<u>**EAL 2024 IRP Stakeholder Committee Questions**</u>

To the extent any of the questions are requesting information subject to the attorney client privilege, privileged information will not be provided.

Energy Efficiency and Demand Side Alternatives:

1. How is EAL factoring the increased adoption of electric vehicles and heat pumps (i.e., "beneficial electrification") into its load growth projections, particularly considering the incentives offered by federal policies such as the energy efficient home improvement credit?
   Entergy Arkansas, LLC's (EAL) annual load forecast and the Integrated Resource Plan (IRP) scenarios include assumptions for increased electric vehicle adoption over time as well as changes in consumption due to changes in the relative shares of different types of space heating (heat pumps vs. furnaces) and changes in space heating efficiency. Like space heating, the forecasts are built using assumptions for changes over time in cooling load that could be due to changes in shares as well as changes in efficiency. The extent to which those may be specifically influenced by tax credits is not known.

2. Is EAL contemplating any changes to its energy efficiency portfolio over the course of the study period in this IRP proceeding?
   EAL's Three Year Plan Cycle for Program Years 2024-2026 was approved by the APSC in Docket No. 07-085-TF, Order No. 187, on November 9, 2023. For purposes of this IRP, EAL has not assumed major changes to the energy efficiency portfolio. The Commission's Order No. 187 allows utilities to continue to add or remove measures within a program as more information becomes available, provided that the Company's overall portfolio remains cost-effective. Additionally, Order No. 187 affords the utility the ability to shift dollars among the various programs within its EE portfolio to meet changing conditions, provided that no program is reduced by more than ten percent and the utility's EE portfolio remains cost effective.

3. How are energy savings resulting from EAL's energy efficiency portfolio incorporated into the load forecast?
   Estimates of the historical effects of energy efficiency are included in the assessment of historical monthly energy supplied by EAL. The relationship between those effects and energy supplied are then applied to forward-looking estimates of energy efficiency to develop the underlying energy in the load forecast.

4. What are the annual energy savings from EAL's energy efficiency program assumed in each year of the IRP forecast?
   The load reductions shown below are based on estimated effects from both EAL's programs and organic energy efficiency.

	Estimated EE Savings (MWH)
2026	249,827
2027	327,610
2028	393,787
2029	449,420
2030	490,759
2031	518,675
2032	538,207
2033	549,182
2034	553,202
2035	548,641
2036	538,648
2037	518,341
2038	499,116
2039	478,293
2040	454,079

5. Are there sensitivity cases (low, medium, high) of the energy savings resulting from energy efficiency programs?
   No.

6. Slide 25 notes that an IRP "is a planning process and framework in which the costs and benefits of supply-side and demand-side alternatives are evaluated to develop resource portfolio options that help meet EAL's planning objectives." Likewise, slide 9 indicates that EAL's 2021 IRP Action Plan included to "identify demand-side management opportunities." What demand-side management opportunities has EAL identified for its 2024 IRP? Does EAL plan to also implement and encourage participation in demand-side management opportunities after they have been identified? Please address the following specific sub-questions related to specific demand-side management opportunities that the Stakeholder Committee has initially identified:
   EAL is continuously researching and evaluating reasonable DR opportunities to expand the Company's DR offerings in a way that provides benefits to all EAL customers.

Environmental Update:

7. Were there any outside influences compelling EAL to implement carbon emission goals, or were the carbon emission goals internally developed?
   These goals were developed internally in the context of and informed by an understanding of the risk posed by climate change and the latest climate science. These factors, along with increasing interest from the Company's customers, owners, and other stakeholders,

plus the recognition of the role electric utilities play in economywide decarbonization – to provide as much low- to zero-carbon power to customers to meet their demand for clean energy – led Entergy to establish not only the most recent interim and long-term climate goals, but also to validate the Company's long-time establishment of carbon goals beginning in 2001. See more on Entergy's updated interim and long-term climate goals, and how they were developed, in the 2022 climate report at https://www.entergy.com/ClimateReport.

10. What is the basis for the timelines assumed in Slide 33? Please provide any relevant reports, documents, or other sources supporting EAL's assumptions regarding these integration assumptions.
    This timeline was provided in the Company's 2022 Climate Report to help stakeholders visualize the technology assumptions forming the basis for the illustrative pathway to net-zero provided in that report. The 2022 Climate Report provides a detailed, robust discussion regarding the various technologies and their ability to provide the affordable, reliable, and sustainable power that customers demand, both today and in the future, and advancements needed to further integrate those technologies into our system. The chart and the entire 2022 Climate Report are inclusive of all five Entergy Operating Companies. See more at https://www.entergy.com/ClimateReport.

11. Do the figures shown in Slide 34 and 35 represent the results of a past IRP? If so, which IRP results are shown? If not, what is the source of these projections?
    No. The figures are the result of the illustrative scenario presented in the Company's 2022 Climate Report. See https://www.entergy.com/ClimateReport.

12. For each of the environmental regulations shown on slide 37, please identify EAL's assumptions about the implementation status of each regulation over the study period in EAL's planning process. For example, did EAL assume the pending legislations would be implemented or rejected in their present states? Or did EAL assume that certain pending legislation would be implemented with modifications?
    To the extent this question is requesting information subject to the attorney client privilege, privileged information will not be provided. Subject to that objection, EAL's assumptions for each of these listed EPA regulations for the study period are as follows:

    For the Cross-State Air Pollution Rule, EAL is currently assuming future allowance pricing consistent with EAL's continued participation in the Group 2 ozone season NOx emissions trading program.

    Slide 64, future 2B addresses the proposed GHG emission standards under Section 111 of the Clean Air Act. Since this slide was developed, EPA Administrator Michael Regan announced that EPA was not planning to finalize GHG emission standards for existing gas turbine generating units in the forthcoming final 111 rule expected to be issued in Q2 2024.[1] Instead, EPA has indicated that it plans to solicit additional feedback and consider a broader range of pollutants in a future regulatory action focused on existing gas turbine generating units. Accordingly, EAL currently does not assume that existing NGCC units will deactivate by 2035 as noted for future 2B on slide 64.

For the Regional Haze second planning period, EAL's assumptions are consistent with the SIP submitted to the US EPA by the Arkansas DEQ, which does not require any additional pollution control investments on any EAL units.

There are no assumptions related to the remaining proposed regulations listed on slide 37 (Effluent Limitation Guideline, Mercury and Air Toxics Standards, and Coal Combustion Residuals), which are anticipated to only apply to coal-fired generating units.

14. Define "accelerated resilience" and its components and costs.
    Resilience is the ability to prepare for, adapt to, and recover from non-normal weather events such as hurricanes, floods, winter storms, wildfires, tornadoes, and other major disruptions. The goal of "accelerated resilience" is to proactively execute projects for Distribution and Transmission infrastructure over the next 10-15 years, which should be targeted for hardening. This is expected to yield benefits in the form of avoided customer interruptions and avoided restoration costs over the next 50 years. The components of accelerated resilience can include, but are not limited to, Transmission rebuilds, Distribution feeder rebuilds, Distribution feeder overhead to underground conversions, Distribution lateral rebuilds, Distribution lateral overhead to underground conversions, and Telecommunications improvements.

Futures and AURORA Modeling Overview:

17. What cost assumptions were used when modeling renewable energy and storage resources on slide 45?
    To the extent EAL understands the question to be asking about the LCOE calculations, solar, wind, and battery costs were derived as a starting point from the latest S&P Global Market Insights, NREL ATB, EPRI, and Woodmac publications. Internal adjustments were made to account for current market conditions in the assessment year, and EAL's overhead costs were added to represent a generic all-in cost for the assets. The installed capital cost and O&M figures on slides 49-52 are the capital cost assumptions that will be used in the IRP modeling. The levelized cost of electricity calculation used the inputs shown on the slide to arrive at the 2023$/MWh.

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[1] https://www.epa.gov/newsreleases/statement-epa-administrator-michael-s-regan-epas-approach-power-sector

18. Slide 64 indicates that EAL plans to rely on the four futures outlined therein to assess supply portfolios across a range of market outcomes. Likewise, Slide 34 provides an illustrative pathway to net-zero by 2050, which illustrates the utility mix percentages for generation and capacity (e.g., gas, nuclear, solar, wind, etc.) Could EAL please provide an illustrative chart similar to what provided on slide 34 to show how the four IRP future scenarios outlined on slide 64 will impact the utility generation mix percentages for generation and capacity?
    The chart on slide 34 is not EAL specific, and EAL's contributions will be informed by its IRP analysis.

19. Please provide all of EAL's load and resource tables for each of the past five years.
    See EAL's prior IRPs available on the EAL IRP website and APSC Docket No. 06-028-R.

20. What reserve margin does EAL plan to incorporate into its load forecast?
    EAL plans to incorporate MISO's current summer (9.0%) and winter (27.4%) PRMs established in MISO's most recent Loss of Load Expectation (LOLE) study as targets for capacity expansion modeling.

    https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf

21. What is the basis of EAL's assumed reserve margin? For example, is it based on a 1-in-10 loss of load event or some other reliability metric?
    See the response to question 20.

22. What is the accredited capacity assumed for each resource type?
    The accredited capacity for solar and wind will be calculated using the dynamic peak credit function within the Aurora model. The credit for non-thermal resources will depend on the net output of such resources in the modeling over the top ~3% net peak hours per season (~22 per month) for the MISO region. For battery storage, accredited capacity tranches are defined using an internal Effective Load Carrying Capability (ELCC) study. The accredited capacity assumptions for thermal resources relies on the MISO schedule 53 class average values and the UCAP ISAC ratios established for the 2024-25 planning year and hosted on MISO's website (links below):

    https://cdn.misoenergy.org/PY%202024-2025%20Schedule%2053%20Class%20Average631181.pdf

    https://cdn.misoenergy.org/UCAP%20ISAC%20Ratio%20for%20PY24-25631824.pdf

23. How will EAL model integration costs for intermittent resources?
    There are no inputs for integration costs in the modeling.

24. Will EAL test/model retirement decisions endogenously within AURORA, or will it conduct separate analyses evaluating retirement decisions?
    Once a retirement decision has been made, it is incorporated in the IRP planning process.

25. Please provide all forecasts of fuel prices over the entire study period.
    Projections of fuel prices will be included in the next set of stakeholder meeting slides.

26. Please provide all forecasts of emissions prices over the entire study period.
    Projections of emissions prices will be included in the next set of stakeholder meeting slides.

27. Please identify all assumptions about carbon prices in EAL's pricing scenarios.
    EAL relies on ICF's 2023 Q4 National CO_2 allowance price view forecast. The values to be modeled will be included in the next set of stakeholder meeting slides.

28. Provide the low, high, and reference economic inputs, including inflation rates, WACC, and fuel costs (including emission price assumptions), and what assumptions and inputs were used to determine these parameters.
    The current IRP futures do not propose to vary the long-term inflation rate or WACC. The low/high/reference fuel and emissions forecasts will be included in the next set of stakeholder slides. Assumptions and inputs used to determine these inputs are beyond the scope of IRP stakeholder process.

29. Referring to slide 60, how will EAL meet the gap in load and supply in 2026 and 2027?
    EAL is evaluating its options.

31. What is driving the reduction in supply resources? Plant retirements, reduction in capacity factors due to renewable resource additions, expiration of PPA contracts?
    Combination of generating units ceasing to use coal per federal requirements (White Bluff 1 & 2), deactivations of generating units (Lake Catherine 4, per federal requirements), and reductions in ELCC for solar resources based on underlying forecasted solar penetration in the market and MISO's Direct Loss of Load (DLOL) proposal, which is targeting implementation in the 2028-29 Planning Year.

32. Referring to slide 62, describe how EAL determines the range of outcomes and values for the major areas of uncertainty used in the Aurora model.
    Electric load in the long term will be affected by a range of factors, including changes in the following variables: population, levels of economic activity, temperature over time, adoption of electric vehicles, adoption of behind-the-meter solar, and increases in energy efficiency (both organic and through participation in demand response programs). Ranges of outcomes for natural gas prices are based on the Henry Hub forecast, which includes low/high scenarios informed by the long-term ranges presented in the point of view of various consultants. Market unit life assumptions are informed by MISO's Transmission Expansion Plan (MTEP) futures process. Federal policy outcomes are informed by current

Environmental Protection Agency (EPA) proposals, hence the inclusion of future 2B, which will measure certain provisions within the recent CAA Rule 111 proposal. Emissions price ranges are based on ICF's probability-weighted forecasts; see the response to question 27. Renewable generation capital cost ranges are based on applying the shape of National Energy Renewable Laboratory's (NREL) Annual Technology Baseline (ATB) cost curves for the conservative and advanced cases to the reference case projections. For MISO market reforms, see MISO's Resource Adequacy Subcommittee page for presentation materials detailing MISO's DLOL proposal, which helps informs IRP modeling with respect to future accredited capacity assumptions.

33. Has EAL incorporated any additional interruptible load in its resource profile? If yes, how did EAL determine the amount and the cost? If no, please explain why not.
EAL includes existing interruptible loads based on current and expected customer participation and expectation of the ability to include that load in its LMR registrations. See also response to question No. 71. Costs for existing and planned interruptible loads (e.g., existing or planned EAL load modifying resources) are consistent across market futures and therefore are not relevant to the comparison of portfolios in the IRP modeling.

34. Referring to slide 63, does EAL uses the Total Relevant Supply Cost metric rather than the Net Present Value of the Revenue Requirement (NPVRR) to determine its optimal portfolio? If yes, please explain the pros and cons of using this metric as compared to the NPVRR.
EAL uses the Total Relevant Supply Cost (TRSC) metric to compare portfolio economics. TRSC represents the present value of revenue requirements associated with new generation identified in the IRP modeling and the variable supply cost consistent with EAL's fleet's forecasted operation in the MISO market calculated using the Aurora model. In other words, TRSC includes the fixed cost for new generation and the total variable cost associated with EAL's entire portfolio (existing plus new generation). Fixed costs associated with existing assets are excluded as they are not relevant to the comparison of portfolios (because the costs would be the same in each scenario).

35. Slide 64 appears to indicate that a carbon tax would be implemented under all Futures. Is EAL willing to consider a future in which no carbon tax is implemented?
See Future 1 definition ('No Cost').

Inflation Reduction Act and Federal Incentives:

36. How is EAL planning to ensure that its 2024 IRP maximizes the benefits available from federal funding opportunities, including the from the Inflation Reduction Act (IRA)?
EAL has included the full PTC/ITC rates as specified in the IRA and applied those tax credits to reduce the cost of the resources over the expected useful life of those resources.
    a. How is EAL modeling the energy community bonus production tax credit in its planning assumptions?

EAL is not incorporating the energy community adder into the quantitative analysis given that the site locations are not known and qualification for this credit cannot be determined with certainty until a new generation unit is placed in service; as such, this adder is not part of the IRP modeling. See https://www.irs.gov/credits-deductions/frequently-asked-questions-for-energy-communities#losestatus.

37. Has EAL included the benefits of the IRA and the Infrastructure and Investment Jobs Act (IIJA) in its IRP analysis? If yes, please provide the assumptions used when modeling the IRA and IIJA in the Aurora model. If not, please explain why not.
See response to question 36. It is not possible to model IIJA benefits at this time because most of these benefits require EAL projects to be selected from a national or state-wide pool of applicants.

38. Slide 48 states that EAL "assumes full PTC rate"? Does this full rate include the available bonus credits, such as the energy community and domestic content credits, or only the base PTC of 30%? Please explain why or why not.
See response to question 36(a).

39. What is EAL's approach to the "energy community" adder to the PTC (or ITC)? Currently, much of Arkansas is considered an "energy community" by the federal government under the employment-related prong. As those areas may change over time, would EAL consider using an approach that accounts for this uncertainty by assuming, for example, 60% of the "energy community" adder? This is the approach Duke Energy Indiana is taking. See Meeting #1, Duke slide 44. For storage, shouldn't Entergy assume the "energy community" adder applies because it could site storage at the White Bluff or Independence facilities?
See response to question 36.

41. Slide 45 - Please explain the application of federal PTC/ITC tax credits for all the renewable energy and energy storage resources. Additionally, does the installed capital costs or the LCOE presented already include the federal ITC/PTC? If not, please provide the values incorporating the relevant federal tax credits.
The installed costs shown in the slide for solar, wind and battery do not include the investment tax credits. The IRA tax credits are reflected in the LCOE for solar and wind because the production tax credit was assumed. The tax credit assumptions are specified on slide 48.

IRP Process:

42. Referring to slide 25, when will EAL provide the results of its market modeling, portfolio optimization and production cost projections to stakeholders?
EAL will provide the results of market modeling and production cost by Q3.

43. Will EAL provide revised AURORA modeling based on stakeholder input to the results of the modeling, portfolio optimization and production cost projections?
    EAL does not anticipate providing revised AURORA modeling.

44. When will the conclusions and action plan be completed?
    Conclusions and the action plan are currently anticipated to be completed by September 2024.

45. Will the conclusions and action plan incorporate stakeholder input and recommended modifications to the IRP modeling? If not, please explain why not.
    See response to question 43.

46. Please explain how EAL will identify themes and opportunities. Will these be based on stakeholder input?
    EAL's IRP strategy helps to inform the steps EAL takes to continue to enhance reliability, affordability, and environmental stewardship for its customers. This approach also provides the flexibility EAL requires to respond and adapt to changing customer needs and expectations. Near-term decisions around new generation or deactivation of existing generation are project-specific and are handled on a case-by-case basis in the appropriate resource-specific dockets. The IRP encompasses longer-term trends that inform long-term planning decisions regarding EAL's generation portfolio.

47. What is meant by establishing a mid-term, actionable plan? When would this plan be established? Will stakeholders be allowed to comment on the mid-term plan and make modifications? If not, please explain why not.
    This refers to the IRP Action Plan that is part of the IRP Report. The stakeholder committee has the opportunity to file its Stakeholder Report along with EAL's IRP Report.

48. Please provide copies of EAL's IRP filings and any final orders associated with the filings for the other jurisdictions it operates in.
    See the response to Question No. 19.

Load Forecast:

50. Please explain the sharp increase in the NCP load observed in 2025 in Slide 56.
    The increase is primarily due to expected increases in large industrial load, including one customer whose large new steel mill has been publicly announced. (https://www.ussteel.com/next-generation-steel-mill)

51. Why do Slides 56 and 57 show NCP load rather than CP load?
    EAL forecasts based on non-coincident peaks (NCPs) as well as MISO coincident peak (CPs). NCP was chosen for these particular slides.

52. What is driving the step-up in load in 2025 and 2040 shown in slide 56?
    See response to question 50 regarding 2025. The increase in the later years, including 2040 and after, is primarily due to increases in EV load resulting from expected growth in EV adoption.

53. Explain why BTM solar is driving load growth.
    BTM solar is not driving and cannot by its very nature drive load growth.

57. Does slide 60 incorporate potential demand growth due to lithium mining in Arkansas? If not, please explain why not.
    No. Expected growth in that or any other sector may be considered in future forecasts.

Nuclear Resources:

60. When will EAL submit the ANO-1 and ANO-2 license extensions, and what are the expected dates for approvals or denials from the Nuclear Regulatory Commission (NRC)?
    Considering Nuclear Regulatory Commission (NRC) regulations at 10 CFR §2.109, EAL currently anticipates that any subsequent license renewal application will be submitted prior to five years before the expiry of the existing operating licenses. See the NRC's webpage at Status Of Subsequent License Renewal Applications | NRC.gov for information on the time that has been required for approval of subsequent (second) license renewal applications at the NRC. Entergy Arkansas cannot predict the time required for processing future ANO license renewal applications.

62. If EAL does not seek ANO-1 and ANO-2 license extensions or if the NRC denies either one or both applications, what are EAL contingency plans to replace the capacities for one and both units?
    The 2024 IRP assumes both units operate through the end of the modeling horizon.

67. What is the Grand Gulf capacity allocated to EAL in the current IRP?
    EAL's allocated portion of Grand Gulf is 303 MW.

68. Is the Grand Gulf capacity reflected in the Capacity Needs on Slide 60, as Grand Gulf's license expires in 2044?
    Grand Gulf capacity is reflected in the Capacity Needs on slide 60 with license expiring after 2044.

Operations:

70. How has MISO's shift to a seasonal construct affected how EAL values capacity throughout the year?
    With the shift to seasonal construct, EAL now evaluates capacity needs based on the seasonal peak requirement. The IRP modeling incorporates summer and winter reserve margin targets and accreditation assumptions.

71. Describe MISO's revised LMR requirements.
    See the following links eLibrary | File List (ferc.gov) and 20231107-08 RASC Item 11aii LMR Accreditation (RASC-2019-9)630751.pdf (misoenergy.org). As a result of MISO's changes to the eligibility rules for LMRs and the resulting incongruence with OISR, EAL was not able to register OISR as a capacity resource and receive auction revenues for the entire year.

72. Has EAL modified its LMR in its IRP planning? If yes, please describe the modifications, including any new or expiring LMRs. What is the dollar impact of modifications to LMR on the most cost-effective resource plan?
    No, EAL has not modified LMRs in the IRP planning.

73. Describe MISO's hybrid resources requirement changes. How do these changes impact EAL's IRP modeling?
    See page 44 (PDF page 215 of 325) of MISO's recent filing to FERC (link below) regarding MISO's proposed accreditation for hybrid and co-located resources. EAL's IRP modeling will rely on the sum of parts accreditation for hybrid resources (i.e., total hybrid accreditation = battery capacity credit + solar capacity credit). See the response to question 22 for more detail on accredited capacity assumptions.

    https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf

Resource Retirement Plans:

76. Please provide the retirement dates and quantities assumed in this IRP for Entergy generation resources on a unit-by-unit basis.
    See the response to Question No. 19, specifically Appendix B from the 2021 IRP and anticipated useful lives provided in the 2024 stakeholder slides.

Technology Assessment:

77. Please provide the assumed capacity values for all generation technologies for all seasons modeled in this IRP.
    See the response to question 22.

79. How did EAL develop the cost assumptions for each of the resources? For example, did they simply use cost projections directly provided by vendors or other external sources? Or did they develop internal forecasts based on data from these sources?
EAL reviews costs from 3rd party data sources like S&P Global, NREL, EPRI, and Woodmac, and supplement with information guided by EAL's internal project costs to incorporate information around EPC and non-EPC owner costs.
    a. Is EAL able to provide the workpapers used to develop or otherwise containing these cost assumptions at this time?
    No. These costs incorporate commercially sensitive pricing data and information using paid subscriptions from outside sources.
    b. Explain how EAL determined the life expectancy for the thermal resources.
    The thermal resource life expectancy data for natural gas resources is a result of external studies provided by Sargent and Lundy.
    c. Why is the life expectancy for SMR only 30 years?
    The assumption in the EPRI tag-web application assumed 30 years, which aligns with EAL's assumption.

80. Is EAL only allowing natural gas resources as candidate resources if they are capable of co-firing hydrogen?
No. EAL is modeling resources capable of complying with final proposed Rule 111.

81. Is EAL assuming that it will own and operate all resources in its modeling?
The IRP modeling does not distinguish between owned resources or power purchase agreements.

82. Please explain how EAL developed each of the reference, low, and high capital cost projections for solar, wind, and battery resources.
The reference case cost projections were developed using a blend of S&P Global and NREL long term growth rates. The low, and high capital costs are scaled relative to the reference case proportionally using the NREL 2022 annual technology baseline advanced and conservative forecasts respectively relative to the moderate forecast.

83. Did EAL develop reference, low, and high capital cost projection for other resources?
No.

84. What is the basis for the assumed transmission interconnection adders?
For new points of interconnection (POIs) the cost is based on a new three breaker ring transmission substation. For brownfield POI substations the cost is based on adding a new node at an existing substation.

85. Is EAL considering extending the life of its ANO plant? If yes, when does EAL expect a decision by the NRC regarding its request? What cost assumptions did EAL use when seeking to extend the life of the nuclear plant? If EAL is not seeking to extend the life of

ANO, please explain why not, in detail, with operating and cost assumptions used to determine whether the life of the plant should be extended.
See response to question No. 60.

Transmission:

86. Please describe how the transmission limitation between MISO North and MISO South, also known as the Regional Directional Transfer (RDT), is modeled in the IRP.
Capacity expansion modeling in the IRP does not consider the RDT limits because capacity expansion is performed for EAL and MISO simultaneously, and siting for MISO units selected in capacity expansion is outside the scope of the IRP.

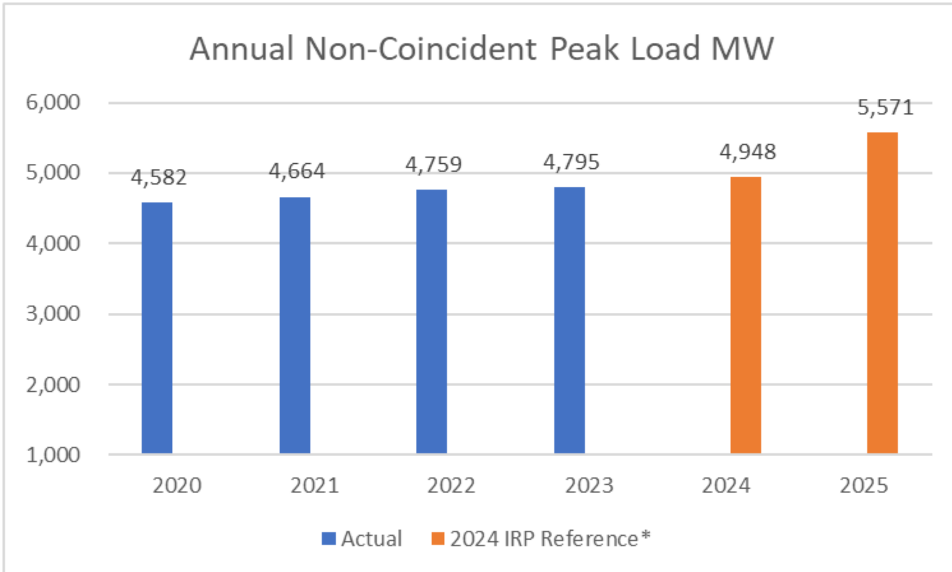
89. Are the costs for additional transmission associated with additional generating resources included in the Aurora model when determining the most cost-effective resource plan?
Transmission interconnection costs are included consistent with the response to question 84 and slide 53 of the IRP stakeholder presentation. Additional transmission costs associated with ERIS or NRIS service in MISO are not included as such costs may vary significantly depending on project location, other projects in the same MISO study, and ongoing reforms to MISO's generator interconnection process.

Uncategorized Specific Questions regarding the Slides:

91. Referring to slide 7, identify the longer-term trends that inform EAL's long-term planning decisions.
There are multiple long-term uncertainties and trends that inform EAL's long-term planning decisions such as sales and load growth projections, customer usage trends, federal policies (e.g., tax credits and environmental regulations), MISO market reforms, forecasted fuel and emission prices, forecasted technology costs, and technology maturity and feasibility.

92. Referring to slide 9:
    a. Please define and explain how EAL will pursue power resilience. What assets are used to secure power resilience?
    See response to question No. 14. EAL evaluates options for power resiliency.
    b. Please explain how and why EAL will "evaluate stakeholder engagement." Why is an evaluation of stakeholder engagement necessary?
    EAL values the input of its stakeholders and utilizes feedback as a means for process improvement.

93. Concerning slide 11, please provide EAL's projected load growth in 2024 and 2025.
EAL's forecasted load reflects a 22% increase over 2020 actual load.



*Forecasted load is weather normalized.

94. Concerning Slides 12 & 13, what are the effects for MISO's "Tranche 3" process on EAL's 2024 IRP?
The LRTP process would not change the previously submitted projects to MISO's MTEP. Tranche 3 could create new projects with Transmission capacity in Arkansas, which in turn could open new locations to site future generation.

95. Concerning Slide 21, what are the current and future "LMR capacity requirements" for EAL and MISO?
See response to question 71.

96. Concerning Slide 21, please list and explain all "MISO Market Participant Changes."
See the following links: eLibrary | File List (ferc.gov)

and 20231107-08 RASC Item 11aii LMR Accreditation (RASC-2019-9)630751.pdf (misoenergy.org).

98. Concerning Slide 33, what are EAL's contingency plans if the "Currently unknown" and "Expected to be viable" technologies are not available to provide the electricity needs for EAL customers?
EAL is working with leading technology vendors to study the feasibility of various future technologies listed on this slide.

99. Concerning Slide 33, what are the proven capacity and general locations for wind resources in AR?

EAL is aware of several resources that have achieved generator interconnection agreements in Arkansas. Additionally, EAL is aware of five wind resources active in the MISO interconnection queue and 2 hybrid resources with a wind component. Information on these projects can be found on the MISO website.

100. Concerning Slides 33 & 60, what are the effects on current and future EAL generation resources regarding MISO's accreditation changes?

Slide 60 depicts an average view of accredited capacity to illustrate EAL's capacity need on an annual average basis. EAL's existing thermal and renewable resources are now accredited according to MISO's Seasonal Accredited Capacity ("SAC") rules outlined in the Tariff and Business Practice Manual 011 (BPM 0-11). EAL has developed a point of view on effective load carrying capability (ELCC) to account for future accreditation changes outlined in its recent DLOL filing to FERC (https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf). See responses to question Nos. 33 and 71

105. Slide 45 - Please provide all financial, capacity, operational, and performance assumptions regarding footnote 4 regarding the "transmission HVDC costs for a 600 mile line". -

Assumptions

$ 4,000,000	HVDC Cost/Mile
600	HVDC Distance (miles)
$ 350	Converter station cost ($/kw)
2	Number of converter stations
1,000	Line capacity (MW)
$ 13,300	O&M - $/line mile per year
$ 40,000	O&M - converter station annual cost

106. Slide 46 - Please explain footnote 3 that, "Hybrid resources will be modeled in Aurora as stand-alone solar with the option to add a coupled storage at a discounted cost." How will Entergy provide the "option" for coupled storage in the model? What is the discounted cost? How will the BESS be discharged in the model?

The Aurora model may select BESS at a 7% capital cost and 20% O&M cost discount relative to the standalone storage installed cost and O&M cost presented on slide 45 of stakeholder materials. These discounts are to account for the savings associated with building and operating a hybrid facility compared to standalone storage. The underlying assumption is a battery that can charge from and discharge to the grid to maximize capacity value. BESS charging/discharging logic attempts to flatten EAL load shape based on EAL demand net of wind, solar, and nuclear output.

107. Slide 48 - Will EAL run contingencies for higher “Inflation Rate Assumptions”?
Not at this time.

108. Slide 49 - Given that no new "rotating turbine plant" as presented currently exist in the MISO Generator Interconnection Queue in Arkansas, please explain Entergy's views on the ability to construct and begin operation of the various natural gas technologies presented in the timeframe provided. How will Entergy get the various resources identified in Slide 49 through the MISO queue with enough time to begin operation by 2028, especially in light of the new Order 2023 reforms?
The purpose of the slide is to show the timing of the costs necessary to bring a generating unit online.

109. Slide 53 - Provide citations regarding the assumed transmission costs. Please describe which generation resources will be assigned the New POI Costs versus the Brownfield POI Costs in the model. Please explain at which point in the modeling process the transmission costs are included, and whether the federal ITC was used for renewable energy or battery storage technologies to help reduce the costs of the transmission upgrades.
Costs for natural gas generation resources assume a brownfield interconnection, as those resources are often generator replacements, and renewables assume a greenfield interconnection as those resources often require a new substation. The interconnection costs are reflected before being entered into the production cost and capacity expansion models.

111. Concerning Slide 67, please explain “Future Stakeholder meetings and data postings” that will occur outside of the stated “Q3 2024 Meeting 2”?
If new information becomes available that does not warrant a meeting, it will be posted to the website and sent out via email to all stakeholders.

2024 IRP Schedule and Next Steps:

112. Is stakeholder engagement limited to the two meetings shown in Slide 67?
Yes, but is subject to change. Stakeholders may also submit questions via email.

113. When will EAL announce the date and time of the second stakeholder engagement meeting that is to occur in Q3 per slide 67?
EAL will provide advanced notice of the second stakeholder meeting.

114. Will EAL coordinate with the stakeholder committee prior to scheduling the second stakeholder engagement meeting in Q3 of 2024 and make a good faith effort to schedule the meeting at a time that avoids common scheduling conflicts (e.g., conferences and APSC filing deadlines)?
See the response to question 113.

115. Will stakeholders be able to provide feedback and modeling suggestions to EAL through other means, such as an online forum or email?

EAL will receive feedback from the representative of the stakeholder committee through email.