ENERGY FUTURES GROUP

PO Box 587
Hinesburg, VT 05461 USA
802.482.5001
info@energyfuturesgroup.com

energyfuturesgroup.com

Topic One Stakeholder Questions

Question 1: The Agencies recognize this study process is purposefully targeted in its nature, with Section 9.15(o) providing clear goals and expectations of the resource adequacy study and resulting report. What additional goals, objectives, or evaluation metrics should be considered, either as part of this study process or future resource adequacy study efforts?

Response:

If designed broadly enough, this study can help determine whether the state's funds to implement CEJA are cost-effectively aligned between eligible resource types or whether a funding realignment is advised.

Question 2: Which variables are the highest priority to explore? Further, are there important policies or drivers missing in addition to those outlined in the preceding stakeholder workshop that could help shape scenario development?

Response:

See response to Question 3.

Question 3: Which of the following drivers are most critical to explore in the resource adequacy modeling scenarios and why?

a. Extreme weather
b. Demand growth
c. Thermal retirements
d. Transmission build and future needs
e. Generation resource diversity
f. Out-of-state reliance on generation resources
g. Some other driver not described above

Response:

Each item outlined will be critical to explore in the resource adequacy modeling. As it relates to the drivers that will likely have the largest impact on the reliability results, we believe those drivers include demand growth and the import/export limits for Illinois and PJM and MISO (assuming this is reflected in the out-of-state-reliance on generation resources). Given the likelihood of the impact of these drivers, we believe these are the higher priority items to consider for scenario development. However, we note that the need for scenarios will be highly dependent on the base case assumptions. The stakeholder presentation noted that the topology of the study would include interactions between the Illinois zones and MISO and PJM[1], however, it is not clear what assumptions will be made around the transmission interconnection between the zones. It will be important to reflect load and generator outage diversity between Illinois zones, MISO, and PJM through the interchange assumptions. GridLab recently released a report[2] on resource adequacy for the Eastern Interconnection under different scenarios and found transmission to be a significant driver in reducing the LOLE. In particular, the study noted that assuming the technical transfer capabilities of lines between regions notably changed LOLE outcomes. This assumption is more aligned with the physics of the bulk power system than traditional RA methodologies which tend to assume power transfer is limited to historical levels and/or to contractual limits. We don't have more specific guidance to offer without more information about the proposed interchange and topology assumptions that will be used in the study.

It is also unclear what level of load growth is going to be included in the base case assumptions. With the potential load growth from high load factor customers like data centers, several different scenarios around assumed levels of growth will be necessary to capture the risk associated with these large load customers. Assuming any significant amount of new, large loads is likely to dramatically impact the modeling results, but there is immense uncertainty associated with the scale of these loads, their realization rates, and ramp rates.

[1] Slide 30. Retrieved from https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250616-presentation-ra-study-workshop1-final-16june2025.pdf

[2] https://gridlab.org/portfolio-item/eastern-interconnection-ra-study-report/

The importance of thermal retirements and generator diversity will become more apparent once there are initial results. Seeing initial model results, in particular when shortfall events occur and their duration, will help provide information about whether a different generation mix might help address events. Since this modeling process is using the PLEXOS model to perform capacity expansion modeling, inputs such as resource costs, resource build limits (if applied), and resource accreditation will be important inputs in the capacity expansion optimization. Without knowing how build limits, resource availability, and resource cost assumptions are going to be modeled in PLEXOS, it is hard to give feedback on those inputs and how they might influence the portfolios that E3 intends to create. For example, the build limits could be so narrowly defined as to dictate portfolio outcomes without consideration to cost. Or if generic pricing based on public sources like the EIA AEO or the NREL ATB are used, the costs of new generation will be dramatically understated.

It's difficult to opine about the reliability impact of thermal retirements without seeing initial modeling results. For instance, if a thermal generator has a high forced outage rate or has a low capacity factor, and can be replaced with a resource or combination of resources that performs better than that thermal generator, the reliability risk associated with that retirement will likely be reduced, or potentially produce a portfolio with a higher level of reliability.

Extreme weather conditions, especially as they relate to load and renewable profiles, should be captured through the weather years that are included in the RECAP study. If there is concern that extreme weather conditions could not be captured through RECAP, it would be helpful for stakeholders to have more information to understand what gaps there might be in the RECAP analysis. Overall, best practice is to ensure that weather correlated demand and generation data are considered reflecting historical weather patterns over several years. If this is followed, extreme weather events and their influence on resource availability and demand will be captured. Clarity on how RECAP generates weather correlated datasets would be helpful (for example, are the weather conditions across a year kept intact, or are new weather data created through sampling).

Question 4: Are there known or expected developments in federal or state policy that should be integrated into scenario development? Please explain in detail and provide references where possible.

Response:

The biggest and most obvious development is the rollback of the PTC and ITC. While this should be a base case assumption, a sensitivity that includes the reinstatement of those tax credits should be included as well since history has generally shown support for those tax credits even after periods of lapse. If development of renewable energy slows, this will expert upwards pressure on gas prices, which may not be reflected in many fuel price forecasts (but should be considered).

Question 5: How should cost implications or other findings beyond potential reliability shortfalls be presented or considered to support constructive policy decisions?

Response:

It is not clear how portfolios will be evaluated if a reliability shortfall is identified. For example, if the existing system portfolio is found to have a Loss of Load Expectation ("LOLE") of .06 / year, and Portfolio A has a LOLE of .08, and Portfolio B has a LOLE of 1.5, how will those results be interpreted? Will Portfolio A be determined to be reliable because it is under the industry threshold of a .1 LOLE or will it be deemed to have reliability concerns since it is higher than the existing system portfolio of a .06 LOLE? Furthermore, it is also not clear what steps might be taken to follow up on any portfolios that have identified reliability shortfalls. For instance, in the example above, Portfolio B has a LOLE of 1.5. Will further exploration on this portfolio be done to see if a different mix of resources would be reliable, i.e., if additional generation resources would result in a reliable portfolio, if a different mix of generation resources, or if additional transmission build with neighbors would solve the reliability shortfall? Performing this additional follow up for any portfolios with identified reliability shortfalls, whether that is defined as being above a .1 LOLE or above the existing system portfolio LOLE to determine the cost impact of addressing reliability shortfalls for that portfolio. For example, could Portfolio B become reliable if additional resources or transfer capability with MISO and PJM result in the portfolio meeting the .1 LOLE threshold, and if so, what would the cost of that action be? In a study performed by Astrapè Consulting, one of the scenarios looked at the level of four-hour storage that was needed to arrive at a .1 LOLE and then a sensitivity was performed to see what level of eight-hour storage would be necessary to bring the system to a .1 LOLE.[3] Similar, iterative looks would likely be helpful for this process as well.

In addition, it's important that reliability outcomes be presented using statistical metrics and visualizations that go beyond LOLE which is only a capacity metric.

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[3] Astrapè Consulting (August 2024). Illinois Deactivations: Maintaining Reliability with Energy Storage at 8.

Expected unserved energy, heat maps or other visualizations to indicate the timing and magnitude of events can provide insights into possible policy solutions. For example, the GridLab Eastern Interconnection study noted that many of the events are short duration and could be addressed with short-duration storage or demand response.

Question 6: What blind spots or gaps in the RA Study process do you worry might be overlooked or otherwise not addressed?

a. Are the identified blind spots or gaps unique to customer segments, modeling scenarios, market conditions or other targeted parameter?

b. How could the identified blind spots or gaps be addressed? (e.g. through additional scenarios, targeted data inputs, utilizing specific modeling, etc.)

Response:

At this point in the process, it is challenging to know if there are blind spots or gaps without having more information as it relates to the input assumptions for the study. As an example, without knowing what is reflected in the load forecast, including assumptions around new large load customers, it is hard to know if the load forecast will result in a gap in the RA Study process. Crucial information related to the load forecast includes how E3's MISO and PJM forecasts align with RTO projections since MISO and PJM assume radically different levels of new load. In addition, if new large loads are included in the forecast for the Illinois zones, are those new customers under contract with the utility or have made a significant financial commitment to deem that new load as a less speculative request? It will be important to provide stakeholders with more information on these key assumptions that will be used to develop the forecast.

It is likely that gaps can be closed as it relates to the load forecast through robust scenarios. For instance, if the base case load forecast assumes 6,000 MW of load growth from data centers for Illinois, but only 3,000 MW of that load is actually under contract or has made significant financial commitments (paid for transmission studies, placed a deposit for constructing facilities, signed agreements with the utility), then it will be crucial for a scenario to be evaluated that only includes the 3,000 MW of load to reflect the risk that the 3,000 MW of load not under contract does not materialize.

Other gaps might exist in the study, but at the moment stakeholders have no information upon which to assess that question.

Question 7: Have any peer jurisdictions developed scenario(s) through the completion of their own resource adequacy assessments or studies that should also be considered by the Agencies through this Resource Adequacy Study?

a. Provide details concerning the scenario(s), which jurisdiction developed the scenario, and provide a link to the supporting detail(s).

b. Is the assessment part of a broader resource adequacy assessment, or an more detailed integrated resource planning effort?

c. Are there any market conditions or policy considerations that are unique to the jurisdiction and/or the scenarios referenced?

Response:

We would encourage the Agencies and E3 to review the eastern interconnection resource adequacy study[4] conducted by GridLab and Telos Energy which includes a wide areas assessment, and in particular, how the study formed its regional transfer capability assumptions described on page 10 of the report.

Topic 2 Stakeholder Questions

Question 8: Are there recommendations for specific data sources that could be utilized in this study?

a. Are there preferences for certain input assumptions that should be made?

b. What prior or concurrent studies could be referenced that might add value or ensure alignment with similar or adjacent work (e.g., queue assumptions, RTO projections)?

Response:

While it is not clear how large loads, such as data centers, will be reflected in the load modeled in RECAP, we recommend that these loads not be modeled in a way in which the load can be influenced by historical weather. We make this recommendation because if RECAP does scale the projected load forecast based on historical weather, this might introduce additional risk hours if the data center loads are scaled similar to other customer classes. This could create additional risk hours in

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[4] Report found at https://gridlab.org/portfolio-item/eastern-interconnection-ra-study-report/ (landing page with other documents are www.gridlab.org/GridPath_EI)

the model and skew the results especially if new large loads that are insensitive to weather are included in the load forecast scenarios. If this is how RECAP models data center load, we recommend that the data center load be modeled like a negative generating unit with an associated 8760 shape that would remain consistent across the weather years. The 8760 shape for the data centers would reflect some of the seasonal diversity in the shape due to cooling requirements in the summer, but this approach would prevent the load from being scaled in response to the historical weather represented in the weather years included in the study.

See also the response to Question 7.

Question 9: Are there specific transmission constraints, expansions, or projects that should be considered and reflected in a model scenario? Further, Are these transmission considerations intended to target and/or solve specific challenges? Please explain, provide supporting documentation justifying inclusion, and provide pertinent reference materials including reports or studies.

Response:

See response to Questions 3 and 7.

Question 10: Are there specific assumptions that should be considered concerning generation resources, including buildout (queue, pace, technology availability) or retirements, both in-state and regionally in the RTO markets?

a. Which proposed assumptions should be considered as part of the base case and which are best considered as part of a prospective scenario? Provide any available references to RA studies, IRPs, or comparable assessments and reports to support your recommendations.

Response:

At this point in the process, it is unclear what approach is going to be taken as it relates to assumptions around the level of resources that will be assigned from the MISO or PJM queue and/or whether the Agencies and E3 will rely entirely on PLEXOS' optimization function. Since this study is using PLEXOS to perform capacity expansion, it is unclear if the approach is going to be allowing PLEXOS to determine the level of new generation resources needed across PJM, MISO, and the Illinois zones or if the study is going to assume a level of resources as going in or fixed decisions based on the MISO and PJM generator interconnection queues and then PLEXOS will fill in any generation need gaps by optimizing the resource selection.

For retirements in PJM and MISO, our recommendation would be to include announced retirements. For generation resources, the approach could be varied. If there is an intent to utilize PLEXOS for optimizing new generation, then the approach could be to review the MISO and PJM generation queues and only include those generators with a signed Interconnection Service Agreement, or an approach like the one used in the Astrapè study where there are weights assigned (100% to generators with a signed Interconnection Service Agreement and 57% to generators with a Facilities Studies Agreement).[5]

b. Which assumptions are contingent upon specific policy and/or legislative conditions being met or otherwise enacted? Please plain in detail.

Question 11: As a component of the RA Study, the Agencies will be seeking to obtain utility and RTO load forecast projections and the underlying assumptions behind the load forecasts. In addition to these utility forecast assumptions, what additional assumptions should also be considered, either embedded in a base case or considered in scenarios? Further, what data sources should be drawn upon, supporting any load forecast modifications? (i.e. large load / electrification growth)

a. Provide details on why these additional assumptions should be considered during the modeling process?

b. Are any proposed load forecast assumptions directly impacted and/or predicated upon specific to policy, legislative, or other conditions being met and/or otherwise enacted? Please explain in detail.

Response:

If the load forecasts for this study will be aggregates of the utility load forecasts, it will be crucial to have supporting information from the Illinois utilities on the underlying details for any new large load customers. For instance, if the utilities have a load interconnection queue with 10,000 MW of prospective customers that are being tracked, but only 3,000 MW of this load queue has signed electric service agreements, and the utility is assuming 5,000 MW of load growth in its forecast, it is important to understand how the utility arrived at 5,000 MW if only 3,000 MW is under contract. Having this level of information will help guide scenario development for the load forecasts considered for this study. The more information that can be collected on the

[5] Astrapè Consulting (August 2024). Illinois Deactivations: Maintaining Reliability with Energy Storage at 7.

status of the prospective customers in the utility's load queue, the better defined that the base case load forecast and alternative scenarios can be for this study.

As part of its load forecast development for the 2025 Load Forecast Report, PJM asked utilities to provide supporting information around the methodology used by the utility. For example, in its documentation, Exelon noted that its large load adjustments for ComEd, PECO, and BGE identified criteria for including new large load customers and assumptions for the forecast:[6]

- Customers with signed engineering agreements/financial deposits
- 8-year ramp for new projects from in-service date
- Utilization rate assumption as a percentage of requested customers capacity realized after the ramp period (Exelon reported that in a majority of cases this rate is around 70%)

Having information on the assumptions that have gone into the utility's load forecast, especially for the Illinois zones, will be crucial for developing base case and alternative load forecast scenarios. Understanding the different levels of commitment from prospective customers (those without any signed agreements, those with signed engineering agreements, and those with signed electric service contracts) will help break down the utility's load queue and provide prospective on helping to identify what level of load growth can be considered firm versus what may be speculative.

Gathering information on additional assumptions, such as Exelon's ramp and utilization rate, will also help align utility assumptions with any assumptions used for this study. Exelon indicated a utilization rate assumption, which has also been used in other forecasts, such as ERCOT's 2025 Load Forecast report. In the development of the large load forecast, ERCOT made three modifications, which included: a 180 day delay to ramp schedules to reflect delays in projects coming online; a reduction of 49.8% to data center additions based on historical data for the average peak consumption compared to the requested MW level from the customer; and a further reduction of 55.4% based on the percentage of the historical level of load energizing as compared to requests.[7]

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[6] Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/exelon-documentation.pdf

[7] 2025 ERCOT System Planning. Long-Term Hourly Peak Demand and Energy Forecast at 9-10. Retrieved from https://www.ercot.com/files/docs/2025/04/08/2025-LTLF-Report.pdf

We highlight these as potential differences that might arise between the Illinois utility load forecast assumptions and the consideration needed for how to approach the risks associated with any large load customers as it relates to whether or not they will materialize, the ramp rate associated with the load, and the potential for those customers to materialize at a lower utilization rate. Scenarios will be needed to reflect this risk. With the information we have available to date, we would recommend at a minimum, performing a scenario with no new large load customers included, a scenario that includes only those new customers with a signed agreement, a higher load forecast scenario that assumes a level of load between those customers with a signed agreement and what is reported as being in the utility's load queue, and an additional scenario that incorporates the risks associated with ramp rates, load materialization, and utilization. An additional scenario that would be helpful to include is if a portfolio does not meet the .1 LOLE is to look at what level of the assumed new large load growth would need to be flexible in order to bring the system to a .1 LOLE.

Question 12: Are there any additional considerations – data inputs, policy, drivers, or assumptions – that Stakeholders believe the Agencies should consider, not already explain in response to the preceding questions? Please explain in detail.

Response:

We have several additional considerations that can be grouped into access to model input and output assumptions, questions on the RECAP model, and items for clarification.

For model inputs and outputs, we recommend that modeling input and output files for PLEXOS and RECAP be shared with stakeholders. Providing stakeholders with access to this information will not only increase transparency for this modeling process, but it will also help stakeholders gain additional insights into model results while also providing stakeholders with additional information to aid in the process of stakeholders sharing feedback on the modeling.

As it relates to modeling performed in RECAP, we have the following questions that will help us better understand model configuration and how that might impact LOLE results:

- What weather years will be modeled in RECAP? Are these weather years kept intact, or are new "weather years" created through sampling and what is that sampling method? Do weather years receive a different probability assignment or are they all weighted equally?

- How are the load profiles developed? Will multiple load growth scenarios be considered, given the uncertainty especially in data center growth?
- How does RECAP scale the historical load profiles to reflect the forecasted demand for the study year evaluated?
- How are renewable profiles developed?
- Does RECAP incorporate load forecast errors in the study? If so, what level of load forecast errors are modeled and how are they determined?
- Will RECAP reflect weather-correlate outages for thermal resources, especially considering cold weather outages?[8]
- Are resources in RECAP dispatched economically or are there any assumptions about resources being must run to help manage model run time?
- Does RECAP use hourly chronology?
- How does RECAP model planned maintenance (is it modeled with specific outage dates or is it a rate that is optimized and typically scheduled during low risk periods?)
- Is RECAP's objective function to minimize system costs? If not, what objective function is RECAP using?

We also have several items to note since we are unsure how they will be reflected in the study and ask that additional information be provided to stakeholders:

- Is the RECAP modeling only looking at a 2030 study year?
- As it relates to comparing LOLE results, how will the MISO four season construct be reflected, i.e. will the LOLE results be reported on an annual or seasonal basis?
- When modeling the PJM and MISO regions, will those regions' portfolios be adjusted to reach a .1 LOLE assumption (i.e. adding perfect resources until a .1 LOLE is reached), or will those regions only reflect resources either hardcoded into the model or selected within PLEXOS? We ask this question to help us

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[8] Please see pages 7-8 of the MISO LOLE 2025-2026 Report. Retrieved from https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

Please see slide 8 of a PJM presentation on LOLE modeling. Retrieved from https://www.in.gov/iurc/files/0-2024-6-6-IURC-Meeting-Resource-Adequacy-and-Accreditation-in-PJM.pdf understand if this will impact what the LOLE might look like for these regions, since the PJM and MISO interaction with the Illinois zones may influence the LOLE results.

- Slide 30 of the Resource Adequacy Study Workshop[9] indicated that imports / exports will be limited by transmission interconnections between zones. Does this mean that at any time, if the Illinois region is in a shortfall and PJM is not, that Illinois will be able to import up to that transmission interconnection at any hour over the study? And is the transmission interconnection assumption going to be based on the physical transfer limit or something else?
- Slide 30 of the Resource Adequacy Study Workshop[10] indicated that “Future portfolio scenarios will be aligned across all zones to ensure consistency”. It is not clear what “zones” means. Do the zones reflect only Illinois, PJM, MISO, or all three? In addition, does this mean that capacity expansion within PLEXOS will be limited in some way? And if the portfolios are all aligned, what impacts do the scenario assumptions have?

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[9] Retrieved from https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250616-presentation-ra-study-workshop1-final-16june2025.pdf

[10] Retrieved from https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250616-presentation-ra-study-workshop1-final-16june2025.pdf