RELIABLE ENERGY'S COMMENTS ON THE DIRECTOR'S REPORT ON AES INDIANA'S 2022 INTEGRATED RESOURCE PLAN

January 12, 2024

Introduction and Summary

Reliable Energy (RE) appreciates the opportunity to review the Draft Director's Report (Draft) on AES Indiana's (AES) Integrated Resource Plan (IRP), which was issued on December 5, 2023 approximately one year after the IRP was submitted to the Indiana Utility Regulatory Commission (IURC or Commission).

Generally, RE finds the Draft report to be comprehensive and consistent with RE's own review as well as other stakeholder comments. Further, RE is comforted by the following two statements in the Introduction which RE believes any CPCN filing must reflect:

- The Research, Policy, and Planning (RPP) Director in the report **does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio"** or any proposed resource action. (Page 3)

- The **resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake**. **Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken.** The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios. (Page 3)

With this background, RE offers the following suggested additions to the Director's Draft to ensure no confusion. Given the IRP will be more than a year old by the time a CPCN filing is made, the Final Director's Report should specifically state,

- The IRP as filed is not a sufficient justification for any CPCN filing given material changes in energy markets when the IRP was prepared compared to current markets. Specifically, AES Indiana should be forewarned that a CPCN filing for refueling of Petersburg Units 3 & 4 based solely upon the IRP does not provide sufficient evidentiary justification.

- The specific market changes that need to be addressed prior to any CPCN filings should include, but are not limited to: fuel prices, timing and cost of renewable options, and recognition and consideration of activities by AES Indiana and other Midcontinent Independent System Operator (MISO) market participants which have a direct impact on reliability and affordability.[1]

[1] While the Draft acknowledges the importance of this on page 22 ("The Director thinks the regional aspect of utility planning and resource acquisition needs to be better addressed in the IRP."), the Director does not indicate any plans to mandate such consideration.

- Any CPCN filing must explicitly consider the Five Pillars (i.e., reliability, affordability, resiliency, stability, and environmental sustainability) put forward in 2023 House Bill 1007, which was passed subsequent to the preparation of the 2022 AES IRP.

- Recovery of stranded costs associated with a premature closure or refueling of a power plant are not guaranteed. The CPCN must consider the stranded costs in the determination of affordability, i.e., rates, if AES expects recovery of such undepreciated capital.

- Any new resource investment decisions must consider full costs, including Firm Transportation for any new gas investments and costs consistent with the shorter of the life span assumed in the IRP, AES corporate net zero carbon targets, and regulatory assumptions.

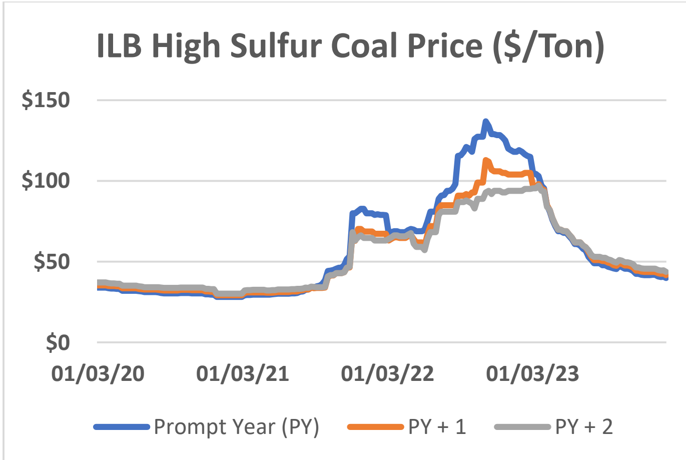
- An explanation of whether (or why not) AES offered generating assets for sale as an alternative to retirement or refueling to ensure such decisions are reasonable and cost-effective for customers. In other words, a "litmus test" of third party interest is needed in order to avoid the appearance of conflicts of interest because AES's generation decisions are being made largely to comply with corporate objectives and meet executive compensation goals, as noted in the RE's comments on the IRP.

While not explicitly discussed in the Draft, but certainly relevant to address in the submittal of any CPCN are the expected resource shortfalls in MISO due plant retirements outpacing resource additions. Instead of addressing its capacity needs on an individual utility basis, AES should consider at a minimum the capacity constraints in all of MISO Zone 6, although a larger footprint may be more relevant. All utilities in Indiana should be similarly required to consider regional capacity concerns.

Finally, a resource evaluation should not be confused with an affordability analysis. A Net Present Value (NPV) of alternative resource options is not equivalent to an affordability analysis, i.e., how customer rates are affected by resource decisions. The string of recent significant rate increases by Indiana utilities has in part been due to accelerated coal plant retirements. Had the utilities been tasked with actually performing an accurate rate impact analysis in addition to a resource analysis based upon an NPV, the Commission and stakeholders would have better understood the true affordability impact of certain resource plans.

Changes in Commodity Prices

As RE identified in its comments on the IRP, AES used coal prices far above prevailing prices in existence at the time the IRP was submitted. AES' justification for the higher prices was weak. Rather than using a long-term forecast in which pricing returned to "normal" (as in fact we have seen happen since the IRP was submitted), AES took the second highest price bid under an RFP it conducted when prices were still inflated. As was clear in December 2022 and even more clear today, coal prices are nowhere near the inflated levels assumed by AES:



Source: Coaldesk

RE appreciates the statement in the Draft that "AES Indiana acknowledges that **numerous assumptions and data inputs will have to be updated and that <u>some</u> of the analysis redone to check if the IRP's preferred portfolio continues to be appropriate.**"[2] The AES statement, however, is not definitive that updated coal prices will be included in the updated analysis. RE believes the Director's Report should make clear that delivered fuel costs must be among the updated assumptions, including both commodity and transport assumptions. Further, the Director should also make clear that keeping Petersburg 3 and 4 operating through the forecast period should not be the only alternative considered. Rather, AES should consider alternative lives for the units recognizing any delay provides greater clarity regarding changing regulations and alternative resource options, and reduces stranded costs.

Finally, more than the commodity prices need to be updated. It has become clear that the costs associated with Firm Transportation for gas have risen significantly in recent years and firm gas commodity pricing under term contracts is largely unavailable. Of note, the studies that evaluated the impact of Storm Elliott on reliability determined that absent dual fuel capability, natural gas generation has significantly lower reliability which should be factored into the analysis.[3]

EPA Regulations

While, as recognized in comments by the Sierra Club, the Good Neighbor Rule (GNR) was a significant consideration for AES in its resource planning with respect to Petersburg units continuing operations, the GNR was only a proposed rule at the time the IRP was filed. In March 2023, the EPA issued a final rule that created new regulatory obligations in 23 states regarding emissions during the five month ozone season (May through September) from power plants and certain industrial facilities alleged to interfere with maintaining or achieving the 2015 ozone National Ambient Air Quality Standards (NAAQS) in downwind states. The final rule differed from the proposed rule in a number of respects, including timing. The rule was published in the *Federal Register* on June 5, 2023, which determined the GNR effective date. The GNR is relevant to AES only if the rule survives legal challenges, as compliance requires plants to be retrofitted

[2] Draft at Page 24 (emphasis added).
[3] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission (ferc.gov), page 51

with Selective Catalytic Reduction (SCR) to operate during the summer ozone season. Only Petersburg 3 is equipped with an SCR.

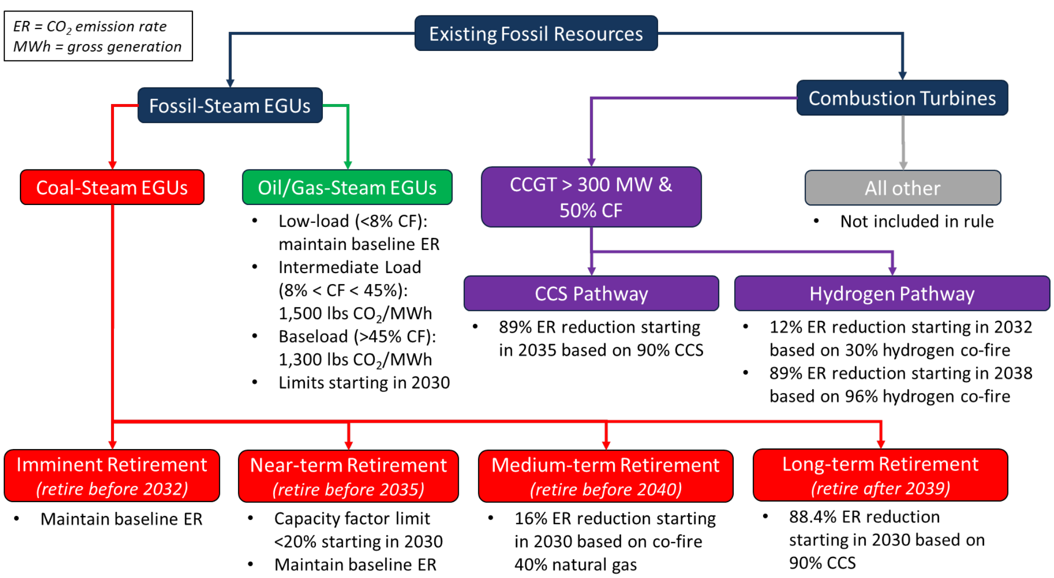
Subsequent to the rule being finalized, there have been a number of legal challenges filed and stays granted. Recently the Supreme Court has agreed to hear the challenges in February 2024.[4]

The challenges include the EPA's failure to approve or deny on a timely basis State Implementation Plans (SIPs) which the final rule replaced with a Federal Implementation Plan (FIP) in a number of states. In addition, concerns have been raised that the justification for the new rules is tied to dated modelling which does not capture reduced emissions associated with coal plant retirements and concerns related to grid stability should compliance with the final rule result in significant plant closures. Regardless of the Supreme Court decision, the timetables are likely to be changed potentially eliminating the urgency associated with a decision.

In May 2023, EPA proposed new rules under Sections 111(b) and 111(d) of the Clean Air Act. Section 111(b) addresses New Source Performance Standards (NSPS) for new natural gas combustion turbines (CTs). Section 111(b) addresses existing coal and natural gas plants. The AES IRP does not reflect these rules as the IRP was published prior to May 2023. If these rules are finalized, all AES fossil plants would be subject to them.

The proposed new rules under Section 111 (d) for existing fossil fuel plants are interesting. As shown below, Petersburg would not be subject to additional compliance obligations if the units are closed in 2031. If the units are converted to natural gas, they would be subject to 1,300 lbs CO2/MWH limits if they are operated in 2030 and 1500 lbs CO2/MWH if they are operated as intermediate load. AES has not demonstrated that this would be the case and/or if there are incremental costs associated with reaching these emission rates.

PROPOSED NEW RULES UNDER CLEAN AIR ACT SECTION 111(D)



Source: EVA, 2023 COALCAST Report

[4] https://www.usnews.com/news/politics/articles/2023-12-20/supreme-court-will-hear-challenge-to-epa-rule-limiting-downwind-power-plant-pollution-in-10-state

EPA has announced plans to finalize the greenhouse gas (GHG) rules as early as April 2024[5] . Given more than one million comments were received, this date could be a challenge. Assuming the finalized rules are published in the *Federal Register* in a timely manner, legal challenges would likely start by mid-year.[6] Implementation of the proposed new rules could proceed prior to resolution of appeals, unless the courts choose to stay implementation pending resolution of the legal challenges. Generally, stays are only granted if there is a belief that the challenges have legal merit and irreparable harm would occur absent a stay.[7]

The Federal Energy Regulatory Commission (FERC) has asserted its interest and concern about the EPA proposal over which it believes it has provenance. On August 8, 2023, FERC Commissioner Danly sent a letter to EPA Administrator Regan stating that "FERC is the agency Congress has charged with overseeing the promulgation of the mandatory standards that ensure the reliable operation of the bulk-power system."[8] The letter noted that the new GHG policies EPA had proposed had not adequately considered their impact on grid reliability, nor had EPA provided the data to FERC required for FERC to perform its own analysis.

On November 9, 2023, FERC hosted its Reliability Technical Conference, which included a session on the impact of EPA's proposed GHG rules on electric reliability."[9] The transcript from the Reliability Technical Conference demonstrates considerable debate as to the impact of the GHG rules on reliability.[10] Not disputed is there is significant disagreement regarding whether EPA had adequately performed a reliability analysis of the rules such that FERC could confirm adequate analysis of grid reliability.[11]

In December 2023, the North American Electric Reliability Corporation (NERC) published its annual reliability report of the Bulk Power System (BPS).[12] NERC is a non-profit international regulatory authority with the mission to assure BPS reliability. NERC noted that the North American BPS "is on the cusp of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change." This report is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. As shown below, NERC concluded that MISO and SERC are at high risk.

[5] https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2060-AV09

[6] https://www.davispolk.com/insights/client-update/epas-proposed-power-plant-greenhouse-gas-emissions-rule-third-times-charm

[7] In February 2016, the Supreme Court stayed implementation of the Clean Power Plan.

[8] https://www.ferc.gov/news-events/news/comment-commissioner-james-p-danly-epas-proposed-new-source-performance-standards

[9] https://www.ferc.gov/media/ad23-9-000-reliability-technical-conference

[10] https://www.ferc.gov/media/transcript-docket-no-ad23-9-000

[11] https://www.ferc.gov/sites/default/files/2023-12/Danly%20Comment%2012-20-23.pdf

[12] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

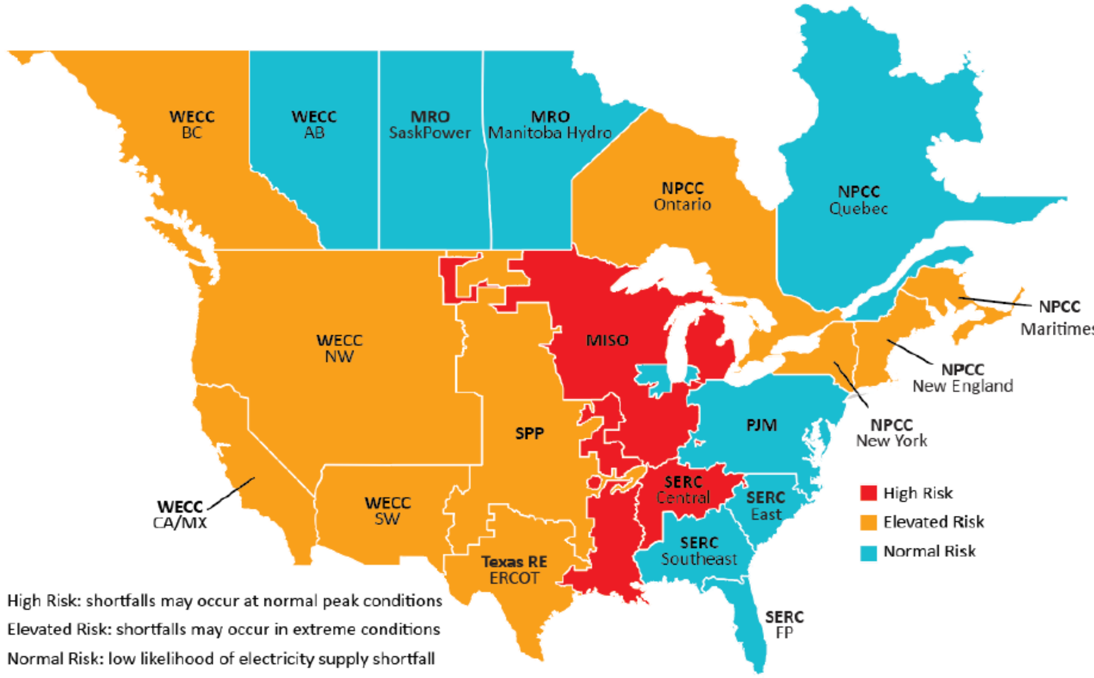


Figure 1: Risk Area Summary 2024–2028[8]

NERC notes "(c)apacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts. Energy risks are projected in areas where the future resource mix could fail to deliver the necessary supply of electricity under energy-constrained conditions." Note that NERC's finding is not a conclusion determined by an analysis focused on an individual utility system. Rather, as should be included in the Director's Final Report, reliability needs to be determined on a regional basis.

NERC notes that in 2023 MISO "transitioned to its first year of seasonal capacity auctions and that anticipated shortfalls did not materialize in 2023 because of market response to the increase in capacity prices in 2022 and new resource additions". NERC found that beginning in 2028, MISO is projected to have a 4.7 GW shortfall with expected generator retirements and new resource additions. The MISO dashboard is provided in Attachment I.

NERC specifically noted concerns about reliability of natural gas generation as a replacement for coal's reliability attributes, citing severe weather events in 2021 and 2022 which provided evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during time of extreme electricity demand. NERC indicated that a "revised guideline" related to these concerns has been developed and "is under review".

The Five Pillars

The 2023 IURC Annual Report explained:

> *Five Pillars of Electric Service (HEA 1007) In House Enrolled Act (HEA) 1007, effective July 1, 2023, the Indiana General Assembly established in statute that it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider the following attributes of electric utility service:*

reliability, affordability, resiliency, stability, and environmental sustainability. These attributes, referred to as the "Five Pillars," are consistent with the recommendations approved by the 21st Century Energy Policy Development Task Force. In response, the Commission adopted GAO 202304 on June 28, 2023, providing guidelines for a utility providing information, discussions, and evidence regarding the "Five Pillars" in its case in-chief for any case filed with the Commission concerning the utility's generation resource mix, energy infrastructure, and electric service ratemaking constructs after June 30, 2023. HEA 1007 also tasked the Commission with conducting a comprehensive study on the topic of performance-based ratemaking for electricity suppliers. The study must take into consideration various aspects of performance-based ratemaking, such as multi-year rate plans, index-driven revenue formulas, and performance incentive mechanisms, and include recommendations on the appropriate design, framework, and requirements. The study is to be completed by Oct. 1, 2025. Finally, HEA 1007 amended Ind. Code § 8-1-8.5-13, commonly referred to as the HEA 1520 report statute, to reduce the amount of electricity a utility could purchase from capacity markets to meet demand from 30% to 15% starting after June 30, 2023. It also required utilities to include information on the spring and fall unforced capacities starting after June 30, 2026. [13]

Applicability of the Five Pillars Each electric utility is encouraged to include information, discussions, and/or evidence regarding the Five Pillars in its case-in-chief for any case filed with the Commission concerning the utility's electric generation resource mix, energy infrastructure, and/or electric service ratemaking constructs, including the following submitted to the Commission after June 30, 2023: a) Base rate cases filed under Indiana Code §§ 8-1-2-42 and/or 8-1-2-42.7. b) Certificates of public convenience and necessity, power purchase agreements, and other resource acquisitions (such as build-transfer agreements, purchase sale agreements, or other similar agreements), under Indiana Code chapter 8-1-8.5 and Indiana Code § 8-18.8-11(b). c) Certificates of public convenience and necessity for federally mandated projects under Indiana Code § 8-1-8.4-6. d) Plans for Transmission, Distribution, and Storage System Improvement Charges pursuant to Indiana Code § 8-1-39-10. ***e) Integrated resource plans submitted pursuant to the Indiana Administrative Code (IAC), specifically 170 IAC 4-7.*** *f) Demand side management and energy efficiency plans made pursuant to Indiana Code § 8-1-8.5-10(j)(10) and 170 IAC 4-8-2. g) Requests for financial incentives under Indiana Code § 8-1-8.8-11. h) Requests for preapproval under Indiana Code § 8-1-2-23. An index should also be provided with the location of information, discussions, and/or evidence regarding each of the Five Pillars attributes. (emphasis added)*

The Draft describes how AES considered the attributes in the Five Pillars. For affordability, AES simply states it determines affordability with a "scorecard evaluation metric" based upon a 20-year Present Value of Revenue Requirements (PVRR).

While the Director's Draft suggests there is a debate as to how to evaluate affordability, RE respectfully disagrees. RE believes the PVRR analysis may be appropriate to compare alternative resource options, it is clearly not the appropriate way to consider affordability. RE appreciates the Director's recognition in the Draft that the PVRR but does have limitations. RE believes that an affordability analysis must focus on

[13] www.in.gov/iurc/files/IURC-2023-Annual-Report.pdf

rates. RE's position is consistent with the Office of Consumer Council's position in CenterPoint Energy Indiana (CEI South) in Cause 49854 as shown below.[14]

> **VII. AFFORDABILITY**
>
> **Q: Is it imperative for the Commission to consider affordability in this proceeding?**
>
> A: Yes. State policy requires affordability to be considered. These considerations must include CEI South's status of having the state's highest electric rates in 13 consecutive annual surveys by the Commission. They must also include the additional multiple upward pressures on rates from various other proceedings.
>
> **Q: How does state policy on affordability apply to this request?**
>
> A: The Indiana General Assembly has recognized the importance of affordability in two separate policy statements. The first was passed in 2016 and encourages investment in infrastructure "while protecting the affordability of utility services for present and future generations of Indiana citizens." I.C. § 8-1-2-0.5. In the midst of unprecedented rate increases, the Indiana General Assembly passed an additional policy statement in the 2023 session. I.C. § 8-1-2-0.6 requires that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider certain attributes, more specifically referred to as the "Five Pillars of Electric Utility Service." One of the Pillars is affordability. As costs and investments systematically increase to historic levels, the consistent upward pressure on ratepayers continues. It is imperative the Commission carefully scrutinize petition requests so as to only approve what is verified and justifiable as reasonably necessary and at a prudent cost. It is also critical to factor customer affordability into the accounting treatment a petitioner may seek, and into the timing of project requests and prioritization.

In CEI South's most recent rate case filing in December 2023 (Cause 45990) which immediately followed the Order in Cause 49854, CEI South notes that its rate base has grown from $1,296 million in the last rate case to $1.733 million as of December 31, 2022.[15] More concerning is CEI South's statement that rate base is projected to grow an additional $1,087 million through the end of the test year (net of the $340 million in securitization costs associated with the early retirement of the AB Brown coal units. CEI South did not include the rate analysis in its IRP supporting this plant closure. The uncomfortable question is why the

[14] https://iurc.portal.in.gov/docketed-case-details/?id=a206fa16-44fa-ed11-8848-001dd8070a7e, TESTIMONY OF OUCC WITNESS KALEB G. LANTRIP , Page 10.

[15] Direct Testimony of Richard C. Leger, page 9.

analysis was not previously performed so that the IURC could understand the rate implications of the securitization plan proposed by CEI South before it was approved by the Commission.

In this new case, CEI South is requesting a base rate increase of $118.8 million which represents an overall increase of 16.02%, based on a forward-looking test year ending December 31, 2025. This is in addition to the rate increase in Cause 49854.

CEI South fully acknowledges in its filing that “(a)ffordability means the electric generation and resource mix and ratemaking constructs result in retail electric service that is affordable across the residential, commercial, and industrial customer classes.” Failing to include a meaningful affordability analyses in the IRP and/or CPCN filings going forward is inconsistent with HB 1007 and RE requests that the Director note in the Final Director’s Report that additional affordability analysis is needed in future filings.

Conclusion

Thank you for the opportunity to comment on the Draft. Reliable Energy would be happy to discuss the issues raised above further with Commission staff.

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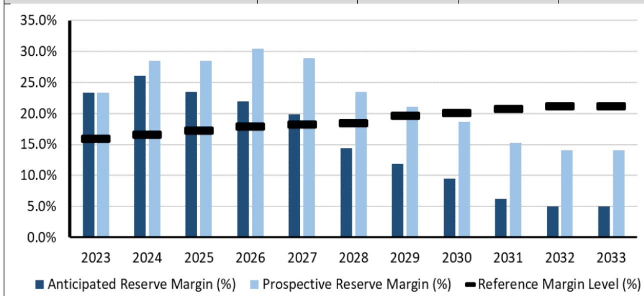
Attachment I. MISO Dashboard

MISO

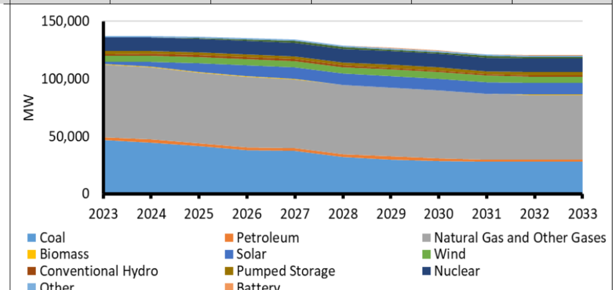
MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy and operating reserve markets that consist of 41 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments. See High Risk Areas for more details.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	121,933	122,726	123,315	123,888	124,659	125,140	125,591	126,135	126,593	126,593
Demand Response	7,776	7,741	7,798	7,812	7,726	7,728	7,729	7,731	7,728	7,728
Net Internal Demand	114,157	114,985	115,517	116,076	116,933	117,412	117,862	118,404	118,865	118,865
Additions: Tier 1	3,135	6,972	10,936	11,744	11,944	11,945	11,945	11,945	11,945	11,945
Additions: Tier 2	2,694	5,771	9,836	10,495	10,672	10,749	10,749	10,749	10,749	10,749
Additions: Tier 3	163	1,096	3,166	6,615	9,989	12,454	13,332	13,450	13,450	13,450
Net Firm Capacity Transfers	2,125	1,129	1,159	1,057	906	911	806	805	781	781
Existing-Certain and Net Firm Transfers	140,831	134,999	129,924	127,394	121,776	119,493	117,122	113,811	112,865	112,865
Anticipated Reserve Margin (%)	26.1%	23.5%	21.9%	19.9%	14.4%	11.9%	9.5%	6.2%	5.0%	5.0%
Prospective Reserve Margin (%)	28.5%	28.5%	30.5%	28.9%	23.5%	21.1%	18.6%	15.3%	14.0%	14.0%
Reference Margin Level (%)	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%	21.2%



Planning Reserve Margins



Existing and Tier 1 Resources