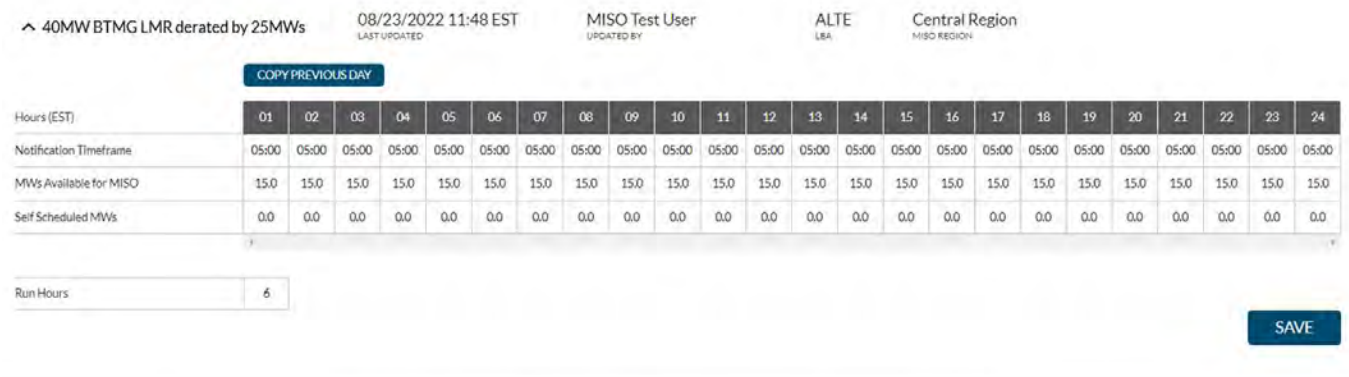
Load Modifying Resources (LMRs) consist of Demand Resources (DR) and Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Load Control Management and other resources that result in additional and verifiable reductions in end-use customer Demand during an Emergency.

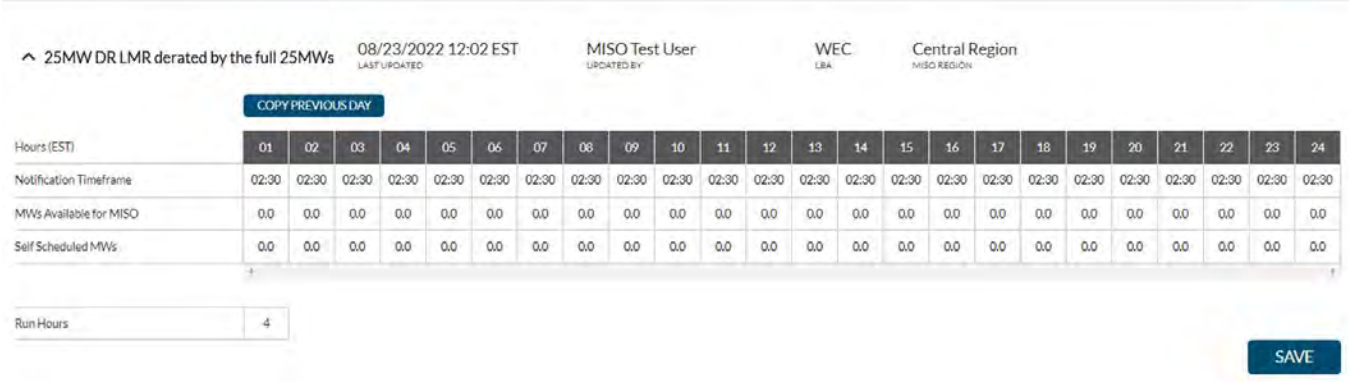
Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a Load Zone CPNode. BTMG is not included in MISO's Setpoint Instructions. An LMR that exclusively relies only on a generator to accomplish the load reduction and remains synchronously connected to the grid, or injects onto the grid, must register as a BTMG. In scenarios where LMRs represent an interruptible program that disconnects the load from the grid and activates a local backup generator to provide power on an asynchronous island, independent from the grid, a DR registration may be used.

BTMG and DR requirements to qualify as an LMR are covered in Sections 4.2.6 - BTMG Qualification Requirements and 4.2.7 - Demand Resource (DR) Qualification Requirements of this BPM.

LMRs differ from Capacity Resources in that they do not have a must offer requirement, however, they must be available for use within MISO as defined in this BPM during Emergency events (including capacity and transmission events) declared by MISO unless unavailable because of maintenance, Force Majeure or other reasons outlined in this BPM. LMRs communicate to MISO their availability through the Demand Side Resource Interface (DSRI). MPs with LMR assets must provide updates to availability specific to each LMR that is listed in

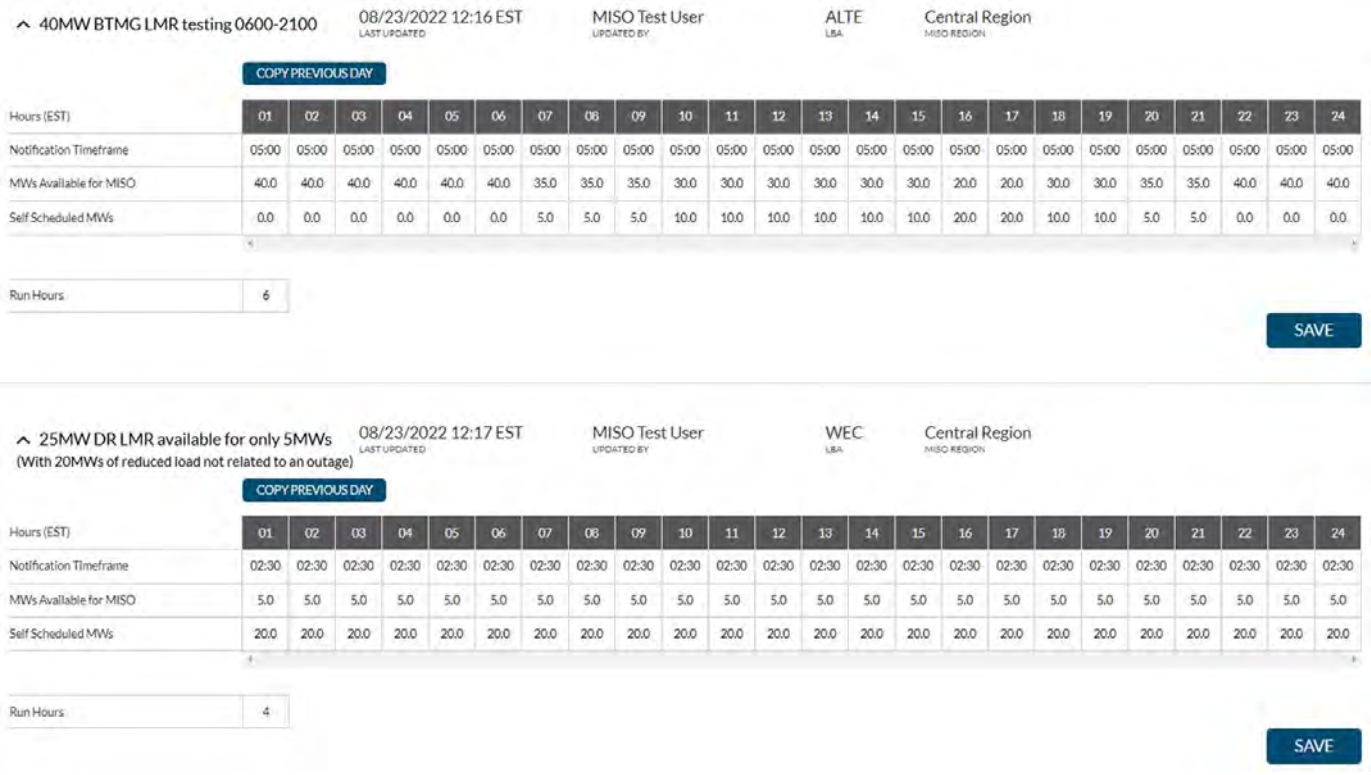
the DSRI. The DSRI is populated with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears in a Planning Resource Auction (PRA) or used in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out times the Demand Reduction Capability Forecast. If the LMR only partially clears the PRA, MISO will grant an opportunity to adjust the monthly MW values to account for the cleared LMR ZRCs. It is critical that LMR availability always be current as the Scheduling Instructions (dispatch directives) and ultimately performance and availability review will utilize the information in the DSRI at the time the Scheduling Instruction is issued and how the Market Participant responds to the Scheduling Instruction. If the LMR is on any type of derate, outage or otherwise not available, the LMR availability should be adjusted by decrementing the availability in the DSRI by reducing the "MWs available for MISO" for the affected LMR. The following are two examples of a 40 MW BTMG LMR derated by 25 MWs, and a 25 MW DR LMR derated by the full 25 MWs and is completely in outage:





If a BTMG is scheduled to be deployed by the MP, the "Self Scheduled MWs" section in the DSRI should be increased for LMR MWs that are scheduled to be deployed and the "MWs available for MISO" amount should be reduced to reflect the remaining MWs available for additional MISO deployment. If a DR is scheduled to be deployed by the MP, or it simply has

reduced load for the end-use at the facility then the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed or has been already reduced, and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. Derates and outages that occur where load is not reduced should not be entered as “MWs available for MISO” or “Self Scheduled MWs”. The following are two examples of a 40 MW BTMG LMR coming online for a test between 0600 – 2100, and a 25 MW DR LMR available for only 5 MWs for MISO because there is reduced load at the facility:



40MW BTMG LMR testing 0600-2100 — LAST UPDATED: 08/23/2022 12:16 EST — UPDATED BY: MISO Test User — LBA: ALTE — MISO REGION: Central Region

COPY PREVIOUS DAY

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00
MWs Available for MISO	40.0	40.0	40.0	40.0	40.0	40.0	35.0	35.0	35.0	30.0	30.0	30.0	30.0	30.0	30.0	20.0	20.0	30.0	30.0	35.0	35.0	40.0	40.0	40.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	10.0	10.0	20.0	20.0	10.0	10.0	5.0	5.0	0.0	0.0	0.0

Run Hours: 6

SAVE

25MW DR LMR available for only 5MWs (With 20MWs of reduced load not related to an outage) — LAST UPDATED: 08/23/2022 12:17 EST — UPDATED BY: MISO Test User — LBA: WEC — MISO REGION: Central Region

COPY PREVIOUS DAY

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30
MWs Available for MISO	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Self Scheduled MWs	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

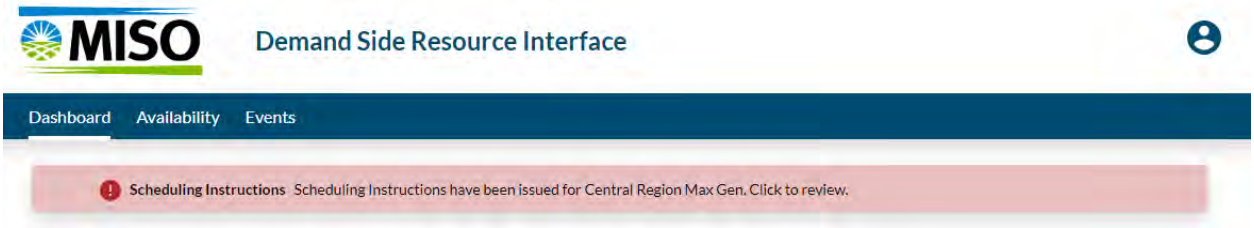
Run Hours: 4

SAVE

For specifics on DSRI functionality, please see the MP LMR Users Guide located in the Learning Center.

If an Emergency is declared by MISO that requires LMR deployment, MISO will issue Scheduling Instructions in the DSRI using the LMR availability information (“MWs available for MISO” and “Self Scheduled MWs”) provided by MPs. Self Scheduled MWs are included in a Scheduling Instruction to ensure that the MW deployed voluntarily by an MP continue to be deployed if required during an Emergency. Self Scheduled MWs are not subject to notification

times because they are already planned to be performing at those levels, as decided by the MP; however, MWs available for MISO are subject to notification times whenever Scheduling Instructions are created. The LBA and the MP will receive a notification of the Scheduling Instructions via a MISO Communications System (MCS) message (LMR Implementation MCS message type). MPs will also receive a Scheduling Instructions event banner within the DSRI application as shown below (with audible alerts until acknowledged).



Market Participants with LMRs must have personnel operating on a 24x7 basis that can receive and respond to MCS messages, Operator Interface Declarations and Messages, and LMR Scheduling Instructions events in the DSRI. The MP will need to acknowledge receipt of the Scheduling Instruction and update the remaining availability, if any, of the LMR(s) being used to meet the Scheduling Instruction in DSRI to reflect the MW amount available in the specified time(s). This update and acknowledgement should be done within one (1) hour of receiving the Scheduling Instruction from MISO. Also, before the Emergency deployment, the MP that registered the LMR(s) should submit the specific designation of LMRs and associated MWs used to meet the total MWs contained in the Scheduling Instruction via the Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI.

MPs that report LMR availability (including self-scheduled MWs) in the DSRI that is less than the performance obligation based on the MW value that is being used to meet RAR, may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declared an Emergency. Meter data for the LMRs used to meet the MWs requested in the Scheduling Instruction mustbe uploaded in the Demand Response Tool within 103 days of the Emergency event or as requested by MISO.

MISO will not violate registration parameters (e.g., notification time) and real time availability updates provided by MPs when issuing a Scheduling Instruction. MISO does, however, rely on real time availability updates provided by MPs when issuing a Scheduling Instruction.

4.2.5.1 *LMRs with Dual Registration*

Market Participants that register LMRs are eligible to also register in the Energy market as Emergency Demand Resources and/or Demand Response Resources.

LMRs that have some capability registered as Emergency Demand Response (EDR) or Demand Response Resource (DRR) should adjust their availability in DSRI to reflect net LMR MWs available to MISO (e.g. decrement total LMR capability by EDR offer amount and DRR cleared Day-Ahead or pending Real Time offer). It is the responsibility of the Market Participant to ensure no double counting of MWs offered across the dual registration types. Double counted MWs may be subject to underperformance penalties.

1.1.1.1.3 4.2.5.1.1 LMRs Also Registered as Demand Response Resource (DRR)

DRR Type I and Type II that have converted SAC to ZRCs which were used to meet seasonal Resource Adequacy Requirements (RAR) are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert all its associated SAC may also register the remaining SAC of the resource as an LMR. In this case, the SAC converted and used to meet RAR under the LMR designation would follow the respective LMR requirements and likewise the DRR SAC if converted and used to meet RAR would carry the must offer requirement. The combined SAC converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned SAC value of the singular resource.

1.1.1.1.4 4.2.5.1.2 LMRs Also Registered as an Emergency Demand Resource (EDR)

A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 to participate in the Energy market regardless of whether it qualifies as an LMR under Module E-1. An LMR may also dually register and qualify as an EDR. In the case of a dual LMR / EDR registration, the resource may be dispatched as an EDR when there is a pending EDR offer (EDR offers are made daily). If the resource is not dispatched as an EDR, it maintains its LMR obligations, and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered. MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff.

For more information regarding the dual registration of LMRs as EDRs, please see Section 6.4 of BPM-026 Demand Response.

1.1.1.2 4.2.5.2 LMR Performance Obligations

The registered capacity of accredited LMRs that has been converted to ZRCs and has cleared in the PRA must be available as outlined above for use in the event of an Emergency declared by MISO. MISO will populate the DSRI with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears times the Demand Reduction Capability Forecast. MPs should keep these values up to date to ensure the availability is accurate as Scheduling Instructions will be based on the LMR Availability in the DSRI. The Available MWs for MISO should be consistent with the availability indicated in the LMR's registration. A Market Participant utilizing LMRs to meet Resource Adequacy Requirements will be subject to the penalties described in Section 69A.3.9 of the Tariff if the LMR is included in the Market Participant's response to Scheduling Instructions and the LMR fails to respond.

A Demand Resource (DR) must respond with an amount greater than or equal to the target level of load reduction or reduce Demand at or below the registered firm service level. DRs that registered with a Firm Service Level Measurement & Verification methodology that partially clear, will have the uncleared portion of the resource added to their registered firm service level (FSL) when evaluating performance. A BTMG must provide the target level of generation increase as indicated on the Market Participant's Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI when responding to Scheduling Instructions Combined, the Market Participant's DR and BTMG responses must meet the total MWs contained in their Scheduling Instruction.

This "target" level MW is indicated by the MP via the DSRI's Resource Deployment tab of the LMR Scheduling Instruction Event which outlines which LMRs were utilized and the associated MW levels to meet the total MWs contained in the Market Participant's Scheduling Instruction. An LSE shall be assessed the costs that were otherwise incurred to replace the Energy deficiency at the time the LMR was dispatched.

MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. LMR values entered in the DSRI availability will also be considered when evaluating whether target levels of generation

increase, or Load reduction have been met. For more information regarding the performance assessment of an LMR, please see BPM-026 Section 6.2.

The operators of LMRs that improperly report to MISO that an LMR is unavailable in the DSRI prior to receiving a Scheduling Instruction or the LMR does not respond when included in a Market Participant's response to Scheduling Instructions will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction for a DR, or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) and properly reflected in the hourly availability in the DSRI for each resource. Likewise, for certain LMRs that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted and the hourly availability in the DSRI should be updated to properly reflect the anticipated capability of the resource.

4.2.6 BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Intermittent BTMG (e.g., solar, wind, run-of-river hydro, etc.) are exempt from submitting the additional documentation for monthly availability and notification time as they are not dispatched via the DSRI.
- Confirming through the registration process such BTMG can be available to provide Energy with no more than 6 Hours advance notice from MISO or the LBA and sustain Energy production for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times as needed during the Summer and Winter and at least the first (3) times as needed during the Spring and Fall by MISO or the LBA for emergency event purposes, consistent with the registration information of the physical capability of the BTMG.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce Energy may qualify in meeting this requirement if located in the same LRZ).

- Behind the Meter Generation must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Behind the Meter Generation with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5 ICAP Deferral.
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource must submit information in accordance with Section 4.2.1.3 Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- For wind resources being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during at least one Season would submit metered values in MW terms for all Hours in the test period.
    - Resources with no commercial operation history of metered values during the Season would receive class average for each Season within the Initial Planning Year.
- For solar resources being registered as BTMG, the following information is required:
    - Resources with at least 30 consecutive days of metered values for that Season would submit metered values in MW terms for all hours in the test period.
    - Resources with less than 30 consecutive seasonal days of metered values would receive class average for the Seasons within the Initial Planning Year.
- For storage resources that do not report to GADS (including but not limited to, batteries, flywheels, compressed air, and pumped storage) being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during no less than 30 consecutive days in a specific Season would submit historic

availability for the top 8 coincident system peak hours for a minimum of one and a maximum of three of the most recent applicable Planning Years for each Season.

- Resources with less than 30 consecutive days of metered values during a Season would receive class average accreditation for the Initial Planning Year.

- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- BTMGs that have been retired prior to the Season will not qualify as a Planning Resource.
- If BTMGs used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.

4.2.6.1 *Submission of New BTMG Registrations*

An MP must register its new BTMG via the Registration screen in the MECT by March 1 prior to the Planning Year. The registering entity must be an MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE's FRAP or RBDC Opt Out, registrations should be submitted no later than February 15 prior to the Planning Year. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.orgMISO Help Center (https://help.misoenergy.org/) to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E contains the information that must be submitted by an MP through the MECT registration screens. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to notify the MP within 15 days after the registration form was submitted regarding whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.6.2 *Termination of BTMG Accredited as LMR*

Because BTMGs need to be accredited seasonally, the "Effective Stop Date" will default to the last day of the applicable Season.

4.2.6.3 *Amendments to Accredited BTMG Registration Data*

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by February 1.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation, or either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1 prior to a Planning Year for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1.

Renewal of BTMG for subsequent Planning Years

BTMG must be reviewed for accreditation as an LMR on an annual basis. An MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested by February 1^{sr} prior to the Planning Year.

NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3, to have SAC values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to review the registration for approval within 15 days after the revised registration form was submitted to determine whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.6.4 *Behind the Meter Generation (BTMG) – SAC Determination*

The SAC value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, and XEFORd value of such BTMG.

BTMG that are intermittent resources will have their SAC determined consistent with the methodology described for similar resource fuel types as described in Section 4.2.1.3,

Intermittent Generation and Dispatchable Intermittent Resources – Qualification Requirements, through 4.2.1.7, Other Intermittent Generation and Dispatchable Intermittent Resources.

4.2.6.5 *BTMG Deliverability*

Each BTMG resource owner must coordinate with their Distribution Provider (DP) to ensure local distribution service for the BTMG resource to qualify as an LMR type Planning Resource for participation in the PRA. The majority of BTMG is interconnected at distribution-level voltage; however, it is possible for BTMG to be interconnected at transmission-level voltage. Additionally, MPs with BTMG must coordinate with their LSE, DP, and Transmission Owner (TO) to determine eligibility to participate in the PRA. This section will outline the roles and responsibilities of an LSE, DP, TO, and MISO for an individual BTMG to participate in the PRA including specific methodologies available to the BTMG MP to demonstrate deliverability. Responsibilities of an entity may differ depending if the Point of Interconnection is on the distribution system or transmission system and will be noted.

1.1.1.2.1 4.2.6.5.1 Roles and Responsibilities to Determine Eligibility for PRA Participation

Additional descriptions of the role and responsibility of each entity is below. The MP owning a BTMG is responsible for providing an attestation to MISO that proper coordination has occurred with each entity.

Load Serving Entity (LSE): Collaborate with BTMG MP to establish eligibility for a BTMG to participate in the wholesale market (e.g., PRA) in accordance with the relevant state regulatory framework.

Distribution Provider (DP): Ensure reliability of distribution system and assess access to the transmission system. Typically, the DP completes an interconnection study to assess the reliability impacts on the distribution system. The DP is responsible for determining engineering studies, facility upgrades, and/or agreements required to permit access of a BTMG to the transmission system.

Transmission Owner (TO): Determine when the transmission system is utilized by a BTMG to serve load and coordinate with the DP and MISO on engineering and facility studies as appropriate. The TO typically ensures studies are completed, per their direction, to ensure

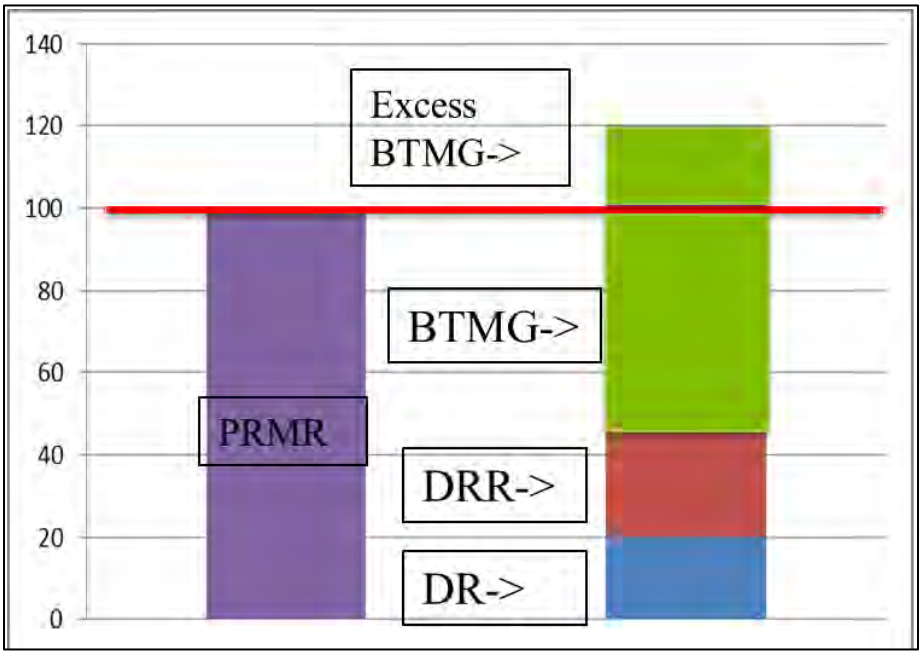
transmission facilities (including other interconnected generators) are not impacted by an additional injection of Energy from a BTMG onto the transmission system. Studies will vary depending on the specific Point of Interconnection.

MISO: Accountable for ensuring BTMG has demonstrated deliverability for use in the PRA (additional details below) and ensuring the BTMG MP has provided attestation of coordination with the LSE, DP, and TO.

1.1.1.2.2 4.2.6.5.2 Definition of "Excess BTMG"

Deliverability of BTMG is established relative to the portfolio of total BTMG assets owned or under contract by an LSE in a singular LBA. A BTMG that utilizes the transmission system or a volume of BTMG exceeding an LSE's "net PRMR" in a singular LBA is considered "Excess BTMG" and will need to demonstrate deliverability utilizing an option described in Sec. 4.2.6.5.3 – Options for BTMG to Demonstrate Deliverability. It is possible for the volume of "Excess BTMG" SAC to be less than the SAC of a singular BTMG. In this instance, the MP is eligible to demonstrate deliverability for a portion of a generator or multiple generators. MISO will collaborate with the BTMG MP to establish the specific Point of Injection onto the Transmission System.

The term "net PRMR" is utilized rather than Initial PRMR because it is possible for an LSE to have a portfolio of ZRCs that include registered Demand Resources (DR) and Demand backed Demand Response Resources (DRR_{demand}) that reduce the expected peak Demand by an LSE and result in a net injection onto the Transmission System. Net injection onto the Transmission System is "Excess BTMG" as represented by the figure below.



1.1.1.2.3 4.2.6.5.3 Options for BTMG to Demonstrate Deliverability

Below are the multiple options for a MP with BTMG to demonstrate deliverability:

Option 1: BTMG utilizing the distribution system to offset Initial PRMR. BTMG used to offset an LSE's load utilizing only the distribution system is considered deliverable up to the volume of "net PRMR" of an LSE in a singular LBA. No additional studies are required.

Option 2: Firm Transmission Service. The MP of the BTMG can apply for Point-to-Point or Network Integration Transmission Service using a type of "Monthly" or "Yearly" depending on the Point of Interconnection (POI). A BTMG with a POI on the distribution system can utilize "Yearly" type firm Transmission Service to facilitate a system impact study, if required. A BTMG with a POI on the Transmission System can use "Monthly" or "Yearly" type of firm Transmission Service since an ERIS study would have been completed. A Network Customer may designate a BTMG as a Network Resource through OATI OASIS utilizing firm Transmission Service.

Option 3: Interconnection Service of NRIS or External NRIS (E-NRIS). The MP of the BTMG can enter the Generator Interconnection Queue and apply for NRIS or E-NRIS. An MP can apply for E-NRIS with a BTMG that has a POI on the distribution system. A BTMG with a POI on the Transmission System is eligible for NRIS. The BTMG would be part of a MISO Definitive

Planning Phase (DPP) study and required to submit an application and deposits as appropriate. Refer to BPM-015 Generation Interconnection for additional details.

Option 4: Historical determination of deliverability. BTMG used to offset an LSE's Initial PRMR located in the same LBA and historically demonstrated deliverability prior to integration with MISO, as accepted by MISO or a Transmission Owner, is considered deliverable. Individual BTMGs may have demonstrated deliverability by confirmation by a Network Customer as a designated Network Resource or completion of a Market Transition Deliverability test prior to an LSE joining MISO.

4.2.6.6 *Measurement and Verification of BTMG*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7 Demand Resource (DR) – Qualification Requirements

MPs with DR can qualify the DR as an LMR by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Registering the reduction capability of the DR excluding transmission losses, consistent with conditions at MISO's seasonal Coincident Peak.
- Confirming through the registration process such DR can be available to reduce Demand with no more than six (6) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the total DR load reduction is not exclusively accomplished and dependent on the dispatch of a BTMG owned or operated by a wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resources within an LBA that can reduce Demand may qualify in meeting this requirement if they are within the same Load Zone CPNode).
- Confirming through the registration process that the DR is capable of being interrupted at least the first (5) times during the Summer and Winter and at least (3) times as needed during the Spring and Fall as needed by MISO or the LBA for Emergency purposes, consistent with the registration information of the physical capability of the DR.

- Confirming that the Market Participant has the authority to reduce demand using the DR. In the case of an ARC registering a DR, this would include uploading into the MECT registration a copy of the signatory pages between the ARC and the load asset customers. MISO does not accept an attestation by the ARC as an artifact to demonstrate the Market Participant possesses ownership or equivalent contractual rights in a Demand Resource.
- Documenting in the MECT the DR's capability to reduce demand to a targeted Demand reduction level or firm service level at the MISO seasonal Coincident Peak. All DR owners should demonstrate Demand reduction capability of at least 50% of their registered capability via Scheduling Instructions from a MISO Event or conduct a real power test for accreditation and provide a procedure document detailing the steps followed to implement the Demand reduction. Additional details regarding the demonstration of Demand reduction capability are in section 4.2.7.8 below. If a DR opts not to demonstrate Demand reduction capability for accreditation, one of the following options may be used for accreditation:
    - Provide documentation from the state that has jurisdiction accrediting the DR program. Additionally, if not specified in the state documentation, provide documentation supporting the capacity of the DR being registered.
    - Verification from a third-party auditor that is unaffiliated with the MP that documents the DR's ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.
    - If past performance data does not exist to demonstrate Demand reduction capability, then a mock test can be provided. The mock test should show:
        - The Demand resource's seasonal meter data from the previous planning year. New resources can provide documentation supporting estimated seasonal Demand.
        - Documentation showing a mock execution or drill of implementing the Demand resource without implementing the Demand reduction.
    - Accreditation documentation, including past performance data, mock test, third party audit, or state commission documentation, supporting the MW being registered should be from the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year. Renewed registrations must submit revised documentation on an annual basis for accreditation.
- If the DR opts out of demonstrating Demand reduction capability via Scheduling Instruction or a real power test, then the DR will be subject to three (3) times the

underperformance penalties during a MISO Emergency event. Specifically, undelivered MWs will be penalized at a rate of LMP times three (3), rather than LMP. The RSG component of the penalty will not be multiplied times three (3), nor will any capacity penalties or lost capacity revenue. Only a DR with a regulatory restriction will be eligible to waive the penalty.

- Documenting in the MECT the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 69A.3.9 of the Tariff. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE's load to weather. An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69A.3.5 of the Tariff.
- DR that has been retired prior to the Planning Year will not qualify as a Planning Resource.
- For every season an MP registers a DR, the underlying customer accounts for ARC registrations must be registered under a single DR registration name for every season in which it is registered. The registered capability and tested status can be different for each Season.

4.2.7.1 *Demand Resource Registration Process*

DR can be registered to be used as a Planning Resource and receive SAC MW that can be converted to ZRCs.

Submission of new DR Registrations

An MP may register new DR via the Registration screen in the MECT by March 1 prior to the Planning Year. To guarantee new Planning Resources can be used in an LSE's FRAP or RBDC Opt Out, registrations of a DR intended to be used in a FRAP or RBDC Opt Out should be submitted no later than February 15 prior to the Planning Year. The registering entity must be an MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, should contact the Customer Registration team at MISO Help Center (https://help.misoenergy.org/) to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D – Registration of DRs contains the information that must be submitted by an MP through the MECT Registrations screen. MISO will review the DR registration information for

completeness, accuracy, and ensure it complies with the qualification requirements for DR. MISO will endeavor to review the registration within 15 days after the registration was submitted to determine whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

Submission of ARC (Aggregator of Retail Customers) **LMR Registrations**

The LBA and LSE will verify the following:

- LBA name
- LSE name
- RERRA name
- CPNode name
- End use customer account number
- Meter identification number(s)
- Maximum level of participation (MWs)
- Address of the assets in the ARC registration.

The maximum level of participation for each asset within an LMR resource should be no greater than that asset's load as evaluated by the LBA or LSE.

The assets' load should be calculated as the average load of the assets up to the last three years' seasonal MISO system peak hours. One or two years of load data may be used if the full three years is not available, but an explanation must be submitted as to why the full three years are not available. For example, a new facility that has only been in operation for two years would be a reason less than three years of load data is accepted.

It is the responsibility of the Market Participant to provide an explanation which demonstrates why historical average peak load is not representative of expected future peak load for an asset and propose an alternative method of calculating the maximum level of participation for review and approval by MISO and the LSE.

If during registration review, the LBA or LSE is identified to be incorrect for assets in a registration, the registration will be rejected. The Market Participant can submit a new registration once the Market Participant has identified the correct LBA or LSE. This will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Any modification to the assets during the review will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Instances where the ARC LMR's customer changes LSEs:

- The LSE identified by the ARC LMR should be correct at the time of the ARC LMR's registration submitted to the Module E Capacity Tracking (MECT) tool. Otherwise, the ARC LMR Registration will be rejected.
- If the ARC LMR's LSE changes during the registration process, the ARC LMR registration can be revised. The date the registration was submitted will be sent along to the LSE for their review.
    - It is the responsibility of the ARC LMR's customers and the ARC to identify LSE changes.
    - It is the responsibility of the ARC LMR to notify MISO, the old LSE, and the new LSE when changes to the ARC LMR's customer's LSE occur.

4.2.7.2 *Termination of Demand Resource Accredited as LMR*

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.7.3 *Amendments to Accredited DR Registration Data*

The Market Participant can amend the registration for a DR for an existing upcoming Planning Year by providing MISO notification no later than March 1, if the original registration was submitted by the February 1 due date.

The MP may modify any of the non-end date information submitted in the registration, which may affect the DR's qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit registration information in the MECT Registrations screen by March 1 prior to the Planning Year for MISO to determine whether the resource still qualifies as an LMR.

4.2.7.4 *Renewal of DR for subsequent Planning Years*

A DR must be reviewed annually for accreditation as an LMR. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT Registrations screen. Renewal of DR must be requested by February 1 prior to the Planning Year. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to notify the MP within 15 days after the renewed registration form was submitted regarding whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as

an LMR, it will be given a unique name for tracking purposes and made available in MECT for use by the MP during the applicable Planning Year. Section 4.2.7.3 Amendments to Accredited DR Registration Data rules also apply to renewed DRs in subsequent Planning Years.

4.2.7.5 *Demand Resources – SAC Determination*

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the Planning Year. Seasonal capacity values for Demand Resources will be based on documentation from the state, third party auditor, past performance, or mock test consistent with their ability at MISO's seasonal Coincident Peak Demand. Since DR is a reduction in Demand, SAC is adjusted upward by applying the MISO PRM and transmission loss percentage for the LBA to the capacity rating.

4.2.7.6 *Demand Resource Deliverability*

The owner of ZRCs converted from DR may use them as part of a FRAP or RBDC Opt Out or offer them into the PRA. The DR ZRCs are considered deliverable regardless of the LRZ where the DR physically resides.

4.2.7.7 *Measurement and Verification of Demand Resource*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7.8 *Demand Resource – Testing Requirements*

The testing period for a DR to demonstrate Demand reduction capability is the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year unless a test deferral is submitted (see section 4.2.7.9 Demand Response Test Deferral). For example, the testing period for the 2025-26 Planning Year will be January 1, 2024 to December 31, 2024. DR shall demonstrate seasonal Demand reduction capability for a minimum of 1-hour duration with an attestation that the DR can continue the reduction for a minimum of 4 consecutive hours. Results should be submitted in accordance with LMR registration deadlines and attached to the LMR registration.

Test results should be adjusted to MISO seasonal Coincident Peak conditions. Upward adjustments shall not exceed +50% of each DR and may include, but not limited to, factors such as temperature, humidity, and/or other process load variations. Downward adjustments are allowed down to the 100kw minimum total for a DR registration. Adjustments to test results should be documented and submitted with the test results to support the capacity accreditation

for the DR. Adjustments to DR test results are subject to MISO review and approval during the LMR registration process each year.

DR are required to demonstrate performance of at least 50% of their registered seasonal capability via Scheduling Instructions from a MISO Event or conduct a real power test. If a DR is only able to demonstrate at 50% to 80% of their intended registered MW capability, an attestation from an officer of the Market Participant registering the DR, or from a financially responsible entity, must be provided to MISO during the registration process documenting the reasons for the difference between the registered capability and the demonstrated amount (i.e., industrial process, temperature, etc.). If demonstrating greater than 80% of the registered capability, the DR shall need to provide documentation supporting the adjustments made to normalize the MW capability to seasonal peak conditions.

Results may be uploaded to the documentation section of the LMR registration in MECT and may include: (1) test results including the meter data for the entire day of the tests, (2) historical meter data for 10 days around the MISO seasonal Coincident Peak with the MISO seasonal Coincident Peak as a midpoint, to calculate the capacity baseline, and (3) any other supporting documentation necessary for the LMR capability adjustment. The templates used for submitting the requested meter data may be found on the MISO public website under Markets and Operations > Demand Response.

If a DR is unable to demonstrate performance of at least 50% of the registered MW capability of the DR [only partially performs], the DR must retest the underperforming portion(s) of the DR or create separate registrations for the portions of the DR that did not exceed the 50% performance threshold. If the DR is unable to demonstrate performance of at least 50% of the registered MW capability during the testing period, the DR may still qualify for the PRA by opting out of the testing requirement, provided that the DR will then be subject to the three (3) times penalty provisions for underperformance described in Section 4.2.9 Electric Storage Resource.

If a DR underperforms during a MISO Emergency event and that event is chosen by the DR owner to satisfy the testing requirement, the tested portion of the DR will equal the actual reduction achieved during the event. If a DR only partially tests, the entire DR may be registered, however, separate registrations will be required. For example, the tested portion of the DR would be one registration and the untested portion of the DR would be another registration. If a DR is made up of an aggregation of different physical locations, each location can demonstrate performance—or elect not to—separately. Tested locations may be

aggregated together and untested locations may be aggregated together in registrations, as long as all locations are within the same Load Zone CP Node. Separate registrations for tested versus untested resources are required in order for MISO to accurately assess penalties for underperformance during a MISO Emergency event, as the untested DR would be subject to the three (3) times penalty, unless the untested DR is not required to test per qualification requirements in 4.2.9 Electric Storage Resource.

When testing a DR, accurate availability should be reflected in the DSRI by showing the DR as self-scheduled. If an MP plans to test DR greater than 20 MW, the MP should notify MISO operations two (2) Business Days prior to conducting a test by submitting the DR Testing Notification Template to the MISO ITOC (ITNOCRequests@misoenergy.org). The DR Testing Notification Template should include: (1) LMR name, (2) MP, (3) Load Zone CP Node, (4) expected MW reduction, (5) expected reduction date and hour(s), (6) notification time, and (7) operator contact information in case MISO Operations has questions. New DR and DR that did not clear the PRA will not be able to update the DSRI, however, these DR should still notify MISO by utilizing the DR Testing Notification Template.

4.2.7.9 Demand Response Test Deferral

The MP must provide written notification to MISO (https://help.misoenergy.org) of their intention to defer Demand Response testing by February 1 prior to the upcoming Planning Year. This DR Testing Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Name
- Local Balancing Authority (LBA) or External Balancing Authority (BA) where located
- Expected DR test value (MW)
- Estimated completion date of DR test

Once the DR test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org).

A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times Energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

If the Market Participant submits the real power test results on or before the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that are equal to or greater than the expected DR test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted.

If SAC associated with a Planning Resource for which DR testing has been successfully deferred are unconverted to ZRCs, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred DR value, in which case the Transmission Provider will adjust the Market Participant's DR value and credit requirement within twenty (20) Business Days.

A Market Participant that provides a DR Test Deferral Notice and that either (1) has not submitted any real power test result for such DR by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year, or (2) has submitted a real power test result by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that demonstrates fewer megawatts are available than the expected DR test value submitted in the DR Test Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency and distributed pursuant to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the DR Test Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

4.2.8 Energy Efficiency Resources

Energy Efficiency (EE) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric Energy

consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecasts used for the PRA for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Season within the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric Energy consumption due to existing EE programs that is reflected in the CPD forecast cannot qualify as an EE Resource. All the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed in the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for a Season within the Planning Year. The Nominated EE Value is the expected average Demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in each Season of the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days of the applicable Season the EE Resource is seeking capacity accreditation, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource by February 1 prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource by February 1 prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource by March 1 prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports by March 1 prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report by March 1 prior to a subsequent Planning Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of seasonal ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to

measure PRA commitment compliance during the Planning Year. Details regarding seasonal PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a seasonal PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE Value that is used to measure seasonal PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in seasonal PRAs or be used in a FRAP or RBDC Opt Out for that Planning Year and three subsequent Planning Years. For example, an EE Resource installed and qualified prior to June 1, 2013, could participate in the seasonal PRAs or be used in a FRAP or RBDC Opt Out for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the EE Resource registers and meets the qualification requirements for each Planning Year. After four years, the EE Resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the Demand forecast.

4.2.8.1 *Energy Efficiency Resource – Measurement and Verification*

See Attachment UU of the Tariff.

4.2.9 Electric Storage Resource

An Electric Storage Resource (ESR) is a resource capable of receiving electric Energy from the grid and storing it for later injection of Energy back to the grid. The ESR includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped storage. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system. An ESR must:

- be capable of injecting a minimum of 100 kW;
- be capable of complying with MISO's Setpoint instructions;
- have the appropriate metering equipment installed; and

- be physically located within the MISO Balancing Authority Area.

4.2.9.1 *Electric Storage Resource - Qualification Requirements*

An ESR may qualify as a Capacity Resource for the Planning Resource Auction (PRA) provided the resource is a Use Limited Resource that is able to continuously discharge for a minimum of 4 hours across the expected peak hour each Operating Day and meets the following criteria:

- An ESR must demonstrate discharge capability during each of the seasonal auctions the ESR will be used to meet RAR.
- Verification of capability will be based on the power (MW) and the Energy rating (MWh) via data included in a populated Non-GADS Performance Template and submitted to MISO through the MECT.
- For an upcoming PRA, the following data for the ESR must be submitted to the MECT by October 31 to qualify for the PRA using the Non-GADS Performance Template: Nameplate Capacity, Net Energy Rating (MWh), and Hourly Equivalent Discharge Amount (MW) from the ESR testing (minimum of 1 hour and a maximum of 4 hours).
- An ESR must demonstrate deliverability in order to qualify as a Capacity Resource for participating in the PRA. If an ESR is interconnected to the MISO Transmission System, the Resource can either obtain Network Resource Interconnection Service (NRIS) under Attachment X or procure Firm Transmission Service in conjunction with Energy Resource Interconnection Service (ERIS). If an ESR is interconnected to the Distribution System, the Resource will be subject to coordination with Distribution Provider, Transmission Owner, and MISO Transmission Service. For more information, see section "4.2.8.5.1 - Roles and Responsibilities to Determine Eligibility for PRA Participation."

4.2.9.2 *Electric Storage Resource - Hourly Equivalent Discharge Amount (MW)*

The Hourly Equivalent Discharge Amount (MW) of an ESR will be calculated as:

$$\frac{Total\ Net\ Energy(MWh)}{Total\ Hours\ tested}$$

where The Total Net Energy Rating (MWh) and the Total Hours tested are based on the data submitted to MISO through a populated Non-GADS Performance Template.

4.2.9.3 *Reporting Historical Data*

Market Participants will use MISO's Non-GADS Performance Template found on the Resource Adequacy page of the MISO website to submit the appropriate unit and operational data for the upcoming Planning Year. A populated Non-GADS Performance Template must be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool to be eligible for accreditation in the Planning Resource Auction applicable to the following Planning Year.

Reporting availability data for an ESR is not required if the ESR has less than 10 MW of nameplate capacity and the Market Participant has never provided such data for the ESR.

4.2.9.4 *ESR Capacity Accredited Value Determination*

MISO will determine the accreditation for each ESR based upon an evaluation of its demonstrated capability, resource availability, and Interconnection Service if applicable. ESRs must demonstrate deliverability prior to participating in the PRA. Deliverability will be demonstrated by the Market Participant and verified by MISO depending upon the Point of Interconnection of the resource. A class average unavailability rate will be applied to an ESR to determine a default class average capacity accreditation value prior to being in service long enough to calculate a unit-specific forced outage rate. A 5% unavailability rate will be assumed until sufficient ESRs exist (30 or more individual units) to come up with an average value. The accreditation of an ESR with sufficient historical data is calculated through the Non-GADS Performance Template.

4.2.10 Qualifying Facilities (QF)

Certain generators may be recognized as a Qualifying Facility under PURPA. MISO offers three modeling options that facilitate market participation for QF generators. Each of the options, described below, are reflected differently in the PRA. Each QF should coordinate with its LSE to determine eligibility.[1]

Gross Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a Generation Resource with a CPNode. QF generators utilizing this option are required to meet the accreditation requirements for testing and

[1]Additional details can be found in MISO's Qualifying Facilities White Papers on the MISO website. Markets and Operations-> Markets and Operations-> Whitepapers.

deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

Hybrid Modeling: When QF generation exceeds the associated QF load, both load and generation may be modeled as a single Generation Resource CPNode. The expected net injection onto the transmission system (e.g., QF generation – process load served by QF generation) is modeled as the GVTC. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

BTMG Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a BTMG. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.6 BTMG Qualification Requirements.

4.2.11 Hybrid and Co-Located Resources

For purposes of accreditation, Hybrid Resources and Co-Located Resources will be accredited in two phases: Phase I – Sum of Parts accreditation and Phase II – Availability-based accreditation. Phase I applies in the initial service life of a Hybrid Resource or Co-Located Resource before operating history is available. Phase II applies once a Hybrid Resource or Co-Located Resource has historical operating data. See Appendix X – Hybrid and Co-Located Resource Accreditation for details.

4.3 Confirmation and Conversion of SAC MW

A ZRC represents 1 MW-day of qualified Seasonal Accredited Capacity (SAC) from a Planning Resource for a specific Season of a Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. To create a ZRC, an MP must confirm the SAC MW and then convert SAC MW from each qualified Planning Resource to seasonal ZRCs through the Convert SAC screen in MECT. SAC confirmation and conversion must be completed per the timeline specified in appendix K.

When seasonal ZRCs are converted from SAC by the Asset Owner, the seasonal ZRCs are populated into the available ZRC account for that Asset Owner. MISO will keep track of how many ZRCs the MP has created, and how many remaining SAC MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the

specific Planning Resources that they were created from to assist with establishing clearing requirements, the auction clearing process, and market mitigation monitoring.

4.4 ZRC Transactions

4.4.1 Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the 'ZRC Transactions' tab in the MECT. Both the 'Buyer' and 'Seller' are required to account for a ZRC transaction in the MECT. The 'Seller' is required to submit the transaction in the MECT and the 'Buyer' is required to confirm the transaction reported. Once the transaction has been submitted and confirmed by both parties, the ZRC transaction volumes will be subtracted from the seller's available ZRC account and added to the buyer's available ZRC account. ZRC transactions are from the transaction date to the end of that Season. In situations where the ZRC transaction is only intended for part of a Season, the ZRCs can be transferred back to the original MP and would be effective for the rest of the Season. The Market Participant that registered the Planning Resource is responsible for complying with all Tariff requirements. The MECT allows transactions based the ZRC balance in the Seller's portfolio. ZRC transactions can occur throughout the PRA auction cycle, including during the Offer window. ZRC transactions can also be utilized during the Planning Year to facilitate ZRC replacement transactions.

a. ICAP Deferral

i. Summary

ICAP Deferrals allow Market Participants (MPs) to participate in the Planning Resource Auction (PRA) using Zonal Resource Credits (ZRCs) that have been credited to the following:

For Schedule 53 Resources:

- an untested new Planning Resource;
- new Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year, an existing Planning Resource that is returning to operation from a catastrophic outage or suspension; an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
- For Non-Schedule 53 Resources:
- an untested new Planning Resource;

- new Non Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year
- an existing Planning Resource that is returning to operation from a catastrophic outage or suspension;
- an existing Planning Resource increasing its capability through increases to GVTC or Interconnection Service (IS);
- an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
-

Schedule 53 Resources that submit ICAP Deferral will get SAC class average for the deferred season(s) while non-Schedule 53 Resources will get the lesser of GVTC or IS, multiplied by (1-class average XEFORd).

ii. Requirements and Timeline

The MP must provide written notification to MISO (https://help.misoenergy.org) of its intention to defer ICAP by February 15 prior to the upcoming Planning Year. This ICAP Deferral Notice should state that the Planning Resource will demonstrate deliverability, demonstrate commercial operation including filing a COD Notification (Appendix E to the GIA) with MISO Resource Integration (ResourceIntegration@misoenergy.org), have confirmed Transmission Service , and/or perform a real power test to submit its GVTC after March 1, but before the last Business Day, prior to the start of the deferred Season. The ICAP Deferral Notice can be found in Appendix T of this BPM. The ICAP Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Type
- Planning Resource Name/CPNode Name/Unit Number
- Local Resource Zone (LRZ) or External Resource Zone (ERZ) where Planning Resource is located
- Planning Resource Fuel Type
- Estimated ICAP Value in MW
- Estimated Completion Date of ICAP
- Reason for deferring (See Appendix U)Season(s) to be deferred

- Generator Interconnection Agreement (GIA) Number (only necessary if deferral includes upgrades to Interconnection Service)
- Expected NRIS and ERIS values
- GVTC / COD declaration for intermittent resources
- Commercial Operation Date
- TSR Number
- Other ICAP Type

Once the GVTC test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org/) by the last Business Day prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. For intermittent resources COD declaration is used to meet the GVTC submittal requirement. For intermittent BTMG an attestation of COD must be submitted to MISO.

New resources must have (i) an executed GIA or an unexecuted GIA accepted by FERC and (ii) be registered in the June Commercial Model prior to the upcoming Planning Year at the time of the ICAP Deferral request. For modeling SAC in the PRA, the resource must be modeled in the March model prior to the PRA in order to offer into the PRA accordingly. For example, the resource needs to be in the March 2025 Commercial Model to participate in the 2025-2026 Planning Resource Auction.

The MP requesting the ICAP Deferral must post 90 days of credit for the ICAP value of the untested ZRCs no later than March 1 prior to the upcoming Planning Year. The credit will be based on the 90 days of daily CONE for the LRZ in which the resource is located.

MISO will adjust the Market Participant's credit requirements within ten (10) Business Days of the full ICAP being met and has been validated by MISO or when the MP provides written notification to MISO Resource Adequacy that a Planning Resource replacement has been completed.

4.5.3 Uncleared ZRCs with ICAP Deferrals

If the untested ZRCs will not be used in a FRAP or RBDC Opt Out or will not be offered into the PRA, the MP that registered the resource may provide notice to MISO by March 1 that it wishes to forfeit the deferred ICAP value. MISO will recalculate the resulting Seasonal Accredited Capacity (SAC) value and will adjust the credit requirements within ten (10) Business Days after

receiving the notice. Furthermore, if the untested ZRCs do not clear the PRA, MISO will release credit back to the MP that submitted the ICAP Deferral Notice.

4.5.4 ICAP Deferral Non-Compliance Charge

The MP that submitted the ICAP Deferral request is responsible for completing ICAP or resource replacement by the last Business Day of prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. Any ICAP not completed or replaced by the last Business Day prior to a Seasons' start date will be subject to the ICAP Deferral Non-Compliance Charge for each day the ICAP or the Planning Resource replacement is not completed.

The ICAP Deferral Non-Compliance Charge will be based on the sum of the applicable seasonal Auction Clearing Price (ACP) and daily CONE based on the LRZ or ERZ of the Planning Resource, multiplied by the number of ZRCs that have not been replaced or tested.

The distribution of ICAP Deferral Non-Compliance Charge will be allocated pro-rata based on each LSE's share of the total seasonal Final Planning Reserve Margin Requirements (PRMR) in MISO.

Please refer to Appendix U for Examples of ICAP Deferrals.

5 Resource Adequacy Requirements

5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resource Zone (LRZ) to meet the MISO footprint's seasonal Final Planning Reserve Margin Requirement (Final PRMR). An LSE can meet its seasonal Final PRMR by any of the following ways:

1) Self-scheduling of ZRCs
2) Fixed Resource Adequacy Plan (FRAP)
3) Participating in the Planning Resource Auction (PRA)
4) Paying the Capacity Deficiency Charge (CDC)
5) Reliability Based Demand Curve Opt Out (RBDC Opt Out)

5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be in the appropriate physical locations within the MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of each LRZ no later than September 1 of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region including, but not limited to, any of the preceding factors, significant changes in membership, the Transmission System and/or Resources.

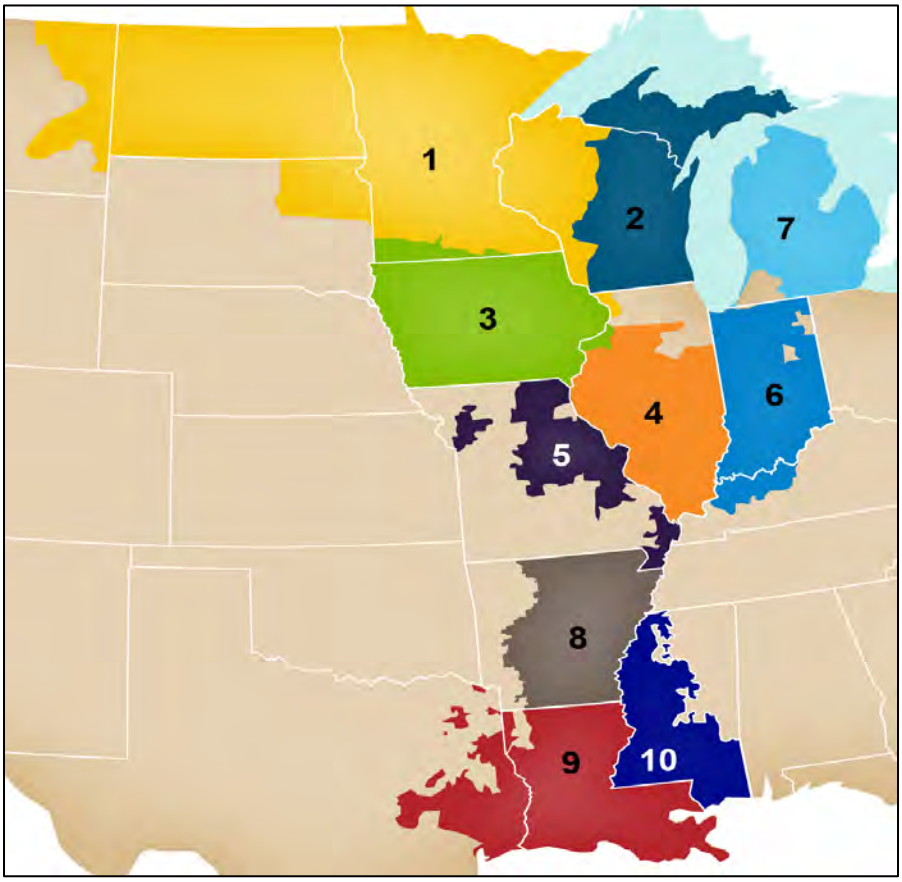


Figure 5: Local Resource Zones Map

5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV that has been accepted by the Federal Energy Regulatory Commission, may change the configuration of the LRZs if a re-evaluation trigger has occurred and after consideration of the criteria outlined for consideration in setting LRZ boundaries. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA. MISO will share any re-evaluation triggers and the results of the analysis documenting the impacts of the proposed LRZ boundary changes with stakeholders in an open and transparent manner prior to making any filings to change LRZ boundaries.

Once the boundaries of an LRZ have changed, its boundaries should stay constant for at least three years to provide stable future locational signals.

5.2.1.1 Re-evaluation Triggers

The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region. Such changes are called re-evaluation triggers, and they include, but are not limited to, the following:

1) Significant changes in membership:
   Re-evaluation may occur for LRZs where there are membership changes in the MISO system or for areas which neighbor the regions where there is a membership change. Re-evaluation may occur prior to or in the cycle immediately following the integration of new members into the MISO system.
2) Significant changes in the Transmission System:
   Transmission infrastructure must be on target to be in-service by June 1 of the year which would follow a filing for an LRZ boundary changes (i.e., the transmission must be in-service for the first summer where the zonal changes will go into effect). The changes to the transmission system should impact transmission constraints represented in the MISO Resource Adequacy construct for the zone(s) being reevaluated.
3) Significant changes in Resources:
   Changes to the resource mix may include the addition of significant new generation or the retirement of significant existing generation. The resource changes should be shown to modify the transmission system flows in the zone(s) being studied, impacting transmission constraints represented in the MISO Resource Adequacy construct.

The existence of a trigger will not guarantee that a zonal change will be implemented; the trigger will allow the analysis to proceed and will be considered as part of the final decision on whether or not to change zonal boundaries.

5.2.1.2 Re-evaluation Considerations

Once a re-evaluation trigger has been met, the geographic boundaries of the zone or zones may be re-evaluated. This re-evaluation will be based upon an analysis that considers the following factors.

1) Electrical Boundaries of Local Balancing Authorities
2) State boundaries
3) Relative strength of transmission interconnection between Local Balancing Authorities

4) Results of LOLE studies
5) Relative Size of LRZs
6) Natural geographic boundaries such as lakes and rivers

The electric boundaries of Local Balancing Authorities, state boundaries, and natural geographic boundaries will be considered by inspection. Additional information on the process used to analyze the other criteria is below.

Relative Strength of Transmission Interconnections between Local Balancing Authorities
Multiple aspects of the transmission system are considered in this portion of the evaluation. These aspects are first investigated individually, and the final assessment considers all of the factors. The assessment includes the following:

- Previously identified LOLE results (Capacity Import and Export Limit constraints)
- Constraint variation(s)
- Transmission projects
- Physical ties including post-contingency connectivity and transmission service

LOLE results identified for Capacity Import and Export Limit analysis before and after the boundary change is applied will be considered. Zonal transfer analysis yields a list of constraints. The most limiting constraint after redispatch determines a zone's limit in the LOLE study. In the re-evaluation analysis, the less limiting constraints are also considered since reconfigurations impact the transfer level at which constraints are limiting. Also, while there can only be one limiting constraint, multiple constraints can be seen at similar transfer levels. For example, assume the most limiting constraint is at a transfer level of 100 MW. There are two additional constraints at 99 MW and one at 90 MW. Since these transfer levels are very close, all four are considered in this evaluation.

Constraint variation is caused by reconfiguration of Local Resource Zones. This variation is caused by changing the generation that is used to create the transfer. Zonal definitions determine which generators are used in the transfer analysis so any change in zonal definition may result in a difference in the impact the transfer has on the constraint. It is possible that a constraint has an impact above the threshold before reconfiguration and less than the threshold afterwards which is considered in this evaluation.

The impact of approved MTEP Appendix A and Target A transmission projects is considered. If a project mitigates a constraint and the project is expected to be in service prior to the Planning

Year under consideration, then the impact of the transmission project to the LOLE results is considered.

MISO will consider the number of ties of any reconfigured zone. Generally, a reconfigured zone should have two or more ties with the rest of MISO. Two or more ties between the zones are optimal when planning for contingencies so the zones are still connected post-contingency. Any LBA being added to an existing LRZ should have two or more ties with an LBA in the new LRZ. Any other impacted LRZs should have contiguous LBAs with two or more ties. Further consideration is needed if an LBA leaving an LRZ results in an LRZ with unconnected LBAs. In addition, confirmed transmission service between zones may be considered when evaluating reconfigurations. Confirmed long-term transmission service indicates transmission capacity between the zones has been previously evaluated.

The Results of LOLE Studies
LOLE studies will be performed with the LRZ configuration being considered. The results of this analysis will be compared with the prevailing LRZ configuration. This LOLE analysis includes a MISO PRM model analysis (Section 3.5), LRZ LRR determination (Section 5.2.2.2), and capacity import and export limit analysis (Section 5.2.2.1) for the LRZ configuration being considered and for the prevailing LRZ configuration. The results of this analysis and comparison with the prevailing system results will be used as one factor in determining whether LRZ changes are warranted, in conjunction with the other LRZ considerations.

Relative size of LRZs
The relative size of an LRZ will contain no less than 2,000 MW of Demand.

5.2.1.3 Determination of LRZ Boundaries

Following the determination of an LRZ re-evaluation trigger, the conclusion of all analysis with consideration of stakeholder feedback will determine whether the LRZ boundaries will be changed. This determination will be based upon the benefits and/or risks that the LRZ boundary changes would present on the system. MISO's final determination will be shared with stakeholders and the changes will be filed with FERC.

5.2.1.4 External Resource Zones

MISO developed External Resource Zones (ERZs) to reflect the physical location of External Resources and establish Auction Clearing Prices for such External Resources (other than

Coordinating Owner and Border External Resources). An ERZ will be created for each External Balancing Authority adjacent to MISO with Planning Resources participating in the MISO PRA. Current External Resource Zones:

ERZ	Area(s)
EZ20	KCPL, OPPD, WAUE
EZ22	PJM
EZ23	OVEC
EZ24	LGEE
EZ26	AECI
EZ27	SPA
EZ28	TVA

External resources ZRCs are counted toward the MISO North/Central region and the MISO South region based on transmission shift factors that are calculated annually.

5.2.1.5 Establishing Sub-Regional Resource Zones (SRRZ)

MISO will also establish SRRZs applicable for each Planning Year. A SRRZ is a zone, comprised of an LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Currently, MISO has two SRRZs: MISO South, defined as LRZs 8, 9 and 10, and MISO Midwest, defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, SPP, and the other Joint Parties. This agreement established Regional Directional Transfer Limits (RDTL) that limit the amount of total transfer between these two SRRZs in the PRA. The RTDL from South to Midwest is 2,500 MW and the RTDL from the Midwest to South is 3,000 MW.

MISO shall establish the Sub-Regional Export Constraint (SREC) and Sub-Regional Import Constraint (SRIC) for each Season by March 1 prior to the Planning Year. The methodology for determining the SREC and SRIC for each SRRZ is described below.

1.1.1.2.4 5.2.1.5.1 Determination of Seasonal SREC and SRIC

The following steps describe the steps MISO will utilize to calculate the SREC and SRIC.

1. Begin with the Regional Directional Transfer Limits (RDTL) between the two SRRZs

2. Complete a feasibility analysis to review operational events from the previous seasonal peaks to determine if a further reduction to the Regional Directional Transfer Limit is warranted for reliability.
3. Decrement the initial RDTL (from step 1) based upon completed feasibility analysis
4. Subtract from the net RDTL (from step 3) the sum of Firm Reservations on MISO OASIS that utilize the contract path between South and Midwest and are exporting the MISO BA for the applicable Season of the Planning Year. This difference determines the SREC and SRIC to be utilized for that Season of the Planning Year.

Example from the 2016-2017 Planning Year

1. The RDTL from South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
2. MISO's feasibility analysis for the 2016-2017 Planning Year determined that no additional reduction of the RDTL was required; 0 MW.
3. The net RDTL for 2016-2017 is equal to the initial RDTL; South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.

4. The MISO OASIS Reservations, in each direction, that exported from the MISO BA for the 2016-2017 Planning Year were summed:
   South to Midwest Direction: 1,624 MW
   Midwest to South Direction: 206 MW

Final SREC and SRIC applied for the 2016-2017 Planning Year:
South SRRZ SREC: 876 MW
South SRRZ SRIC: 2,794 MW
North SRRZ SREC: 2,794 MW
North SRRZ SRIC: 876 MW

1.1.1.2.5 5.2.1.5.2 Regional Directional Transfer Limit Feasibility Analysis

On an annual basis, prior to administrating the PRA, MISO will review operational data from the previous seasonal peaks to determine if operational events experienced in the past and forecasted expected conditions for the applicable Planning Year Season warrant a reduction in the initial RDTL between the MISO South and Midwest Regions. MISO will review the results of the feasibility analysis with stakeholders prior to implementing in a PRA.

The following data sources are considered for the feasibility analysis:

- Studies that assess MISO transfer capability between Regions
- Studies that assess load diversity between Balancing Authorities
- Transmission system constraints
- Congestion history on relevant transmission constraints
- Capacity or Transmission Emergency alerts, warnings, or events

5.2.2 Local Requirements and Transfer Capability

5.2.2.1 Calculation of Transfer Limits for the Planning Resource Auction(s)

MISO will determine the seasonal import and export limits for each LRZ by performing a transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values which represent a zone's ability to import and export capacity in every Season, respectively. The seasonal ZIA and ZEA values are adjusted by the amount of exports (Controllable Exports (CE)) to non-MISO load from the zone to determine a zone's seasonal CIL and CEL. Seasonal CIL and CEL determine the maximum amount of ZRCs that can be imported or exported respectively to/from that zone in that Season. The seasonal ZIA is an input to the calculation of the seasonal Local Clearing Requirement (LCR) for each LRZ, as described in Section 5.2.2.3 (Establishment of Local Clearing Requirement). Seasonal LCR, CEL, and CIL are inputs to the Planning Resource Auction clearing process. Transfer analysis will be performed on seasonal Powerflow models appropriate for the upcoming Seasons in the next planning year.

Transfer analysis is not required to calculate an ERZ CEL; instead, MISO will determine the seasonal CEL of each ERZ by determining the volume of SAC for External Resources within that zone. The seasonal CEL will be set to the MW SAC in the ERZ no later than eight (8) business days before the last business day in March.

Transfer Analysis

Transfer capability is the measure of the ability of interconnected electric systems to reliably transfer power from one area to another under certain system conditions. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. First Contingency Total Transfer Capability

(FCTTC) indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability.

$$Total\ Transfer\ Capability\ (TTC) = Base\ Power\ Transfer + \ FCITC$$

Linear FCITC analysis will identify limiting constraints with a minimum Distribution Factor (DF) cutoff of 3%, meaning the transfer and contingency must increase the loading on the overloaded element by 3% or more. In addition, facilities must have loadings 100% or more of the normal rating for system-intact conditions and loadings 100% or more of the emergency rating for N-1 contingencies.

Export and import capabilities of subsystems will be respected and machine limits are enforced. Exporting an LRZ's available capacity will include offline units. A pro-rata dispatch is used which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base dispatch from its maximum dispatch, which reflects the available capacity of the unit. Refer to Table 2 and the equation below for an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Max dispatch – Unit Dispatch)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 2: Example Subsystem

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

General Assumptions

Power flow models and input files are required to determine the import and export limits of each LRZ in each Season. Input files (subsystem and contingency) from MTEP studies built for timeframes matching the effective period of the transfer limit study will be used. Single-element contingencies in MISO and seam areas are evaluated. Other than the power flow model, all other input files will be the same across all Seasons within the Planning Year.

Subsystem files will be modified to include required source and sink definitions, details are provided in the next two sections (Import and Export Limit Determination Sections). The monitored file will include all facilities under MISO functional control and Seam facilities 100 kV and above.

Power flow models will contain approved MISO MTEP Appendix A and Target A projects with effective dates on or before the effective date of the study model. Planning Resources, internal and external to MISO will be dispatched in the base model according to the Generator Modeling and Transactions/Interchanges sections of the Transmission Planning Business Practices Manual, or BPM-020. The following generators are excluded from the incremental transfer analysis dispatch:

- Nuclear
- Generators with negative dispatch
- Hydro
- Wind
- Solar

Wind and solar will be ramped down for transfers and will not be ramped up. Maximum wind output will be limited to base dispatch in the power flow model which is set by the wind capacity credit. MISO and external area interchange in the base case will be set to the net of the expected firm transactions with its neighbors.

If a Transmission Owner has identified a zonal import limit that is binding as a result of the exclusion of nuclear (headroom) or other resources in the sink of the transfer study, the TO may inform MISO of the limitation and MISO will evaluate the ZIA and update accordingly, at MISO's sole discretion.

Seasonal Zonal Import Ability (ZIA) and Seasonal Capacity Import Limit (CIL) Determination

To determine an LRZ's seasonal limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) while decreasing generation inside the LRZ under study. LBAs that are interconnected with the LRZ under study are considered adjacent. Tiers are used to define the generation pool used for import studies and are comprised of the adjacent systems of the zone being studied.

- Tier 1 – Generation in the MISO LBAs adjacent to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO LBAs adjacent to Tier 1

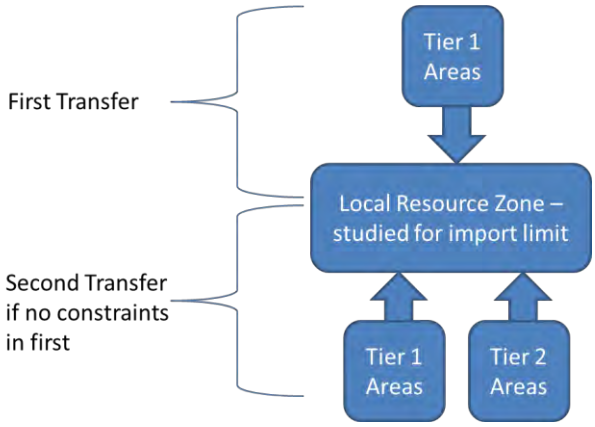


Figure 5.1: Tiered import illustration

Import limit studies are analyzed first using Tier 1 generation only. If no constraint is identified, the source is expanded to include Tier 2 and the transfer is retested. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the source is expanded to include Tier 2 and the transfer is retested. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone's import limit.

The results of the analysis produce the seasonal Zonal Import Ability. This value will be used to determine the seasonal CIL after accounting for exports to non-MISO load.

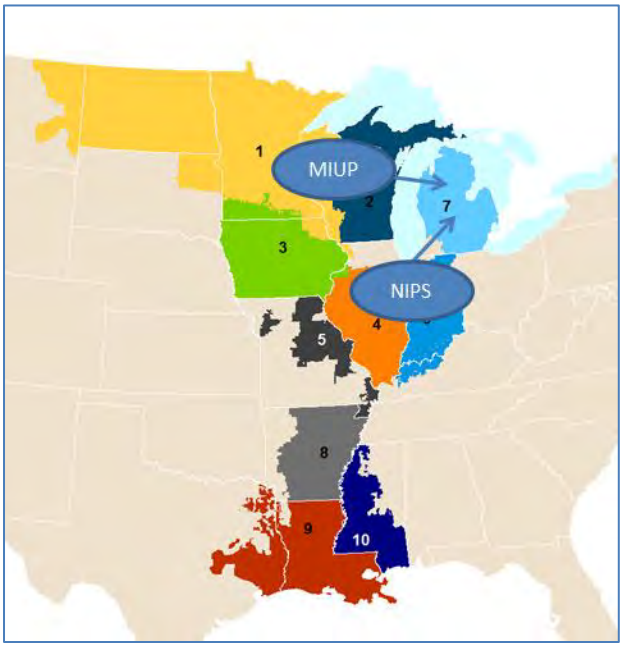


Figure 5.2: Example - MISO LBAs Used for First Test of LRZ 7 import limits

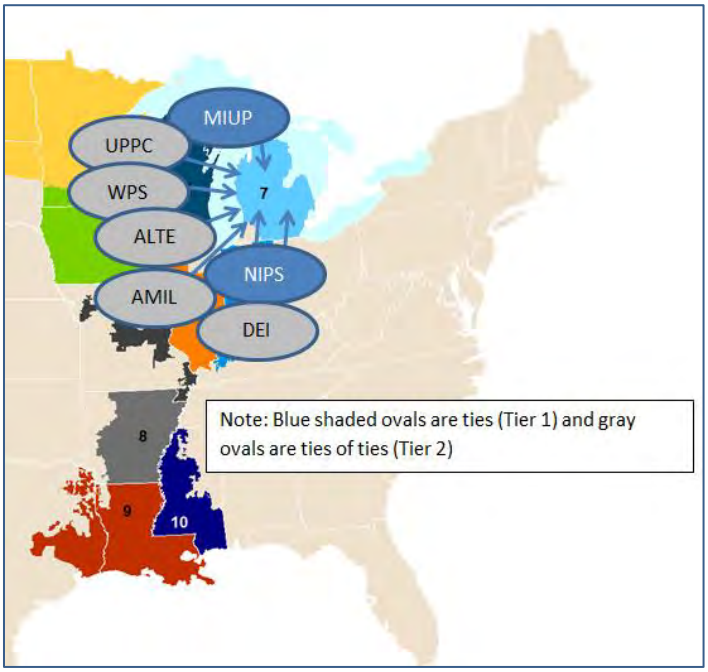


Figure 5.3: Example - MISO LBAs Used for Second Test of LRZ 7 import limits

Seasonal Zonal Export Ability (ZEA) and Seasonal Capacity Export Limit (CEL) Determination

The LRZ being studied for a seasonal export limit, is the source subsystem for the transfer. Available generation within the LBA(s) contained in that particular LRZ is increased proportionately while all generation dispatched, except for nuclear, wind and other intermittent resources, in all other MISO LBAs is decreased proportionately. This method produces the seasonal ZEA which is used to determine the seasonal CEL after accounting for exports to non-MISO load.

Figure 5.4: Example - MISO LBAs Used for LRZ 7 export limits

Redispatch

LOLE study redispatch is based on prior MTEP study methods. The base assumptions are as follows:

- No more than 10 conventional plants or wind plants will be used
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- Nuclear units are excluded
- Wind and other intermittent resources can only be ramped down

For import redispatch scenarios, all generation resources in the zone being studied and adjacent systems (Tier 1 or Tiers 1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. If the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

For export redispatch scenarios, only MISO generation resources within the zone being studied are eligible to be ramped up. All MISO generation resources are eligible to be ramped down. As with import redispatch, if the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

Adjustment for Exports to Non-MISO Load

FERC issued an order on December 31, 2015 which required studies to be neutral to units within MISO areas that are exporting to non-MISO load. MISO identifies and removes the impact of these exporting units on zonal area interchange. These adjustments result in an increase to CIL and decrease to CEL for zones with exports to non-MISO load.

Generation Limited Transfer

When conducting transfer analysis, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO has developed a process referred to as Generation Limited Transfer, or GLT, to identify transmission constraints in these situations.

After running the FCITC analysis to determine import and export limits for each LRZ, MISO will determine whether a zone is experiencing a GLT. If the LRZ is experiencing a GLT, MISO will adjust the base model dependent on whether the analysis is an import or export study and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LBAs under study) MISO will decrease load and generation dispatch in the study zone. The objective of the adjustment is to create additional capacity to export from the zone. After the adjustments are complete, MISO will perform transfer analysis on the adjusted model to be in line with section 5.2.2.1 (Calculation of Transfer Limits for the PRA). If a GLT is observed again, further adjustments will be made to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after (a) decreasing all generation within the LRZ under study, (b) or dispatching all generation within Tiers 1 & 2, MISO will adjust load and generation in the source subsystem, Tiers 1 & 2. This will increase the capacity available to import into the study zone. After the adjustments are complete, the transfer analysis will be completed on the adjusted model to be in line with section 5.2.2.1. If a

GLT is observed again, further adjustments to the model would be made to the load and generation in Tiers 1 & 2.

FCITC could result in the transmission system supporting large thermal transfers for some zones which might result in some additional considerations. First, large GLT adjustments for export limits could result in reactive-power issues in the zone. Additionally, any load scaling beyond 50% of the zone's load in the base model could result in unrealistic modeling for a summer peak scenario and could lead to unreliable limits and constraints. Therefore, load scaling for both import and export studies will be limited to 50% of the zone's load.

If the GLT does not produce a limit for a zone(s), whether due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph or in the case of a Zone where no valid limit is found in a particular Season, then the seasonal CIL or seasonal CEL will use the following equation where Capacity is the amount available to export or import from Tier 1 & 2 LBA's in the Base Case and where Base Case Flows is the Area Interchange for the study LRZ in the base Powerflow model.

ZIA/ZEA = Capacity + Base Case Flows

MISO shall report that LRZ as having no seasonal CIL/CEL limit and ensure that the transfer amount in the PRA will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

Voltage Limited Transfer for import studies

Zonal imports may be limited by voltage constraints due to a decrease in the generation dispatch in the zone being studied. Voltage constraints might occur at lower transfer levels than thermal limits that are determined by linear FCITC. As such, LOLE studies may include evaluation of Power-Voltage curves for major disturbances for LRZs with known voltage-based transfer limitations. Known transfer limitations will be identified through existing MISO or member Transmission Owner studies. Additionally, a study could be considered if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from non-zonal resources. MISO will coordinate with stakeholders as these scenarios are encountered.

Processing and Reporting Results

The transfer analysis results for each LRZ consist of a list of constraints and their corresponding FCITC and FCTTC values up to the requested transfer level. The constraint with the smallest

FCTTC will be used to determine each Seasons' ZIA, ZEA, CIL and CEL. The limits are the total transfer capability of the corresponding limiting constraint. Refer to Section 5.2.2.3 Establishment of Local Clearing Requirementregarding how the seasonal ZIA impacts the seasonal Local Clearing Requirement (LCR) calculation. Stakeholder review of the constraints will occur through the LOLE working group.

If a zone's seasonal Local Clearing Requirement (LCR) is greater than the zone's seasonal Initial Planning Reserve Margin Requirement (PRMR) and an existing MTEP project is not expected to increase the seasonal ZIA, MISO will follow the process outlined in section 4.5.1 of the Transmission Planning BPM to identify a project to increase the zone's seasonal CIL.

Timeline and Posting of Results
Posting of power flow models and input files will be completed before analysis begins, if stakeholders have feedback for the models, it should be provided to MISO in a timely manner. The models and associated input files will be made available to the same location where MTEP Powerflow models are shared (https://misoenergy.sharefile.com/).

The outcome of this process will identify a ZIA, ZEA, CEL and CIL for each of the LRZs for each Season within the next Planning Year. MISO will publish the values for each LRZ by November 1 preceding the applicable Planning Year.

5.2.2.2 Establishment of Local Reliability Requirement

Each LRZ's seasonal Local Reliability Requirement (LRR) is the amount of SAC MWs required, located within the specific LRZ, to yield a 0.1-day-per-year LOLE at the load level for the LRZ at the time of the LRZ peak, without assistance from resources outside the respective LRZ (other than Border External Resources and Coordinating Owner External Resources modeled in the zone as described in section 4.2.3.2 (External Resource Qualification Requirements)). The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

Each Seasons' LRR will be established using the following iterative process:

- Use the LOLE model to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and internal resources from the PRM Analysis.

- For each LRZ, the model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year for the LRZ. This is comparable to adding Coincident Peak seasonal Demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the LRZ until the LOLE reaches 0.1 day per year for the LRZ.
- After solving for 0.1 day per year on an annual basis, risk-deficient Seasons will have a minimum reliability criteria set to 0.01 LOLE and adjustments to capacity in the model will be made until the LOLE reaches 0.01 day per Season.

The minimum amount of capacity above the zonal seasonal Coincident Peak Demand required to meet the reliability criterion of a 0.1 day per year LOLE value will be utilized to establish the Local Reliability Requirement (LRR) for each Local Resource Zone for each Season within the Planning Year. The LRR study utilizes the Year 2 zonal seasonal Coincident Peak Demand supplied by LSEs in the prior Planning Year PRA cycle. The per-unit LRR values are annually calculated by MISO and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit seasonal LRR values are multiplied by the total zonal seasonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) for the prompt Planning Year PRA(s), inclusive of transmission losses, to calculate each Local Resources Zone's Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

5.2.2.3 Establishment of Local Clearing Requirement

The final steps in calculating an LRZ's seasonal LCR is to account for the external transmission ties and controllable exports to non-MISO systems, by reducing the seasonal LRR by the seasonal ZIA determined in accordance with Section 5.2.2.1 (Calculation of Transfer Limits for the PRA) and by controllable exports. Controllable exports are firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies. All 10 LRZs have LCRs for each season and they must be met by resources internal to the zone, or by Border External Resources. For example, an LSE with Initial PRMR in LRZ 1, must meet that with ZRCs originated in LRZ1 to meet LRZ1's Local Clearing Requirement. ZRCs from other zones can be used to meet the incremental PRMR greater than LCR up to that zone's Initial PRMR subject to CIL/ CEL and SRIC / SREC.

The formula for determining the seasonal LCR is as follows:

$$\text{Seasonal LCR}_{z1} = \text{Seasonal LRR}_{z1} - \text{Seasonal ZIA}_{z1} - \text{controllable exports}_{z1}$$

MISO will publish preliminary seasonal LCR determinations as part of the preliminary PRA data. These values will be updated no later than mid-March with final, updated controllable export values and seasonal ZIAs.

5.3 Pre-PRA arrangement of capacity scheduling

5.3.1 Fixed Resource Adequacy Plan ("FRAP")

The FRAP will identify resources for which an LSE has ownership or contractual rights that will be relied upon to meet the LSE's Planning Reserve Margin Requirement while also conforming to the Local Clearing Requirement ("LCR") in each LRZ where the LSE has a Initial PRMR in each Season within the Planning Year. An LSE must submit its FRAP for applicable Season(s) via the MECT by the 7th business day of March prior to each Planning Year. MISO will review the FRAP and endeavor to notify the LSE of any issues by March 15. LSEs will have until the PRA(s) offer window opens to resolve any issues identified by MISO.

An LSE can designate its seasonal ZRCs in the FRAP up to the LSE's seasonal Initial PRMR. The seasonal ZRCs used in a FRAP will be deducted from the available seasonal ZRC balance of Planning Resources in the MECT. Any portion of an LSE's seasonal Initial PRMR not covered by the FRAP (or met through paying the Capacity Deficiency Charge) will be cleared in the seasonal PRA.

An LSE submitting a FRAP may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Initial PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with the FRAP is physically located multiplied by the volume of the ZRC associated with the FRAP. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and seasonal obligation included in a FRAP will be modeled in the PRA for the applicable Season.

5.3.2 RBDC Opt Out

An LSE may elect to use the RBDC Opt Out for the upcoming and the next two years' PRAs with an obligation (Final PRMR) that is calculated as shown in section 3.1, and with the RBDC Opt Out Adder determined at the first year of RBDC Opt-Out utilizing the following formula:

$$Final\ PRMR_{LSE} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times \left(1 + PRM_{RTO} + Adder_{RBDC\ Opt\ Out}\right)]$$

Where attributes are seasonal for the following:
Final $PRMR_{LRZ}$ = Final Planning Reserve Margin Requirement per LSE
$CPDf_{LBA}$ = Coincident Peak Demand forecast per LBA
FRP_{LBA} = Full Responsibility Purchase per LBA
FRS_{LBA} = Full Responsibility Sale per LBA
$TL_{LBA}\%$ = Transmission Loss Percentage of LBA
PRM_{RTO} = Planning Reserve Margin in Unforced Capacity set by LOLE Studies
$Adder_{RBDC\ Opt\ Out}$= RBDC Opt Out Adder (Defined in Module A 72.0.0)

In MECT, the LSE's choice of RBDC Opt Out is administrated at the granularity of Asset Owners that have load obligations.

5.3.2.1 Establishment of RBDC Opt Out Adder

MISO will use the systemwide and regional RBDCs, and historical market clearing data (e.g., last three Planning Years's market data) to determine the initial RBDC Opt Out Adder that will be applicable to LSEs that elect the RBDC Opt Out starting with Planning Year 2025-2026. MISO will post the determination of the RBDC Opt Out Adder on the MISO website per the timeline defined in Appendix K.

5.3.2.2 Request for RBDC Opt Out and ZRC designation

A Market Participant representing an LSE that plans to use the RBDC Opt Out must submit its initial intent to do so through the MECT. Such request must include the name and contact information of the RERRA(s) (email, phone number), where its load is subject to jurisdiction, and must be submitted no later than January 15 prior to the upcoming Planning Year. Market Participants representing the LSE need to contact MISO if there are complexities regarding the RERRA-LSE relationship (e.g., an LSE is subject to the jurisdiction of multiple RERRAs). MISO will verify the information and notify the RERRA(s) within five (5) business days following deadline of the LSEs initial submission. The RERRA(s) has up to twenty (20) Business Days to notify MISO whether the requested RBDC Opt Out has been authorized, on or before timeline listed in Appendix K.

If the RERRA(s) notifies MISO that the LSE is not authorized to use the RBDC Opt Out in the upcoming PRA, MISO will deny the LSE's initial submission in MECT. If the LSE is subject to the jurisdiction of more than one RERRA, MISO will deny the LSE's initial submission proposing to use the RBDC Opt Out if any one RERRA indicates that the LSE is not authorized to use the RBDC Opt Out. The LSE may withdraw its initial submission even if it receives authorization from RERRA(s). Otherwise, the LSE must submit its final confirmation to use the RBDC Opt Out in the MECT and must demonstrate that the LSE has designated ZRCs for each Season to meet the LSE's Final PRMR, and its share of LCR, by the 7th business day of March prior to each Planning Year. An LSE that elects the RBDC Opt Out may not use any other options to participate in the PRA (e.g., self schedule, FRAP, participating auction) to meet its Final PRMR, but may offer any ZRCs in excess of its Final PRMR into the PRA that is consistent with Section 64.1.1.d of Module D.

MISO will notify the LSE prior to March 15th before the applicable Planning Year whether the ZRCs submitted for the RBDC Opt Out meets the LSE's final PRMR and share of LCR for each LRZ requirement for each Season during the applicable Planning Year. An LSE that does not demonstrate sufficient ZRCs to meet its seasonal Final PRMR and share of LCR on LRZ basis before the PRA offer window opens will be subject to the Capacity Deficiency Charge based on the amount of shortfall in each Season.

An LSE that elects the RBDC Opt Out may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Final PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with RBDC Opt Out is physically located, multiplied by the volume of the ZRC associated with the RBDC Opt Out. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and associated seasonal obligations related to the RBDC Opt Out will be modeled in the PRA for the applicable Season.

5.3.3 LSE's Local Clearing Requirement for LSE's Using a FRAP or RBDC Opt-Out

LSEs that choose to use a FRAP or RBDC Opt Out must designate a sufficient volume of Planning Resources located in the same LRZ to meet the LRZ's LCR requirement in each Season individually. The amount of resources that must be sourced from within the LRZ to satisfy the LSE's seasonal LCR share is equal to the load ratio share of the LSE multiplied by

the total seasonal LCR for its LRZ. The following formula is used to determine each LSE's FRAP or RBDC Opt Out LCR requirements for each Season.

$$LSE\ LCR = \left[\frac{LSE\ PRMR'}{Zonal\ PRMR'}\right] * Zonal\ LCR$$

$$Minimum\ LSE\ \ ZONE\ = \max\left(0, \left[\frac{LSE\ LCR * LSE\ \ NON\ ZONE}{(LSE\ PRMR' - LSE\ LCR)}\right]\right)$$

$$for\ the\ given\ LSE\ \ NON\ ZONE$$

$$Maximum\ LSE\ \ NON\ ZONE\ = \max\left(0, \left[\frac{LSE\ \ ZONE * (LSE\ PRMR'\ -\ LSE\ LCR)}{LSE\ LCR}\right]\right)$$

$$for\ the\ given\ LSE\ \ ZONE$$

Where:

LSE LCR:	Amount of ZRCs that must be supplied from the same LRZ where the LSE's Initial PRMR is located
LSE ZONE:	ZRCs that are in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE NON ZONE:	ZRCs from an ERZ or that are not in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE PRMR':	Total Initial PRMR the LSE has in the LRZ
ZONAL PRMR':	Total Initial PRMR for all LSEs in the LRZ
Zonal LCR:	The minimum amount of ZRCs that are located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ.

EXAMPLE :

All LSE Initial PRMR in following example is calculated based on the MISO-established PRM, even if the LSE is subject to the jurisdiction of a state that has established its own PRM

LSE Initial PRMR = 100 MW in LRZ 1
LSE LCR = 80 MW in LRZ 1

To apply ZRCs from other LRZs or an ERZ in the FRAP (or RBDC Opt Out), the following condition must be satisfied when the LSE LCR≤ LSE Initial PRMR:

$$\left[\frac{(LSE\ ZONE + LSE\ NON\ ZONE)}{LSE\ PRMR}\right] \leq \left[\frac{LSE\ ZONE}{LSE\ LCR}\right]$$

When the LSE LCR>LSE Initial PRMR, the LSE should only use ZRCs inside the resource zone to meet its Initial PRMR:

$$LSE\ NON\ ZONE = 0$$

Substituting the value for *LSE LCR* from above, the above formula can be rearranged and rewritten as:

$$\min(1, \left[\frac{Zonal\ LCR}{Zonal\ PRMR}\right]) \leq \left[\frac{LSE\ ZONE}{(LSE\ ZONE + LSE\ NON\ ZONE)}\right]$$

Where *LSE Total* is simply the sum of the FRAP from within and outside of the zone. To state more simply, an LSE must maintain a balance of FRAP (or RBDC Opt Out) in zone to total FRAP (Or RBDC Opt Out) greater than or equal to the ratio of the zone's LCR and Initial PRMR.

Case 1: LSE ZONE = 40MW in LRZ 1
LSE NON ZONE = 10 MW from LRZ 2

$$\left[\frac{(40+10)}{100}\right] \leq \left[\frac{40}{80}\right] \Rightarrow \left[\frac{1}{2}\right] \leq \left[\frac{1}{2}\right] \Rightarrow Pass: 10\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ allowed\ for\ the\ given\ LSE\ \ NON\ ZONE\ of\ 10\ MW,$$

$$Minimum\ LSE\ \ ZONE\ = \left[\frac{80 * 10}{(100-80)}\right] = 40\ MW$$

NOTE: 40 MW represents the minimum amount of FRAP (or RBDC Opt Out) that must be fulfilled by the ZRCs in LRZ 1 in this case.

Case 2: LSE ZONE = 60 MW
LSE NON ZONE = 20 MW

$$\left[\frac{(60+20)}{100}\right] \leq \left[\frac{60}{80}\right] \Rightarrow \left[\frac{4}{5}\right] \leq \left[\frac{3}{2}\right] \Rightarrow Fail: 20\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ not\ allowed$$

for given LSE ZONE of 40 MW,

$$Maximum\ LSE\ \ NON\ ZONE\ = \left[\frac{60 * (100 - 80)}{80}\right] = 15\ MW$$

NOTE: 15 MW represents the maximum amount of ZRCs from other zones which can be used to FRAP or RBDC Opt Out LSE's Initial PRMR in LRZ 1 in this case.

5.4 Hedges and Zonal Deliverability Benefit

5.4.1 Zonal Deliverability Benefit

Price separation between Local Resource Zones (LRZs), External Resource Zones (ERZs), or groupings of LRZs, including Sub-Regional Resource Zone (SRRZs) occurs due to constraints binding in the Planning Resource Auction(s) (PRA). Zonal Resource Credits (ZRC) will receive the Auction Clearing Price (ACP) based upon the LRZ or ERZ where the Planning Resource underlying the ZRC is physically located for each Season within the Planning Year.

As a result of price separation, the Transmission Provider may collect more debits from LSEs than it credits the owners of the seasonal ZRCs. Excess amounts will be distributed as follows:

1. Historical Unit Considerations (HUCs) and Zonal Deliverability Charge (ZDC) Hedges owed payment.
2. Any remaining excess revenue shall be distributed on a *pro rata* basis to Deliverability Benefit Zones (DBZs). A DBZ is a group of one or more LRZs with equal ACPs driven by the same auction constraint.

5.4.1.1 Zonal Deliverability Benefit Pro Rata Allocation Methodology

The *pro rata* distribution is applied to each applicable Season and is based upon the LSE's eligible Adjusted Final PRMR. . Adjusted Final PRMR is the Final PRMR minus HUCs and ZDC Hedges.

MPs with Fixed Resource Adequacy Plans or RBDC Opt Out are eligible to receive ZDB.

The *pro rata* methodology to allocate ZDB uses a weighted average approach to calculate the benefit, in dollars, to importing DBZs of all exports within MISO – a weighted average exporting ACP. This weighted average pool of dollars is then allocated to importing DBZs within MISO on a *pro rata* methodology based upon the difference between the importing DBZ ACP and the

weighted average exporting ACP and the MW amount of imports into a DBZ. The ACP for each LRZ within an importing DBZ is adjusted by dividing the benefit dollars allocated to the DBZ by the total PRMR of all LRZs within a specific DBZ. The specific steps to allocate ZDB are described below.

1. Subtract Final PRMR and ZRCs associated with HUCs and ZDB Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC).
2. Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint.
3. For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
4. Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

5. Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

6. Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

FRAP or RBDC Opt Out Contribution to ZDB

Furthermore, ZDB includes credits collected from FRAPs or RBDC Opt Out that contain ZRCs located in LRZs that have a greater ACP than the respective PRMR's LRZ. This ZDB will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is physically located.

Allocation of Zonal Deliverability Charge ("ZDC")

A FRAP will be subject to a ZDC if the ACP of the LRZ where the ZRC is physically located is less than the ACP of the LRZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located. ZDC collected by the Transmission Provider that is not associated with a ZDC Hedge will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located.

A detailed example of ZDB *pro rata* allocation methodology is in Appendix P.

5.4.2 Historical Unit Considerations (HUCs)

A HUC is a financial hedge against ACP differentials between LRZs or between an LRZ and an ERZ. HUCs for existing capacity agreements hold LSEs harmless from price separation to the extent that excess auction funds are sufficient. HUCs for existing LSEs will be eligible until the end of the original term of the arrangement, not including any evergreen extensions, or for two years – whichever is longer.

The following criteria must be satisfied for HUC approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs or a resource located in an ERZ
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year
- Contracts must be a) Grandfathered Agreements, b) arrangements executed and in place on or before July 20, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones
- For both new and existing LSEs, HUCs will expire at the end of the contract term, unit ownership change or unit retirement date, whichever is sooner. Contracts expiring during the upcoming Planning Year are not eligible for a HUC covering the planning year. Contracts that have been renewed by evergreen contract provisions are only valid for two Planning Years from the date of the HUC registration

- A HUC must be registered in the MECT by November 1 prior to each Planning Year[2]. HUC Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Resource Zone and TSR and/or NITS identification number(s). Once the SAC MW for Planning Resources is published, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Resource Zone, and TSR and/or NITS ID number information only. Updates will need to be completed by February 1 prior to the Planning Year
- A separate HUC registration is required for each Planning Resource and load within each LRZ or a resource located in an ERZ
    - One Planning Resource in a registration can only select one LRZ or ERZ
- The MW in HUC registrations that are paid will not exceed the LSE's seasonal Final PRMR minus their LCR.
- If there are more HUCs than a DBZ's Final PRMR minus its LCR, then HUC payments will be pro-rated by multiplying the difference between Final PRMR and LCR divided by the total HUCs.
- If Market Participants enter a seasonal ZRC transaction to fulfill contracts that meet the criteria for a hedge, MISO must be able to determine the source of the ZRCs in order to apply the HUC financial hedge to the auction results
    - ZRCs transacted to fulfill existing contracts will need to have specific unit identifiers from aggregate deliverable generators
- Based on the ZRCs transacted, MISO will work with the MP that qualified the HUC to determine in which LRZ or ERZ the Planning Resource is located

If a Load is in an LRZ with a higher ACP than the LRZ or ERZ where the Resource is located, the MP serving the Load will pay an amount equal to the difference of the ACPs between the LRZ and the LRZ or ERZ where the Resource is located, multiplied by the amount of the unhedged load if a HUC Hedge does not exist. This distribution will be limited by the excess auction revenue collected in a given PRA.

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as HUCs, provided that the agreements otherwise satisfy the criteria.

[2]

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the HUC Hedge provided that the HUC criteria is satisfied.

Firm resources that meet HUC Hedge criteria may be included as part of a FRAP or RBDC Opt Out or offered into the annual auction. Any MWs of ZRCs in a FRAP or RBDC Opt Out that are qualified under a HUC will not be subject to a Zonal Deliverability Charge assessment and will not receive a HUC payment

5.4.3 Zonal Deliverability Charge Hedge

LSE can obtain a ZDC Hedge as described herein as a financial protection from zonal price differences. Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a ZDC Hedge. Also, any cost shared upgrades would not be eligible for a ZDC Hedge. The participant that funds the upgrades and submits the transmission service request is the participant who is eligible for the ZDC Hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1 prior to the Planning Year to demonstrate eligibility. ZDC Hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

5.5 Planning Resource Auction (PRA)

5.5.1 Timing of Auctions

Seasonal Planning Resource Auctions will be conducted in the first 20 business days of April, with results posted near the end of April which is approximately one month before the beginning of the first Season of the associated Planning Year (PY). All four seasonal (Summer, Fall, Winter and Spring) PRA's will be conducted in April prior to the PY.

5.5.2 Amount of Capacity Cleared in Each Auction

The seasonal PRA(s) and Transitional PRA shall clear seasonal ZRC offers in order to satisfy 100% of the seasonal Final PRMR for each LSE, less the amount of seasonal Initial PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a seasonal FRAP or RBDC Opt Out, in each LRZ. For a Season, if the total volume of seasonal

ZRC offers is less than total seasonal Final PRMR, MISO will clear the total volume of offered ZRCs for that Season respecting established CIL, CEL, SRIC and SREC.
For LSEs not selecting the RBDC Opt Out, the Final PRMR is established as a result of the PRA clearing using RBDCs. For LSEs selecting the RBDC Opt Out, Final PRMR is the same as Initial PRMR, which is based on the sum of the applicable PRM plus the applicable RBDC Opt Out Adder, as demonstrated in section 3.1. LSEs under state jurisdiction where the state has elected to establish its own planning reserve margin will have a Final PRMR based on the planning reserve margin established by the state.

5.5.3 Conduct of the PRA

The seasonal Planning Resource Auctions shall be sealed bid auctions, which will determine the seasonal Auction Clearing Prices (ACP) for each Local Resource Zone (LRZ) and External Resource Zone (ERZ) modeled in that auction. The auction shall determine the outcome of all seasonal ZRC offers accepted during the qualification process and submitted during the auction offer window.

Step 1: Compilation of Offers
Offers for each of the seasonal auctions must be submitted in the MECT's Submit Offer screen for each specific seasonal auction during the auction offer window period. The offer window for the auction will be opened during the last four business days in the month of March prior to the start of the new Planning Year. Owners of jointly owned facilities can individually offer their share of any such resources into the seasonal PRAs, either as self-schedule price takers or with specific offers or use their share of such resources as part of a seasonal FRAP or RBDC Opt Out.

MISO shall compile all of the offers for each Season, as follows: The MP acting on behalf of any Planning Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of seasonal ZRCs that the MP would commit to provide from the Resource in the associated modeled LRZ and/or ERZ during the Season within the Planning Year. An offer shall be defined by the submission of up to five price and quantity pairs, each having a strictly greater price than the previous price in the submission. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for each price. Each segment of each offer is separately evaluated.

Step 2: Determination of the Outcome

MISO shall use the seasonal ZRC offers to determine the aggregate supply curves for each MISO modeled LRZ and/or ERZ. MISO will use the seasonal offers in conjunction with the seasonal import and export constraints, seasonal local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., if an LRZ needs 50 MW, but a Market Participant has a 100 MW Resource; only 50 MW will clear). At any non-zero clearing price, a pro-rated clearing from tied bids will be applied in conjunction with need, location of resources subjected to tied bids, and import and export limits of respective LRZs. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Inadequate Supply

While the auction process will endeavor to select seasonal ZRC offers sufficient to meet the seasonal requirements of each LRZ, it is possible that sufficient resources are not available in the LRZ and the LRZ would thus be short of Planning Resources for that Season within the Planning Year. In such cases, the auction will clear all seasonal ZRC offers in the LRZ for that Season and, if the LRZ is short ZRC's to meet the seasonal requirements, the entire LRZ will clear at the LRZ's seasonal CONE value. If the LRZ is short of ZRC's to meet the requirements for more than one Season within the Planning Year, then the ACP for such Seasons will be determined as described in section 69A.7.1 of Tariff Module E-1.

5.5.4 Market Monitoring

All participation by Market Participants is subject to the market power mitigation rules regarding physical and economic withholding of capacity as described in Module D of MISO's Open Access Transmission Tariff and Market Monitoring BPM-009. All Planning Resources except for External Resources, Load Modifying Resources, and Energy Efficiency Resources are subject to physical and economic withholding monitoring. Below are additional details regarding the application of these market monitoring provisions. In addition to these details, please refer to Module D and BPM-009 Market Monitoring and Mitigation for additional details.

5.5.4.1 Physical Withholding

Sec. 64.1.1.d of Module D describes the Physical Withholding Provisions in the PRA. The IMM has established a Physical Withholding Threshold Limit of 50 MW per LRZ that is applied as a sum to a Market Participant (MP) and its Affiliates. Thus, there is a total of 50 MW of deliverable

SAC (ZRCs) whose rights are owned by an MP and its Affiliates in each LRZ that are not required to submit an offer into the PRA or be part of a FRAP or RBDC Opt Out. If the sum of deliverable SAC MW withheld exceeds the Physical Withholding Threshold Limit, the MP and its Affiliates would fail for conduct (Conduct Test) for physical withholding and be subject to the Impact Test described in Module D.

5.5.4.2 Economic Withholding

Sec. 64.1.2.d of Module D describes the Economic Withholding Provisions in the PRA. By default, each Planning Resource subject to economic withholding has an initial Reference Level for their PRA offer of $0/MW-Day. A Conduct Threshold equal to 10% of the LRZ Daily CONE (Daily CONE = LRZ CONE / 365) is allowed for a PRA offer without failing conduct (Conduct Test) for economic withholding and be subject to the Impact Test described in Module D.

An MP may submit a request for a Facility Specific Reference Level (FSRL) to the IMM. The request must be accompanied by evidence and documentation of Going Forward Costs (operating and capital) to operate the Planning Resource for the next Planning Year. Going Forward Costs must be sufficient detail to specify costs specific to suspension or retirement. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

Market Participants have the option to use Default Technology Specific Avoidable Costs (DTSAC) calculated by the IMM as specified in Module D for operating cost recovery in lieu of submitting their own documentation for operating costs. The DTSAC values in Module D are broken down by different generator classifications for suspension and retirement requests. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

5.5.5 Target Reliability Value

The resultant target reliability value for each Season for each LRZ will be the greater of the system-wide seasonal Planning Reserve Margin Requirement based on MISO's seasonal PRM or the seasonal LCR value. The sum of these seasonal LRZ target reliability values will be the system's target seasonal reliability value, that is, the amount of SAC MW that must be obtained, if available, from the auction.

5.5.6 Resource Offers

Any seasonal ZRCs that were not used in a FRAP or RBDC Opt Out can be offered into the seasonal PRA during the auction window period. The following business rules are applied to the seasonal ZRC offers for the seasonal PRA:

- Offer cannot be changed or withdrawn after the auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.
- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each Season and zones (LRZ and ERZ) is the annual LRZ/ERZ CONE divided by the total number of days in the Season.
- The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear). At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Self-Scheduling

LSEs that "self-schedule" ZRCs by submitting offers into the PRA(s) with a price of $0.00 will always clear the auction.

Sub-Regional Constraints

The Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) are the transmission constraint parameters which must be respected, in addition to CILs and CELs for each LRZ, when conducting the PRA or in the Resource Replacement process. A SRRZ consists of more than one LRZ. The North/Central SRRZ consists of LRZs 1-7, and the South SRRZ consists of LRZ 8-10.

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, seasonal SRECs and seasonal SRICs as soon as practical but no later than the first business day of March for the following Planning Year.

5.5.7 Seasonal Simultaneous Feasibility Test (SFT)

Background

The test identifies transmission constraints resulting from power transfers between LRZs and imports to the MISO system from ERZs. To the extent transmission constraints cannot otherwise be mitigated via redispatch of seasonal Planning Resources while holding LRZ imports and exports constant, new seasonal CIL and CEL values (as applicable) are established. Resulting transfers in the auction will be simultaneously reliable and feasible. The seasonal SFT is completed after the seasonal auction clears and is driven by section 69A.7.1 of Tariff Module E-1.

Base Model

Base modeling represents the transmission topology and associated transmission ratings, Demand, and anticipated net interchange for the associated Season: summer, fall, winter, and spring. This is accomplished by the following modeling assumptions:

- Base model
  - Latest available MISO model with expected generation and transmission topology for the effective date of each Season within the Planning Year
- Transmission Topology
  - Includes Appendix A and other Model On Demand projects in-service by the effective date of the specific Season within the Planning Year
- Load
  - Final PRMR cleared through seasonal auction
  - LMRs are modeled as reduction of seasonal Final PRMR where LMRs are physically located
- Dispatch
  - Seasonal FRAP
  - Seasonal RBDC Opt Out
  - Seasonal ZRC offers cleared through the auction
- External representation
  - Latest Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group series model matching Planning Year timeframe for each Season where applicable within the Planning Year

The latest seasonal models from the annual MISO series model build provides the best representation of the system and is a better representation than the one-year-old LOLE model used to establish the seasonal CIL and CEL limits. The latest model contains up-to-date topology and has gone through more recent stakeholder review.

Interchange Detail

External units that clear the auction are accounted for by Balancing Authority Area and then the interchange between MISO and the Balancing Authority Areas with cleared units is adjusted to represent the cleared amount. Units within MISO with an external capacity commitment will be dispatched to external load. Interchange will be adjusted to reflect the transaction.

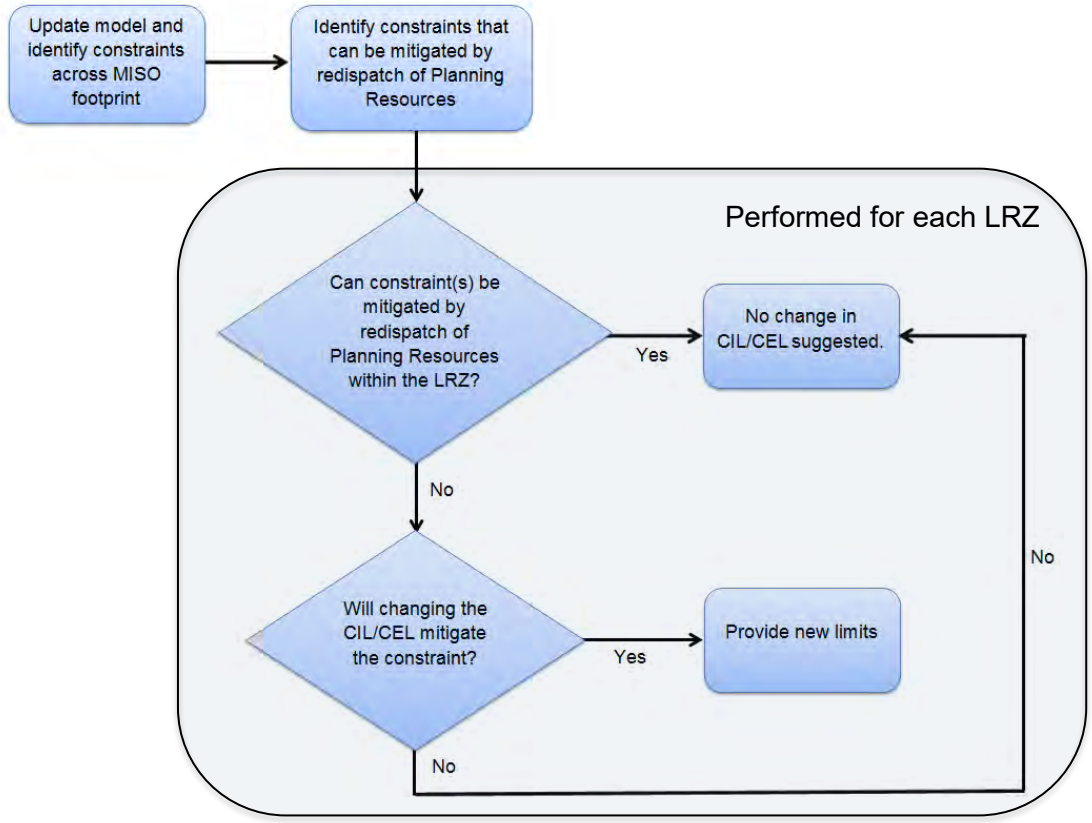
Topology Validation

Model checks are performed prior to the SFTs and PRAs. First, the ratings of facilities found to be limiting in the LOLE study are checked for rating changes. If the facility ratings are updated, the impact on seasonal CEL, CIL and/or ZIA must be determined and included as inputs to the PRAs. Transmission projects included in the LOLE models that were supposed to be in service by the effective date of the model, are validated and updated accordingly if a project's in-service date changes.

Power flow Analysis

The only controllable elements of the auction are the seasonal CIL and CEL. The seasonal SFT determines if any changes to CIL and CEL are required. The initial limits are determined in the annual LOLE study where seasonal CIL and CEL limits are established. These limits are an input to the initial auction clearing process. The SFT process is outlined in Figure 5.5 below.

Figure 5.5: SFT Process Flow



Seasonal CIL and CEL may be modified when the dispatch of Planning Resources within that Season outside the LRZ is the only action to mitigate constraints. To determine if changes are required, it must first be determined if the LRZ is an exporter or importer from the auction results of that Season. If the LRZ is an exporter within the seasonal CEL bounds, no change to limits should cause the LRZ to export more. Similarly, no change to limits should cause an importing LRZ to import more. The changes to limits that are impactful for exporters and importers are outlined as:

- Potential change if Planning Resources outside an LRZ is the only mitigation identified
- Decrease export or import limit if Planning Resources outside LRZ can be ramped up or down respectively to mitigate the constraint
- Decrease limit by MW amount needed to mitigate constraint

The Tariff allows for up to three iterations of the auction clearing process. The first iteration uses the seasonal CIL and CEL values from the LOLE study while the second and third iteration use any updated CIL and CEL values as determined by the seasonal SFT. The second and third iterations are performed only if needed. The clearing iterations are outlined as:

1st Pass

- Inputs to the auction clearing process are seasonal CILs and CELs from LOLE study, seasonal LCR, seasonal SRECs, and seasonal SRICs as applicable
- If all LRZs pass the SFT in that Season, auction results are final and the 2nd and 3rd iteration of auction clearing is not required.

2nd Pass

- Inputs to the auction clearing process are updated. Seasonal CILs and CELs from the 1st Pass and
- If all LRZs pass the SFT, results are final.

3rd Pass

- Inputs to the seasonal auction clearing process are updated. Seasonal CILs and CELs from the 2nd Pass if all zones pass the SFT, results are final. If at least one LRZ does not pass the SFT, the iteration with the fewest MWs of network violations will be deemed as the final auction result.

5.5.8 Auction Results Posting

MISO will post the summary of the Planning Resource Auction results on its website twenty (20) Business Days after the auction offer window is closed. The summary includes the following information for MISO system wide and each LRZ for each Season within the Planning Year: Final PRMR, Total Offer + FRAP+RBDC Opt Out, Offer Cleared + FRAP+RBDC Opt Out, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, deficient amount, and Total Offer Cleared volume for the system.

One month following the completion of any PRA, MISO will post the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

Resource Adequacy Settlement

Transmission Provider will settle each PRA using the following steps:

1. Determine the ACP for ZRCs within each LRZ for every Season.
2. Determine each LSE's Final PRMR. For details see 5.6.

3. Provide HUC credits equal to the zonal ACP differential to Load subject to HUCs in every Season in the Planning Year.
4. Provide ZDC Hedge credits equal to the zonal Auction Clearing Price differential to ZDC Hedge Load amounts in every Season in the Planning Year.
5. Provide ZDB credits to all remaining Final PRMR in the LRZ. The ZDB is a credit against the ACP paid by LSEs with Final PRMR in each LRZ in every Season in the Planning Year.

Settlement calculations for each Season in the PRA will be conducted on a daily basis and the results will be shown under the Real Time Settlements statement. Please refer to the Market Settlements BPM for further details. Below are charge types under the PRA(s) Settlement:

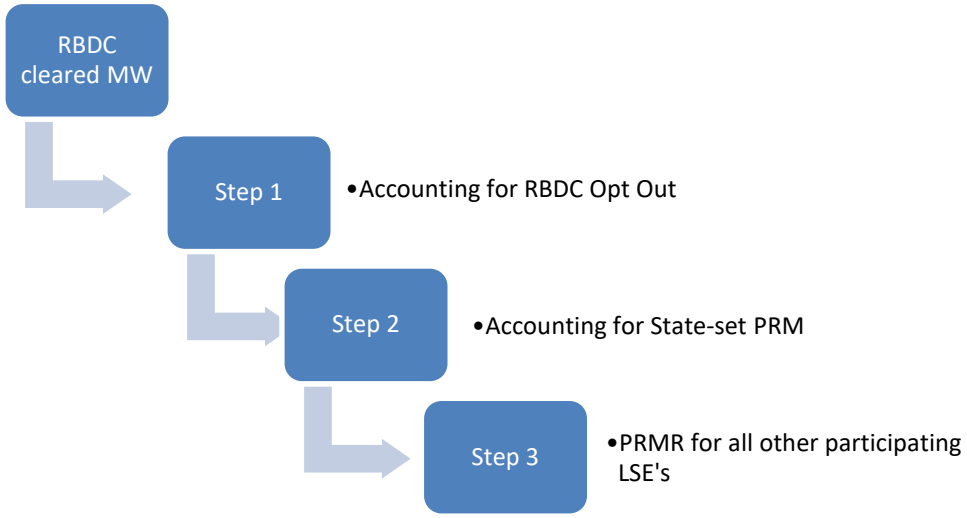
- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP or RBDC Opt Out)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared seasonal ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's seasonal FRAP or RBDC Opt Out will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when an LSE clears more seasonal ZRC in the PRA than its seasonal Final PRMR. The LSEs that converted SAC MW to seasonal ZRCs will receive the seasonal auction clearing price for the entire Season for those seasonal ZRCs that cleared in the seasonal PRA.

5.6 Final PRMR Allocation Process

The Final PRMR of an LSE is determined based on RBDC clearing and the LSE's participation option (such as RBDC Opt Out, market participation, etc.) in the PRA. The RBDC cleared MWs determined during the PRA clearing process will be allocated to determine LSE's Final PRMR using the steps outlined below (Figure 5.6).

Figure 5.6: Overview of Final PRMR allocation process



Step 1: Accounting for RBDC Opt Out

First, determine cumulative MWs corresponding to PRMR obligation of LSEs choosing the RBDC Opt Out option as per Section 5.3.2. Then, deduct this cumulative MWs from the total cleared MW from the PRA clearing. Remaining cleared MWs, if any, are then passed on to step 2.

Step 2: Accounting for State-set PRM

Then, the Final PRMR for LSEs who are under State jurisdiction with the State defined PRM is determined. For such LSEs, their Final PRMR is calculated based on the PRM defined by the respective State. Then, the sum of Final PRMR of LSEs who are under State jurisdiction with the State defined PRM is deducted from the remaining cleared MWs that were calculated in step 1. At the end of step 2, remaining cleared MWs, if any, are determined and then passed on to step 3.

Step3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

If the remaining cleared MWs after step 2 of the Final PRMR allocation process are greater than zero, then step 3 of the Final PRMR allocation process will be executed. In this step, remaining cleared MWs, determined in step 2 of the Final PRMR allocation process, will be distributed across remaining LSE's not covered under step 1 or step 2 on a pro-rata basis with respect to their Coincident Peak Load Forecast including transmission losses.

For LSEs participating using FRAP provisions, the quantity that is covered through FRAP provisions will be considered after step 3 of the Final PRMR allocation process. Any additional ZRCs that such LSEs need to procure from the market to meet their share of Final PRMR, will be charged the applicable ACP.

Example 1: RBDC Out Out, No State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load, and
- LSE C has 35 MW load.

Assumptions:

- No State has defined PRM for its jurisdictional entities
- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation calculation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

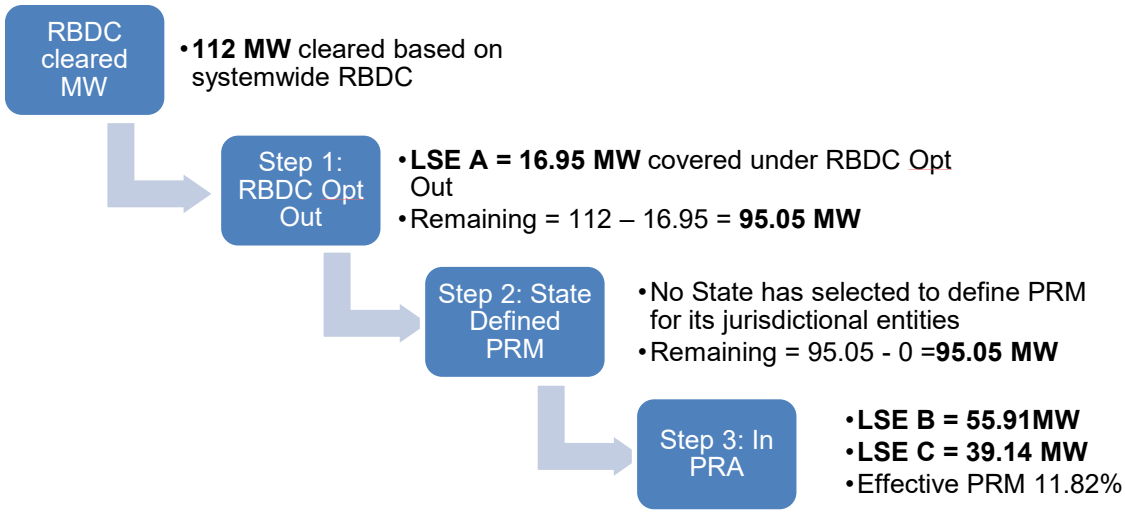
Step 2: Accounting for State-set PRM

In this example, there is no load subjected to State defined PRM. Hence, no Final PRMR is allocated in this step and 95.05 MW of cleared RBDC capacity will still remain (112 MW - 16.95 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, remaining RBDC cleared 95.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 85 MW. Hence, the Final PRMR for LSE B will be **55.91 MW**, calculated as 50 * (95.05/85), and the Final PRMR for LSE C will be **39.14 MW**, calculated as 35 * (95.05/85). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 11.82%.

The example is graphically summarized ahead.



Example 2: RBDC Opt Out, State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions
- LSE B has 50 MW load and subjected to State defined PRM of 10%
- LSE C has 35 MW load

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%

- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

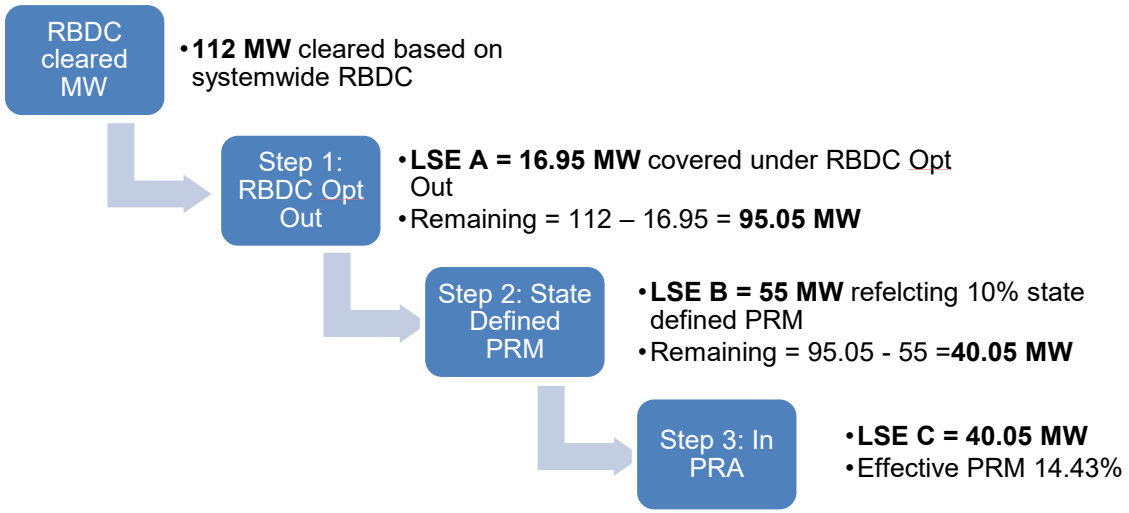
Step 2: Accounting for State-set PRM

In this example, LSE B's load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 40.05 MW of cleared RBDC capacity will remain (95.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 40.05 MW, determined after step 2, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **40.05 MW**, calculated as 35 * (40.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 14.43%.

The example is graphically summarized ahead.



Example 3: RBDC Opt Out, State setting PRM, & Final PRMR lower than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load and subjected to State defined PRM of 10%.
- LSE C has 35 MW load.

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 108 MW (indicating RBDC clearing at 8% above load forecast, lower than PRM)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 91.05 MW of cleared RBDC capacity will remain (108 MW - 16.95 MW) for further distribution in the following steps.

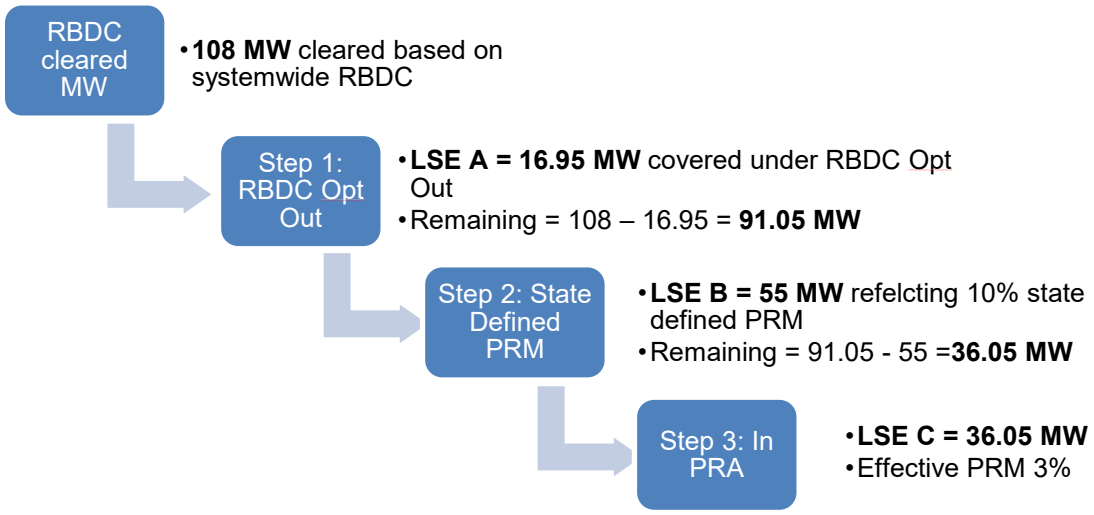
Step 2: Accounting for State-set PRM

In this example, LSE B's load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 36.05 MW of cleared RBDC capacity will remain (91.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 36.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **36.05 MW**, calculated as 35 * (36.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 3%.

The example is graphically summarized ahead.



5.7 Retail and Wholesale Load

Retail and Wholesale Load switching between LSEs can be tracked through the MECT after the start of the in each Season within the new Planning Year. As a result of load switching, the seasonal Final PRMR of the LSEs involved in the load switching will change. Switching of seasonal Retail load will not change an Electric Distribution Company's (EDC) total area

seasonal Final PRMR. Similarly, wholesale seasonal load transaction will not change the total MISO seasonal Final PRMR.

5.7.1 Retail Load Switching

By January 15 11:59 p.m. EST prior to the start of the new Planning Year, retail supplier LSEs will confirm their share (e.g. PLC) of the EDC's area seasonal Initial PRMR. After the Planning Year starts, the Retail LSE's seasonal Final PRMR will change during each Season within the Planning Year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with Demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

EDCs are responsible for updating the seasonal Final PRMR associated with each retail choice LSE in the MECT. The Retail Load screen in the MECT is provided for EDCs in Retail Choice states to track the Retail LSE's day-to-day migration of loads at the Asset Owner (AO) level.

Using the daily retail load switching information in the MECT, MISO Settlements calculates each retail choice LSE's new seasonal Final PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

The daily retail load switching information includes:

- Name of the EDC
- Name of the LBA
- Operating Date of Retail load switching
- Season (Summer, Fall, Winter or Spring)
- Name of AO(s)
- AO's new Retail MW (with granularity of tenth of a MW)

5.7.2 Wholesale (Non-Retail) Load Switching

A Wholesale Load obligation can be switched from one LSE to another using the Wholesale Load Switching screen in the MECT during each Season of the Planning Year. When Wholesale Load switching occurs, the daily capacity charges of the Wholesale Load will be transferred from the current LSE to the new LSE. The seasonal Final PRMR for affected LSEs will be

decreased or increased, as appropriate, by the amount of the wholesale load plus the seasonal PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Season within the Planning Year may enter a Wholesale Load switching contract representing seasonal Final PRMR in the MECT.

For the case of Wholesale Load switching, the amount of the seasonal Final PRMR transferred via the wholesale load transaction process will transfer the Final PRMR of the current LSE to the new LSE starting with the effective date specified in the wholesale transaction for the applicable Season. The transaction must be confirmed in the MECT by both parties before the start of the effective date.

5.7.3 Peak Load Contribution (PLC)

The EDC calculates each retail LSE's load ratio share of the retail LSEs peak Demand of the EDC's peak Demand at the MISO seasonal Coincident Peak Load prior to the Planning Year. The aggregate PLCs will be set equal to the seasonal Initial PRMR of the EDC. Specific methods used by the EDC to calculate each Retail LSE's PLC must be provided to both MISO and LSEs no later than December 15 prior to the upcoming Planning Year. LSEs will have until January 15 prior to the upcoming Planning Year to verify the seasonal EDC provided data in the MECT.

5.7.4 Settlements of Wholesale and Retail Switching

All confirmed load switching information submitted by the Settlements deadline (per the Market Settlements BPM) will be transferred to Market Settlements for settlement calculation purposes.

An LSE's seasonal Final PRMR will change based on the information submitted in the MECT for both Wholesale and Retail Load Switching.

MISO will calculate the new charges and credits by applying the seasonal Auction Clearing Price ("ACP") for the applicable LRZ to the new daily seasonal Final PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE's seasonal Final PRMR will change if Retail Load switching information in the

MECT or daily load data for Settlements is resubmitted per the Settlement's rerun process (i.e., S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

5.8 Capacity Deficiency Charge

LSEs are allowed to opt out all or a portion of their seasonal Initial PRMR from participating in the auction by paying the Capacity Deficiency Charge. This is achieved by making a voluntary entry into the "Capacity Deficient Amount (MW)" field of the MECT equal to the MW amount of seasonal Initial PRMR opting out of the seasonal auction before the auction window opens. The Capacity Deficiency Charge for an LSE is the MW amount in the "Capacity Deficient Amount (MW)" field multiplied by 2.748 times the seasonal Cost of New Entry ("CONE") which is calculated by Annual CONE/365 multiplied by the days in the Season for the LRZ where the LSE's seasonal Initial PRMR is located.

LSEs that choose the RBDC Opt Out must demonstrate sufficient ZRCs to meet their seasonal Final PRMR (equal to the Initial PRMR) before the PRA auction window opens. Otherwise, the shortfall is subject to the Capacity Deficiency Charge by multiplying 2.748 times the seasonal CONE price.

Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed on a *pro rata* basis based upon the cleared MW of seasonal Final PRMR to other LSEs in the Transmission Provider's footprint who did not opt to pay the Capacity Deficiency Charge. If the LRZ where the LSE opted to pay the Capacity Deficiency Charge failed to meet its seasonal LCR, then seasonal Capacity Deficiency Charge revenues will be allocated solely to LSEs within that LRZ that did not opt out of the seasonal auction by paying the seasonal Capacity Deficiency Charge. MISO will assess the seasonal Capacity Deficiency Charge on the first business day after the results of the seasonal PRA have been published.

6 Performance Requirements

6.1 Must Offer Requirement

The must offer requirement applies to any Market Participant who converts the SAC of a Capacity Resource to seasonal ZRCs, and those ZRCs are used in a seasonal FRAP or RBDC Opt Out or clear in a seasonal auction within the Planning Year. The must offer volume is the effective ICAP times the % of the total seasonal ZRCs a resource clears (for example, a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP), except for

Intermittent Resources. The effective ICAP equals the lesser of GVTC or Interconnection Service (NRIS+ERIS) for each Season (e.g. effective ICAP = Min(GVTC, IS)). The must offer obligation for Intermittent Resources is based on the cleared seasonal ZRCs, or ZRCs used in a FRAP or RBDC Opt Out, divided by the seasonal Resource credit (e.g. wind capacity credit for a wind resource) as described in Section 4.2.1.5 – Wind and Solar Capacity Credit. Additionally, no must offer requirement will exceed the resource's firm level of transmission service. LMRs do not have a must offer requirement, their obligations are covered in section 4.2.5 - Load Modifying Resource Obligations and Penalties.

6.1.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation

MPs that own a Capacity Resource with ZRCs that clear in the PRA or are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out must offer the ICAP equivalent of the cleared and FRAP or RBDC Opt Out ZRCs into the Day-Ahead Energy Market and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Capacity Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff. Outages and derates must be reported in the MISO Outage Scheduler (CROW).

Compliance with "must offer" requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze compliance with "must offer" requirements in both the Day-Ahead and RAC by considering information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

6.1.2 Dispatchable Intermittent Resource and Intermittent Generation

An MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or ZRCs which clear in a PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

The must offer requirement applies to the effective ICAP of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the SAC amount. The must offer obligation for Intermittent Resources is replaced with the forecast in the DA market based on the weather forecast and performance of the Intermittent Resources.

For wind resources, the ICAP-equivalent must offer obligation is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. For non-wind Intermittent Generation and Dispatchable Intermittent Resources, the XEFORd will be set equal to the SAC divided by the ICAP, where the ICAP shall be the maximum value registered in the Commercial Model. For non-wind Intermittent Resources not modeled in the Commercial Model, the ICAP will be the nameplate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by the close of both the DA and Forward Reliability Assessment Commitment (FRAC) market offer periods will be used to monitor compliance with the must offer requirement when the unit's availability is affected by non-mechanical and/or non-maintenance reasons. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast. The same Intermittent Forecast data file used in Day-Ahead Must Offer compliance shall be utilized in FRAC if no further update is provided. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the cleared Installed Capacity as the mustoffer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

When submitting data to the Intermittent Resource Forecast Update tool, a header row should be included at the beginning of the file in this format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO's Outage Scheduler (CROW). The must offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only. The thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

6.1.3 Use Limited Resource

An MP that commits a Capacity Resource that has ZRCs which clear in a Planning Resource Auction (PRA) or are used in a Fixed Resource Adequacy Plan must submit the ICAP value of ZRCs which either clear the PRA or is used in a Fixed Resource Adequacy Plan in the Day-Ahead Energy Market, each pre Day-Ahead, and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

A Use Limited Resource is required to submit into the Day-Ahead Market to satisfy the must offer requirement of at least four (4) continuous hours daily across MISO's forecasted daily peak (including weekends). The must offer period of four (4) hours includes the two (2) hourly intervals prior to the forecasted peak hour, the peak hourly interval, and one (1) hourly interval after the forecasted peak load. This approach enables MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO's peak period will be based on the forecast published one day prior to the operating day in the Market Report section of the MISO website: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports >Select "Summary" under Navigator to find the latest reports.
All outages and derates for Use Limited Resources need to be reflected in MISO's Outage Scheduler (CROW) or SDX. Thresholds for Use Limited Resources will only be applied during the four continuous hours across MISO's peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency.

6.1.4 External Resources

The maximum must offer requirement applies to the registered capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or clear in a PRA must submit the ICAP-equivalent value of FRAP or RBDC Opt Out or cleared ZRCs as Energy offers into the Day-Ahead Energy Market for every hour of every day, except to the extent that the Generation Resource is

unavailable due to a full or partial forced scheduled outage or the offers are from a Use Limited Resource. The must offer requirement will be capped at the resource's ICAP value.

Offers in the Day-Ahead Energy Market can only be Normal Energy type, with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Forward Reliability Assessment Commitment (FRAC).

Therefore, the must offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via MISO Market Capacity Emergency SO-P-EOP-00-002.

The MP that has either identified ZRCs from a FRAP or RBDC Opt Out or cleared ZRCs in a Planning Resource Auction (PRA) from an External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator. External Resources must be available to schedule Energy into MISO during Emergencies if needed by MISO. MISO Market Capacity Emergency SO-P-EOP-00-002 includes a mechanism to schedule all External Resources into MISO's Balancing Authority Area. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR" in all capital letters with no spaces. In the Value field, the MP should list the Capacity Resource name that matches the Module E External Resource registration name in the MECT.

External Resources that are Use Limited Resources must follow the Day-Ahead must offer requirements for Use Limited Resources as documented in Section 4.2.2.1 of this BPM.

Compliance with must offer requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze the compliance with must offers in both the Day-Ahead and RAC by considering information provided by MISO's CROW Outage Scheduler, and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited, or Intermittent Generation.

6.1.5 DRR T*ype I and Type II*

The same must offer requirement described in Sec. 6.1 applies to the Installed Capacity of DRR Type I and Type II, (and not the SAC rating) used to meet Resource Adequacy Requirements. Installed Capacity refers to the amount of ZRCs cleared in an PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – XEFORd) of the Capacity Resource.

6.2 Must Offer Monitoring

MISO will monitor whether the offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market, and first post Day-Ahead RAC process meets the seasonal must offer requirements. The must-offer requirements are in terms of Installed Capacity (ICAP) of the resource, where ICAP is the minimum of GVTC and Total Interconnection Service.

The offers should be greater than or equal to the seasonal must offer requirement minus approved outages or derates minus the applicable threshold as detailed in this section, but not to exceed the firm level of established Transmission Service. This excludes Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO including DIR- registered Hybrid Resources.

[Firm Service] > [Offer] ≥ [Offer requirement] – [Outage or Derate] – [tolerance threshold]

If the offer amount is greater than or equal to the must offer requirement minus the approved outage or derate in CROW minus the appropriate threshold, then the MP will have passed the must offer monitoring check. Otherwise, the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the market portal of their must offer status.

Outages & Derates

If the Offers for Day-Ahead and first post Day-Ahead RAC are less than the must offer requirement, then MISO will compare the difference to approved outages or derates in MISO's Outage Scheduler (CROW) for such resources. Approved outages, approved derates, and offers will be captured based on the information provided at both the Day-Ahead Energy Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM.

Tolerance Threshold

MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT for the applicable Season. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO's Outage Scheduler (CROW). Importantly, this does not relieve the MP of the obligation to meet the overall seasonal must offer requirement. The tolerance threshold volume will be applied at the CPNode level except for those resources noted otherwise in this BPM. The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

Market Participant Review

If a Market Participant believes there is a discrepancy in their must offer report, the Market Participant can notify MISO via the MISO Help Center of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage.

MISO will review the information submitted and notify the Market Participant within seven (7) Business Days via email of the outcome of the review.

IMM Access

The IMM also has access to the reports published on the market portal and may contact Market Participants directly on any compliance issues.

6.3 Annual Calculation of CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each LRZ annually by September 1 of each year for the following Planning Year. The CONE value for each individual LRZ will be the same in every Season (Summer, Fall, Winter and Spring).

In calculating CONE values, the IMM and MISO will consider the following factors:

- Physical factors: type of resource, location, costs for fuel
- Financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- Other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE. CONE values approved by FERC are posted on the MISO website.

Net CONE will be determined as per the section 69A.8 of Tariff Module E-1.

6.4 Replacement Resources

6.4.1 Maximum Outage & Derate Threshold (Greater than 31 day rule)

If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts or Power Purchase Agreements for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs or new resources per Section 6.4.5 (On Ramping New Resources Mid-Planning Year for ZRC Replacement) to transfer the performance requirements applicable to the planning Resource or pay the Capacity Replacement Non-Compliance Charge (Tariff Module E-1 Section 69A.3.1.h). The CRNCC charge will be calculated after the completion of the season in the timeliest manner by MISO and the IMM.

The Must Offer Monitoring threshold described in section 6.2 (Must Offer Monitoring) will not apply when evaluating charges and ZRC replacement regarding the 31-day outage rule. The performance obligation is in terms of effective ICAP and thus the amount of ZRCs needed to be replaced will back calculate to ZRC values.

For example, a wind resource that has a 100 MW ICAP and 20 MW SAC and clears 20 ZRCs in the market will have a must offer requirement of 100 MW. The forecasts submitted to the DA market will overwrite the 100 MW requirement based on projected wind performance on an hourly basis. If the wind resource undergoes planned maintenance or repowering and planned

derates the facility to 80 MW ICAP for an entire Season, they will need to replace ZRCs when outages in a Season exceed 31 days since derate ICAP (must offer requirement – derates of facility 100-80=20MW) is greater than zero, and the amount of ZRCs to be replaced will be in SAC/ZRC terms. The original ICAP is 100 MW which resulted in 20 MW SAC, the resource is on a derate of 20 MW down to 80 MW, thus resulting in only 4 ZRCs needing replacement. 20 MW SAC / 100 MW ICAP = 20%, 20MW derate ICAP *20% = 4ZRCs. To complete the example, 80 MW ICAP*20% = 16 MW SAC. The cleared SAC obligation is 20 ZRCs, and the derate results in 16 ZRCs, therefore 4 ZRCs must be replaced, or charges assessed for any days over 31 in that Season.

$$\frac{20\ ZRC}{100\ ICAP} = 20\%\ Original; 20MW\ ICAP\ derate * 20\% = 4\ ZRC$$

Similarly, for conventional resources the conversion process is the same. For example, a 100 MW ICAP thermal resource has 50 MW SAC, if they clear all 50 ZRCs in the auction for that Season the must offer obligation is still 100 MW. If the resource is derated to 80 MW, the ZRCs needing to be replaced will be: 80 MW *50% = 40 MW, with a 50 MW SAC obligation, so 10 ZRCs would need to be replaced or charges assessed when the outage exceeds 31 days within that Season.

For resources that are completely offline due to planned or reasonably known outages for greater than 31 days, the penalty would be assessed on the cleared ZRCs of that resource, regardless of resource type. The CRNCC would be charged to the asset owner who converted SAC to ZRCs.

6.4.2 Attachment Y Retirement or Suspend Status

A Planning Resource used to meet seasonal RAR must be replaced by the registering Market Participant prior to the effective date of a status change to ‘retired’ or ‘suspend’ via an Attachment Y filing.

6.4.3 Transfer of Resource Adequacy Requirement and Performance Requirements through ZRC Replacement

ZRC replacement is available for use by Planning Resources that cleared a Season in the Planning Year and that go on suspension, retirement, catastrophic outage, ICAP Deferral, or that experience a Generator Planned Outage or derate greater than 31 days in that Season. Planning Resources already on a forced outage or knowingly offline during the effective date, cannot be used for ZRC Replacement. ZRC replacements are not allowed for any other reason.

In the event of such ZRC Replacement any performance requirements associated with the Resource that is being replaced (e.g., must offer obligation) will be transferred to the substituting Resource(s) for the duration of the ZRC Replacement period. ZRC Replacement is forward looking, MPs cannot replace ZRCs retroactively.

A Resource being used for ZRC replacement must not be on a full or partial Generator Planned Outage during the term of the ZRC replacement and must otherwise meet the applicable performance requirements set forth in section 69.A.3.1.h of Module E-1 of the Tariff.

6.4.4 ZRC Replacement Transactions

Replacement transactions in each Season can be entered at any time during the Planning Year and, unless otherwise modified, are valid through the end of the applicable Season within the Planning Year.

Replacement ZRCs may be sourced from any LRZ or ERZ subject to LCR, CIL, CEL, SREC, and SRIC constraints from the associated seasonal PRA. A replacement calculator is available in the MECT to check for any constraint violation. Planning Resource replacement transactions should be entered into the MECT tool at least seven (7) Calendar Days prior to effective date of replacement to ensure it has been entered and validated properly. This ensures adequate time for MPs and MISO staff to review and confirm accurate and proper entry of the ZRC replacement.

Replacement ZRCs can be from the Market Participant's own Planning Resources or ZRCs procured through a bilateral transaction from another Market Participant in the same seasonal auction These ZRCs can be sourced from other LRZ's provided they do not violate any LCR, CIL, CEL, SRIC or SREC. ZRC replacements from LRZs other than the original resource will be processed in accordance with the following parameters:

- ZRC replacement shall be processed on a first come, first served basis.
- The amount of cleared seasonal ZRCs in each LRZ at the time of a ZRC replacement shall be based upon the current amounts of cleared seasonal ZRCs, including any previous replacement transactions.

Replacement ZRCs should be input in the MECT with an intended effective date. The termination date of a Replacement ZRC transaction will be set as end of the Season by default. Market Participants can update the termination date to a different date before end of the

Season, provided that replacement capacity must be designated for RAR until at least 95% of its ZRCs have been replaced.

ZRC replacement shall have no impact on settlements from the PRA and FRAPs and RBDC Opt Out. The “Replacement Calculator” option is available in the MECT which can be used for verifying if the Planning resource being used for the replacement will meet all of the required LRZ parameters including LCR, CIL and CEL, as well as ERZ CEL.

6.4.5 On Ramping New Resources Mid-Planning Year for ZRC Replacement

If a new resource is expected to be available at the start of a Season within the Planning Year, the preferred course for the Market Participant would be to enter the ICAP Deferral process.

However, if a new resource is unable to utilize the ICAP Deferral Process, the new resource may be eligible to receive uncleared Zonal Resource Credits (ZRCs) in the middle of the Planning Year and prior to the start of a Season only under the following conditions:

i. Market Participant must coordinate with the IMM to obtain confirmation the new resource did not physically withhold capacity from a particular seasonal auction.
ii. The new resource must be in Commercial Model at time of request.
iii. The new resource must submit applicable testing (i.e. GVTC into MISO PowerGADS or Non-GADS Performance Template into MECT, DR tests, etc.).
iv. The new resource must become commercially operable as of date of replacement.
v. Requests must be submitted at least 3 weeks prior to start of replacement.
vi. If the new resource is an LMR no part of the Behind-The-Meter Generation (BTMG) or Demand Response (DR) assets can have been previously registered for the Planning Resource Auction by the registering Market Participant.
vii. If the new resource is an ARC LMR the contract with the customer/asset must have been signed after the March 1 Registration deadline.

6.4.6 MECT ZRC Replacement Calculator

The Replacement Calculator screen in the MECT is used to help MPs assess whether the ZRCs being used for the replacement will meet all of the required parameters including seasonal LCR, CIL, CEL, SREC, and SRIC.

For each Local Resource Zone, the Replacement Calculator screen displays the seasonal Final PRMR, LCR, CIL, CEL, sum of cleared Offers, sum of FRAP and sum of RBDC Opt Out, , Total Import and Total Export for each LRZ, and Total Export for each ERZ from the seasonal PRA.

Import Available and Export Available numbers are updated each time the Resource Replacement process is completed.

- Import Available number represents the maximum ZRCs allowed to import into the LRZ without violating the CIL in that Season. Import Available for the LRZ is calculated as:
  Seasonal Import Available = CIL – Total Import from PRA + (Sum of all Export* - Sum of all Imports*)
- LRZ Export Available number represents the maximum seasonal ZRCs allowed to export out of the LRZ without violating the CEL. Export Available for the LRZ is calculated as:
  LRZ Export Available = CEL – Total Export from PRA + (Sum of all Import - Sum of all Exports*)
  ERZ Export Available represents the maximum ZRCs allowed to export out of the ERZ without violating the CEL. It is calculated as: ERZ Export Available = ERZ CEL – ZRCs cleared, including FRAPs and RBDC Opt Out, in ERZ

Example:

LRZ 1 has an LCR of 15,070 MW; and Import Available of 4,628.7 MW
LRZ 2 has an Export Available of 1,023.7 MW
LRZ 3 has an Export Available of 1,759.4 MW
ERZ 1 has an Export Available of 1,000 MW

Total MW needing replacement in LRZ 1: = 200 MW (Original Resource = AAA1)

Replacement ZRCs from LRZ 1: Of that 200 MW, 100 MW will be replaced by other Planning Resources located in LRZ 1 (Substitution Resource = AAA2)

ZRCs in LRZ 1 (after same LRZ replacement): LRZ 1's total ZRCs from LRZ 1 after replacement = Offers Cleared + FRAP +RBDC Opt Out - Total MW needing replacement + Replacement ZRCs from the same LRZ = 18,522.3 – 200 + 100 = 18,422.3

LCR Test: Since 18,422.3 > LRZ 1's LCR of 15,070, the LCR Test result is "Pass"

Amount Exported: Remaining Replacement ZRCs of 100 MW are imported from LRZ 2 and LRZ 3:

o LRZ 2's Exported ZRCs = 40 MW (Substitution Resource = BBB3)
o LRZ 3's Exported ZRCs = 60 MW (Substitution Resource = CCC4)

Import Test: LRZ 1's total Imported ZRCs = 100 MW (40 MW + 60 MW). Since 100 MW < Import Available of 4,628.7, the Import Test result is "Pass"

Export Test: Since LRZ 2's Export of 40 MW < Export Available of 1,023.7 MW and LRZ 3's Export of 60 MW < Export Available of 1,759.4 MW, the Export Test results for LRZ 2 and 3 are "Pass".

This scenario will require the following 3 separate Resource Substitution Registrations to replace AAA1 for the full amount of 200 MW in LRZ 1:

o First 100 MW of AAA1: replaced by AAA2 for 100 MW from LRZ 1
o Second 40 MW of AAA1: replaced by BBB3 for 40 MW from LRZ 2
o Remaining 60 MW of AAA1: replaced by CCC4 60 MW from LRZ 3
o No change for ERZ 1

6.4.7 Capacity Replacement Non-Compliance Charge and Distribution

Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. The charges will be applied to the asset owner that converted the SAC to ZRCs for the resource . MISO's Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions.

Capacity Non-Compliance Charge = [# days failure to comply with replacement] * [# ZRCs failed to be replaced] * [Seasonal Zonal ACP + Daily Zonal CONE]

The number of Days counted will be on an hourly basis (31 days x 24 hours = 744 hours) since outages may only cover a portion of some Days. The number of hours that failed to comply or replace will be determined by ranking generator performance across the Season and applying charges to hours with the least violations in the Season beyond 744 hours. The charges assessed will round down to the number of whole Days in excess of 31 Days. For example, 815 hours minus 744 hours and then divided by 24 hours = 2.96 Days. In this case, the penalty charged for will be for two days.

Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a pro rata basis, based upon their respective LSEs' share of total Final PRMR for the Transmission Provider Region.

6.5 LMR performance

6.5.1 BTMG Performance

When a BTMG that either is used in a seasonal FRAP or RBDC Opt Out or cleared in a seasonal PRA fails to perform during an Emergency when included in a Market Participant's Resource Deployment response to a Scheduling Instruction, the penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increases and (b) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

The revenues from charges resulting from BTMGs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation in response to a Scheduling Instruction or where the resource is claimed to be unavailable as indicated in the DSRI as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the BTMG not being available as needed during Emergency and may, if deemed appropriate, disqualify that resource from receiving ACP payments for that Planning Year. The BTMG may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the BTMG's registered availability period; or the resource has reached its registered maximum number of deployments for that Season). However, should a BTMG resource indicate availability in the DSRI at any time in any Season of the Planning Year, it is considered available in the event of an Emergency during that Season and may receive Scheduling Instructions.

In the event the same BTMG does not sufficiently respond or is unavailable, except for reasons of Force Majeure or other acceptable reasons defined in the Tariff or in this BPM on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours), the MP that registered the BTMG will be subject to the penalties described herein (if that BTMG fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above for its first performance failure, and the BTMG will no longer be eligible to receive ACP payments for the current Planning Year and for the next Planning Year.

If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or to avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

6.5.2 DR Performance

If a DR that either is used in a seasonal FRAP or RBDC Opt Out or cleared in the seasonal PRA fails to perform during an Emergency when included in a Market Participant's Resource

Deployment response to Scheduling Instructions, penalties will be calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of load reduction not achieved, including Load above the registered firm service level for those DR registered as such and (b) the LMP at the CPNode associated with the DR; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

Unless already entered as Self Scheduled for the event, DRs registered with a firm service level must still show a load reduction. Advanced Reporting should reflect the best estimate of load reduction available (i.e. load above the firm service level) during the event. Penalties will still be measured as load above the registered firm service level.

The revenues from charges resulting from DRs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction or registered firm service level or the resource is unavailable, including those circumstances where the resource is unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration is made outside the DR's registered availability period, or the resource has reached its registered maximum number of deployments for that Season). However, should a Demand Resource indicate availability in the DSRI at any time in a

Season within the Planning Year, it is considered available in the event of an Emergency during that Season and may receive scheduling instructions.

In the event the same DR is not sufficiently responsive, including being unavailable, on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours) when included in a Market Participant's response to Scheduling Instructions; except when unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM, the MP that registered the DR that was used to meet Resource Adequacy Requirements will be subject to the penalties described herein. The MP using the DR shall be assessed the same penalty as indicated above for a first performance failure, and the DR will no longer be eligible to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s).

If, in review of the DR's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as pursue other legal options at the sole discretion of MISO.

7 Integration of New LSEs

This section serves as a guide for those new Load Serving Entities (LSEs) integrating into MISO's region between the time MISO has completed the PRA(s) and the next Planning Year starts.

Once the integration date is set, MISO will work with both existing and new LSEs to ensure that the newly integrating LSEs have sufficient Planning Resources to meet their anticipated Coincident Peak Load Forecast plus an appropriate planning reserve margin.

To ensure the PRMR for new LSEs is met, MISO may conduct a Transitional PRA following the same registration requirements and auction protocols as the PRA.

MISO may provide the following when integrating new LSEs for applicable Season(s):

1. Define, as needed, new Local Resource Zone and their associated zonal parameters including:
    - Calculate CONE for the LRZ
    - Determine ZIA, ZEA, CIL and CEL

- LOLE Analysis (Section 3.4.2)
- Establishment of Local Reliability Requirement (Section 5.2.2.2)

2. Calculate Seasonal Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Seasonal Planning Reserve Margin (Section 3.4.1)
    - Review of CPD Forecasts (Section 3.2.5)
3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Auction Results Posting (Section 5.5.8)

MISO may coordinate the proper timing of the data collection effort with the new LSEs for the successful completion of the Transitional PRA. The Transitional PRA will ensure that sufficient Planning Resources are procured to meet the Final PRMR of the newly integrating MISO region for the applicable Seasons in the remaining Planning Year.

The Resource Adequacy Timeline for the seasonal PRAs is shown in Appendix K. MISO will determine the Resource Adequacy timeline for the Transitional PRA and will publish it on the Resource Adequacy webpage under the Planning Section of the MISO public website. The Resource Adequacy timeline for the Transitional PRA will be reviewed by stakeholders prior to publishing on the MISO public website.

8 Testing Procedures and Requirements

8.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J that apply for Planning Years 2011-2012 and beyond.

9 Appendices

Appendix A – Wind Capacity Credit

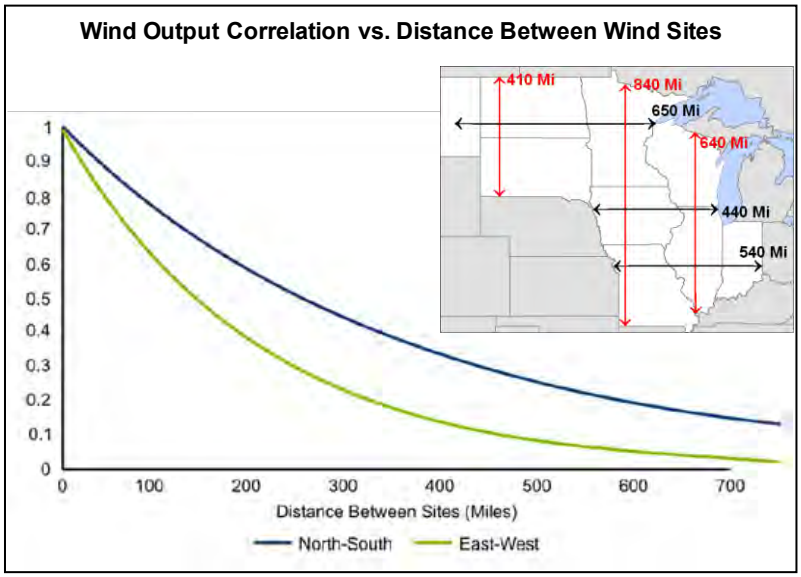
The goal of establishing wind accreditation is to estimate the reliable output of wind as a percentage of the Installed Capacity (ICAP), for each Season, for the MISO system and by Commercial Pricing Node (CPNode). The data driving wind accreditation includes the following:

- The hourly load and the hourly wind output for the sampled peak load period for each Season. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system-wide seasonal Effective Load Carrying Capacity (ELCC) of the wind fleet.
- The hourly wind output for the top 8 seasonal MISO coincident daily peak hours for the most recent 3 years' worth of operational data per Season, both for the MISO system and by individual wind CPNodes. The system-wide and individual CPNode performance and ICAP data is used to allocate the system-wide seasonal wind ELCC among the individual wind CPNodes currently in operation.
- The hourly amounts by which individual wind CPNodes are dispatched downward are part of Dispatchable Intermittent Resources (DIR) activity in the market. Non-DIR resources are not required to submit Day-Ahead Energy Market offers—subsequently, curtailments are only considered for DIR wind resources that do offer into the Day-Ahead Energy Market.

Since 2009, MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO wind accreditation process, as developed and vetted through the MISO stakeholder community, consists of a two-step method. The first step utilizes a probabilistic approach to calculate the MISO seasonal system-wide ELCC value for all wind resources in the MISO footprint. The second step employs a deterministic approach using unit-specific metrics to allocate the single seasonal system-wide ELCC value across all wind CPNodes in the MISO system, resulting in an individual wind capacity credit for each wind node in operation for the sampled peak load period for each Season.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process

needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. For each upcoming Planning Year, the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the increasing integration of new resources into the system. The sections of this appendix and current results illustrated here are broken down to provide an example detailing the two-step method adopted by MISO for determining wind accreditation from the 2012-13 Planning Year.



Step-1: MISO System-Wide Wind ELCC Analysis

Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as one year is the period for which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being

served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one “with” and one “without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) annual LOLE criteria.

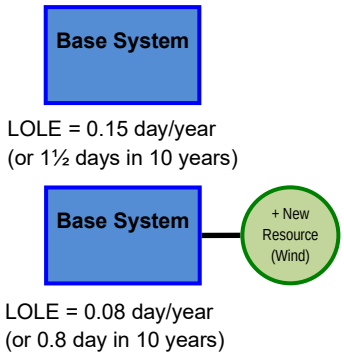


Figure 1: Example System “With” and “Without” New Resource

With each case being at the same reliability level, as shown in Fig. 2, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. This number may be divided by the ICAP of the new resource and then expressed in percentage form. ICAP for a wind resource is defined as the lesser of a wind resource’s Maximum Output as it is registered in the Commercial Model and its total Interconnection

Service. The new resource in the ELCC example Fig. 2 has an ELCC of 30 percent of the resource's nameplate capacity, assuming nameplate capacity is equivalent to ICAP.

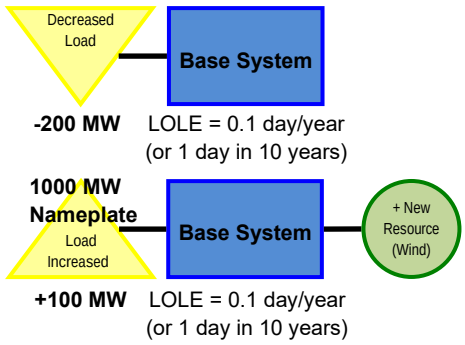


Figure 2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 2 was utilized as the analytical approach for the determination of the seasonal system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied, there were two types of cases analyzed: cases with and cases without the wind resources included in the model. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. [2]

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology, MISO uses an LOLE model capable of sequential Monte Carlo simulation to calculate LOLE values with and without the wind resource modeled. This analysis primarily considers three major inputs:

- Generator Forced Outage Rates (EFORd)
- Actual Historic Hourly Load Values
- Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These EFORd are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system.

To incorporate historical performance, the actual historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic seasonal ELCC values for the wind generation in the MISO on a system-wide basis.

Step-2: Wind Capacity Credit by CPNode Calculation

Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system, a deterministic approach involving a historic-period metric is used to allocate the system-wide seasonal ELCC values of wind to all the registered and in-service wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPNode locations, because location relates to deliverability due to possible congestion on the transmission system in the MISO market. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance are valuable inputs in determining the tradeoffs between constructing wind facilities in high-capacity factor locations, that in the case of the MISO system are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The fleet-wide wind ELCC value (%) for a particular Season multiplied by the total ICAP for registered and in-service wind resources results in the total seasonal fleet-wide allocatable wind accreditation (MW). The total seasonal fleet-wide wind accreditation is then allocated to the applicable wind CPNodes in the MISO system.

Allocation considers the historic output, both in terms of with and without curtailments, for each wind CPNode over the top 8 daily peak hours for each Season included in the analysis. A capacity factor for each CPNode during all historical daily peak hours is represented in the Wind CPNode Equations contained in this appendix by "$PKmetric_{CPnode}$" for a particular CPNode, which is also referred to as the peak performance capacity factor.

This peak capacity factor for each Season is calculated using two methods:

- one method includes (adds back in) megawatts of a wind resource that were curtailed
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two methods above, for each individual resource, forms the basis for allocating the total seasonal fleet-wide wind accreditation to the CPNodes.

New wind CPNodes that do not have sufficient historic output data will receive the seasonal fleet-wide wind capacity credit percentages applied to their ICAP as their default seasonal capacity accreditation for their first year in operation.

Tracking the top 8 daily peak hours in a Season is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $PKmetric_{CPnode}$ over multiple years.

Wind CPNode Equations

The relationship of the wind accreditation to a CPNode's ICAP and Capacity Credit (%) is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{ICAP}_{\text{CPNode n}} \times (\text{Capacity Credit \%})_{\text{CPNode n}} \quad (1)$$

Where $ICAP_{CPnode\ n}$ = Installed Capacity of the wind facility at the CPNode level.

The right most term in equation (1) above, the $(\text{Capacity Credit \%})_{CPNode\ n}$, can be replaced by the expression (2):

$$(\text{Capacity Credit \%})_{\text{CPNode n}} = \text{K} \times (\text{PKmetric}_{\text{CPNode n}}\%) \quad (2)$$

Where "K" for was found by obtaining the PKmetric at each CPNode over the time period, and solving expression (3):

$$K = \frac{ELCC}{\sum_{1}^{n} (ICAP_{CPNoden} \times PKmetric_{CPNoden})} \quad (3)$$

This results in the sum of the Wind Capacity Rating (MW) calculated for the CPNodes approximately equal to the total fleet-wide seasonal wind ELCC.

References

[1] Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-85, no. 8, pp. 910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; "Capacity Value of Wind Power," Power Systems, IEEE Transactions on, vol. 26, no. 2, pp. 564-572, May 2011

Appendix B – GADS Events Outside Management Control (OMC Codes)

There are a number of outage causes that may prevent the Energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. Such outages include (but are not limited to) ice storms, hurricanes, tornadoes, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated a list of OMC codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

GADS Cause Codes Outside Plant Management Control (OMC)

3600	Switchyard transformers and associated cooling systems – external
3611	Switchyard circuit breakers – external
3612	Switchyard system protection devices – external
3619	Other Switchyard equipment – external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st Substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st Substation (see code 9300 if applicable)
9000	Flood
9001	Drought
9010	Fire, not related to a specific component
9015	Pandemic
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9031	Tornado
9035	Hurricane
9036	Storms (ice, snow, etc.)
9040	Other catastrophe

9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels
9132	Wet Fuel – Biomass
9135	Lack of water
9139	Ground water or other water supply problems
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low Btu coal due to low BTU vane of coal not expected (Outside Management Control)
9260	Low Btu oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiative
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9520	Oil spill in Gulf of Mexico
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

Appendix C – Registration of Energy Efficiency Resources

Energy Efficiency	
Registration Requirements	**Explanation**
Name	Enter the name of the Energy Efficiency Resource
Plan Year	The Auction you are registering your Energy Efficiency Resource for displays in this field.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this Energy Efficiency Resource is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this Energy Efficiency Resource is located.
Documentation	Attach supporting documentation.
Program Information	Indicate if this is a new program or previously registered program.
Program Inception Auction	Select auction program began
Program Name	Name of program that is being registered.
Added Capability	Enter MW capability of program for given Auction
Total Capability	Total cumulative MW capability of program.
Eligible Capability	Sum of MW capability of 4 most recent Planning Years.
Forecast Capability	Total Capability minus Eligible Capability.
Energy Efficiency Capability at MISO Peak	MW value of program at MISO Peak.
Certify that registrant possesses ownership or equivalent contractual rights	Indicate whether registrant has all necessary rights to register this resource.
Comments	Submit any comments for this registration.

Appendix D – Registration of DRs

Demand Resource (DR)	
Registration Requirements	**Explanation**
Auction	The Season(s) in the PY you are registering your DR for displays in this field.
Name	Enter Name of the DR.
Description	Enter type of resources, additional names, and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this DR is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this DR asset is located.
Load Zone CP Node	Enter the CP Node where the DR asset is located.
CP Node Override	Check box if the Load Zone CP Node and Asset Owner combination that is needed, is not in the dropdown. MECT would allow then any Load Zone CPNode to be selected for any Asset Owner, assigned to the MP.
Aggregate Retail Customer (ARC)	Check box if resource registered as an ARC and fill out appropriate account and address information.
Retail Choice	Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer.
Accreditation Method	Choose accreditation method and attach supporting documentation.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource limited by any relevant regulatory or contractual restrictions.

Demand Resource (DR)	
Registration Requirements	**Explanation**
	Seasonal values shall be provided beyond the 2-year monthly window. Provide seasonal (Summer and Winter) MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of the DR. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this DR	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO Emergency. If other selected, please describe in box.
Exclude Season	Check this box to exclude the registration from participation in the specified Season.
Capability at MISO Peak	Enter MW capability being registered at MISO's Seasonal Peak.
DRR Registered	Check box if resource is registered as a DRR. If yes, select the name of the DRR CP Node.
Emergency Demand Response (EDR)?	Check box if DR registered as an EDR. If yes, select the name of the EDR resource.
Load Control Method	Select if load is direct control or interruptible load.
Max Interruptions	Select the max interruptions for the resource.
Max duration (hours)	Select the max duration for the resource.
Notification	Enter the notification time required for this DR. Notification time(s) must cover all hours and cannot be more than 6 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop

Demand Resource (DR)	
Registration Requirements	**Explanation**
	with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300).
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on DR Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix E – BTMG registration

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Auction	The Season(s) within the PY you are registering your BTMG for displays in this field.
Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this BTMG is located displays once the Asset Owner and LBA is selected, and the registration is saved.

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Local Balancing Area (LBA)	Select the LBA where this BTMG asset is located.
Load Zone CP Node	Enter the CP Node where the BTMG asset is located.
Documentation	Add supporting documentation as necessary.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can inject in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions. Summer and Winter values shall be provided beyond the 2-year monthly window for levels associated with the amount of MW you can inject in the given Summer and Winter Season consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this BTMG	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO declared Emergency. If other selected, please describe in box provided.
Exclude Season	Check this box to exclude the registration from participation in the specified Season
Generators	Select the name of the Generator(s)
Wind Capacity Factor %	If a wind unit is selected, the Wind Capacity Factor will be displayed.
Transmission Loss %	Indicates the Transmission Loss % to be applied to the UCAP calculation based on the LBA selected.
Capability at MISO Peak	Indicates the calculated MW value for the BTMG resource based on its GVTC

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
XEFORd	Displays the XEFORd to be applied in the UCAP calculation for the BTMG resource. If multiple Generators are selected, this field will display the weighted average XEFORd.
Emergency Demand Response (EDR)?	Check box if BTMG registered as an EDR and if yes, select the name of the EDR resource
Max Interruptions	Select the maximum interruptions for the resource
Max Duration (hours)	Select the maximum runtime hours for the resource
Startup notification time details (in hours)	Enter the notification time required to deploy this BTMG. Needs to be no more than 6 hours and cover all hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on BTMG Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix F – External Resources

External Resources	
Registration Requirements	**Explanation**
Name	Enter name of the External Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
BER/COR	Indicate if this Resource is a Border External Resource or Coordinating Owner Resource by checking this box.
Auction	The Season(s) in the Planning Year you are registering the resource for displays in this field.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Load Zone CP Node	Select the required Load Zone CP Node where this Resource is serving load.
Local Balancing Area (LBA)	Select the LBA where the External Resource sinks within MISO.
Local Resource Zone (LRZ)	Indicates the Local Resource Zone where the load served by this resource is located.
Ownership	Indicate if the External Resource is directly owned or from a PPA.
Entitled Capacity	Enter MW value the Market Participant can register.
PPA Type	Select whether PPA MWs are defined in MISO ICAP or UCAP.
Generator	Select name of GADS or Non-GADS Generator.
Ownership Share Type	Select Megawatt or Percent to indicate how much capacity corresponds to the registration.
External Balance Area where Resource are located	Enter Balancing Authority where the resource is physically located.

External Resources	
Registration Requirements	**Explanation**
Capacity at MISO Peak (Calculated)	The amount of seasonal capacity on a megawatt basis corresponding to the registration in terms of NRIS and ERIS.
Interface CPNode	Select Interface Load Zone CPNode.
XEFORd	The seasonal forced outage rate associated with the Generator(s) from GADS, excluding Outside Management Control (OMC) events. Can be overridden by the Market Participant.
NERC Regional Entity	Select NERC Regional Entity where the resource is located.
Use-Limited Resource Qualification	Indicate if this resource meets all Use Limited Resource qualification requirements.
Diversity Contract	Indicate whether this resource is part of a Diversity Contract exchange.
IDC Name	Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement.
Documentation	If Resource is not owned directly, attach supporting PPA or other pertinent documentation here.
Firm transmission to the MISO Border	Input effective date and OASIS reservation number and select Transmission Provider.
Firm transmission within the MISO Transmission System	Input effective date and OASIS Reservation number.
Have you accepted the terms and conditions of the MISO Tariff ?	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this Resource.
Have you notified the host BA?	Indicate if you have contacted your host BA of this registration.
Will this External Resource be used exclusively as a Capacity Resource for MISO?	Indicate that you certify that this External Resource is being used as a Capacity Resource exclusively for MISO.
Is this External Resource available the entire auction?	Indicate if this External Resource is available for the entire Season within the upcoming Planning Year.

External Resources	
Registration Requirements	**Explanation**
Have all other requirements been met?	Indicate if all other requirements have been met.
Resource Operator Contact Name (24x7)	Enter who to contact for deployment of External Resource. The contact should be available 24x7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24x7)	Enter phone number for 24x7 operator.
Resource Operator Contact Email (24x7)	Enter email address for 24x7 operator.
Season(s) registration is being submitted for	Summer ☐ Fall ☐ Winter ☐ Spring☐
Comments	Submit any comments for this registration.

Appendix G – Reliability Based Demand Curve

Overview

The key features of the Reliability Based Demand Curve include:

- Target point defined by: (a) x-axis centered on MISO's reliability requirement at a loss of load expectation (LOLE) of 0.1 days per year; and (b) y-axis centered on the estimated Net CONE that would be needed to attract new resources. This target point reflects the central concept that price levels must be consistent with achieving system reliability objectives.
- Curve proportional to incremental reliability value, such that prices decline with increasing quantities of capacity, and such that pricing levels are rationalized against reliability risk across each of the four seasons.
- Price cap at 1 × Cost of New Entry (CONE, or Gross CONE) in each season, and 4 × CONE in total across the four seasons.

RBDCs are developed for the entire MISO system as well as for the two subregions (North/Central & South) of the MISO system, utilizing the same reliability-based concept. The demand curves for the subregions will reflect the additional reliability value that capacity resources can contribute by being located in a subregion with more acute reliability needs than the broader system. The total reliability value (and price) awarded to capacity in a particular subregion will reflect the sum of its contribution to avoiding system-wide reliability events (reflected in the system-wide RBDC) plus its contribution to avoiding additional reliability events that would occur in the subregion (reflected by the subregional RBDC).

In total, MISO utilizes twelve (12) RBDCs for any particular Planning Year: four (4) seasonal curves for the system-wide RBDC, four (4) seasonal curves for the North/Central subregion, and four (4) seasonal curves for the South subregion.

RBDCs are drawn in proportion to reliability value at each quantity point and are drawn through the target point at the reliability requirement and Net CONE.

System-wide Reliability Based Demand Curves

The system-wide RBDC is defined in proportion to system-wide Marginal Reliability Impact (MRI), which is measured as avoided Expected Unserved Energy (EUE), or the reductions

to load shedding that would be achieved by adding one more MW of perfect capacity (or UCAP) to the system. This is derived from the seasonal Loss of Load Hours (LOLH) predicted at a specific quantity of supply, and the observation that 1 MW of perfectly-available UCAP supply would have avoided 1 MW-hour of outages across all of the simulated events. Mathematically, MRI is defined as:

MRI = Avoided EUE from Incremental Capacity = LOLH x 1 MW UCAP

Where:

- MRI (MWh per UCAP MW) is the incremental reliability value of adding 1 UCAP MW of capacity to the system.
- Avoided EUE (MWh per season) is the reduction in expected involuntary load shedding caused by adding incremental capacity.
- Incremental Capacity (UCAP MW) is the volume of perfectly-available capacity added.
- LOLH (hours per season) is the number of shortage hours predicted in reliability simulations across the season in question, in correlation with a specific quantity of UCAP MW available in that season.

To calculate MRI as a function of capacity, MISO utilizes the same resource adequacy model used in the determination of resource adequacy Requirements.

MRI curves are convex and monotonically downward-sloping, reflective of the declining marginal reliability value of capacity when supply is abundant, as well as the increasing marginal reliability value of capacity when supply is scarce. MRI is calculated above and below the reliability requirement by first establishing the supply quantity at which the system achieves the reliability target, and then adding/subtracting perfectly-available UCAP MW (in equal increments of no less than 50 MW and no more than 250 MW) to determine the marginal reliability value of the incremental capacity.

EUE is calculated at consistent variances in incremental and decremental amounts of capacity in the model for each season. The starting point for the seasonal MRI curves is the amount of capacity (in terms of UCAP) that results in the LOLE criteria corresponding with the demonstrated risk for each season. The Monte Carlo modeling for the system-wide MRI curve is copper plate, which assumes no internal transmission limitations within the MISO system.

Subregional Reliability Based Demand Curves

The development of subregional MRI curves follows the same process used for developing the system-wide curves—however, with the addition of bi-directional subregional transfer limits in the resource adequacy model that exists between the two subregions.

The starting point for each subregion's MRI curve is the PRMR from the system-wide analysis. Decrease/increase capacity in one region and simultaneously increase/decrease capacity in the other by the same amount and record reliability metrics for each region individually and MISO as a whole.

Subregion-specific Net CONE values are used to calculate subregional scaling factors, which are multiplied by the subregional MRI curves in each season to calculate the subregional RBDCs. Subregional RBDCs reflect the additional reliability value associated with capacity that can avoid reliability events that occur only in that subregion due to import limits, but that are not experienced system-wide.

Beyond the import capability, only capacity located in that subregion can help to avoid those localized shortfall events, so the incremental reliability and pricing value awarded would only apply to local capacity resources. The subregional RBDCs are calculated considering only local outage events, not considering system-wide outage events that are driven by system-wide supply shortfalls. Therefore, the subregional RBDCs are defined as additive in nature to the system-wide RBDCs.

The role of the system-wide demand curve is to signal the value of adding more capacity in total in MISO, regardless of where it is located. The role of the subregional RBDCs is to signal where within the system capacity is most needed (and where additional capacity cannot be as effectively utilized).

The steps for calculating subregional RBDCs include:

1. Initialize the resource adequacy model with each subregion at a target of 0.1 days per year: Beginning with the system-wide resource adequacy model, apply subregional transfer limits. Then subtract capacity in each season until each subregion is at a minimum seasonal LOLE criteria of 0.01 days/season for seasons demonstrating minimal risk. This reliability target reflects the subregional interpretation resource adequacy criteria in the MISO Tariff used as the basis for setting starting points in the subregional RBDCs.

2. Calculate Subregional Seasonal resource adequacy metrics Across Reserve Margins for Each Subregion: From this starting point, add (or subtract) perfectly-available UCAP MW
   capacity to the subregion in each season. Adding capacity to the system and the relevant subregion and observing the change in LOLE, LOLH, and EUE measures the incremental value of locating capacity in that region. When the subregion in question becomes highly import-dependent, events in that subregion will become large (even though the broader system will maintain similar levels of reliability). When the region becomes a large exporter of capacity, local events will drop to zero (even though system-wide events will not drop to zero given that the maximum capacity limit will be enforced more often and local excess supply will not be possible to export in all cases).
3. Calculate Seasonal Subregional MRI Curves: The subregional MRI curve has a somewhat different meaning as compared to the system-wide MRI curve, in that the subregional MRI curve aims to measure the additional value achieved by locating capacity within a particular import-constrained region (beyond the value already reflected by the system-wide curve). Subregional MRI will be positive when the region is import-constrained and zero when the subregion has excess capacity. Therefore, the MRI curve for each subregion is first calculated as the total MRI including both system-wide and subregional events (the direct model result), and then the share of system-wide events is subtracted out. The resulting MRI curve reflects subregional events only.
4. Calculate the Subregional Scaling Factor: Calculate the subregional scaling factor from the subregional Net CONE value, divided by the subregional MRI at a quantity consistent with the resource adequacy target LOLE of 0.1 days/year from Step 1.
5. Calculate Seasonal Subregional RBDCs: Calculate the RBDCs for capacity in each subregion based on the MRI curve times the Subregional Scaling Factor from Step 4. The
   resulting subregional RBDC will produce a positive price whenever the subregion is anticipated to be import constrained during times of potential shortage, and incremental capacity in that subregion would help to alleviate the shortfall.

Translating MRI Curves to RBDC

Translating the MRI curves (in units of incremental EUE per MW) into a capacity demand curve (in units of dollars per MW-day) requires a system scaling factor. The system scaling factor is calculated so as to support annual average prices at annualized Net CONE when the system is at the annual LOLE requirement of 0.1 days/year. If more than one season shares a meaningful portion of the LOLE risk, the LOLE risk could be summed from the estimated values across 2–4 seasons. Mathematically, system scaling factor is defined as:

System Scaling Factor = Average System Annual Net CONE ÷ System MRI @ 0.1 LOLE

Where:

- System Scaling Factor ($/MWh) is the payment rate at which the system-wide Reliability Based Demand Curves would incentivize investment in additional supply.
- System Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net
  annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a system-wide basis.
- System MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a system-wide copper-sheet basis (i.e., without considering transmission constraints) when the system is at the annual LOLE requirement of 0.1 days/year.

The prices on all the curves are derived by multiplying the MRI curves by the uniform system scaling factor (in $/MWh of EUE avoided) given by the annual break-even revenue requirement from the capacity market at the LOLH corresponding to a LOLE of 0.1 days/year.

Once the System Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. These four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces
greater variability and uncertainties in outage and resource availability risks may also produce a
somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Similar to System Scaling Factor, scaling factor to scale subregional MRI curve is determined as follows.

Subregional Scaling Factor = Average respective subregion Annual Net CONE ÷ subregional MRI @ 0.1 LOLE

Where:

- Subregional Scaling Factor ($/MWh) is the payment rate at which the Subregional Reliability Based Demand Curves would incentivize investment in additional supply.
- Subregional Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a subregional basis.
- Subregional MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a subregional basis when the system is at the annual LOLE requirement of 0.1 days/year.

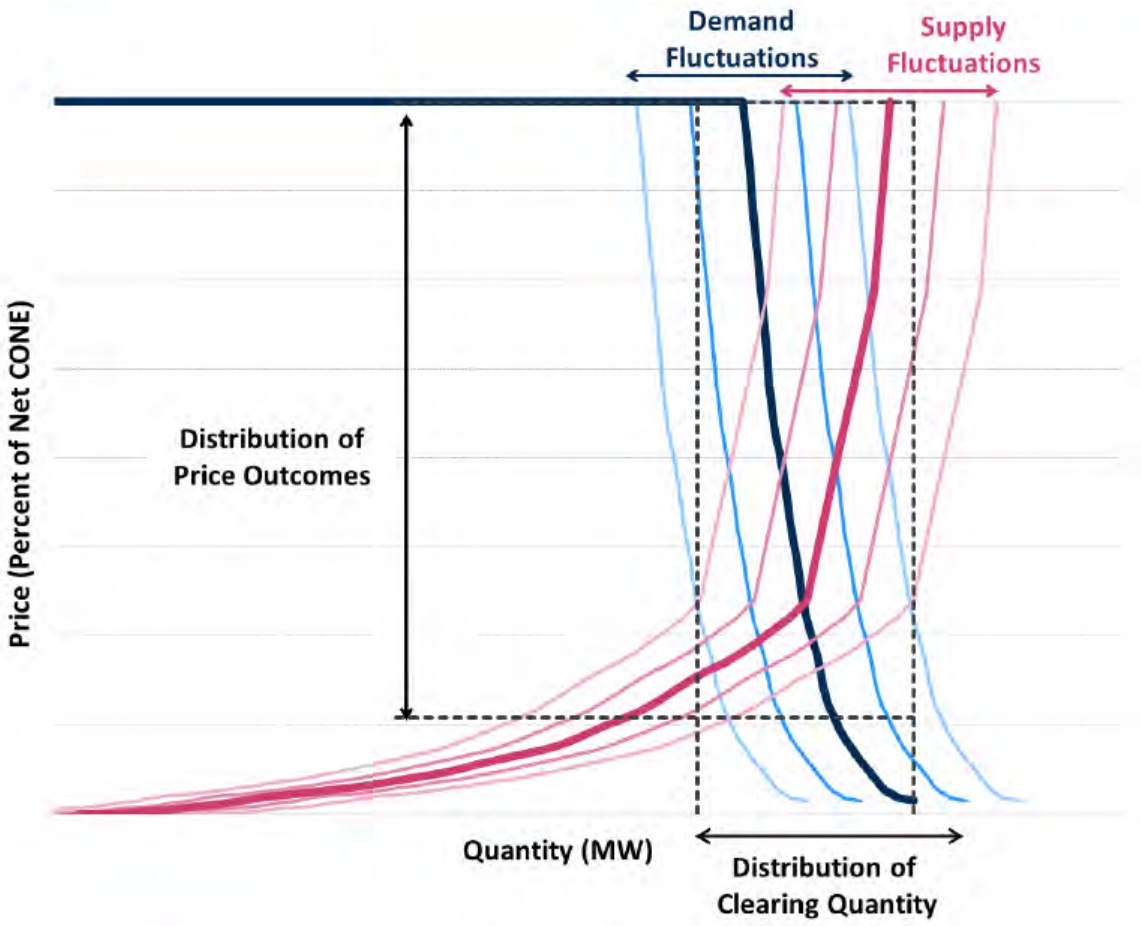
Once the Subregional Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. On subregion basis, these four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces greater variability and uncertainties in outage and resource availability risks may also produce a somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Long-run Equilibrium Analyses

Monte Carlo simulations are performed on supply curves and potential RBDCs to assess the achievement of long-run equilibrium conditions where the objective is for the average of all seasonal prices to be equivalent to Net CONE. Seasonal ACP and supply quantity outcomes are modeled in the simulations to account for variability in supply curve shapes, supply quantity, demand quantity, and opt out quantity. All model inputs are derived from historic MISO market data. Long-run equilibrium analyses should result in an expected distribution of price, quantity, and reliability outcomes that, when compared to the design objectives of RBDC, achieve the reliability objectives, produce better capacity market price signaling, and accurately recognize the reliability value of incremental capacity.

The long-run equilibrium analyses involve separate Monte Carlo simulations and will be performed every three (3) Planning Years.



In-market supply curves consist of three (3) component pieces:

6. Price Offers: supply offers at prices above zero, shape based on historic MISO offer curves, and independent of demand curve shape.
7. Year-to-Year Variability in Supply: zero-priced supply block, quantity varies with each draw to generate variability in supply offers, and tuned to true historic availability in supply.
8. Market Entry and Exit: zero-priced annual supply block with seasonal capacity ratings proportional to a combustion turbine reference resource, quantity varies across draws so that the average of seasonal clearing prices across all seasons is equal to the annual net CONE.

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources

The following sets of equations establish how the SAC values (NRIS SAC, including E-NRIS SAC, and ERIS SAC) are determined for Planning Resources to account for resource performance and availability. Schedule 53 resource accreditation is outlined in Appendix Y.

H.1 Planning Resource SAC calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on MISO's Transmission System

The Seasonal Accredited Capacity (SAC) calculation is based on resource type and volume of seasonal Interconnection Service, seasonal GVTC, and seasonal forced outage rate (XEFORd).

H.1.1 Planning Year SAC Calculation for each Season

The following steps are used to calculate NRIS SAC and ERIS SAC for each Planning Resource.

Determine ICAP:

The first step is to determine the Installed Capacity (ICAP) that the Planning Resource can reliably provide, which is equal to the lesser of its GVTC or its total volume of Interconnection Service (Network Resource Interconnection Service and/or Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$ICAP = \begin{cases} Total\ Interconnection\ Service,\ If\ GVTC > Total\ Interconnection\ Service \\ GVTC,\ If\ GVTC \leq Total\ Interconnection\ Service \end{cases}$$

Determine Total SAC:

The next step is to convert the resultant ICAP value into a Total SAC value by applying its seasonal forced outage rate (XEFORd).

A forced outage rate class average for each Season is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a forced outage rate specific to the Planning Resource. A

Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

$$Total\ SAC = ICAP \times (1 - XEFOR_d)$$

If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated Total SAC will be zero.

If the Planning Resource does not report historical outage data to GADS, its historical performance during seasonal peak hours should be provided to MISO through the Non-GADS Performance Template, which will leverage prior performance to establish seasonal GVTC values indicative of typical seasonal capabilities. In this case, XEFORd would not be used to reduce Total SAC. This process excludes Demand Response Resources.

Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:

The Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC.

$$NRIS\ SAC = \begin{cases} ICAP * (1 - XEFORd), & If\ ICAP = NRIS \\ \big(Minimum\ of\ (NRIS, GVTC)\big) * (1 - XEFORd), & If\ ICAP > NRIS \end{cases}$$

The remaining balance of Total SAC is allocated to ERIS SAC (i.e. ERIS SAC = Total SAC – NRIS SAC.

$$ERIS\ SAC = \begin{cases} 0, & If\ ICAP = NRIS \\ Total\ SAC - NRIS\ SAC, & If\ ICAP > NRIS \end{cases}$$

Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

Effective ICAP

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service.

$$Total\ SAC\ Eligible\ for\ ZRC\ Convsersion\ = (NRIS\ SAC) + (ERIS\ SAC\ with\ TSR)^{*}$$

*Amount of TSR needed is dependent on ICAP amount

Ex	Size	NRIS	SAC	Total IS	GVTC	ICAP	Total SAC	NRIS SAC	ERIS SAC	TSR	ZRC
1	100	**100**	0	100	100	**100**	**75.0**	75.0	0.0	0.0	**75.0**
2	100	**50**	50	100	100	**100**	**75.0**	37.5	37.5	50.0	**75.0**
3	100	**50**	50	100	75	**75**	**56.3**	37.5	18.8	25.0	**56.3**
4	100	**0**	100	100	100	**100**	**75.0**	0.0	75.0	100.0	**75.0**

Examples for Illustrative Purposes

In example 3 above, a 100 MW Resource with 50 MW NRIS and 50 MW ERIS submitted a GVTC value at 75.

The ICAP will be 75 MW because the GVTC is less than the Interconnection Service of 100 MW.

Since the 50 MW NRIS is less than the Resource's ICAP, the Total SAC value of 56.3 MW of the Resource is not fully allocatable to NRIS SAC.NRIS SAC in example 3 was determined to be 37.5 MW. The remaining Total SAC minus the NRIS SAC is allocated into the resource's ERIS SAC. Thus, ERIS SAC level is 56.3 MW – 37.5 MW = 18.8 MW.

The resource would be credited with 56.3 MW of Total SAC which is comprised of 37.5 MW NRIS SAC + 18.8 MW ERIS SAC with firm Transmission Service for the corresponding seasonal PRA.

The resource was able to convert its entire Total SAC into seasonal ZRCs because the resource obtained full deliverability up to its ICAP, where 50 MW of NRIS plus 25 MW of firm Transmission Service is equal to its ICAP of 75 MW.

H.2 SAC calculation for a GADS-reporting External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource SAC calculation is based on its seasonal GVTC and seasonal forced outage rate (XEFORd). The ERIS SAC is calculated by applying its seasonal XEFORd to its seasonal GVTC.

$$ERIS\ SAC = GVTC \times (1 - XEFOR_d)$$

A seasonal forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

The ERIS SAC represents the capacity in MW that are eligible to be converted into seasonal Zonal Resource Credits with valid transmission service.

H.3 SAC calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

For resources that don't report outage data to GADS, MISO calculates the Total SAC based on the past historical season-specific output assessing either the median for Run-of-River Hydro or

average for all other intermittent resources that are not wind resources. The calculation requires a minimum of 30 consecutive seasonal days of output for a unique seasonal accreditation value. If that is not available, a class average seasonal accreditation value will be applied to the nameplate of the resource. A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

For wind resources, MISO produces an annual wind capacity credit study for every Season in the upcoming Planning Year using the Effective Load Carrying Capability (ELCC) methodology, as described in Appendix A, to determine a fleet-wide SAC value to be allocated across all in-front-of-the-meter wind resources in that Season. Deterministic allocation of the total fleet-wide wind SAC across the studied wind resources is dependent on the reliability value of the entire wind fleet (as determined through probabilistic modeling) at the aggregate level and the historical performance history of the wind resources at the unit level during specific historical MISO system Coincident Peak Demand hours.

A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

BTMG wind Resource owners are required to submit the historical performance history of their BTMG wind Resources during specific historical MISO system Coincident Peak Demand hours for the purpose of accrediting these resources with a SAC value based on their performance during periods of MISO system seasonal peak Demand for the three prior applicable years for each Season. This results in resource-specific SAC values for each BTMG wind Resource in operation.

> *BTMG Wind SAC = [capacity factor over the 8 seasonal peaks over the past 3 years] * [k] * [ICAP]*
>
> *Where k = [seasonal MISO Fleet ELCC] / Sum of [Fleet ICAP * PKmetric] (see BPM-011 Appendix A)*

New wind Resources that do not yet have historical performance history for an entire Season would receive the class average wind capacity credit for that Season (as determined by the Wind and Solar Capacity Credit study produced every year) applied to the wind Resource's ICAP to derive an appropriate Total SAC value. Please reference Appendix A for more details regarding the accreditation procedure for wind Resources.

The amount of SAC eligible to be converted into seasonal Zonal Resource Credits will be based on the application of a deliverability-adjusted capacity factor.

H.3.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on MISO's Transmission System

The following sections establish how SAC values (NRIS SAC and ERIS SAC) are determined for Intermittent Generation and Dispatchable Intermittent Resources that have a Point of Interconnection on MISO's Transmission System to account for resource performance and deliverability.

H.3.1.1 Planning Year SAC Calculation for Wind Resources

The first step is to determine the total installed capacity of the wind Planning Resource, which is the Installed Capacity (ICAP). It is equal to the lesser of its seasonal GVTC (Registered maximum output in the Commercial Model) or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to determine the resource's total SAC. MISO determines a unit-specific seasonal wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind by allocating the total fleet-wide seasonal ELCC capacity. The wind capacity credit is determined by applying the larger of two allocation methodologies, as noted in Appendix A:

- one method which includes (adds back in) megawatts for wind resources that were curtailed (applies to DIR wind resources only)
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two results becomes the individual resource's Total SAC.

$$Total\ \ SAC = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The next step is to determine how much of the total SAC is eligible to be converted into seasonal ZRCs.

The total SAC for a wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs, either convertible SAC or undeliverable ERIS SAC.

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical seasonal peak observances of an intermittent resource and is calculated by 'capping' historical intermittent output during seasonal peak load observances to the resource's demonstrated deliverable amount divided by the resource's ICAP. Whereas a peak performance capacity factor also uses the same historical seasonal peak observances divided by the resource's ICAP but does not cap those observances.

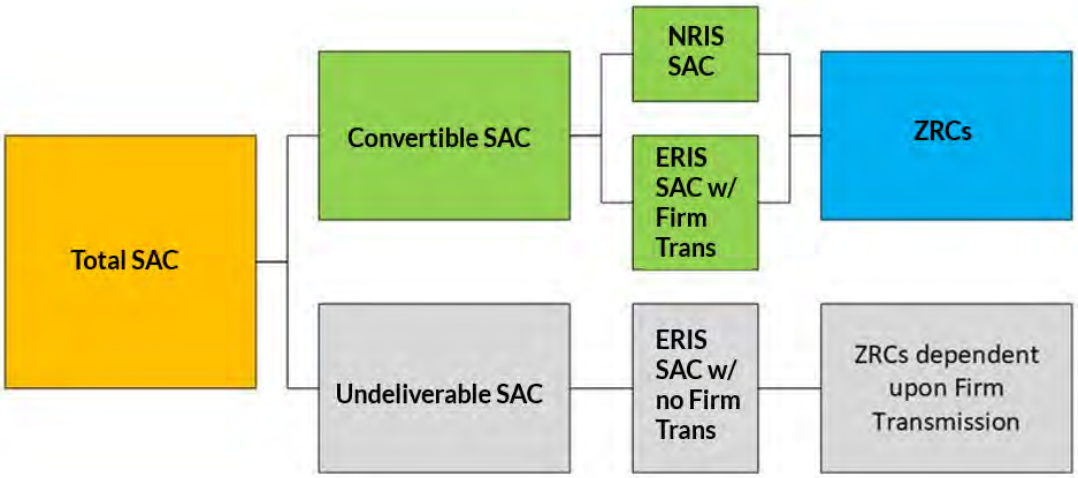
Formula for determining Convertible SAC

$$Convertible\ SAC = Total\ \ SAC * \frac{Deliverability\ Adjusted\ Capacity\ Factor}{Peak\ Capacity\ Factor}$$

The remaining Total SAC that is left after calculating Convertible SAC is considered the undeliverable ERIS SAC.

$$ERIS\ SAC = \begin{Bmatrix} 0, Total\ Interconnection\ SAC = \ Convertible\ SAC \\ Total\ Interconnection\ SAC - Convertible\ SAC, Total\ Interconnection\ SAC > Convertible\ SAC \end{Bmatrix}$$

Optionally, the classified undeliverable ERIS SAC can become eligible to be converted into seasonal ZRCs by procuring firm Transmission Service.

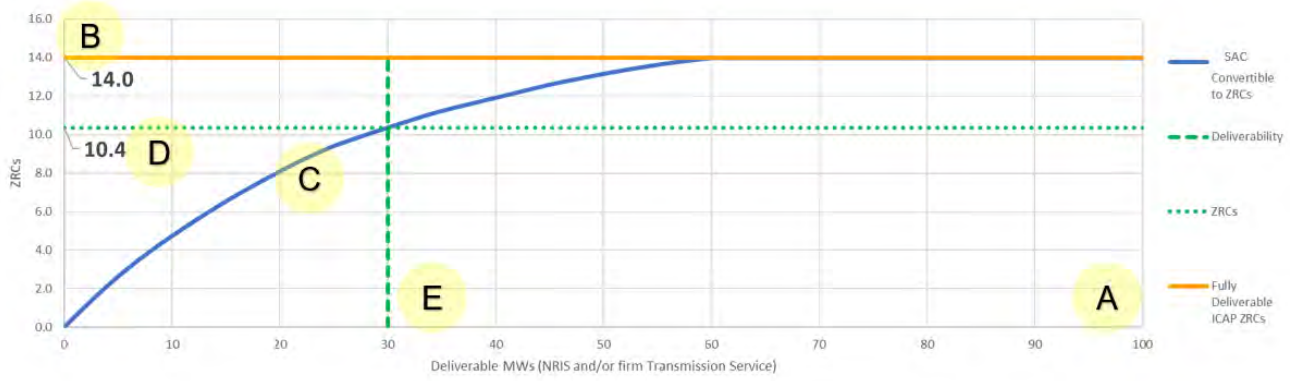


Converting ERIS SAC to Convertible SAC using the Resource's Deliverability Adjusted Historical Performance

ERIS SAC is not generally convertible to seasonal ZRCs at a one-to-one MW ratio. Each resource will have unique conversion data generated based on its past seasonal performance and deliverability which indicates the level of firm Transmission Service necessary to be obtained to gain a given level of seasonal ZRCs.

An example and further explanation is shown in the figure below:

ZRC Deliverability Curve Chart



Where:

A: Equals the maximum output of resource (RMax). In this example, this resource is 100 MW.

B: Total SAC, or SAC (Max) that can potentially be converted into seasonal ZRCs. This also represents the share of the total fleet-wide seasonal ELCC capacity. This value is based on the size and performance of the resource.

C: This is the Convertible SAC function which is the resource's Total SAC multiplied by the ratio of its Deliverability Adjusted Capacity Factor divided by its Peak Capacity Factor. Convertible SAC varies depending on the amount of Deliverability of the resource.

D: This is the resulting Convertible SAC value for a corresponding Deliverable amount in MW.

E: This is the amount of Deliverable MWs, or Deliverability. The point at which E intersects C provides the amount of seasonal ZRCs the Market Participant would obtain based on the size, performance, and deliverability of the resource.

H.3.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The first step is to determine the Total Installed Capacity that the Planning Resource can reliably provide, which is the Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to allocate the Total SAC based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be deliverable through the market transition deliverability test then that quantity will be allocated first to NRIS SAC. The remaining Total SAC will then be allocated to ERIS. If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated SAC will be zero.

$$NRIS\ SAC = \begin{cases} Total\ SAC, & Total\ SAC \leq NRIS \\ NRIS, & Total\ SAC > NRIS \end{cases}$$

$$ERIS\ SAC = \begin{cases} 0, & Total\ SAC \leq NRIS \\ Total\ SAC - NRIS, & Total\ SAC > NRIS \end{cases}$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The total SAC for an intermittent non-wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs. This would be considered Convertible SAC, either NRIS SAC or ERIS SAC coupled with firm Transmission, or undeliverable ERIS SAC (no associated firm Transmission).

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical summer peak observances of an intermittent non-wind resource and is calculated by 'capping' historical intermittent output during peak load observances to the

resource's demonstrated deliverable amount divided by the resource's ICAP. (See Appendix V for examples)

H.3.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following sections apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS SAC represents the capacity in MWs that are eligible to be converted into seasonal ZRCs.

Appendix I – XEFORd Calculation

XEFORd is equivalent forced outage rate Demand excluding events outside of management control (OMC). XEFORd will be calculated on a seasonal basis. A description and list of the MISO OMC events can be found in Appendix B. The MISO equation is:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} * 100\%$$

where:

SH = service hours
Synch Hours = synchronous hours
RSH = reserve shutdown hours

FOH_d = forced outage hours Demand = f_f x FOH
f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})}$
r = average forced outage duration = (FOH)/(# of FO occurrences)
D = average Demand time = (SH + Synch Hours)/(# of unit actual starts)
T = average reserve shutdown time = (RSH)/(# of unit attempted starts)
FOH = forced outage hours

$EFDH_d$ = (f_p x EFDH)
AH = available hours
f_p = partial forced outage Demand factor = (SH + Synch Hours)/AH
EFDH = equivalent forced derated hours

Special cases are evaluated in the following order:

If reserve hours < 1, then f_f =1,
then if (SH + Synch hours) = 0, then f_f = 1,
then if (1/r + 1/T + 1/D) = 0, then f_f = 0,
then if # of FO occurrences = 0 or FOH = 0, then 1/r = 0,
then if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0,
then if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0,
then if (SH + RSH + Synch Hours) = 0, then f_p = 0,
then if ((FOHd + SH + Synch Hours) = 0, then EFORd = 0

SH, RSH and Synch Hours are reported through the MISO Market Portal in the PowerGADS application by the users in their Performance data. The rest of the statistics are calculated by PowerGADS based on the user submitted Event data. Forced outage rates for each unit can be found in the Generator Outage Rate Program (GORP) report. The statistics used in calculating forced outage rates can be found in the Statistics Report, Performance Report, and the Seasonal XEFORd Report.

The MISO calculation is based on the EFORd equation defined in the NERC Generating Availability Data System Data Reporting Instructions Appendix and the IEEE Standard No. 762-2006 Standard *Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity*. The MISO XEFORd calculation differs as follows:

- The NERC and IEEE EFDH formula is (Derated Hours * Size of Reduction)/Net Max Capacity while the MISO formula uses net dependable capacity rather than net max capacity and is (Derated Hours * Size of the Reduction)/Net Dependable Capacity. The size of the reduction is the Net Dependable Capacity minus the Net Available Capacity.
- MISO also includes synchronous hours in the XEFORd, average Demand time (D), and the partial Demand factor (f_p) calculations while NERC and IEEE do not.

Example XEFORd Calculations

Raw Data									
Unit	SH	Synch Hours	RSH	AH	Actual Starts	Attempted Starts	EFDH	FOH	FO Events
1	4,856	0	2,063	6,919	34	34	146.99	773	12
2	4,556	0	1,963	6,519	31	31	110.51	407	5
3	3,942	132	3,694	7,768	36	36	19.92	504	11
4	6,460	0	516	6,976	17	18	131.03	340	14
5	6,904	0	62	6,966	16	16	35.81	138	12

Calculated Values								
Unit	**1/r**	**1/T**	**1/D**	**f_f**	**FOHd**	**f_p**	**EFDHd**	**XEFORd**
1	0.0155	0.0165	0.0070	0.8205	634.25	0.7018	103.16	13.43%
2	0.0123	0.0158	0.0068	0.8049	327.61	0.6989	77.23	8.29%
3	0.0218	0.0097	0.0088	0.7813	393.78	0.5245	10.45	9.05%
4	0.0412	0.0349	0.0026	0.9666	328.63	0.9260	121.34	6.63%
5	0.0870	0.2581	0.0023	0.9933	137.08	0.9911	35.49	2.45%

Unit 3 Example XEFORd Calculation Detail

r = average forced outage duration = $\frac{FOH}{FO\ events} = \frac{504}{11} =$ 45.82 hours, then 1/r = 0.0218

T = Average reserve shutdown time = $\frac{RSH}{attempted\ starts} = \frac{3694}{36}$ = 102.61 hours, then 1/T = 0.0097

D = average Demand time = $\frac{(SH+synch\ hours)}{actual\ starts} = \frac{3942+132}{36} = 113.17$ hours, then 1/D = 0.0088

f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})} = \frac{(0.0218+0.0097)}{(0.0218+0.0097+0.0088)} = 0.7816$

FOHd = forced outage hours Demand = f_f x FOH = 0.7813 x 504 = 393.78 hours

f_p = partial forced outage Demand factor = $\frac{(SH+synchhours)}{AH} = \frac{(3942+132)}{7768}$ = 0.5245

EFDH = fp x EFDH = 0.5245 x 19.92 = 10.45 hours

XEFORd = $\frac{(FOHd+EFDHd)}{(FOHd+SH+synch\ hours)} * 100 = \frac{(393.78+10.45)}{(393.78+3942+132)} * 100 = 9.05\%$

Units with 12 or more consecutive months of actual data: The XEFORd of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months.

Units with less than 12 consecutive months of actual data: The XEFORd of a unit in service less than twelve full calendar months shall be determined by the class average rate for units of the same type and within the same range of capability. A unit will use the class average value until 12 consecutive months of data is obtained and a new Planning Year begins. The class average will be the 5-year forced outage rate from the latest Loss of Load Expectation (LOLE) Study.

Units with Low Service Hours

Units with an average of less than 20 service hours per Season and attempted starts greater than zero will have their service hours adjusted if the unit has at least 12 consecutive seasonal months of GADS data. The adjusted service hours will be based on 60 service hours (20 service hours x 3 Seasons) or a fraction of 60 if there is less than 9 consecutive seasonal months of GADS data. This adjustment will be performed in the MECT. The calculation for the adjustment is as follows:

MO = consecutive seasonal months in operation
If SH = Service Hours < (MO/9*60) and attempted starts is greater than zero, then

SH' = seasonal adjusted low service hours = $\left[\left(\frac{actual\ starts}{atempted\ starts}\right) * \left(\frac{MO}{9} * 60 - SH\right)\right] + SH$

External Resources

Market Participants are responsible for making sure that GADS data is submitted for the External Resources that they are seeking qualification as ZRCs. The Market Participant can submit this data to MISO's GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the MISO Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator, then it is the Market Participant's responsibility to receive and submit this data for the External Resource.

Catastrophic Outages

Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous months. A catastrophic outage may be a forced full or partial (forced derating) outage. A scheduled outage (planned, planned extension, maintenance, or maintenance extension) cannot be a catastrophic outage. For an outage to be considered catastrophic, the MP must notify the MISO Resource Adequacy team in writing within 75 days of determining the outage is a Catastrophic Outage, including a description of the Catastrophic Outage, start date of outage, expected return date, etc.

If the MP chooses not to replace a Planning Resource that suffers a Catastrophic Outage, then the XEFORd will be based on actual GADS data.

If the MP chooses to replace a Planning Resource that suffers a Catastrophic Outage, the XEFORd will be based on class average when the unit returns to service. The class average value will be used until 12 consecutive months of data is obtained and a new Planning Year begins.

> Resource replacement must be completed within 75 days of catastrophic outage.
> Resource replacement must be in accordance with section 6.4 of this BPM.
> Once the unit returns from Catastrophic Outage, Planning Resource qualification requirements still apply. Partial replacements are allowed.

If the outage is a forced derate with total or partial replacement, or a full forced outage with partial replacement, the resources XEFORd upon returning to service will be the class average for the portion of the resource replaced and the actual XEFORd for the remainder of the unit. A blended XEFORd will be calculated by MW weighting the class average and actual XEFORd values.

For Schedule 53 resources that experience a catastrophic outage and replaced the ZRCs accordingly during the time the resource was unavailable, the time it is out will be considered non-RAR and would not be counted in the SAC calculation consistent with ZRC replacement section of this BPM and Appendix Y. In situations where this leads the resource to have less than 60 days of RAR performance history during the 3-year lookback period, the Schedule 53 resource would be granted Schedule 53 class averages for the impacted seasons.

Fleet Weighted Average Forced Outage Rates

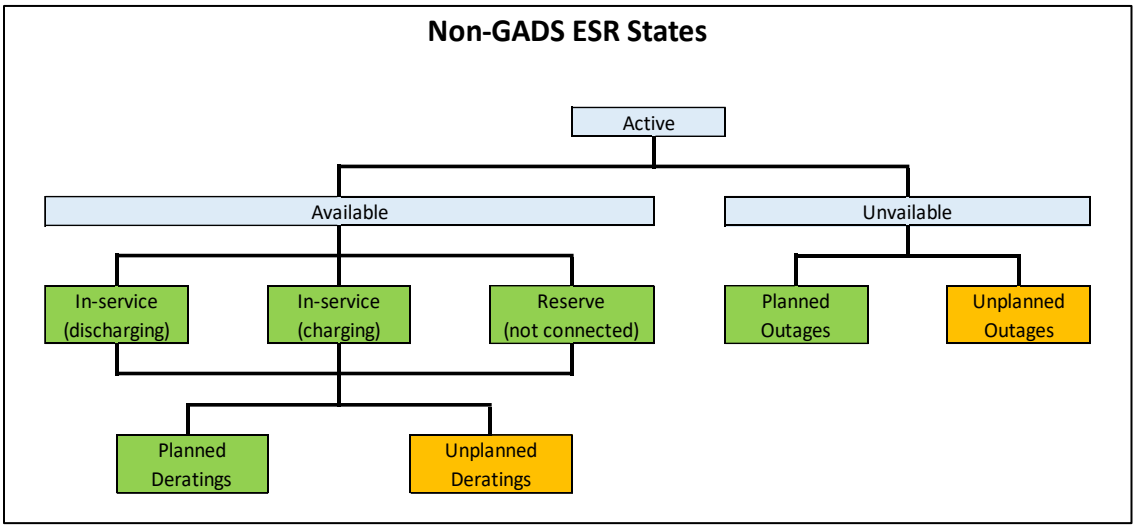
External Resources may participate using a fleet of resources. A weighted average forced outage rate is calculated using the individual unit forced outage rates and GVTC values. The resulting rate is applied to the total fleet GVTC to determine the fleet UCAP. See Appendix Q for more information regarding the Fleet XEFORd Calculation.

XEFORd for Non-GADS Electric Storage Resources (ESR)

The XEFORd for a non-GADS ESR is its Forced Unavailability and will be determined as follows.

A non-GADS ESR is forced unavailable when it is in an unplanned outage or an unplanned derating (see oranges boxes). All other states are unforced availability and include in-service

(discharging or charging), reserve (not connected), planned outages, or planned deratings (see green boxes).



An available resource that is not derated is 100% available. If a resources availability changes during an hour, the Forced Availability should be pro-rated. For example, if a 10 MW resource experiences a 23-minute Unplanned Outage during the hour, its equivalent Forced Unavailability would be (23 min/60 min) * 10 MW = 3.8 MW or 38%. Similarly, for an Unplanned Derating of 2.4 MW for 47 minutes of the hour the equivalent Forced Unavailability would be (47 min/60 min) * 2.4 MW = 1.9 MW or 19%.

Examples for a 10 MW resource	Unforced Availability (MW)	Forced Unavailability (MW)	Unforced Availability (%)	Forced Unavailability (%)
The resource is 100% available and in-service discharging	10.0	0.0	100.0%	0.0%
The resource is 100% available and charging	10.0	0.0	100.0%	0.0%
The resource is 100% available and in reserve not discharging	10.0	0.0	100.0%	0.0%
A portion of the resource is unavailable due to a planned derating and the remainder is available	10.0	0.0	100.0%	0.0%
4 MW of the resource is unavailable due to an unplanned derating and 6 MW is available	6.0	4.0	60.0%	40.0%
4.5 MW of the resource is unavailable due to a planned derating and 5.5 MW is unavailable due to an unplanned	4.5	5.5	45.0%	55.0%
The resource is unavailable due to a planned outage	10.0	0.0	100.0%	0.0%
The resource is unavailable due to a unplanned outage	0.0	10.0	0.0%	100.0%
23 minutes unplanned outage	6.2	3.8	62.0%	38.0%
2.4 MW unplanned derate for 47 minutes	8.1	1.9	81.0%	19.0%

Additional information:

- Pumped Storage Resources submit their availability and GVTC data through the MISO PowerGADS application.
- All other ESR types must submit their availability and GVTC (Hourly Equivalent Discharge Amount) data using the Non-GADS Performance template.
    - The template provides the 8 MISO coincident peak hours per Season for the last three years.
    - The average of these 24 seasonal unforced availability values is divided by the Hourly Equivalent Discharge Amount (MW) to calculate a seasonal unavailability factor.
    - Market Participants with less than 8 availability values in a Season will be given the default unavailability factor.
- Availability Reporting is optional for resources less than 10 MW. Resources that choose not to report, will be given the default unavailability factor. Once a resource chooses to report for the first time, they will be required to report every year thereafter.

Appendix J – GVTC Testing Requirements

J.1 Overview

All Generation Resources, External Resources, Behind the Meter Generation (BTMG) and Demand Response Resources backed by BTMG that intend to qualify as a Planning Resource are required to perform a real power test or provide past operational data. This test, or past operational data, shall be used to determine a planning resource's GVTC value. GVTC data is submitted through the MISO Market Portal into MISO PowerGADS.

Each seasonal corrected net test capability is the gross output (MW) that a planning resource can sustain averaged over the test period, if there are no equipment, operating, or regulatory restrictions, less station service and process load served, corrected to MISO coincident seasonal peak conditions.

			(A)	(B)	(C)	(D)= (A)-(B)-(C)	(E)	(F)	(G)	(H)= (D)+(E)+(F)+(G)
NERC Unit Type		Example Unit	Gross (MW)	Station Service (MW)	Process Load Served (MW)	Net Test Capacity (MW)	Air Temperature Correction (MW)	Relative Humidity Correction (MW)	Cooling Water Temperature Correction (MW)	Net Corrected (MW)
Combined Cycle	CC	CT1	95.0	1.0	0.0	94.0	-15.0	-0.1	N/A	78.9
Combined Cycle	CC	ST1	300.0	15.0	0.0	285.0	N/A	N/A	-1.0	284.0
Combined Cycle	CC	Unit 4	250.0	5.0	100.0	145.0	-3.5	-0.1	-0.5	140.9
Combustion Turbine	CT	CT3	50.0	0.1	0.0	49.9	3.0	0.1	N/A	53.0
Diesel	DS	Diesel 5	2.5	0.0	0.0	2.5	N/A	N/A	N/A	2.5
Fluidized Bed Combustion	FB	Unit 4	200.0	10.0	0.0	190.0	N/A	N/A	-2.0	188.0
Hydro	HD	Hydro 12	10.0	0.0	0.0	10.0	N/A	N/A	N/A	10.0
Nuclear	NU	Unit 1	1,000.0	50.0	0.0	950.0	N/A	N/A	-1.5	948.5
Pumped Storage	PS	Unit 5	300.0	1.0	0.0	299.0	N/A	N/A	N/A	299.0
Fossil Steam	ST	Unit 2	600.0	30.0	0.0	570.0	N/A	N/A	-3.0	567.0

GVTC Table J.1 – Examples of net corrected net test capability for different unit types. **Examples may not be representative of your situation. If you have unit specific questions, please contact Resource Adequacy.

If a Planning Resource fails to perform a real power test and report the test data to MISO's PowerGADS byOctober 31 prior to the start of the planning year t, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero SAC MWs for the upcoming Planning Year.

J.1.1 Test Period and Reporting Deadline

The real power test shall be performed between September 1 and August 31 prior to the upcoming planning year. The test data shall be submitted no later than October 31.

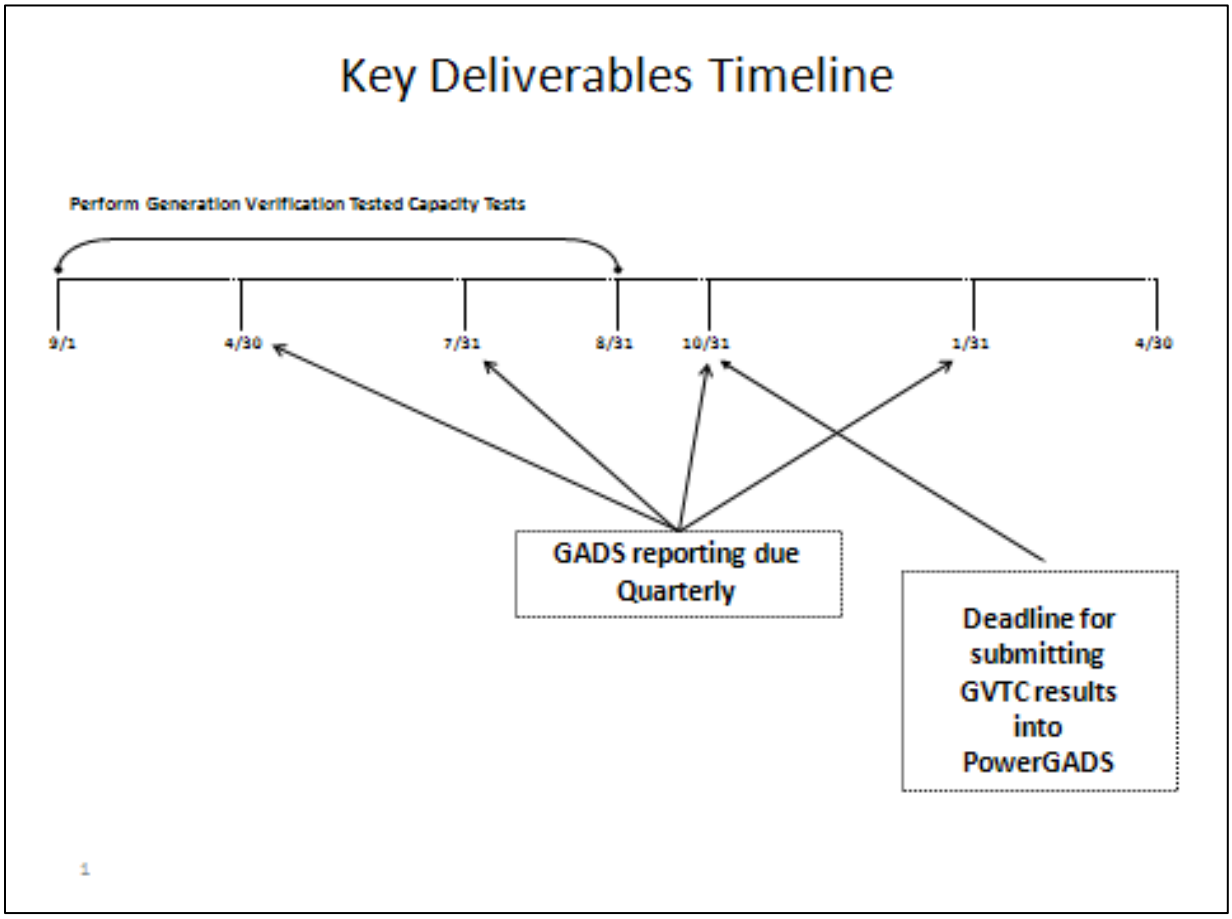
Example: For the 2023-2024 planning year (June 1, 2023 through May 31, 2024), the test must be conducted between September 1, 2021 and August 31, 2022, and submitted no later than October 31, 2022 to qualify as a Planning Resource for the upcoming Planning Year.

J.2 When to Perform and Submit a Generation Verification Test Capacity

Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31 to qualify as a Planning Resource for the upcoming Planning Year. A real power test shall be performed, or past operational data may be used, during the period between September 1 and August 31 prior to the upcoming Planning Year. In addition to performing and submitting GVTC data to qualify as a planning resource for the annual capacity auction, a planning resource must conduct a test and submit data when:

- a modification that changes, increases, or decreases, the rated capacity of a unit is completed,
- returning from a suspension,
- returning to MISO after an absence including but not limited to, catastrophic events,
- not qualifying as a Planning Resource under Module E-1
- being qualified as a Planning Resource for the first time
- or for a Planning Resources in an approved “Suspension” status.

If a Planning Resource is unable to complete a real power test, the responsible MP must include the timing and cost requirements to complete a test when requesting a facility specific reference level.



J.3 Corrections to Establish GVTC

The GVTC shall be corrected to the average conditions of the date and times of MISO's four seasonal coincident Peaks, measured at or near the generator's location, for the last 5 years. MISO publishes the date and time of the past 5 seasonal coincident Peaks. When local weather records are not available at the plant site, the values shall be determined from the best data available (i.e., local weather service, local airports, river authority, etc.).

The corrections required to establish the GVTC of a unit include, as appropriate for each electric generating technology, dry air temperature, relative humidity, cooling water temperature, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

J.3.1 Process Load Reporting in MISO PowerGADS to Establish GVTC

The Generator Owner shall forecast the maximum process load (PL) expected to be present at the time of the upcoming MISO seasonal peaks. MISO publishes the date and time of past coincident seasonal peaks as a reference for predicting the PL that is forecasted to be present at the time of the upcoming MISO peaks.

For calculating GVTC, the PL being forecasted and reported by the Generator Owner is allocated to the underlying generating unit of the Planning Resource and deducted from a unit's gross MW unless provisions are in place to curtail the load in the event of a MISO Capacity Emergency, or for electric load, is included in an LSE forecast. If such provisions for curtailment are in place or, for electric load, it is included in an LSE forecast, the PL is non-firm for the purpose of calculating GVTC.

Process Load can be electric load or thermal load in the case of a Combined Heat and Power (CHP) facility. Thermal PL is converted to units of MW by determining the reduction of power output caused by serving that load. Thermal loads can be PL because steam that would have otherwise been used to drive turbines to produce electricity may have been diverted to support process load, thus reducing the electrical capacity of the overall plant relative to the MISO system.

Thermal load that causes an increase in power output, as served from a back-pressure turbine for example, is not a PL for these purposes. However, the GVTC test should be performed or corrected for conditions that are a conservative expectation of the amount of thermal load that would be present coincident with MISO peak load conditions.

PL can be firm or non-firm. The following criteria should be applied to determine whether the PL is firm or non-firm:

- PL is firm if it continues to exist when one or more of the underlying generating units of the Planning Resource are derated or out of service. Such firm PL would be served by one or more of the underlying generating units of the Planning Resources at the same location or from the MISO system.
- PL is non-firm if it does not continue when the underlying generating unit of the Planning Resource is out of service.
- To the extent that PL that continues to exist when the underlying generating unit of the Planning Resource is out of service is served by resources that are not Planning Resources, such as auxiliary boilers, that portion of the PL is non-firm.

The amount of firm PL will be adjusted by multiplying by (1+PRM) and dividing by (1-XEFORd). The sum of the firm and non-firm PL will be reported in PowerGADS.

PL = (adjusted firm PL) + (non-firm PL)

Adjusted firm PL = firm PL * (1 + PRM) / (1 - XEFORd)

PL calculations are performed outside of PowerGADS and the MECT. PL is only deducted from an underlying generating unit of the Planning Resource's gross MWs one time. PL is part of the GVTC calculation that is entered into PowerGADS. MISO performs a PowerGADS integration that retrieves the GVTC value from the PowerGADS data base and populates the MECT. A Planning Resource may be comprised of one or more underlying PowerGADS units.

The UCAP PRM is from the most recent LOLE Study Report. The XEFORd is the appropriate value for the 36-months ending on August 31 proceeding the planning year, which can be found in PowerGADS.

J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in MISO PowerGADS lasted a minimum of 90 consecutive days prior to the test date and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact MISO's Resource Adequacy Department for a review of its request.

J.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

J.5 GVTC Real Power Test Requirements by NERC Unit Type

J.5.1 Fossil Steam (FS), Fluidized Bed Combustion (FB), and Nuclear (NU)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The impact of the observed steam turbine exhaust pressure will be corrected to the past five years average rated daily maximum circulating water temperature measured at the unit location, at the date and time of MISO's coincident peaks.

J.5.2 Combined Cycle (CC)

The determination of the GVTC of a combined-cycle unit will depend on the structure of the unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion and steam turbine components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

For each Season, the impact of the observed steam turbine exhaust pressure will be corrected to the past five years average daily maximum circulating water temperature measured at the unit location on the day of MISO's Coincident Peak.

The impact of the observed ambient air temperature and relative humidity on combustion turbine performance will be corrected to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's Coincident Peaks. Where inlet cooling is used to reduce inlet air temperature, the temperature at the discharge of the inlet coolers shall be the basis for ambient temperature adjustment.

J.5.3 Miscellaneous (MS)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The test will be seasonally corrected per J.3 Corrections to Establish GVTC.

J.5.4 Combustion Turbine (CT)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The impact of observed dry air temperature and relative humidity on combustion turbine performance will be corrected, for each Season, to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's seasonal coincident

peaks. Where inlet cooling is used to reduce turbine inlet air temperature, the temperature at the discharge of the Inlet coolers shall be the basis for air temperature correction.

J.5.5 Hydro (HD) and Pumped Storage (PS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The GVTC established for hydroelectric plants shall recognize the head available considering environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The seasonal historic median head shall be determined as the median of all head measurements from the most recent five (5) years up to the most recent fifteen (15) years. If 15 years of historic data is not available for this period when the 15-year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15-year requirement is met. The hours ending 1500, 1600, and 1700 EST apply to all days of the Summer (June, July, August), Fall (September, October, November), and Spring (March, April, May). The hours ending 0900, 1000, 1900, and 2000 EST apply to all days of the Winter (December, January, February).

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

MISO PowerGADS does not accept seasonal corrections for Hydro and Pumped Storage resources. If a Generation Operator (GO) elects to submit seasonal corrections they can use the Hydro and Pumped Storage GVTC Corrections template which can be found at https://www.misoenergy.org/planning/resource-adequacy/#nt=/planningdoctype:RA%20Guides%20and%20References/raguidetype:GVTC. If a GO elects to submit seasonal corrections, they must submit a test in MISO PowerGADS and

the Hydro and Pumped Storage GVTC Corrections template to the MISO Help Center help.MISOEnergy.org.

J.5.6 Diesel (DS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

No corrections apply to this unit type.

J.5.7 Electric Storage Resources (ESR)

This section is for all ESR except Pumped Storage. For pumped storage see J.5.5.

The test shall be at least one (1) continuous hour and data shall be averaged over the test period. The test shall be conducted at the discharge rate that would be expected if the ESR were dispatched for four (4) continuous hours. The test results must be submitted in the Module E Capacity Tracking (MECT) tool (Planning Resources > Non-GADS Resource Registration) using the Non-GADS Performance Template posted on the MISO Website.

J.5.8 General Requirements

If a generating unit has not been in operation for five years, then as many years as the unit has been in operation shall be used. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Peaks.

The unit shall be operated with the regularly available type and quality of fuel.

The Station Service shall be representative of the conditions expected to occur during MISO's coincident peaks.

For facilities consisting of multiple units, shared station power and process load served shall be allocated to the individual units to compute unit net capability.

J.6 Reporting

The following information shall be reported to MISO's PowerGADS as described in MISO's *Net Capability Verification Test User Manual*. Certain data will be reported or calculated for each of the 4 Seasons – summer, fall, winter and spring.

CARD	Must be "90"
Utility	Required

Unit	Required
Year	Required
Test Index	Must be a "1"
REVISIONCODE	Must be "0" for initial upload, "R" to Revise, or "D" to Delete
Corrected Net - Seasonal	Calculated by PowerGADS
Test Start Date	Required
Test End Date	Required
Gross MW	Required
Station Service	Required
Process Load Served	Required
Net Test Capability	Required, Gross MW – Station Service – Process Load Served
Reactive Generation MVAR	Optional
Total Power MVA	Calculated by PowerGADS if Reactive Generation MVAR entered
Power Factor	Calculated by PowerGADS if Reactive Generation MVAR entered
Dry Air Temperature Observed - Seasonal	Required for certain unit types
Dry Air Temperature Rated - Seasonal	Required for certain unit types
Air Temperature Correction	Required, may be zero
Relative Humidity Observed - Seasonal	Required for certain unit types
Relative Humidity Rated - Seasonal	Required for certain unit types
Relative Humidity Correction	Required, may be zero
Cooling Water Temperature Observed - Seasonal	Required for certain unit types
Cooling Water Temperature Rated - Seasonal	Required for certain unit types
Cooling Water Temperature Correction	Required, may be zero
STANDARD	Must be "MISO"

Appendix K – Resource Adequacy Timeline for activities for the Planning Year 2025-2026

Please check for the latest online version posted on the Resource Adequacy webpage of MISO's corporate website.

Date	Process and Notes	Responsible Entity	Tariff Reference
Sep 01, 2024	Start Cost of New Entry (CONE) calculation in coordination with IMM.	MISO/IMM	69A.8(a)(3)
Sep 09, 2024	MISO to publish historical monthly and seasonal Coincident Peak Load hours and LRZ seasonal coincident factors.	MISO	69A.1.1.(c)
Oct 01, 2024	Last day to submit outage exemption related resolution requests regarding Schedule 53 resources through the MISO Help Center.	Resource Owner	
Oct 01, 2024	MISO opens the new Planning Year in the MECT for all 4 Seasons. (1st Business Day - October)	MISO	
Oct 01, 2024	Transmission losses by Local Balancing Authority are posted by MISO. (1st Business Day - October)	MISO	69A.1.1(b)
Oct 15, 2024	MISO posts RA hours to be used for accreditation calculation	MISO	
Oct 31, 2024	Generation Verification Test Capacity (GVTC) due. Resource Owners submit operational data or real power test for September 1 - August 31 period.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Oct 31, 2024	Populated Non-GADS Performance Templates due in MECT.	Resource Owner	69A.3.1.a(1)(d)
Oct 31, 2024	Generator availability data due in GADS for resources required to report for Q3. Resource Owners must ensure at least 36 months of data is provided.	Resource Owner	69A.3.1.a(1)(c)
Nov 01, 2024	Seasonal Coincident and Non-Coincident Peak Demand forecasts by LSE/EDC, monthly peak Demand, seasonal peak Demand and energy-for-load forecast values by LSE due. No action needed by Retail Choice LSEs.	LSE, EDC	69A.1.1(a)
Nov 01, 2024	Loss of Load Expectation study results published by MISO.	MISO	68A.2 68A.4 68A.5

Date	Process and Notes	Responsible Entity	Tariff Reference
Nov 07, 2024	MP must request an extension from within 5 business days after October 31 deadline.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Nov 15, 2024	Review list of units with conditional Interconnection Service for results of annual study. Units may have NRIS/ERIS balance re-allocated.	MISO	
Dec 01, 2024	For individual States establishing their own seasonal PRM, submission of written letter by authorized State regulatory authority representative notifying MISO.	State Regulatory Authority	68A.1
Dec 15, 2024	RBDC opt out adder % posted on MISO website	MISO	69A.9.1 (l)
Dec 15, 2024	Initial UCAP/ISAC ratio, initial Seasonal Capacity accreditation values and validation files are published by MISO.Resources that do not meet the October 31 deadline will have their initial capacity accreditation calculated using estimated capacity submitted along with GVTC extension requests. MP may begin submitting resolution requests though the MISO Help Center.	MISO	
Dec 15, 2024	PLC submissions by EDC due. EDC will send the details of the PLCs to the respective LSEs and to MISO for review. The EDC-provided PLC data will be the default value for the LSE's Retail Choice Coincident Peak.	Retail Choice EDCs	69A.1.1(e)
Dec 15, 2024	Last day for MPs to submit to March Network & Commercial Model changes to qualify for ICAP Deferral.	Resource Owner	
Jan 15, 2025	LSE submit initial RBDC Opt Out Plan in MECT, including its RERRA contact	LSE	69A.9.1 (c)
Jan 15, 2025	Generation Verification Test Capacity (GVTC) due for generators that requested an extension.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Jan 15, 2025	LSEs confirm the seasonal Retail Choice PLC in the MECT. LSEs should have all PLC questions resolved by this date. If an LSE desires a change in their PLC value, the appropriate EDC should be contacted directly.	LSEs, Retail Choice EDC	69A.1.1.1
Jan 15, 2025	Evidence for seasonal HUC/ZDC hedges due.	LSE	69A.7.7(b)

Date	Process and Notes	Responsible Entity	Tariff Reference
Jan 20,2025	MISO notifies RERRA its regulating LSE's initial plan for opting out RBDC	MISO	69A.9.1 (d)
Jan 31, 2025	Default technology-specific avoidable costs posted by the IMM. Resource owners may use the default costs in lieu of submitting facility specific operating costs for a facility specific Reference Level request. (59 days prior to deadline for offers)	IMM	64.1.4(f)(ii)
Jan 31, 2025	Generator availability data due in GADS for resources required to report for Q4.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Feb 01, 2025	Last day to submit non-exemption related resolution requests on ISAC posted for Schedule 53 resources through the MISO Help Center.	Resource Owner	
`Feb 01, 2025	Existing Load Modifying Resource, Energy Efficiency, and External Resource registrations due for prompt Planning Year.	LMR/EE/ER Owner	
Feb 01, 2025	Loss of Load Expectation study begins for next Planning Year.	MISO	
Feb 01, 2025	Evidence of Demand Resource testing due. Last day to submit evidence. DR testing or performance must take place during the calendar year prior to the upcoming Planning Year.	DR Owner	69A.3.5
Feb 01, 2025	Written letter from officer of company stating intention to leverage DR testing deferral provisions due.	DR Owner	69A.3.5(l)
Feb 07, 2025	Last day to submit a Full Responsibility Transaction. (due the 5th business day of February)	LSE	
Feb 14, 2025	If utilizing FSRL, last day to submit request to IMM regarding Going-Forward Cost determination. Submit data for facility ZRC reference levels to IMM. (45 days prior to close of PRA offer deadline)	Generation Owner	64.1.4.f.iii.b
Feb 15, 2025	Final UCAP/ISAC ratio and SAC values for Schedule 53 resources will be posted on MECT. Schedule 53 resource owners can start confirming SAC and converting SAC into ZRCs.	MISO	
Feb 15, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval to be considered for inclusion in seasonal FRAP or RBDC Opt Out.	LSE	69A.9(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
Feb 15, 2025	LSEs submit request to revise seasonal Coincident Peak Demand forecast originally submitted on November 1. MISO will review and either approve or deny request.	LSE	
Feb 15, 2025	Written letter from officer of company stating intention to leverage ICAP Deferral provisions.	Resource Owner	69A.7.9(a)
Feb 17, 2025	Last day that RERRA notifies MISO if it denies any of the LSE's plan for opting out RBDC	RERRA	69A.9.1 (d)
Feb 28, 2025	Capacity accreditation updated for resources granted ICAP Deferral.	MISO	
Mar 01, 2025	Seasonal Generator Verification Test Capacity and generator availability data for new resources or resources with increased capacity due for prompt Planning Year.	Generation Owner	69A.3.1.a(d)
Mar 01, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval in the MECT for the prompt Planning Year.	LMR/EE/ER Owner	69A.9(a)
Mar 01, 2025	Deadline to satisfy credit requirements for DRs opting out of or deferring testing. Credit posting only required if DR doesn't have regulatory restrictions or contractual obligations that preclude testing.	DR Owner	69A.3.5 (j)(2)&(l)
Mar 01, 2025	MISO to complete its seasonal Coincident Peak Demand forecast review process.	MISO	69A.1.1(c)
Mar 01, 2025	Satisfy credit posting requirement for seasonal capacity accreditation issued from resources granted ICAP Deferral.	Resource Owner	69A.7.9(b)
Mar 01, 2025	Resource Owners submit Attachment Y requests for units scheduled for retirement/suspension between 3/30 and 5/31 to receive exemption from physical withholding.	Resource Owner	38.2.7.a.(i)
Mar 03, 2025	Publish seasonal Sub Regional Import Constraint (SRIC) and seasonal Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) no later than first business day in March.	MISO	68A.3.1
Mar 10, 2025	Finalize and submit HUC registrations in the MECT.	LSE	
Mar 11, 2025	Seasonal Fixed Resource Adequacy Plan due by LSE. (7th Business Day of March)	LSE	69A.9(a)
Mar 11, 2025	LSE confirms its RBDC Opt Out Plan in MECT (7th Business Day of March)	LSE	69A.9.1(c)
Mar 14, 2025	Last day to notify IMM of deliverable resources requesting to be excluded from offering into seasonal PRAs or included in a FRAP or RBDC Opt Out.	Generation Owner	
Mar 15, 2025	Fixed Resource Adequacy and RBDC Opt Out Plan review completed by MISO. The LSE will have until the auction	MISO(LSE)	69A.9(a) 69A.9.1(c)

Date	Process and Notes	Responsible Entity	Tariff Reference
	offer window opens to remedy any deficiencies in their FRAP or RBDC Opt Out.		
Mar 19, 2025	Final date to update seasonal CIL and CEL values for each LRZ prior to the Planning Resource Auction. Changes due to firm capacity commitments from MISO resources to neighboring regions established prior to the PRA.	MISO	68A.4
Mar 19, 2025	CEL determined for each ERZ. Equal to the ZRC quantity of the External Resources registered to participate in the PRA. (8th business day in March prior to the last business day)	MISO	68A.4
Mar 19, 2025	Final posting by MISO of preliminary seasonal PRA data, reflective of updated information from LSEs, Resource Owners and PJM auction results. Coincides with seasonal CIL/CEL calculations.	MISO	
Mar 27, 2025	Provide Facility Specific Resource Level(s) to MPs 5 days prior to the close of the PRA offer window.	IMM	64.1.4.f
Mar 25, 2025	Final day for confirming/converting SAC in MECT.	Resource Owner	
Mar 26, 2025	Planning Resource Auction offer window is opened for all Seasons. Auction Offer window is opened at 8:00 AM EPT, 3 business days prior to the last business day in March.	MISO	69A.7.1(a)
Mar 31, 2025	Planning Resource Auction offer window is closed for all Seasons. Auction Offer window is closed at 6:00 PM EPT on the last business day of March.	MISO	69A.7.1(a)
Apr 01, 2025	Iterations of seasonal auction runs with adjusted seasonal CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding. The reference levels are used to determine financial withholding. The mitigation of financial withholding can be expected to reduce the Auction Clearing Price. (First 20 Business Days of April)	MISO/IMM*	69A.7
Apr 28, 2025	Seasonal Planning Resource Auctions results posted. (20th Business Day of April)	MISO	69A.7
Apr 30, 2025	Generator availability data due in GADS for resources required to report for Q1.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
May 01, 2025	MISO to assess seasonal Capacity Deficiency Charges for applicable LSEs.	MISO	69A.10(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
May 8, 2025	MISO sends Capacity Deficiency Charges to applicable LSEs 5 business days after assessment.	MISO	
May 19, 2025	Capacity Deficiency Charge payments distributed to MPs. Payment made within 7 business days of receipt.	MISO	
May 28, 2025	Publish details of the seasonal ZRC offers submitted in the PRA. Market Participant IDs are not revealed. (One month after PRA)	MISO	69A.7.4
May 28, 2025	MISO publishes cleared LMRs to DSRI. MISO publishes must offer performance requirements in the applicable Operations tool.	MISO	
May 30, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Summer Season. (Last business day of Planning Year)	LSE	69A.7.9(a) (2)
May 30, 2025	Information due to satisfy DR Deferral Notice must be submitted to MISO in order to release credit requirements and avoid LMP performance penalties.	DR Owner	69A.3.5
Jun 01, 2025	Summer Season in new Planning Year starts.	All	69A.7
Jun 01, 2025	Daily settlements for the Summer Season starts.	All	
July 31, 2025	Generator availability data due in GADS for resources required to report for Q2.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
August 29, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Fall Season. (Last business day)	LSE	69A.7.9(a) (2)
Sep 01, 2025	Fall Season in new Planning Year starts.	All	69A.7
Sep 01, 2025	Daily settlements for the Fall Season starts.	All	
November 26, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Winter Season. (Last business day)	LSE	69A.7.9(a) (2)
Dec 01, 2025	Winter Season in new Planning Year starts.	All	69A.7
Dec 01, 2025	Daily settlements for the Winter starts.	All	

Date	Process and Notes	Responsible Entity	Tariff Reference
February 27, 2026	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Spring Season. (Last business day)	LSE	69A.7.9(a) (2)
Mar 01, 2026	Spring Season in new Planning Year starts.	All	69A.7
Mar 01, 2026	Daily settlements for the Spring Season starts.	All	

Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the seasonal LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission value for each Local Balancing Authority (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak during each of the four previous Seasons.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA load, at each seasonal MISO peak hour.

The seasonal LBA transmission loss percentage calculated by the Transmission Provider will apply to the LSE's applicable seasonal LBA Coincident Peak Demand forecast to determine the LSE transmission losses for the calculation of the seasonal Initial PRMR. The LBA transmission loss percentage calculated by the Transmission Provider coincident with each LRZ’s seasonal Peak Demand forecast will determine the LSE transmission losses for the calculation of LRR. Both the MISO and Zonal Transmission Losses will be posted on the MISO public website by November 1 before the upcoming Planning Year.

Initial PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Initial PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

APPENDIX M: PLANNING RESOURCE AUCTION FORMULATION WITH RELIABILITY-BASED DEMAND CURVES

Disclaimer

This document is prepared for informational purposes only and is intended to help the user understand how the MISO Tariff provisions relating to Resource Adequacy Requirements and Reliability-Based Demand Curves are implemented in MISO's Planning Resource Auction (PRA). MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff. MISO owns the intellectual property of this document and content.

Purpose of this document

MISO's Resource Adequacy construct provides LSEs in the MISO footprint an ability to procure planning resources through a PRA for each Season within the Planning Year (PY). A Linear Programming (LP) based optimization tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization formulation that is used for clearing the seasonal PRA and explains how the zonal Auction Clearing Prices are calculated for each Season within the PY.

1 Overview of Auction Clearing Processes

MISO is introducing sloped demand curves in its Resource Adequacy construct through the implementation of Reliability-Based Demand Curve (RBDC) in the 2025 PRA. Specifically, MISO utilizes distinct sloped demand curves at both the systemwide and sub-regional levels: one systemwide RBDC and separate subregional RBDCs for the North/Central (N/C) and South subregions (also called planning areas). The systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. As a result, for each season, MISO will utilize one systemwide RBDC and two sub-regional RBDCs in the PRA, totaling twelve RBDCs over the course of a Planning Year.

A subregional RBDC acknowledges the specific reliability needs of each sub-region. It is crucial to provide a price signal that reflects this regional diversity to promote efficient capacity pricing, resource planning, and grid reliability across MISO. Since MISO's footprint is divided into two subregions, each subregion will have two obligations to meet for resource adequacy: one from its share of the systemwide RBDC and the other from its own subregional RBDC. The share of systemwide RBDC is the systemwide RBDC weighted by the coincident peak demand share (with transmission losses) of the subregion. To ensure resource adequacy, the higher of these two obligations should be prioritized; meeting the higher obligation will automatically satisfy the lower one. The method for PRA clearing and pricing is outlined below.

Step 1 (RBDC identification): For each subregion, identify the RBDC curve between (i) share-of-systemwide RBDC and (ii) subregional RBDC that produces higher MW obligation in the neighborhood of the intersection of supply and demand curves.

Step 2 (Clearing and pricing): Use specific RBDCs identified in step 1 for each subregion and solve the clearing and pricing problem.

This solution methodology is summarized in **Error! Reference source not found.**.

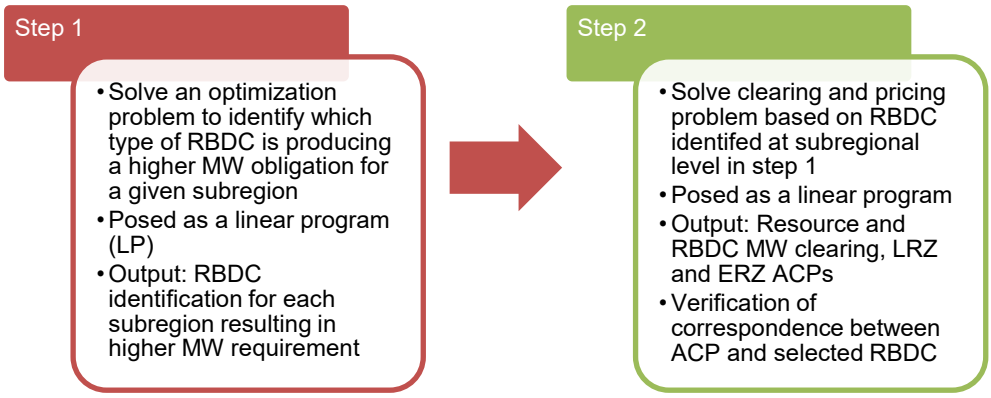


Figure 1. Overview of solution methodology

2 Preliminaries

This section defines the notation used in the optimization problem. In cases of ambiguity, we use the superscript SR to denote parameters or decision variables associated with subregional RBDC clearing, while the superscript SYS is used in reference to systemwide RBDC clearing. The optimization variables are in orange font.

2.1 Sets

Set DC = {Systemwide RBDC (SYS-RBDC), North/Central subregion RBDC (NC-RBDC), South subregion RBDC (S-RBDC)}

Set R = {North/Central subregion (NC), South subregion (S)}

Set Z = {All local resource zones (LRZs) in the transmission planning area}

Set Z_r = {All local resource zones (LRZs) in the subregion $r \in R$}

Set Z_n = {All North/Central subregion LRZs (LRZ 1 through 7)}

Set Z_s = {All South subregion LRZs (LRZ 8 through 10)}

Set E = {All external resource zones (ERZs) participating in the PRA}

Set F = {All resource offers in the system including LRZs and ERZs}

Set G = {All resources in LRZs}

Set G_k = {All resources in LRZ k}

Set G_r = {All resources in the LRZs within subregion $r \in R$}

Set H = {All resources in external zones (including dual connected external zones)}

Set H_e = {All resources in external zone *e*}

Set J_{dc} = {All demand segments in RBDC $dc \in DC$}

Set J_r = {All demand segments in subregional RBDC for subregion $r \in R$}

Set MC = {All resources which are part of fixed resource adequacy plans (FRAPs), or self-scheduled resources ($0 offer price), or resources covered by RBDC Opt Out}

2.2 Parameters

The following parameters are used to set up the constrained optimization problem for the PRA:

$INITIALPRMR_k$	Initial Planning Reserve Margin Requirement (PRMR) for LRZ *k*. Initial PRMR refers to PRMR for achieving the seasonal systemwide LOLE target (1-day-in-10 for Summer and 1-day-in-100 for other seasons)
$CPDF_k$	Coincident Peak Demand Forecast (CPDF) for LRZ *k*
LCR_k	Local Clearing Requirement for LRZ *k*
CIL_k	Capacity Import Limit for LRZ *k*
CEL_k	Capacity Export Limit for LRZ *k*
CEL_e	Capacity Export Limit for external zone *e*
$SREC_r$	Subregional export constraint (SREC) for subregion $r \in R$
$SRIC_r$	Subregional import constraint (SRIC) for subregion $r \in R$
$OFFERPRICE_i$	The offer price for resource *i*[3]
$OFFERMW_i$	Offered MW value for resource *i*
$SF_{r,e}$	Shift Factor ∈[0, 1] to subregion *r* for resources in external zone *e*[4]

ACP_k	Auction Clearing Price for Zone k
$CONE_k$	Annualized cost of new entry (CONE) for LRZ *k*
$CONE_n$	Average annualized CONE for LRZs in the North/Central subregion
$CONE_s$	Average annualized CONE for LRZs in the South subregion
$CONE_{SYS}$	Average annualized CONE for all LRZs in MISO
$SEASONALCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the season
$SEASONALCONE_e$	For dual connected ERZ e: maximum annualized CONE of all LRZ*s* divided by number of days in the season. For ERZ e connected to a single subregion: maximum annualized CONE of all LRZ*s* in that subregion divided by number of days in the season.
$DAILYCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the planning year
$RBDCPRICE_{j,dc}$	RBDC Price ($/UCAP MW-day) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
$RBDCSTEP_{j,dc}$	RBDC Step Size (UCAP MW) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
u_r	Binary parameter for MISO subregion $r \in R$ indicating the RBDC selected for step 2 of the solution methodology: 0 refers to share-of-systemwide RBDC, and 1 refers to the subregional RBDC
α_k^{SYS}	CPDF share of LRZ *k* with respect to all the LRZs in the system given by the following equation: $$\alpha_k^{SYS} \overset{def}{=} \frac{CPDF_k}{\sum_{k \in Z} CPDF_k} \in [0,1]$$
α_r	CPDF share of region $r \in R$, given by: $$\alpha_r \overset{def}{=} \sum_{k \in Z_r} \alpha_k \in [0,1]$$
α_k^r	CPDF share of LRZ *k* in subregion $r \in R$ with respect to all the LRZs in that subregion, given by:

$$\alpha_k^r \overset{def}{=} \frac{\alpha_k}{\alpha_r} \in [0,1]$$

2.3 Decision Variables

The optimization variables for the two linear programs are as follows (**all variables are non-negative**):

$clearedMW_i^{SYS}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i^{SR}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i$	Cleared MW value of offer *i* to meet selected RBDC demand in step 2
$clearedDemand_{j,r}^{SYS}$	Cleared MW value of systemwide RBDC segment *j* for subregion $r \in R$ [5]
$clearedDemand_{j,r}^{SR}$	Cleared MW value of subregional RBDC segment *j* for subregion $r \in R$
S_k^{SYS}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting systemwide RBDC demand in step 1
S_k^{SR}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting subregional RBDC demand in step 1
S_k	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL in step 2

3 Step 1: RBDC identification

The objective of the RBDC identification procedure is to determine which RBDC between share-of-systemwide RBDC and subregional RBDC is producing a higher MW requirement for each subregion. The requirements are determined through a solution to a linear program.

The identification of the RBDC producing a higher requirement is challenging, a priori. This difficulty is illustrated via the two plots on the first row of **Error! Reference source not found.** c orresponding to the summer season in the MISO N/C region and MISO South region, respectively: on the left, the subregional RBDC will always result in a higher MW requirement as compared to the share-of-systemwide RBDC for any clearing price point. However, on the right, both RBDCs are intertwined and depending on supply and demand curve intersection either systemwide or subregional RBDC could result in a higher MW requirement. This systemwide

and the subregional RBDC interaction increases the complexity of the PRA clearing process. To address this, an LP based optimization approach is utilized for the determination of the correct RBDC (higher MW requirement) for each subregion in a given season; this selected RBDC is used for the optimization in step 2.

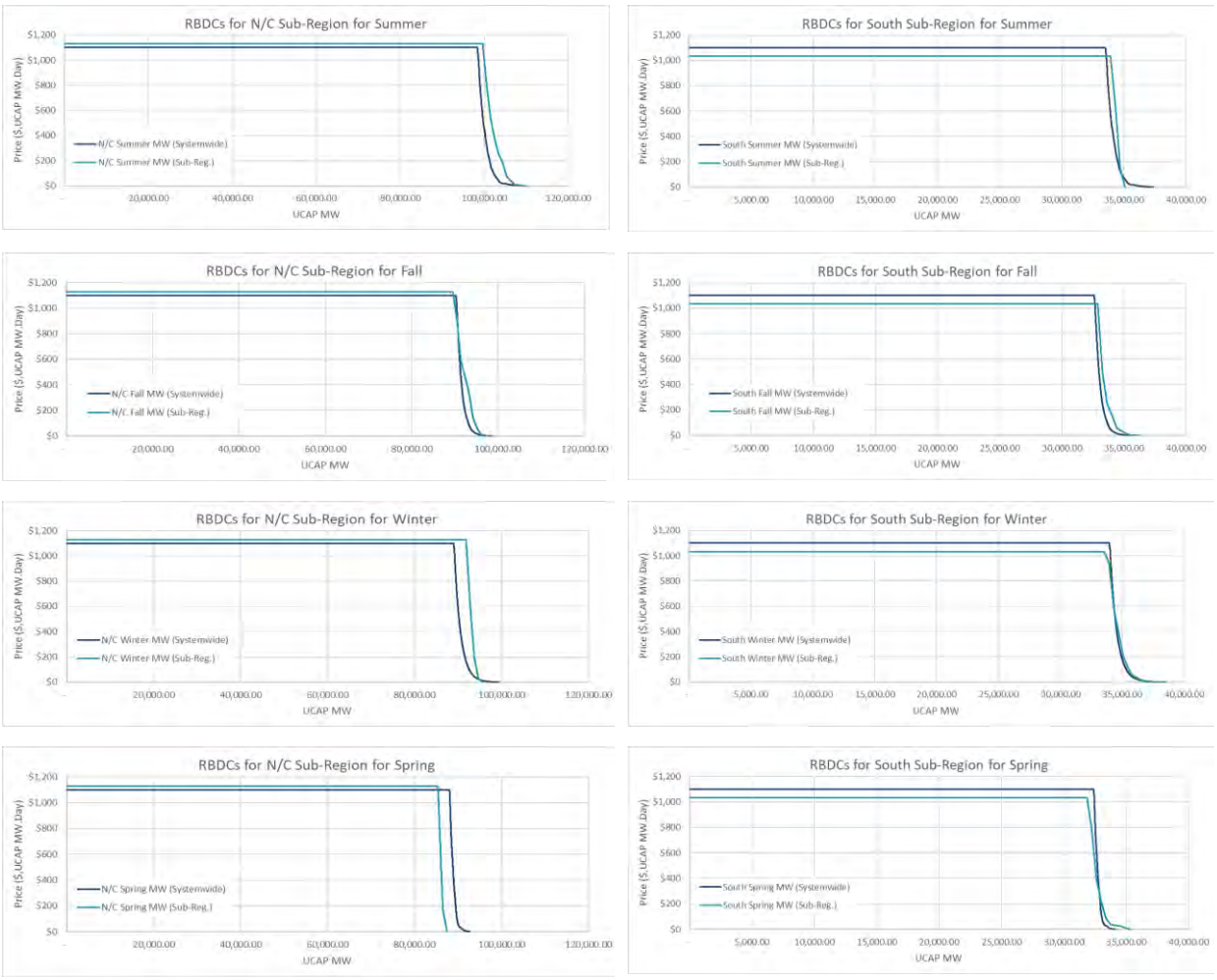


Figure 2. Indicative seasonal RBDC curves for N/C and South subregions, also showing the load-share-based projection of systemwide RBDC on to the sub-region.

3.1 Step 1 Formulation

The optimization problem for the RBDC identification step is posed as a linear program with the objective to minimize the cost of balancing capacity & demand for two scenarios: (i) demand is from share-of-systemwide RBDC in each subregion, and (ii) demand is from subregional RBDC

in each subregion. In this formulation, these two scenarios are enforced independently. Subregional power balancing constraints and zonal clearing constraints are also enforced independently for each scenario.

After solving the LP, the demand cleared on the basis of share-of-systemwide RBDC is compared with the demand cleared on the basis of the subregional RBDC clearing for both N/C and south subregions: for each subregion, the type of RBDC (share-of-systemwide RBDC or subregional RBDC) which produces the higher MW requirement is identified and selected for use in step 2 of the clearing process. The optimization formulation for step 1 is presented in the following.

3.1.1 Objective Function

The linear minimization objective is as follows:

$$\text{Minimize } f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda, \tag{3.1.a}$$

with SC referring to the supply cost which is the area under the offer curve, SB and RB referring to the reliability benefits from the systemwide and subregional RBDCs which are the areas under the systemwide RBDC and subregional RBDCs, respectively, and Λ as the shortage penalty for zonal LCR shortage or initial PRMR shortage beyond the capacity import limit (CIL) of the zone. These terms are expressed as follows:

$$SC \stackrel{\text{def}}{=} \sum_{i \in F} OFFERPRICE_i \times (clearedMW_i^{SYS} + clearedMW_i^{SR}) \tag{3.1.b}$$

$$SB \stackrel{\text{def}}{=} \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \tag{3.1.c}$$

$$RB \stackrel{\text{def}}{=} \sum_{r \in R} \sum_{j \in J_r} RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \tag{3.1.d}$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k \in Z} SEASONALCONE_k \times (S_k^{SYS} + S_k^{SR}) \tag{3.1.e}$$

3.1.2 Constraints

The optimization constraints are based on system, subregional, and zonal balancing requirements, in addition to bounds on resource and segment clearing. Note that all decision variables are restricted to be in the domain of non-negative real values.

3.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i^{SYS} \leq OFFERMW_i, \quad \forall i \in F \tag{3.2.a}$$

$$clearedMW_i^{SR} \leq OFFERMW_i, \quad \forall i \in F \tag{3.2.b}$$

3.1.2.2 RBDC segment bounds

Price sensitive demand, characterized by different RBDCs, has limits based on the segments of the RBDC; MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq RBDCSTEP_j, \quad \forall j \in J_{SYS-RBDC}, \quad \forall r \in R \tag{3.3.a}$$

$$clearedDemand_{j,r}^{SR} \leq RBDCSTEP_j, \quad \forall j \in J_r, \quad \forall r \in R \tag{3.3.b}$$

3.1.2.3 Power balance constraints

Systemwide supply-demand balance constraints. To properly value the reliability given the clearing outcome, the supply-demand balance equations enforce the condition that cleared supply is greater than or equal to cleared demand.

In step 1, the supply-demand balance must hold for both the system and subregional RBDC curves: the cleared quantity of demand from each RBDC curve must be met by corresponding supply-side variables.

$$\sum_{i \in F} clearedMW_i^{SYS} \geq \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{3.4.a}$$

$$\sum_{i \in F} clearedMW_i^{SR} \geq \sum_{r \in R} \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \tag{3.4.b}$$

Subregional supply-demand balance constraints. These constraints ensure that the difference between the cleared supply available within a subregion and the cleared demand associated with the subregion is within the subregional import and export limits (SRIC and SREC, respectively). In step 1, the constraints are imposed for clearing associated with both systemwide and subregional RBDCs as follows, respectively:

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SYS} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SYS} - \sum_{j \in J_{SYS-RBDC}} \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \quad \forall r \in R \tag{3.5.a}$$

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SR} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SR} - \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \leq SREC_r, \quad \forall r \in R \tag{3.5.b}$$

3.1.2.4 Zonal Clearing Constraints

Local Clearing Requirement (LCR) and Capacity Import Limit (CIL) constraints ensure that the quantity of cleared supply in the zone must exceed the minimum of the LCR and the share of Initial PRMR that cannot be met by imports. If the quantity of cleared supply falls short of either of these limits, the shortfall variable is penalized at the zone's seasonal CONE value in the objective function (3.1.a). In Step 1, the LCR and CIL are enforced for both the systemwide and subregional RBDC clearing outcomes. The LCR constraints are as follows:

$$\sum_{i \in G_k} clearedMW_i^{SYS} + S_k^{SYS} \geq LCR_k, \quad \forall k \in Z \tag{3.6.a}$$

$$\sum_{i \in G_k} clearedMW_i^{SR} + S_k^{SR} \geq LCR_k, \quad \forall k \in Z \tag{3.6.b}$$

The quantity of imports in the zone to meet initial PRMR requirements must be below CIL. Only the tighter of the LCR and CIL constraints will bind, so we can use the same shortage variables for both LCR and CIL constraints. The CIL constraints are as follows:

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i^{SYS} - S_k^{SYS} \leq CIL_k, \quad \forall k \in Z \tag{3.7.a}$$

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i^{SR} - S_k^{SR} \leq CIL_k, \quad \forall k \in Z \tag{3.7.b}$$

Capacity Export Limit (CEL) constraints ensure that the quantity of exports for the zone does not exceed the available transfer capabilities (CEL). The exports are the difference between the cleared supply in the LRZ and the load obligations of the LRZ. The load requirement for an LRZ is calculated based on the CPDF share of the LRZ with respect to the cleared demand in the subregion. Consequently, the LRZ obligations based on systemwide RBDC clearing and subregional RBDC clearing are given by, respectively,

$$LRZReq_k^{SYS} = \sum_{j \in J_{SYS-RBDC}} \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS}, \quad \forall k \in Z_r, \forall r \in R \tag{3.8.a}$$

$$LRZReq_k^{SR} = \sum_{j \in J_r} \alpha_k^{r} \times clearedDemand_{j,r}^{SR}, \quad \forall k \in Z_r, \forall r \in R \tag{3.8.b}$$

The CEL constraints for each LRZ corresponding to the systemwide RBDC and the subregional RBDCs are given by, respectively,

$$\sum_{i \in G_k} clearedMW_i^{SYS} - LRZReq_k^{SYS} \leq CEL_k, \quad \forall k \in Z \tag{3.9.a}$$

$$\sum_{i \in G_k} clearedMW_i^{SR} - LRZReq_k^{SR} \leq CEL_k, \quad \forall k \in Z \tag{3.9.b}$$

Since ERZs have no load obligations, their CEL constraints for systemwide RBDC and subregional RBDCs are given by, respectively,

$$\sum_{i \in H_e} clearedMW_i^{SYS} \leq CEL_e, \quad \forall e \in E \tag{3.9.c}$$

$$\sum_{i \in H_e} clearedMW_i^{SR} \leq CEL_e, \quad \forall e \in E \tag{3.9.d}$$

4 Step 2: Clearing and Pricing

Following step 1: RBDC identification, the effective RBDCs for each subregion are established. In step 2, these identified RBDCs are used to determine resource and RBDC MW clearing along with the Auction Clearing Prices (ACPs). This clearing and pricing optimization problem is an LP problem.

In the social welfare optimization problem in step 2, for each subregion, we select the RBDC (between share-of-systemwide RBDC and subregional RBDC) that resulted in a higher requirement in that subregion. This selection is done via parameter u_r: for a given subregion $r \in R$, the parameter u_r is a binary parameter which is determined based on the clearing results of step 1. Parameter u_r is set to 0 if share-of-systemwide RBDC resulted in a higher clearing in step 1 (i.e., share-of-systemwide RBDC is selected for step 2), while it is set to 1 if the subregional RBDC resulted in a higher clearing in step 1 (i.e., subregional RBDC selected for step 2). The parameter selection for each subregion is given by the following equation:

$$u_r = 1\left(\left\{\sum_{k\in Z_r} LRZReq_k^{SYS} \leq \sum_{k\in Z_r} LRZReq_k^{SR}\right\}\right), \qquad \forall r \in R, \tag{4.1}$$

where 1 is the indicator function[6], and the LRZ clearing requirements are from step 1 as defined in (3.8).

4.1 Step 2: Formulation

Since we are selecting the RBDCs using the parameter u_r, step 2 does not require separate supply variables or constraint equations to distinguish between systemwide RBDC and subregional RBDCs. The details of the LP formulation for the clearing-and-pricing step 2 are as follows.

4.1.1 Objective Function

The linear minimization objective is given by the following equations, with the same terminology as defined in Section 3:

$$\text{Minimize } f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda, \tag{4.2.a}$$

$$SC \stackrel{\text{def}}{=} \sum_{i\in F} OFFERPRICE_i \times clearedMW_i \tag{4.2.b}$$

$$SB \stackrel{\text{def}}{=} \sum_{j\in J_{SYS-RBDC}} \sum_{r\in R} (1-u_r) \times \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \tag{4.2.c}$$

$$RB \stackrel{\text{def}}{=} \sum_{r\in R} \sum_{j\in J_r} u_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \tag{4.2.d}$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k\in Z} SEASONALCONE_k \times S_k \tag{4.2.e}$$

4.1.2 Constraints

In step 2, the power balancing constraints and the segment bounds are imposed for the selected RBDC using the parameter u_r. This subsection provides expression for the constraints in the LP.

4.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i \leq OFFERMW_i, \qquad \forall i \in F \tag{4.3}$$

4.1.2.2 RBDC segment bounds

MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq (1-u_r) \times RBDCSTEP_j, \ \forall j \in J_{SYS-RBDC}, \qquad \forall r \in R \tag{4.4.a}$$

$$clearedDemand_{j,r}^{SR} \leq u_r \times RBDCSTEP_j, \qquad \forall j \in J_r, \qquad \forall r \in R \tag{4.4.b}$$

The multiplication involving the parameter u_r in the above equation ensures that the segment-wise clearing variables are allowed to take non-zero values only for the selected RBDC; the segment-wise clearing variables will be zero for the non-selected RBDC.

4.1.2.3 Power balance constraints

The system power balance constraint is represented below: the cleared systemwide supply should exceed the total system cleared demand from the selected RBDCs.

$$\sum_{i \in F} clearedMW_i \geq \sum_{r \in R} \sum_{j \in J_r} u_r \times clearedDemand_{j,r}^{SR} + \sum_{r \in R} \sum_{j \in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{4.5}$$

The subregional power balancing constraints ensure that the difference between the selected RBDC cleared demand and subregion cleared supply, including external resources clearing for the subregion, respects the subregional import and export constraints, as follows:

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k - \sum_{j \in J_r} u_r \times clearedDemand_{j,r}^{SR} - \sum_{j \in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \qquad \forall r \in R \tag{4.6}$$

4.1.2.4 Zonal Clearing Constraints

The LCR and CIL are requirements that need to be met with local resources or penalized in cases of shortage. These constraints are represented as follows, respectively,

$$\sum_{i \in G_k} clearedMW_i + S_k \geq LCR_k, \ \forall k \in Z \tag{4.7}$$

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i - S_k \leq CIL_k, \quad \forall k \in Z \tag{4.8}$$

The CEL constraints are imposed with respect to the load obligation for each LRZ. The load obligation for LRZs is expressed as the zonal CPDF share of the cleared demand from the selected RBDC. This is given by,

$$LRZReq_k = \sum_{j \in J_{SYS-RBDC}} (1 - u_r) \times \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS} + \sum_{j \in J_r} u_r \times \alpha_k^r \times clearedDemand_{j,r}^{SR}, \quad \forall k \in Z_r, \forall r \in R \tag{4.9}$$

The difference between the zonal cleared supply and the LRZ load requirement should be below CEL:

$$\sum_{i \in G_k} clearedMW_i - LRZReq_k \leq CEL_k, \quad \forall k \in Z \tag{4.10.a}$$

Since ERZs do not have load obligations, their CEL constraints are given by:

$$\sum_{i \in H_e} clearedMW_i \leq CEL_e, \quad \forall e \in E \tag{4.10.b}$$

4.2 Verification of selected RBDC for Step 2

For a given subregion, if both the share-of-systemwide RBDC and the subregional RBDC are intertwined near the intersection of the supply and demand curves, then the RBDC producing higher requirement may be inconsistent between step 1 and step 2. Therefore, additional verification is performed to ensure that the curve selected for step 2 results in an appropriate requirement. This verification process is described below.

Verification step 1: Determine the subregional clearing price for subregion $r \in R$ as the sum of the shadow prices corresponding to the system and subregional power balancing constraints, i.e., the sum of the shadow prices (which are the dual variables) for the constraints (4.5) and (4.6).

Verification step 2: For the subregional clearing price calculated in verification step 1, determine the associated UCAP MW for the share-of-systemwide RBDC and the subregional RBDC for each subregion *r*. Note the RBDC that results in the higher requirement.

Verification step 3: For a given subregion, if the RBDC with the higher UCAP MW as determined in verification step 2 matches with the RBDC selected via the binary parameter u_r (0 implies selection of share-of-systemwide RBDC and 1 implies selection of subregional RBDC), then the PRA clearing solution is valid and we can proceed with the computation of clearing prices and obligations for the market participants.

If the verification fails for a given subregion, then this failure implies that the RBDC with the higher UCAP MW as determined in verification step 2 is different from the type of RBDC (share of systemwide or subregional) selected via the parameter u_r; hence, the PRA clearing solution is not valid. In such a case, the value of the parameter u_r for the subregion is switched to its complement (0 to 1, or 1 to 0), and step 2 of the PRA clearing process is solved again with this updated parameter.

4.3 Auction clearing Price calculations

Following the PRA clearing solution obtained in the step 2 optimization problem, the clearing prices are calculated for every LRZ and ERZ. This section describes the methodology for computing the auction clearing price (ACP).

4.3.1 ACP determination

The initial auction clearing price is calculated using the shadow prices (SP) of the system, subregional, and zonal power balancing constraints, which are defined below. All prices in this document are in units of $/MW-day.

$systemBalanceSP$ — Non-negative shadow price corresponding to the systemwide supply demand balancing constraint (4.5). This SP applies to all LRZs and ERZs.

$SRICSP_r$ — Non-negative shadow price corresponding to the subregional import constraint: left-hand side inequality of (4.6). A positive shadow price implies that the imports for subregion *r* are equal to the SRIC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$SRECSP_r$ — Non-positive shadow price corresponding to the subregional export constraint: right-hand side inequality of (4.6); a negative value implies that the exports for subregion *r* are equal to the SREC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$LCRSP_k$ — Non-negative SP for the LCR constraint (4.7) for LRZ $k \in Z$. This only applies to LRZs. A positive SP for the LRZ implies that the total cleared generation in LRZ *k* is either exactly equal to the LCR for *k*, or that the total generation offered in LRZ *k* is short of the LCR for *k* (in which case, seasonal CONE pricing is used as a shortage penalty).

$CILSP_k$ — Non-negative SP for the CIL constraint (4.8) for LRZ $k \in Z$. This only applies to LRZs. A positive SP implies that the difference between the initial PRMR and the total cleared generation in the LRZ is either exactly equal to CIL or is more than CIL in case of a shortage.

$CELSP_k$ — Non-positive SP for the CEL constraint (4.10) for zone $k \in Z \cup E$. This applies to both LRZs and ERZs.

The ex-ante ACP for an LRZ $k \in Z_r$ in subregion $r \in R$, prior to the calculation of LCR price adder is the minimum of (i) seasonal CONE of the LRZ and (ii) the sum of shadow prices corresponding to the LRZ (for zones without multi-season shortage, the ex-ante ACP will also be the ex-post ACP for the LRZ):

$$ACP_k^{EA} = min\{SEASONALCONE_k, systemBalanceSP + SRICSP_r + SRECSP_r + LCRSP_k + CILSP_k + CELSP_k\} \quad (4.11.a)$$

The ACP for an ERZ $e \in E$ is the minimum of (i) the maximum seasonal CONE of all the LRZs in the subregion to which the ERZ is connected (for dual connected ERZs, this is the maximum seasonal CONE of all LRZs in the entire transmission area; and (ii) the sum of the shadow prices corresponding to the ERZ:

$$ACP_e = min\{SEASONALCONE_e, systemBalanceSP + CELSP_e + \sum_r SF_{r,e} \times (SRICSP_r + SRECSP_r)\} \quad (4.11.b)$$

4.3.2 ACP under multi season LRZ shortages, or near-shortages, on local clearing requirement

When an LRZ has more than one season in any combination of ZRC shortage conditions and/or ZRC near-shortage conditions, the final Auction Clearing Price (ACP) for the LRZ will be determined as follows.

Let $\tilde{Z}$ the set of all LRZs with multi-season LCR or CIL shortage or near-shortage conditions. Let N_k^S denote the total number of shortage or near-shortage days for the LRZ $k \in \tilde{Z}$ across the entire planning year. Then, the LCR price adder for LRZ k is given by,

$$LCRPRICEADDER_k = CONE_k / N_k^S \quad (4.12)$$

The ex-post ACP for an LRZ k with multi-season shortage or near-shortage is,

$$ACP_k^{EP} = min\{SEASONALCONE_k, systemBalanceSP + SRICSP_r + SRECSP_r + LCRPRICEADDER_k\}, \quad \forall k \in \tilde{Z} \quad (4.13)$$

5 Final Auction Clearing Quantities for LRZs

The Final PRMR of an LSE is determined based on RBDC clearing in the corresponding subregion and the LSE's participation option (such as RBDC Opt Out, market participation, etc.)

in the PRA. The detailed procedure to determine Final PRMR is presented in Section 5.6 of this Business Practice Manual.

6 Examples

6.1 Small System Examples

Assume a system as shown in **Error! Reference source not found.** below. It consists of two L RZs and two subregions. There is a limited transfer capability between the subregions, and it is reflected in the subregional power balance constraint limit (SRPBC): the SRPBC limit in the following examples is a simplified representation of the SRIC/SREC constraints included in the preceding mathematical formulation.

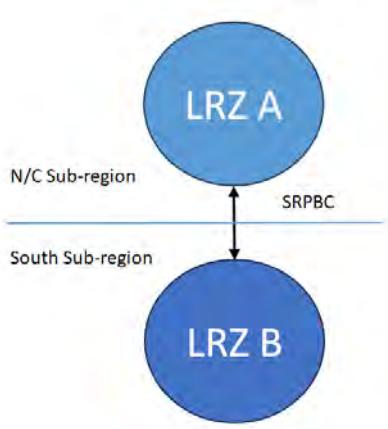


Figure 3. System setup for clearing examples: Two LRZ system with two subregions

Case 1: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and there are no binding subregional import/export constraints. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	23 (sub-regional RBDC)	48	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	8
R4	South Sub-region	$14	40	40

Case 2: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and the subregional import/export constraints are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

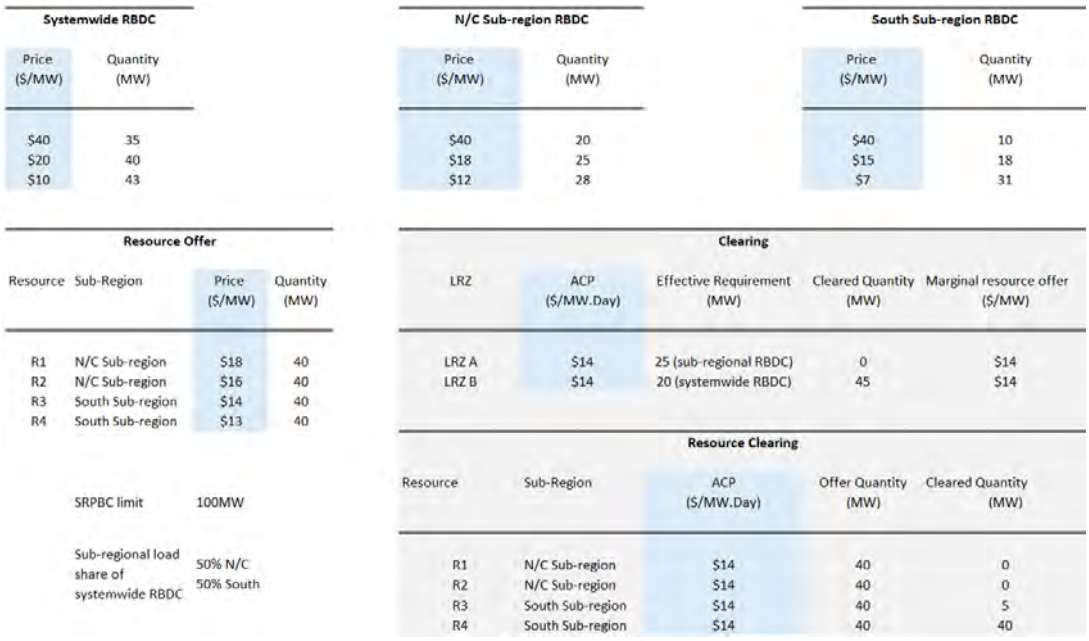
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	20	$16
LRZ B	$13	23 (sub-regional RBDC)	28	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	20
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	28

Case 3: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are not binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	20 (systemwide RBDC)	45	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	5
R4	South Sub-region	$14	40	40

Case 4: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	10MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	15	$16
LRZ B	$13	20 (systemwide RBDC)	30	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	30

Case 5: Systemwide RBDC results in a higher requirement in both subregions, and no SRIC/SREC binding. Offer, RBDC, and clearing details are in the following figure.

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	500 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$13	20 (system RBDC)	0	$13
LRZ B	$13	20 (system RBDC)	40	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$13	40	0
R2	N/C Sub-region	$13	40	0
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	40

Case 6: Systemwide RBDC results in a higher requirement in both subregions, and SRIC/SREC are binding. Offer, RBDC, and clearing details are in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	20 (system RBDC)	15	$16
LRZ B	$13	20 (system RBDC)	25	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	25

6.2 PRA Clearing Examples using Indicative RBDCs

This section provides an illustrative graphical representation of the auction clearing with RBDCs: the plots representing the PRA clearing outcomes with indicative RBDCs for PY 24-25 Summer Season are presented in **Error! Reference source not found.**. The indicative RBDCs are d eveloped based on PY 24-25 loss-of-load study and the associated models. Resource offers submitted for the PY 24-25 Summer Season are used for the supply curves. The parameters for the zonal CIL, CEL, and LCR constraints are the same as those used in the PY 2024/25 PRA. The solution to the linear programming-based formulation results in an Auction Clearing Price of about $140/MW-day with no subregional or zonal price separation. The systemwide RBDC is setting up the requirement in both subregions with a total cleared demand of 140.1GW, because the share-of-systemwide RBDCs are to the right of the subregional RBDCs in both subregions.

The SREC limit from the south subregion to the north/central subregion is 1,900 MW; the capacity exports from the south subregion to the north/central subregion are 1,581 MW as reflected in **Error! Reference source not found.**. The RBDCs shown in the dashed lines for t

he exporting subregion (south) have been shifted to **the right by the export quantity**, while those for the importing subregion (N/C) have been shifted to **the left by the same quantity**. The original RBDCs are in solid lines.

The horizontal line represents the ACP, which is set at the intersection of the supply curve and import/export-shifted RBDC for each subregion (red dot in the figure). The Final PRMR for an importing subregion (N/C) is to the **right** of the intersection of the supply curve and the import-shifted RBDC by the import quantity (1,581 MW in the figures below). Similarly, for the exporting subregion (south), the final PRMR is to the **left** of the intersection of the supply curve and the export-shifted RBDC by the export quantity of 1,581 MW. The Final PRMR is shown by the dotted dark-gray vertical line passing through the intersection of the horizontal ACP line and the requirement-setting RBDC (share-of-systemwide RBDC for Summer 2024 in both subregions—plots in orange solid lines).

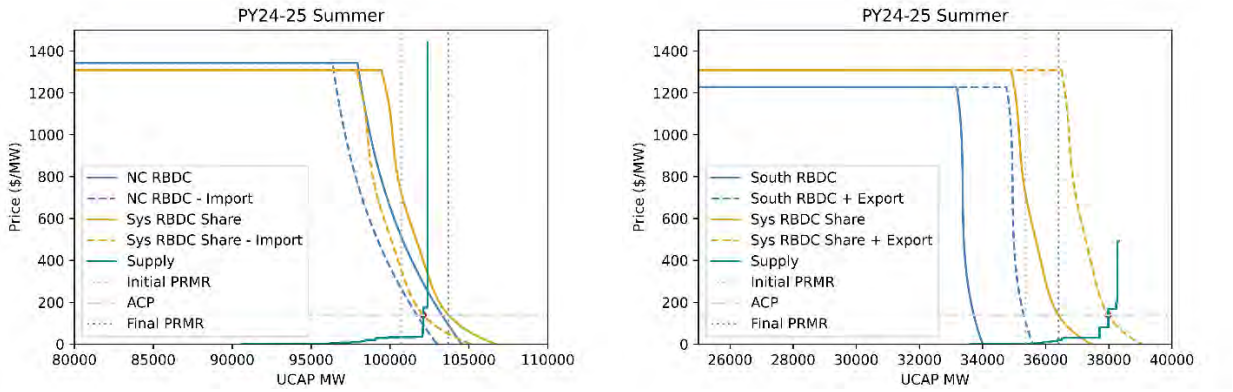


Figure 4. PRA clearing with indicative RBDCs representing PY24-25 Summer season with actual offers submitted for PY24-25 Summer season.

For completeness, the zoomed-in version of PRA clearing presented in **Error! Reference source not found.** is shown below in **Error! Reference source not found.**.

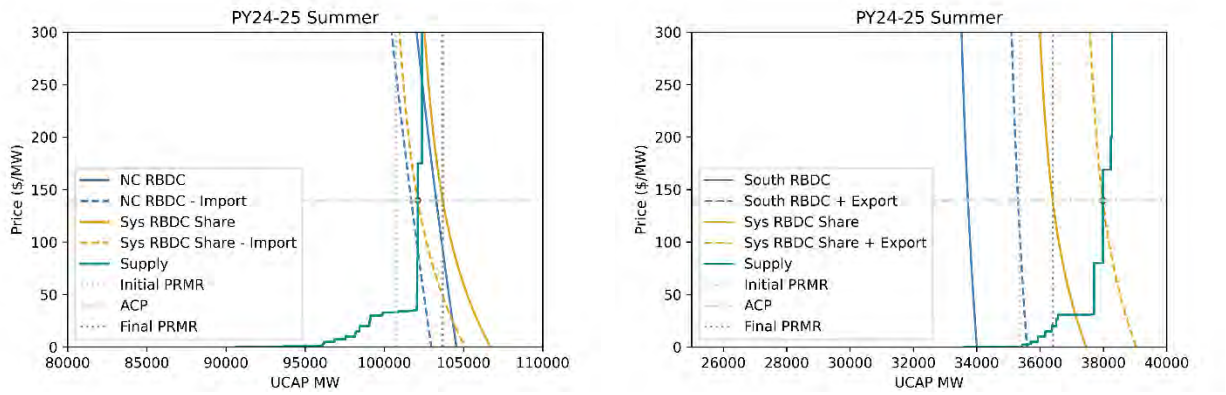


Figure 5. Zoomed in version of illustrative PY 24-25 Summer season PRA clearing

Appendix N – Seasonal Demand and Energy Forecast Characteristics

Forecast Criteria	Coincident Peak Demand and Zonal Coincident Peak Demand Forecasts	Non-Coincident Peak Demand Forecast	Energy for Load Forecast
Includes Demand Served by Energy Efficiency Planning Resources	Yes	Yes	Yes
Includes Demand Served by Energy Efficiency Programs	No	No	No
Includes Demand Served by Demand Resources	Yes	Yes	Yes
Includes Demand Served by BTMG Planning Resources	Yes	Yes	Yes
Includes Demand Served by resources that are not qualified as Planning Resources	Yes	No	No
Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR	No	Yes	Yes
Includes Transmission Losses	No	No	Yes
Coincident with reporting Load Serving Entities' system	No	Yes	No
Demand reported at Physical LBA Location	Yes	Yes	Yes
Include Demand from Power Plant Station or Auxiliary Needs	No	No	No

Appendix O – Parties Responsible for Reporting Seasonal Demand and Energy Forecasts

Data	EDC	Retail Choice LSE	Non-Retail Choice LSE
MISO Coincident Peak (Total CPF)	No	No	Yes
MISO Non-Coincident Peak (Total NCPF)	No	No	Yes
Zonal Coincident Peak (Total CPF)	No	No	Yes
RC Coincident Peak (Total CPFEDC Area)	Yes	No	No
RC Coincident Peak (Total NCPF) Load Contribution	Yes	No	No
RC Zonal Coincident Peak (Total CPFEDC Area)	Yes	No	No
Non-Coincident Peak	Yes	No	Yes
RC Non-Coincident Peak	No	Yes	No
Energy for Load	Yes	No	Yes
Retail Choice (MISO Peak)	Yes	No	No
Retail Choice (Zonal Peak)	Yes	No	No

Appendix P – Zonal Deliverability Benefit *Pro Rata* Allocation

This Appendix is an illustrative example of the ZDB *pro rata* allocation methodology in the presence of Historical Unit Considerations (HUC) and Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out. The results from the Planning Resource Auction for the 2020/2021 Planning Year are used in this example to educate Market Participants. The resulting Auction Clearing Prices illustrated here are different than those settled for the 2020/2021 Planning Year. Starting in Planning Year 2023-2024, the ZDB calculation will be performed separately for each Season in which the ZDB calculation is required.

Step 1Subtract PRMR and ZRCs associated with HUC Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC). ZRCs are FRAP + RBDC Opt Out + Self-scheduled offers + cleared Non-self-scheduled offers.

RZ	ACP	Final PRMR	ZRC	HUC (MW)	ZDC Hedges (MW)	Adjusted Final PRMR	Adjusted ZRC
Z1	$5.00	18,476.0	18,742.0	191.7	0	18,284.3	18,550.3
Z2	$5.00	13,728.2	13,590.0	0	0	13,728.2	13,590.0
Z3	$5.00	10,129.1	10,551.0	0	0	10,129.1	10,551.0
Z4	$5.00	9,794.6	8,462.1	0	0	9,794.6	8,462.1
Z5	$5.00	8,456.3	7,952.8	0	0	8,456.3	7,952.8
Z6	$5.00	18,720.6	17,054.6	0	0	18,720.6	17,054.6
Z7	$257.53	21,945.3	21,727.5	0	0	21,945.3	21,727.5
Z8	$4.75	7,986.9	10,183.1	0	0	7,986.9	10,183.1
Z9	$6.88	21,711.7	20,893.7	107.3	0	21,604.4	20,786.4
Z10	$4.75	5,030.6	5,244.2	0	0	5,030.6	5,244.2
E20	$4.90	0.0	347.2	0	0	0.0	347.2
E22	$5.00	0.0	633.8	0	0	0.0	633.8
E23	$5.00	0.0	30.1	0	0	0.0	30.1
E24	$5.00	0.0	148.4	0	0	0.0	148.4
E26	$4.92	0.0	24.0	0	0	0.0	24.0
E27	$4.89	0.0	168.3	0	0	0.0	168.3
E28	$4.90	0.0	226.5	0	0	0.0	226.5

Step 2: Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. In this example, Zone 7 is a DBZ because the PRA bound on its LCR.

RZ	ACP	Adjusted Final PRMR	Adjusted ZRC	**DBZ Grouping**
Z1	$5.00	18,284.3	18,550.3	Zone A
Z2	$5.00	13,728.2	13,590.0	Zone A
Z3	$5.00	10,129.1	10,551.0	Zone A

Z4	$5.00	9,794.6	8,462.1	Zone A
Z5	$5.00	8,456.3	7,952.8	Zone A
Z6	$5.00	18,720.6	17,054.6	Zone A
Z7	$257.53	21,945.3	21,727.5	Zone B
Z8	$4.75	7,986.9	10,183.1	Zone D
Z9	$6.88	21,604.4	20,786.4	Zone C
Z10	$4.75	5,030.6	5,244.2	Zone D
E20	$4.90	0.0	347.2	Zone E
E22	$5.00	0.0	633.8	Zone A
E23	$5.00	0.0	30.1	Zone A
E24	$5.00	0.0	148.4	Zone A
E26	$4.92	0.0	24.0	Zone F
E27	$4.89	0.0	168.3	Zone G
E28	$4.90	0.0	226.5	Zone E

Step 3: For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
In this example, Zones A, B, and C are net importing DBZ's and Zones D, E, F and G are net exporting DBZs.

DBZ	Adjusted Final PRMR	Adjusted ZRC	Difference	Result
Zone A	79,113.1	76,973.1	-2140.0	Net Importer
Zone B	21,945.3	21,727.5	-217.8	Net Importer
Zone C	21,711.7	20,893.7	-818.0	Net Importer
Zone D	13,017.5	15,427.3	2,409.8	Net Exporter
Zone E	0.0	573.7	573.7	Net Exporter
Zone F	0.0	24.0	24.0	Net Exporter
Zone G	0.0	168.3	168.3	Net Exporter

Step 4: Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

DBZ	Net Export	ACP	Net Export*ACP
D	2409.8	$4.75	$11,446.55
E	573.7	$4.90	$2,811.13
F	24	$4.92	$118.08
G	168.3	$4.89	$822.99
Total of Exporting Zones	3175.8		$15,198.75
Weighted Average Export ACP =(Total Net Export*ACP)/(Total Net Export)			$4.79

Step 5: Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

DBZ	Net Import	ACP ($/MW-day)	Weighted Average Export ACP	ZDB Credit ($/day)
A	2140.0	$5.00	$4.79	$458.39
B	217.8	$257.53	$4.79	$55,047.69
C	818.0	$6.88	$4.79	$1,713.05
Total of Importing Zones	3175.8			

Step 6: Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

DBZ	ZDB Credit ($/day)	RZ	Adjusted Final PRMR	ZDB Rate ($/MW-day)	ACP	Net ACP
A	$458.39	1	18,284.3	$0.01	$5.00	$4.99
		2	13,728.2			
		3	10,129.1			
		4	9,794.6			
		5	8,456.3			
		6	18,720.6			
		Total DBZ A	79,113.1			
B	$55,047.69	7	21,945.3	$2.51	$257.53	$255.02
C	$1,713.05	9	21,604.4	$0.08	$6.88	$6.80

Appendix Q – Fleet XEFORd Calculation

This appendix walks through the process for calculating fleet XEFORd. This process is used for External Resources that participate in the PRA as one MECT resource which represents the aggregate of a fleet of units. In order to qualify, resource owners must submit help tickets to help.misoenergy.org to let MISO know which resources to be included in your fleet by November 15, otherwise the resource will not be able to participate in the PRA. For example, an external area might have 100 units in its fleet with a total capacity of 10,000 MW of which it plans to commit 1,000 MW on an installed capacity basis to MISO. MISO will then calculate a seasonal SAC based on a seasonal weighted average forced outage rate of all units in the fleet. Intermittent and class average units are excluded from the fleet XEFORd calculation. This appendix will walk through a weighted average example calculation for a set of fleet units.

Utility	Unit	Unit Name	GVTC (MW)	XEFORd (%)	Weighted XEFORd (%)
99A - Midwest ISO	101	Carmel 1	100.0	15.0%	4.5%
99A - Midwest ISO	102	Carmel 2	120.0	10.0%	3.6%
99A - Midwest ISO	601	Eagan 1	65.0	7.5%	1.5%
99A - Midwest ISO	602	Eagan 2	50.0	5.0%	0.7%
99A - Midwest ISO	501	Little Rock 1	20.0	Intermittent	Excluded
99A - Midwest ISO	502	Little Rock 2	25.0	Intermittent	Excluded
99A - Midwest ISO	401	Metarie 1	5.0	Class average	Excluded
99A - Midwest ISO	402	Metarie 2	3.0	Class average	Excluded
		Fleet Total	388.0		
		Fleet Total included in Fleet XEFORd Calculation	335.0		10.3%

Formulas

- Unit Weighted Average XEFORd = (Unit GVTC (MW)) / (Total GVTC (MW)) * (Unit XEFORd)

  (for Carmel 1 weighted XEFORd is 100.0/335.0*15.0% = 4.5%)

- Fleet Total GVTC (MW) = Sum of GVTC (MW) for all units

  (100.0 + 120.0 + 65.0 + 50.0 + 20.0 + 25.0 + 5.0 +3.0 = 388.0)

- Fleet GVTC w/ XEFORd = Sum of GVTC for all units with an XEFORd value

  (100.0 + 120.0 + 65.0 + 50.0 = 335.0)

- Fleet Weighted XEFORd = Sum of Weighted XEFORd for all units

  (4.5% + 3.6% + 1.5% + 0.7% = 10.3%)

Appendix R – Annual CONE Calculation

MISO calculates gross Cost of New Entry (CONE) values for each LRZ for each Planning Year. This CONE value will be used for all Seasons within the entire Planning Year. MISO calculates CONE for each LRZ based upon the costs associated with an advanced combustion turbine generator (CT). MISO uses the following approach:

1. MISO begins with an estimate of a CONE value not specific to an LRZ,
2. MISO uses "the law of one price" where applicable (e.g., turbines that are sold competitively),
3. MISO develops zonal differences to reflect different locational costs (e.g., labor, technical enhancements and others) using the most recent United States Energy Information Administration (EIA) document, and
4. MISO uses the Net Present Value (NPV) algorithm to calculate CONE values for each LRZ.

MISO allows factors such as the weighted average cost of capital, escalation rates, and other factors where global competition drives prices to have no locational differences to be constant.

In order to determine the appropriate CONE value for each LRZ, MISO relies upon the most recent EIA report on "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (EIA Report)". The EIA Report contains detailed specifications for a hypothetical advanced CT, including information regarding the differences in project costs for an advanced CT with a nominal capacity of 237 MW, based upon the state where the facility is constructed. The report is available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/.

MISO uses an NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each LRZ. In accordance with Section 69A.8.a of Module E-1, MISO considers many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and

maintenance expenses). MISO does not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

CONE values for each Planning Year are based, in part, upon data supplied by the EIA, which are adjusted using the implicit price deflator from the Bureau of Economic analysis in order to convert EIA cost data into present value dollars. In order to produce the annualized CONE value for each LRZ from these cost numbers, for the 2023/2024 Planning Resource Auction MISO assumed: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term; (iii) a 5.16 percent debt interest rate; (iv) a 2.2 percent Operation and Maintenance escalation factor; (v) a 2.2 percent GDP deflator; (vi) a 25-31 percent combined effective federal and state tax rate; (vii) property tax and insurance costs of 1.5 percent of the capital costs; (viii) a calculated weighted average cost of capital of 7.99 to 8.17 percent; (ix) and a 13.4 percent after tax internal rate of return on equity. None of these factors vary by LRZ to any significant degree that is discernible in available data. MISO will continue to examine these factors in the future to determine if any LRZ specific modifications are indicated. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates.

Steps for calculating CONE

1. Obtain latest 'Base Project Cost $/kW'
   Obtain the latest Energy Information Administration (EIA) report for *EIA,* Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies. It provides the following data:

   - Plant Capital Cost in $/kW. MISO currently uses the number for advanced CT.
   - Location Based Costs Table: Location Percent Variation, Delta Cost Difference and Total Location Project Cost columns

2. Use Bureau of Economic Analysis (BEA) data to calculate implicit price deflator
   Use Table 1.1.9 - Implicit Price Deflators for Gross Domestic Product from NIPA data. Using the table, calculate the *Escalation Rate* from base year to planning year, based on historical and projected quarterly PCE deflator values. Use this Escalation Rate to calculate "Total Location Project Cost" in current year dollars.

3. Calculate LRZ and Base total capital costs, adjusted by multiplying with the Escalation Rate
   For LRZs - Use averages of adjusted project costs for locations (for which data is available) in each zone.

4. Calculate the after-tax weighted average cost of capital (WACC)

$WACC = (E * R_e) + (D * R_d * (1 – T_c))$.

Where E = Equity Fraction of Project

R_e = Cost of Equity. Assume as the after-tax IRR

D = Debt Fraction of Project

R_d = Cost of Debt (20-year BB corporate bond rate)

T_c = Combined effective federal and state tax rate

5. Calculate estimated annualized costs for each LRZ and also for the Base.

- Calculate annualized capital costs using total capital costs, after-tax WACC and assuming the project lifespan. (Use PMT function)
- Calculate the O&M costs based on O&M data, project lifespan, WACC and US GDP Deflator (Use PMT and NPV functions)
  - Assume suitable O&M escalation factor
  - Assume/Update US GDP Deflator
- Assume insurance and property tax costs.

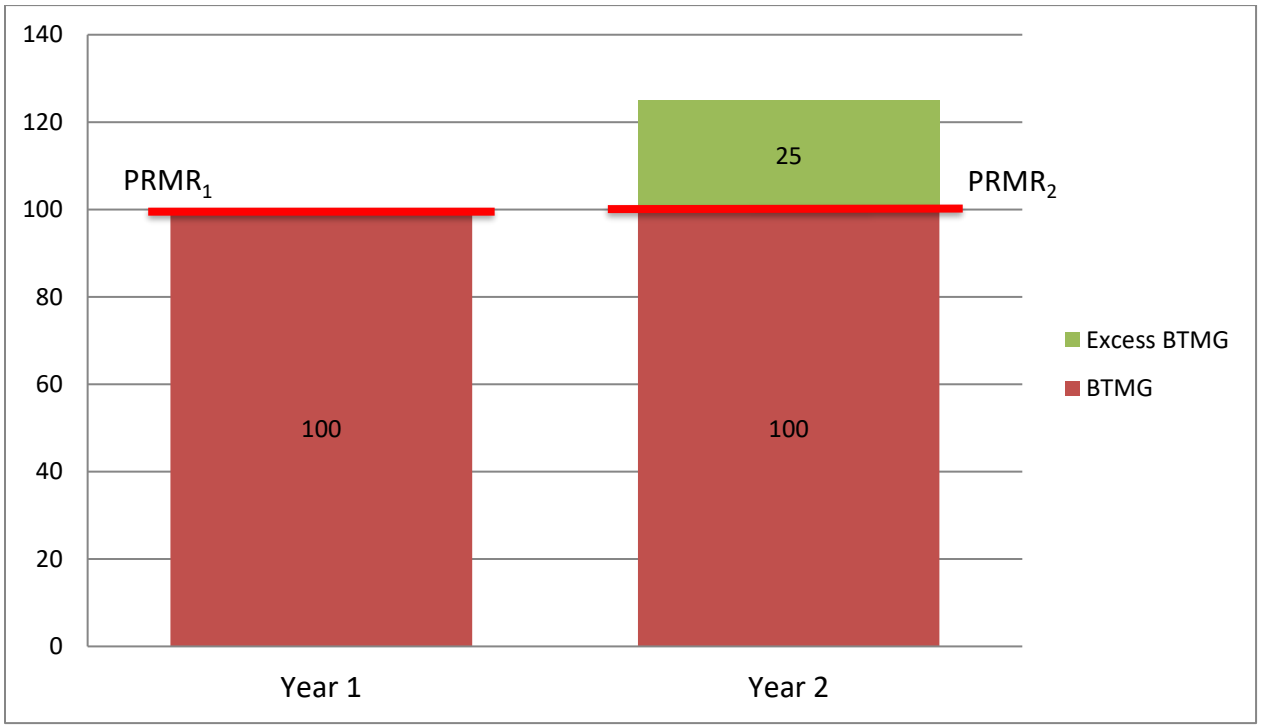
Appendix S – Example Scenarios of "Excess BTMG"

This Appendix shares a few illustrative examples of how BTMG may change to "Excess BTMG" from one year to the next. The examples below show how some specific factors may cause BTMG to be classified as "Excess BTMG" from one year to the next. Below are four examples of "Excess BTMG".

(All PRMR being referred in this appendix are Final PRMR cleared through PRA auction)

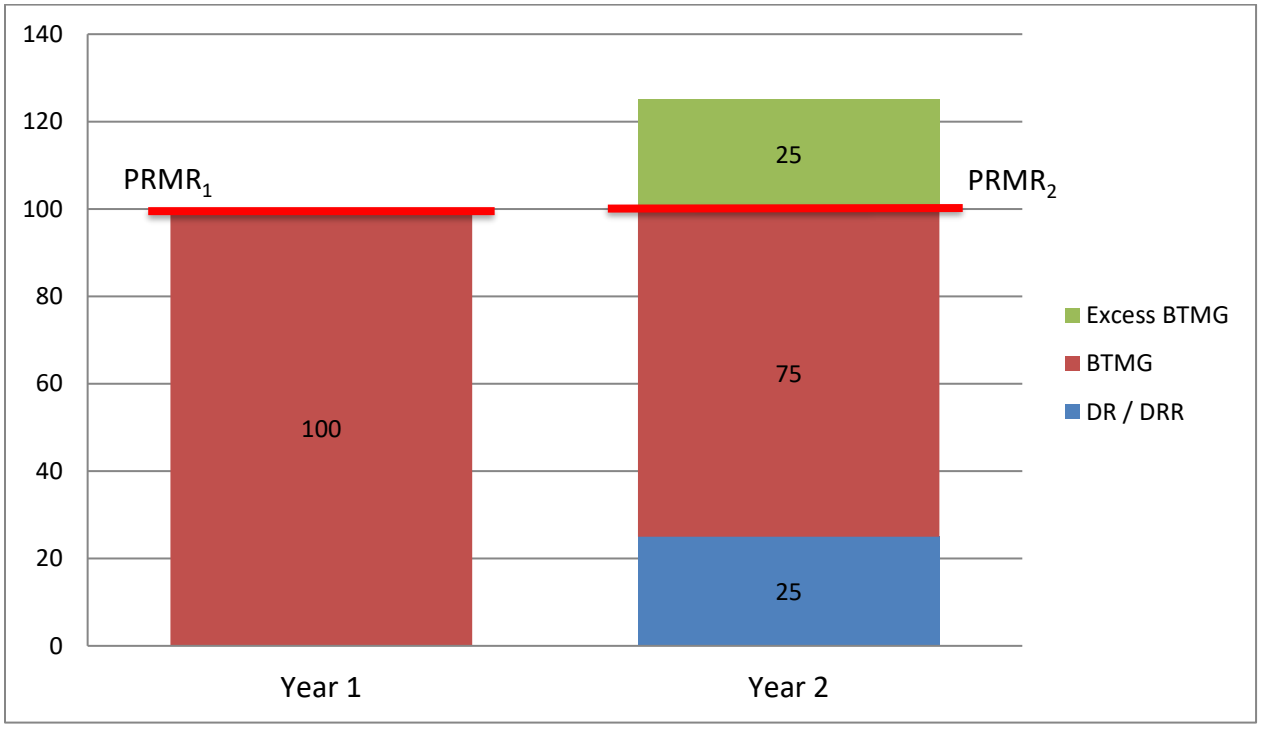
1. Increase in BTMG and No Change to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in BTMG SAC from one year to the next while PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in BTMG of 25 MW—however, seasonal PRMR remains unchanged. In Year 2, the chart shows that BTMG SAC is 125 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.



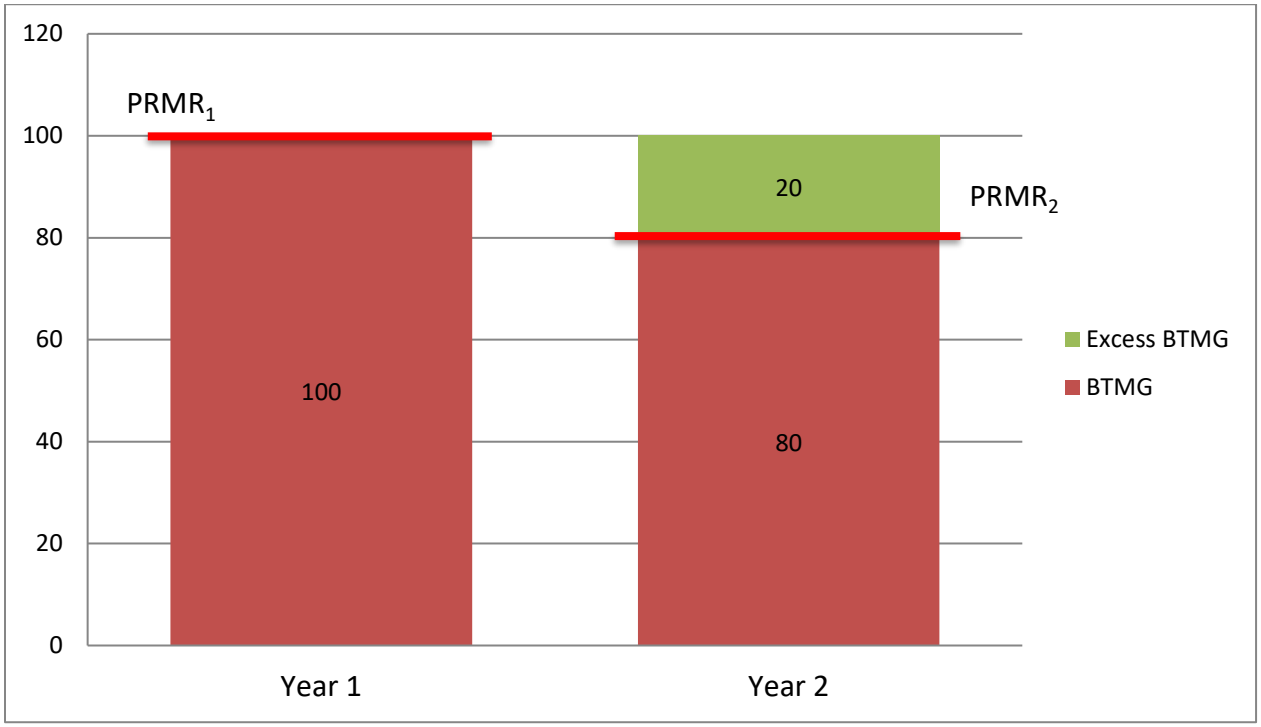
2. Increase in Demand Resources and/or Demand Response Resources and No Change to PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in DR / DRR SAC from one year to the next while seasonal PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in DR / DRR SAC of 25 MW, however, seasonal PRMR remains unchanged. In Year 2, the chart shows that DR / DRR is 25 MW and BTMG is 100 MW and the seasonal PRMR is 100 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.



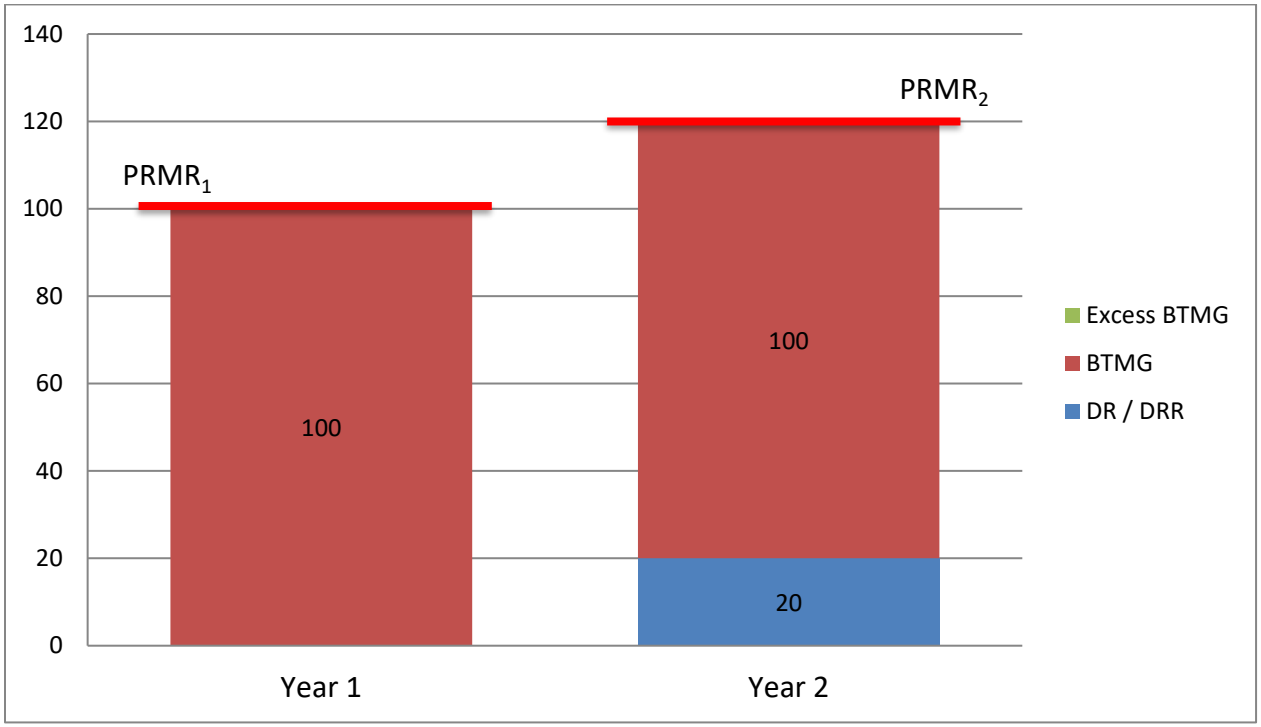
3. No Change to BTMG and Decrease to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences a decrease in seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no “Excess BTMG” in Year 1. Between Year 1 and Year 2, the Market Participant experiences a decrease in seasonal PRMR of 20 MW, however, BTMG SAC remains unchanged. In Year 2, the chart shows that BTMG is 100 MW the seasonal PRMR is now 80 MW; therefore, the Market Participant has 20 MW of “Excess BTMG” in Year 2.



4. Equal Amount Increase in DR / DRR and Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an equal increase in DR / DRR SAC and seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an equal increase in DR / DRR and seasonal PRMR of 20 MW each, however, BTMG remains unchanged. In Year 2, the chart shows that DR / DRR is 20 MW, BTMG is 100 MW and the seasonal PRMR is 120 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR, however, due to the equal increase in DR / DRR and seasonal PRMR there is no "Excess BTMG" in Year 2.



Appendix T – ICAP Deferral Notice

ICAP Deferral Notice
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032-7574
Attn.: Resource Adequacy
(Delivered via email to help@misoenergy.org)

[Current Date]

[Insert Company Name] ICAP Deferral Notice – [Planning Resource Name/CPNode Name, if applicable]
Select Planning Resource being deferred:
☐Generation Resource – [Insert CPNode Name, Unit Number]
☐Dispatchable Intermittent Resource (DIR) – [Insert Name]
☐Demand Response Resource (DRR) – [Insert Name]
☐External Resource – [Insert Name]
☐Behind the Meter Generation (BTMG) – [Insert Name]

Dear Resource Adequacy,

[Insert Company Name] is providing this written notification in accordance with Section 69A.7.9 of the Midcontinent Independent System Operator (MISO) Tariff, Module E-1 Resource Adequacy regarding an Installed Capacity (ICAP) Deferral for the Planning Resource selected above. [Insert Company Name] intends to increase ICAP between March 1 and the last Business Day of the applicable Season(s) for the [Insert Planning Year] Planning Year.

[Contact Name, Phone Number and Email]	Planning Resource Type
MISO MP ID/NERC ID of Company	
Planning Resource Name	
Local or External Resource Zone (LRZ or ERZ) where located	
Planning Resource Fuel Type	
Estimated ICAP Value (MW) *Note: this is the total ICAP value not the incremental increased value from a prior ICAP*	Summer
	Fall
	Winter
	Spring
Check applicable deferred Season(s)	Summer [ ], Fall [ ], Winter [ ], Spring [ ]
Estimated completion date of ICAP	
Reason for deferring (See Appendix U)	
Please fill out the following that is applicable to the Planning Resource being deferred:	
Generation Interconnection Agreement (GIA) Number and expected contract execution date *Note: only necessary if deferral includes upgrades to Interconnection Service*	

Expected NRIS and ERIS values with Interconnection Service upgrades	
Commercial Operation Date	
TSR Number	

Sincerely,
[Name], [Title – must be an officer], [Company Name], [Contact Information]

Appendix U – ICAP Deferral Examples

- Deliverability

Example 1: Unit is capable of testing at 150 MW, but currently only has 100 MW of NRIS with MISO. The unit is in the queue to have its NRIS increased to 150 MW by the last Business Day prior to the start of a Season in the upcoming Planning Year. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. For a Schedule 53 resource, even though the ICAP will increase, SAC will not. For a non-Schedule 53 resource, both ICAP and SAC will increase.

- Increased GVTC and Deliverability

Example 1: Unit currently tested for 100 MW and has 100 MW of NRIS. The unit is in the queue to have NRIS increased to 150 MW and plans to retest after upgrades are in place. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. Please note that the current unit should already submit a GVTC test of 100 MW by October 31.

- Commercial Operation

Example 1: The unit currently is subject to an environmental regulation that prevents the unit from operating. The unit is in the process of installing additional equipment to comply with the new environmental regulation. Thus, the unit is deferring GVTC until after all necessary approvals are completed.
Example 2: A resource that is a Dispatchable Intermittent Resource (DIR) would not submit GVTC, but instead receives capacity accreditation based on past historical data. If a DIR is new and is not expected to have Commercial Operation approved until after March 1, then it would be eligible to qualify for capacity credit by submitting an ICAP Deferral for Commercial Operation if Commercial Operation is expected before the last Business Day of prior to the deferred Season.
Example 3: The unit is currently waiting for upgrades to existing Interconnection Service and the upgrades have been completed, however, the unit has yet to be declared Commercial with MISO. The resource owner needs to file an Exhibit E with MISO Resource Integration to finalize the Commercial Operation of the unit. The unit must be in the March Commercial Model prior to the start of the Planning Year. Once this has been done, the Commercial Operation deferral will be considered complete. The resource owner should assist with coordination with MISO Resource Adequacy and MISO Resource Integration throughout the process.

- Suspension of Catastrophic Outage

Example 1: A unit is planning to return from suspension in August and will submit a new GVTC for the upcoming Fall Season prior to the last Business Day of the summer Season. Units returning from suspension are required to retest. The MP may defer the retested value.

- TSR Number

Example 1: A unit is planning to participate in the upcoming Planning Year; however, the unit does not have a Transmission Service Request (TSR) or NITS Scheduling Rights (SR) on the MISO OASIS with a status of “Confirmed” by March 1 to convert the SAC to ZRC to offer into the Auction. The unit expects to have its TSR or SR Confirmed by MISO prior to the last Business Day of prior to the start of the deferred Season. Once the TSR achieves “Confirmed” status on the MISO OASIS, the MP should reach out to help.misoenergy.org. If the TSR or SR status is “Confirmed” prior to June 1, the deferral requirement has been met.

- Additional GVTC Examples

Example 1: The unit defers 100 MW and the test submitted is for 80 MW. The unit is required to replace the UCAP value of 20 ICAP MW. For example, if the XEFORd for the unit is 25%, then the deferred ZRCs is 75 and the submitted test ZRCs is 60. The MP is required to replace the difference of 15 ZRCs through Resource Replacement, Interconnection Service, Cleared Volumes, Bi-lateral ZRC transactions, etc.

Appendix V – Solar and Run-of-River Hydro Accreditation

This appendix walks through examples for calculating solar and run-of-river hydro accreditation. For existing solar resources, the total Seasonal Accredited Capacity (SAC) is determined by the historical average output of the resource during the Summer, Fall, and Spring Seasons for the hours ending 15, 16, and 17 EST and for hours ending 8, 9, 19, and 20 EST for the Winter Season. Existing run-of-river hydro resources can submit up to 15 years of output data over the same hours as for solar resources, with total SAC determined by the median of that data. Market Participants will use the Non-GADS Performance Template found on the MISO website to submit the appropriate historical data for the upcoming Planning Year. The Non-GADS Performance Template can be found on the MISO website under Planning > Resource Adequacy > PRA Documents > PY (Current Plan Year). The populated template should be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool.

For new solar resources, the maximum SAC that can be accredited is 50% for summer, fall, and spring and 5% for winter of the unit's registered maximum output or nameplate capacity. To convert all SAC to seasonal ZRCs, the resource would need to show firm deliverability through NRIS or ERIS with a firm TSR equaling the resource's ICAP value.

For existing solar resources, the historical performance used to calculate the resource's total SAC for a given Season is based on their average output over the defined seasonal peak hours for the last 3 years.

- The amount of total SAC that is convertible into ZRCs is based on the amount of deliverability (NRIS or ERIS with a firm TSR)
- Convertible SAC = total SAC * (deliverability-adjusted capacity factor / peak performance capacity factor)
- Where:
    - Peak performance capacity factor is calculated is calculated by taking an average of the resource's output and then dividing by nameplate capacity.
    - Deliverability-adjusted capacity factor is calculated by adjusting the adjusting output across the seasonal peak hours so that it is capped to the resource's deliverability, taking an average of the resource's output, and then dividing by nameplate capacity.

The examples below show how solar capacity credit is calculated for new resources in the Summer Season only—however, the examples may also be applied to run-of-river hydro resources as well. For the purposes of the examples, the following information will be used in each:

Solar Nameplate = 10 MW
Transmission Losses (vary by LBA) = 5%
Solar Class Average Summer Capacity Credit = 50%
Year 1 Average Historical Summer Output = 6.5 MW (Year 1 data only)
Year 2 Average Historical Summer Output = 7.0 MW (Average of Years 1 and 2 data)

Example 1: New solar (or run-of-river hydro) resources with less than 30 consecutive Summer days or no Summer data

In this example, the new solar resource does not have any historical Summer performance data to submit. Thus, the solar resource will receive the solar class average accreditation for the initial Summer Season in the Planning Year. In Year 2, the resource will use the average (run-of-river hydro resources use a median value) historical Summer performance from Year 1 to determine the accredited amount. In Year 3, the resource will use the average historical Summer performance from Years 1 and 2. In Year 4, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 5, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance. Below are examples of how both BTMG and CPNode solar resources will be accredited.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1 + Transmission Losses)
→ SAC_{BTMG} = 10 * 50% * (1 + 5%)
→ SAC_{BTMG} = 5.25

Year 2 → SAC_{BTMG} = 10 * (65%) (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 3 → SAC_{BTMG} = 10 * (70%) (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit

→ Total SAC_{CPNode} = 10 * (50%)
→ Total SAC_{CPNode} = 5.0

Year 2 → Total SAC_{CPNode} = 10 * (65%) = 6.5

Year 3 → Total SAC_{CPNode} = 10 * (70%) = 7.0

Example 2: New solar resource with at least 30 consecutive Summer days

In this example, the new solar resource has at least 30 consecutive Summer days of performance. Thus, the solar resource will not receive the solar class average for the initial Planning Year. In Year 1, the average historical Summer performance from Commercial Operation data will be used to determine the accredited amount. In Year 2, the resource will use the average historical Summer performance from Year 1 and 2. In Year 3, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 4, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1+ Transmission Losses)
→ SAC_{BTMG} = 10 * (65%) * (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 2 → SAC_{BTMG} = 10 * (70%) * (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit
→ Total SAC_{CPNode} = 10 * (65%)
→ Total SAC_{CPNode} = 6.5

Year 2 → Total SAC_{CPNode} = 10 * (70%)
→ Total SAC_{CPNode} = 7.0

Once the total SAC value for a resource has been determined, it is compared with the Interconnection Service assigned to that resource. Resources that are fully deliverable are eligible to convert all of their total SAC to ZRCs with no further action needed.

For resources that are not fully deliverable, having either partial or no deliverability, the following steps would be used:

1) MISO calculates a deliverability-adjusted capacity factor for the resource.

2) For SAC not considered convertible, the Market Participant may choose to obtain firm Transmission service in some level to convert some or all of the undeliverable SAC to Convertible. MISO supplies documentation to the MP on the MECT tool that can be used to determine the level of SAC that can be converted given some level of firm Transmission obtained.

3) Subsequently, the MP uses the Confirm SAC function to move the desired Convertible SAC amount to the Convert SAC MECT page. Once there, the associated firm Transmission information is entered after selecting the ERIS SAC value.

4) After MISO approval of the firm Transmission data that was entered by the MP, the SAC may then be converted to ZRCs for use in the PRA.

SAC is allocated by type of Interconnection Service (NRIS or ERIS with a TSR). SAC associated with ERIS may be converted into Zonal Resource Credits for use in the PRA with an approved Transmission Service Request.

Appendix X – Hybrid and Co-Located Resource Accreditation

This appendix describes the accreditation process for Hybrid Resources and Co-Located Resources. A Hybrid Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection and that provides a single energy offer in the MISO DA/RT Energy Markets. A Co-Located Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection where each separate Electric Facility provides separate energy offers in the MISO DA/RT Energy Markets.

Hybrid Resources and Co-Located Resources will be accredited in one of two phases depending on how much operating data is available. The Phase I – Sum of Parts approach will apply default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource. The Phase II – Availability-based approach will consist of tracking the historic availability of each separate Electric Facility of the Hybrid Resource or Co-Located Resource. A Hybrid Resource or Co-Located can be Phase I for a Season and then get Phase II for a subsequent Season that it has operational data for. Once a Hybrid Resource begins receiving Phase II availability-based accreditation, the resource will continue to receive Phase II availability-based accreditation.

For Co-Located Resources, allocation of total Interconnection Service at the shared Point of Interconnection among the separate Electric Facilities must be provided to MISO Resource Adequacy staff by the incumbent Asset Owner, or the Market Participant(s) representing the incumbent Asset Owner, prior to conversion of Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs).

Phase I – Sum of Parts

Each Hybrid Resource or Co-Located Resource may be operating in very different ways from other Hybrid Resources or Co-Located Resources with a similar configuration depending on the goals of the resource owner and operator. Until historical operating data exists, default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource will be applied. Co-Located Resource owners must inform MISO how the total Interconnection Service granted at the shared Point of Interconnection should be allocated among each separate Electric Facility for conversion purposes. Phase I accreditation will apply for each Season until a minimum of 30 consecutive historical days of operation for the corresponding Season have been observed.

For Phase I, Market Participants must submit a populated Non-GADS Performance Template to MISO through the MECT for each separate Electric Facility that includes the nameplate capacity (or registered maximum output from the Commercial Model) and resource type of each Electric Facility, unless the Electric Facility qualifies as a Schedule 53 resource.

Phase II – Availability-based

Phase II accreditation will apply after a Hybrid Resource or Co-Located Resource has sufficient operating history to determine a resource-specific seasonal accreditation value.

Availability is measured as historical net output (exception for ESR below) and will be determined in the following ways:

- For Hybrid Resources, the combined historical net output of each Electric Facility, provided via a single populated Non-GADS Performance Template.
- For Co-Located Resources, the separate historical net output of each Electric Facility, provided via several populated Non-GADS Performance Templates.
- For the ESR component of a Hybrid Resource or Co-Located Resource, availability for a given hour will be measured as the maximum of the net output or the output potential on that hour. Output potential should be determined as the minimum of the Hourly Equivalent Discharge Amount or the state of charge minus the Emergency Minimum Energy Storage Limit for a given hour.

Market Participants must submit Non-GADS Performance Templates to MISO through the MECT. In addition to historical operating performance, populated Non-GADS Performance Templates must include nameplate capacity (or registered maximum output from the Commercial Model) and resource type.

Appendix Y – SAC Calculations for Schedule 53 Resources

This appendix describes the process of calculating Seasonal Accredited Capacity (SAC) for Schedule 53 Resources.

1. Identification of Resource Adequacy Hours

Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include Emergency Declaration periods and the hours when the operating margin, a measure of available supply capacity above Demand and reserve requirements, is at its lowest. RA Hours are determined seasonally and at a subregional level (North/Central and South) based on emergency events, the tightest operating margin hours (65 hours per Season), and a maximum operating margin threshold established at 25 percent.

RA Hours will be used to determine each resources' availability for calculating its seasonal accreditation. The number of RA Hours in a Season can exceed the target when a high number of hours during declared system or subregional emergencies occurs.

Provisions also ensure Seasons have a minimum target number of RA Hours by supplementing any deficient hours with Annual Average Offered Capacity (AAOC) over all RA hours across the year. The RA Hours used for determining the AAOC (or AAOC Hours) are the hours with emergency events and the tightest 3 percent of operating margin hours below the 25% threshold for each year, up to 260 hours per year. The AAOC Hours are determined on a sub-regional (North/Central and South) basis. Not all AAOC Hours are RA hours.

1.1 **Definition and Identification of RA Hours**

RA Hours are defined over the three most recent historical years from September - August, based on declared MaxGen alert, warning and event hours supplemented by the tightest 3 percent of hours per Season where the realized operating margin for the region is at or below the threshold of 25 percent.

1.1.2 Hourly Operating Margin Calculation

The Operating Margin is determined using historical information to identify RA Hours and AAOC Hours within the three (3) most recent periods beginning September 1 and ending August 31.

We first express the power balance between load and supply, where:

$$Load = Thermal\ Resource\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange \quad (1)$$

$$Supply = Thermal\ Resource\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange - Operating\ Reserve \quad (2)$$

Substituting (1) into (2), we have

$$Margin(MW) = [Thermal\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange\ (NSI)] - [Thermal\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange] - Operating\ Reserve = Thermal\ Resource\ EmergencyMax - Thermal\ Resource\ Energy - Operating\ Reserve$$

The power balance between equation (1) and (2) suggests the renewable Energy and net-scheduled interchange have been implicitly reflected in the margin calculation but has no impact on the overall margin calculation used for RA hour identification as in the steps below.

By re-arranging the $Margin(MW)$ and broken down to online and offline components, we re-express the Operating Margin Equation as below

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + offline\ margin\ (12\ hour\ leadtime)(MW)_j}{Real\ Time\ (RT)Load\ (MW)_j}$$

Where:

$$Online\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - EnergyMW_i - cleared\ operating\ reserve_i)$$

for all Resources that are online and under normal dispatch control; and

$$Offline\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - cleared\ offline\ supplement\ reserve_i)$$

for Resources where all of the following is true: (i) Resource is Offline; (ii) its cold-start lead-time is less than or equal to 12 hours; and (iii) it is not on outage.

Load Modifying Resource (LMR), and Emergency Demand Response (EDR) are excluded in the Online margin (MW) and Offline margin (MW) calculations because they require emergency declarations in order to access.

1.1.2 Selection of RA Hours

Hours during which MaxGen declarations are in effect automatically become RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within each of the three (3) most recent September-August periods.

For non-MaxGen declaration hours in each of the 12 Seasons of the past three-year period, additional RA Hours with the tightest margin will be identified until reaching the (65 hours) for

each Season; if a Season already has more than 65 hours because of MaxGen declaration, this step will be skipped.

Finally, a maximum margin threshold is applied to exclude hours with an operating margin greater than 25 percent.

Going through the steps above, some Seasons will have more than 65 hours because of MaxGen declarations, while some other Seasons may have less than 65 hours if there are hours excluded based on the 25 percent maximum margin threshold criterion and a low number of hours with MaxGen declarations, reflecting underlying Demand, supply and weather conditions. The deficiency from the 65 target hours leads to the need for AAOC Hour as described in the next section.

Additionally, each individual resource will have its own set of RA hours that are dependent on outage exemptions and whether it was designated for Resource Adequacy Requirements (RAR) in previous year's seasonal auctions. Like the system-wide RA hours, if a resource has deficient RA hours in a Season, that resource's AAOC will be supplemented for the deficient hours.

Non-RAR resources are not subject to SAC calculation using seasonal RA and AAOC hours.

If the unit was designated as RAR within the 3-year lookback period, the following logic will apply.

- When a unit is RAR and has 60 days or more during the 3-year lookback period of that particular Season's operational data, for that Season SAC will be calculated with that historical operational data. Operating days that a unit was in full outage will be excluded from the statistics.
- If the unit has less than 60 days of data designated as a RAR for that Season over the 3-year lookback period they will receive Schedule 53 seasonal class average SAC accreditation. Operating days that a unit was in full outage will be excluded from the statistics.
- For resources that have a generation capacity change due to upgrades or seasonalization that had a non-zero offer historically, the RT EmerMax will be prorated based on the capacity change/ICAP% of the historical offers, capped at the new GVTC of the resource.
- For resources that have a generation increase due to upgrades or seasonalization, that have zero historical offer information, will receive Schedule 53 seasonal class average SAC accreditation for that Season

- In the case where a schedule 53 generator was derated due to transmission limitations imposed by the incumbent Transmission Operator, the MP can work with MISO to determine if any exemptions for those hours can be granted
- Exemption status for a unit's outage should be validated and resolved with MISO if needed, per timeline defined in BPM-008 (Business Manual -- Outage Operations)

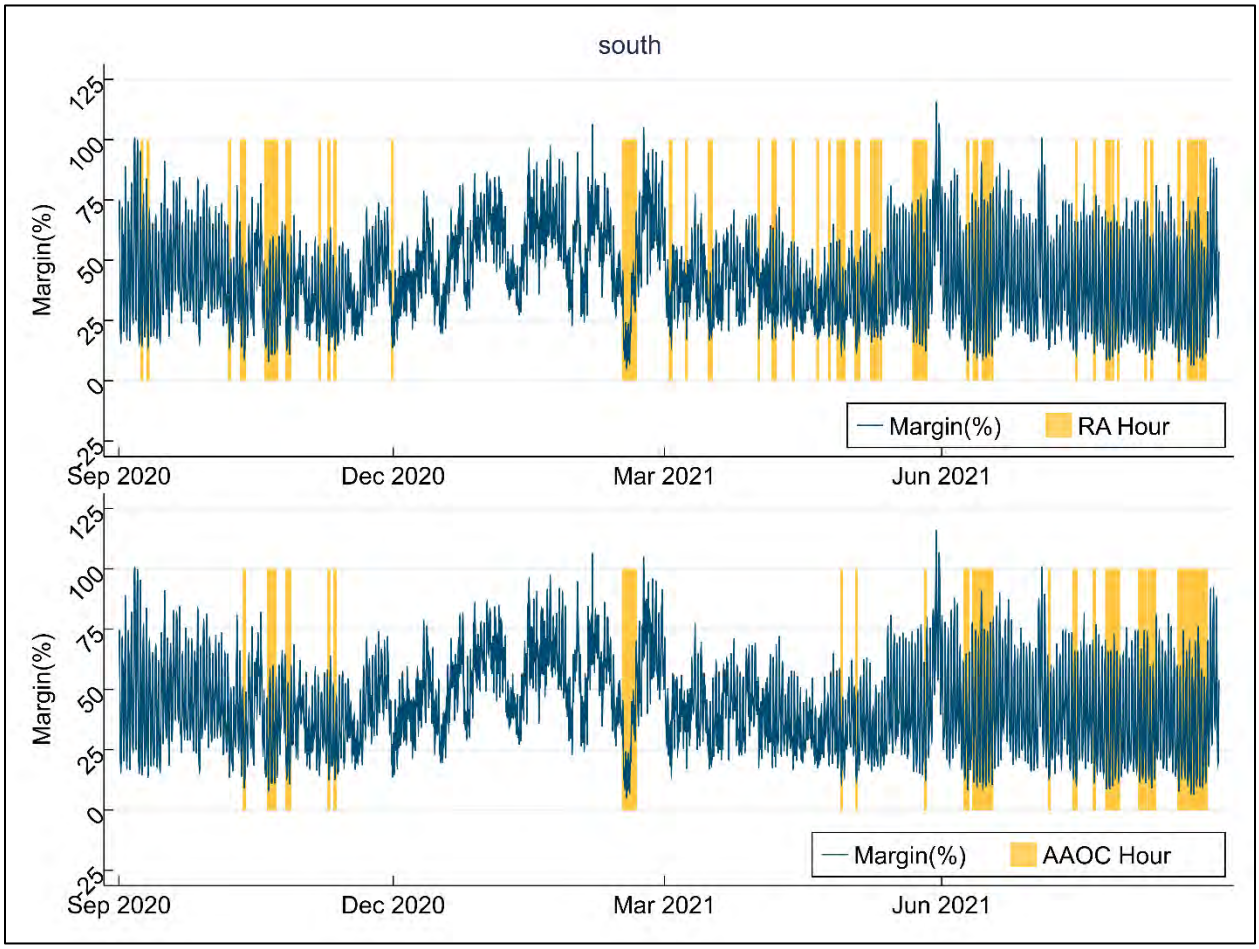
1.1.3 Selection of AAOC RA Hour

Hours where MaxGen declarations are in effect automatically become AAOC RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within the three (3) most recent periods.

For the rest of non-MaxGen declaration hours in each year of the past three-year periods, additional AAOC RA Hours with the tightest margin will be identified until reaching the (260 hours) for each year. For a unit to receive exemption for an AAOC hour they must have Tier 2 exemption during that hour.

1.1.4 Illustration of Selected RA Hour

The figure below, using South region as example, illustrates the variation of hourly Margin (%) between September 1, 2020, and August 31, 2021, and labels the selected RA Hour / AAOC Hour. In this example, there are 65 RA Hours identified in each of the four Seasons, hence the AAOC Hour will not be needed for backfilling any deficiency hour.



1.2 **Seasonal Accredited Capacity Calculation**

Resource Accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. The following sections illustrate the two-tiered weighting structure to calculate Intermediate Seasonal Accredited Capacity (ISAC) reflecting general availability while emphasizing availability during times of greatest need. Each Resource will have its ISAC determined based on its Real-Time offered availability (Emergency Maximum Limit) during seasonal RA Hours (Tier 2) as described in Section 1.1 and Non-RA Hours (Tier 1).

1.2.1 Prepare Hourly Real-Time Offered Availability Dataset

The first step is to prepare the hourly Real-Time Offered Availability dataset for a Resource, including (1) hourly timestamp (EST); (2) offered Real-Time availability (EmerMax MW); (3) lead time(Start up time + Start up notification time) (in hours); (4) binary indicator if a resource is in outage from either the commit status or from records in Control Room Operations Window (CROW) Outage Scheduler; (5) binary identifier indicating if a Resource is online.; (6) ICAP (MW); and (7) binary indicator if a resource has received outage exemption.

Figure below provides a sample screenshot of the dataset, using a sample Resource located in Central/North region. If a Resource is in Derated status but not in outage, its offered availability already accounts for the impact of derates.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)
summer	2020-07-29 00:00:00	76	1	0		71.6	0
summer	2020-07-29 01:00:00	76	1	0		71.6	0
summer	2020-07-29 02:00:00	77	1	0		71.6	0
summer	2020-07-29 03:00:00	77	1	0		71.6	0
summer	2020-07-29 04:00:00	77	1	0		71.6	0
summer	2020-07-29 05:00:00	77	1	0		71.6	0
summer	2020-07-29 06:00:00	77	1	0		71.6	0
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0

In sample data above, the outage indicator is set to 1 (outage) either if there is a valid full outage ticket in CROW or the unit was offered as outaged in real time for the specific hour. The online indicator is based on unit's control mode from ICCP data as described in 2.4.7 in BPM-031 (ICCP Data Requirement).

1.2.2 Prepare Calculation for Annual Average Offered Capacity (AAOC)

If a Resource does not have 65 RA hours in a Season, AAOC is needed for backfilling the availability during deficiency hours in later steps. To calculate AAOC, the RT Offer EmerMax data is paired with AAOC hours by timestamp. Availability (MW) during AAOC hour is then generated through these following steps:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during AAOC hour; this step caps RT Offer EmerMax at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during AAOC Hour;

(3) Set availability = zero if a Resource is not online and not in outage and has lead time (Start up time + Start up notification time) greater than 24 hours during AAOC Hour.

(4) Set availability = NULL if a Resource has been granted outage exemption during AAOC Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during AAOC hour through the steps described above.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Annual RA Hour Identifier (Classic)	Availability in AAOC Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		
summer	2020-07-29 01:00:00	76	1	0		71.6	0		
summer	2020-07-29 02:00:00	77	1	0		71.6	0		
summer	2020-07-29 03:00:00	77	1	0		71.6	0		
summer	2020-07-29 04:00:00	77	1	0		71.6	0		
summer	2020-07-29 05:00:00	77	1	0		71.6	0		
summer	2020-07-29 06:00:00	77	1	0		71.6	0		
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		

1.2.3 Prepare Calculation for Intermediate Seasonal Accredited Capacity (ISAC)

To calculate SAC, the RT Offer EmerMax data is paired with RA Hour by timestamp. Availability (MW) during RA Hour is then generated through these following steps:

For availability during Tier 1 Non-RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 1 Non-RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 1 Non-RA Hour;

(3) Set availability = NULL if a Resource has been granted outage exemption during Tier 1 Non-RA Hour.

For availability during Tier 2 RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 2 RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 2 RA Hour;

(3) Set availability = zero if a Resource is not online and not in out-of-service outage and has lead time (start up time + Start up notification time) greater than 24 hours during Tier 2 RA Hour;

(4) Set availability = NULL if a Resource has been granted outage exemption during Tier 2 RA Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during seasonal Tier 1 and Tier 2 RA hour through the steps described above.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Seasonal RA Hour Identifier (Classic)	Availability in Seasonal Tier 1 (non-RA) Hour (MW) after Outage Exemption	Availability in Seasonal Tier 2 RA Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 01:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 02:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 03:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 04:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 05:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 06:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		71.6	
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		71.6	
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		71.6	

1.2.4 Calculation of Annual Average Offered Capacity (AAOC)

For each of the past three years, the AAOC is calculated as the sum of availability over AAOC hours, divided by the total number of AAOC hours (excluding outage exemption hours) in each year, as shown in the table below for a sample resource.

CY	# AAOC Hours	Sum of Availability (MW) over AAOC Hours	Annual Average Offered Capacity (MW)
Formula Key	A	B	B/A
CY17Sept18Aug	260	15,990	62
CY18Sept19Aug	260	17,444	67
CY19Sept20Aug	243	17,171	71

1.2.5 Calculation of Intermediate Seasonal Accredited Capacity (ISAC)

For Non-RA Hours (Tier 1), Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 1 Non-RA hours, divided by the total number of seasonal Tier 1 Non-RA hours across the past three years.

CY	Season	# of Tier 1 non-RA Hours after outage exemption	Sum of Availability (MW) over Tier 1 non-RA Hours after outage exemption	Tier 1 3-year average ISAC after outage exemption
Formula Key		A	B	C=SUM(B1, B2, B3)/SUM(A1, A2, A3)
CY17Sept18Aug	fall	2,119	3,509	
CY18Sept19Aug	fall	2,119	128,215	44
CY19Sept20Aug	fall	1,731	129,457	
CY17Sept18Aug	winter	2,095	131,376	
CY18Sept19Aug	winter	2,095	89,229	61
CY19Sept20Aug	winter	2,091	163,989	
CY17Sept18Aug	spring	2,143	147,505	
CY18Sept19Aug	spring	2,142	151,993	72
CY19Sept20Aug	spring	2,192	164,796	
CY17Sept18Aug	summer	2,143	154,731	
CY18Sept19Aug	summer	2,143	149,724	71
CY19Sept20Aug	summer	2,143	154,375	

For RA Hour (Tier 2), its Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal RA hours and AAOC multiplied by the deficient RA hours, then averaged over total number of Tier 2 RA hours across the past three years. A particular Season will be excluded from a unit's tier 1 and tier 2 ISAC calculation if either condition is met: 1) a unit has not been designated as RAR for the Season or 2) it has not been offering into Real-Time market due to an exempt outage for the whole Season.

CY	Season	# of Tier 2 RA Hours after outage exemption	Sum of Availability (MW) over Tier 2 RA Hours after outage exemption	Deficient # of Tier 2 hours	Annual Average Offered Capacity (MW) after outage exemption	Sum of Availability (MW) over Deficient hours	Sum of total Availability (MW)	Sum of Tier 2 hours	Tier 2 3-year average ISAC after outage exemption
Formula Key		A	B	C = Max((65 hours-A), 0)	D	E=C*D	F=B+E	G=A+C	H=SUM(F1, F2, F3)/SUM(G1, G2, G3)
CY17Sept18Aug	fall	65	0	0	62	0	0	65	
CY18Sept19Aug	fall	65	4,788	0	67	0	4,788	65	47
CY19Sept20Aug	fall	31	1,949	34	71	2,402	4,352	65	
CY17Sept18Aug	winter	65	5,348	0	62	0	5,348	65	
CY18Sept19Aug	winter	65	3,274	0	67	0	3,274	65	68
CY19Sept20Aug	winter	4	321	61	71	4,310	4,631	65	
CY17Sept18Aug	spring	65	4,784	0	62	0	4,784	65	
CY18Sept19Aug	spring	55	3,256	10	67	671	3,927	65	68
CY19Sept20Aug	spring	16	1,178	49	71	3,462	4,640	65	
CY17Sept18Aug	summer	65	4,683	0	62	0	4,683	65	
CY18Sept19Aug	summer	65	4,678	0	67	0	4,678	65	72
CY19Sept20Aug	summer	65	4,674	0	71	0	4,674	65	

1.2.6 Tier Weighting of ISAC

The final Intermediate Seasonal Accredited Capacity (ISAC) value is the weighted averaged over its values from two tiers as calculated from steps above. The corresponding tier weightings are:

	Weighting by Planning Year		
Tier	2023- 2024 Planning Year	2024-2025 Planning Year	2025-2026 Planning Year and beyond
$ISAC_{Tier1_weighting}$	40%	30%	20%
$ISAC_{Tier2_weighting}$	60%	70%	80%

$$ISAC = ISAC_{Tier\ 1\ MW} \times ISAC_{Tier\ 1\ weighting} + ISAC_{Tier\ 2\ MW} \times ISAC_{Tier\ 2\ weighting}$$

The table below illustrates the ISAC of a sample resource.

WEIGHTED ISAC by SEASON with outage exemption	Season	ISAC
	fall	46
	winter	67
	spring	69
	summer	72

1.2.7 Final conversion to SAC

Lastly, the ISAC is converted back to SAC in UCAP term using the formula and as illustrated in the sample table below. The Conversion Ratio is calculated for each Season on a system-wide basis for all Schedule 53 resources.

$$SAC = ISAC \times Conversion\ Ratio_{UCAP/ISAC}$$

Conversion Ratio UCAP / ISAC	Season	SAC
1.1754	fall	54
1.131	winter	75
1.152	spring	80
1.068	summer	77

The following rules are applied for determining units to be included/excluded in ratio calculations.

1. Only resources are included in both LOLE study and SAC calculations for the same Season of planning year are included in the UCAP/ISAC ratio calculation.2. Resources that are granted with a class average for one or multiple Seasons, are not included in ratio calculation for the Season(s)

1.2.8 SAC calculation for Combined Cycle (CC)units

Due to complicated nature of modeling and market participation options for combined cycle units, MISO will calculate their ISAC/SAC values based on how they are modeled and historically been offered into the Real-Time market, and how the combined cycle units submit their test capacity (GVTC) data in MISO GADS data:

1. If the owner of combined cycle unit submits GVTC data on the parent CP node only, MISO will calculate the SAC value on the parent node, by combining the Real-Time children's offer data if needed and capped at the latest GVTC. MISO will only provide planned outage exemptions for the SAC calculation, if all of the children units are fully outaged with valid exempt outage requests.

2.If the owner of combined cycle unit submits GVTC data on the children's CP nodes, or submits GVTC data on the parent node, but with specified % split of each children node, MISO will calculate SAC values for each children CP node. MISO may need to split the Real-Time offer (Emergency Max) based on the % ratios of all the children's GVTC data, if needed. In this scenario, each children's exempt outage will be reflected in their own SAC calculations.

1.2.9 SAC calculation for Jointly Owned Units (JOU)

Jointly Owned Units (JOUs) SAC values will be calculated the same way as regular units as long as the owners submit their separate GVTC data in the MISO GADS system. For units that have experienced ownership and/or share percentage changes within the last 3 years where Real-Time offer data is used, MISO may need to combine all the owner's Real-Time offers, capped by their total GVTC and then split again based on the latest GVTC ratios among ownerships before calculating each owner's SAC values.

1.3 **Class Average based SAC calculation**

New Schedule 53 Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the class average SAC to ICAP Ratio for its Resource type. MISO will calculate Schedule 53 class averages based on existing GADS fuel type categories from the existing MISO Schedule 53 fleet.

Per MISO's discretion and agreement with the resource owner, MISO may grant the unit class average, if a unit's operation and offer history no longer represents its future economical and physical characteristics.

Class averages (% values) are calculated based on units with sufficient Real-Time offer in each resource type by dividing their total seasonal ISAC values divided by total effective ICAP (lesser of GVTC or interconnection service):

$$Class\ Average\ \%_{type\ of\ resource} = \sum_{type\ of\ resource} ISAC \Big/ \sum_{type\ of\ resource} Effective\ ICAP$$

For units whose SAC is calculated based on a class average, their class average % is applied to the unit's ICAP (lesser of GVTC or Interconnection Service) to determine the ISAC. The UCAP/ISAC ratio per Season will then be applied to identify the final SAC for the Season

1.4 SAC conversion to ZRC

1.4.1 Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:

Schedule 53 Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC as defined in Module E 69A.4.5

$$NRIS\ SAC = \min(NRIS, ICAP) \times \frac{Total\ SAC}{ICAP}$$

The remaining balance of Total SAC is allocated to ERIS SAC with following formula:

$$ERIS\ SAC = \max\big(0, (ICAP - NRIS)\big) \times \frac{Total\ SAC}{ICAP}$$

1.4.2 Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service. .

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 135
Holtec News Release

Holtec Receives Coveted “Tier 1 First Mover Award” from the USDOE to Accelerate Deployment of its Dual-Unit SMR-300 Plant at the Company’s Palisades Energy Site

- Holtec Highlights (https://holtecinternational.com/category/holtec-highlights/)
  - 2025 (https://holtecinternational.com/2025/)
  - 2024 (https://holtecinternational.com/2024/)
  - 2023 (https://holtecinternational.com/2023/)
  - 2022 (https://holtecinternational.com/2022/)
  - 2021 (https://holtecinternational.com/2021/)
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  - 2011 (https://holtecinternational.com/2011/)
- Videos (https://holtecinternational.com/news/videos/)

December 2, 2025

Camden, NJ, December 2, 2025: We are delighted and honored to have been selected as a recipient of the U.S. Department of Energy's Tier 1 "First Mover Team Support" award under the U.S. Government's Generation III+ Small Modular Reactor (SMR) Pathway to Deployment Program. The award, valued at $400 million, will catalyze the first-of-a-kind (FOAK) deployment of Holtec's dual-unit SMR-300 plant at the Company's Palisades Energy site where a formerly shuttered 805-MWe PWR is poised for imminent restart with the support of a DOE loan. Fittingly, the twin-unit SMR-300 plant has been named *PIONEER 1&2*, which captures its trailblazing mission to spearhead the rise of the SMR industry in the U.S. and the world. This FOAK project, which will add 680-MWe in a dual unit (340 MWe per unit) configuration, is envisaged to be built by Holtec with construction financing from the DOE's Loan Programs Office. With the financial pathway secured, we look with guarded confidence to implement our "*Mission 2030,*"which contemplates the Pioneer reactors being brought online in the first years of the 2030s.

Rendering of the first two Holtec SMR-300 units at the Palisades Energy site in Covert, Michigan.

As part of the program, DOE will provide milestone-based cost-share support that is intended to advance licensing, pre-construction, and supply-chain mobilization for the Palisades SMR-300 project. Holtec's proposal includes a multi-site deployment pathway that establishes a repeatable, fleet-scale model — a core requirement of the Tier 1 program intended to drive down costs and shorten construction durations through standardization and manufacturing efficiency. The DOE's support is an essential enabler of the Palisades SMR-300 project, moving it from development to deployment by building on the government's prior support for Holtec's SMR technology under the 2020 DOE Advanced Reactor Demonstration Program (ARDP) *Risk Reduction for Future Demonstrations* to support commercial readiness.

"Holtec realizes the future of nuclear energy as a source of reliable baseload electricity to power the economy of the future is realized only if we, in the industry, make the reactors predictably cost competitive. With a well-exercised and proven supply chain, a world-class (exclusive) alliance partner, Hyundai E&C, and the plant design marinated with four decades of practical corporate experience, we consider it our duty to lead the industry in building, owning, and operating the first SMR-300 plant in the United States. We are energized by DOE's confidence in our SMR-300 reactor, which we view as validation of our 14-year quest to develop a walk-away-safe and cost-competitive nuclear reactor. This grant positions Holtec to accelerate deployment of a standardized SMR-300 fleet that strengthens U.S. energy security and grid resilience and will further bolster Holtec as one of the largest U.S. exporters of nuclear equipment," said Dr. Kris Singh, CEO and Executive Chairman of Holtec International.

Holtec has repeatedly demonstrated its peerless execution capacity for nuclear projects over the past four decades, both domestically and abroad. From mechanical upgrades of nuclear plants to spent fuel management facilities to the ownership and decommissioning of nuclear power plants, Holtec has built a reputation for turnkey delivery. The Palisades restart project, which is the world's first restart of a retired nuclear plant, is due to be synchronized with the grid early next year, months ahead of the committed schedule and substantially below the allotted budget, provides contemporary evidence of our execution credentials.

Finally, we applaud the restart program for having created an operational platform, an operator and maintenance staff training pipeline, and a "can-do" nuclear project environment that is expected to have a salutary effect on the accelerated deployment of the SMR-300 fleet. In recognition of the importance of this SMR project to the Company, our President, Kelly Trice, who has shepherded the Palisades restart program since its inception, will also helm the Palisades SMR-300 project.

DOWNLOAD (HTTPS://HOLTECINTERNATIONAL.COM/WP-CONTENT/UPLOADS/2025/12/HH-40.24.PDF)

TAGS: PALISADES (HTTPS://HOLTECINTERNATIONAL.COM/TAG/PALISADES/), SMR (HTTPS://HOLTECINTERNATIONAL.COM/TAG/SMR/)

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New Fuel Arrives at Palisades to Power Its Imminent Restart (https://holtecinternational.com/hh-40-22/)

Holtec International's Companies, Divisions & Affiliates

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