Stakeholder Comments on IRP/Mitigation Plan Workshop #2: Resources

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1. Introduction

Ameren Illinois Company ("AIC" or the "Company") appreciates the opportunity to provide comments on the second IRP/Mitigation Plan stakeholder workshop held on April 10, 2026, which addressed eligible resources, resource cost and performance inputs, and emissions treatment for the IRP modeling framework. These comments respond to the stakeholder questions posed by the ICC, the IPA ('the Agencies') and E3.

AIC is broadly supportive of the resource categories and analytical approach presented in Workshop #2. The Company's comments focus on areas where the proposed inputs may not fully reflect current market conditions or where targeted refinements could improve the accuracy and credibility of the IRP's resource evaluation.

2. Responses to stakeholder questions

2.1 Are there specific resource types that are not adequately captured by the proposed categories and should be reflected in the IRP framework?

AIC does not believe any major resource types are missing from the proposed categories. The Company notes, however, that the treatment of VPPs as a single composite resource (discussed further in our answer to question 6 - Section 2.5) may obscure meaningful differences in cost, performance, and system value across the underlying asset types. AIC recommends that VPP building blocks be treated as distinct resource options rather than aggregated into a single representative VPP, as the underlying technologies differ materially in cost, performance, and availability. These distinct resources can potentially be 'bundled' together, but only once we ascertain the underlying resources' cost and performance characteristics can we understand how they overlap/interplay in a combined setting.

2.2 Are there any resource categories that should be added, removed, or redefined to better reflect meaningful differences in cost, performance, or system value?

The set of resources considered are broadly sufficient. AIC expects that other stakeholders may prefer to delineate additional LDES technologies under the broader characterization. However, it appears that only Form's iron-air or hydrogen battery would fit the 80-100hr use case described. Both technologies' readiness level and existing deployment references (in GW-years of operation) reasonably renders their consideration for an Advanced Technology Acceleration scenario with the anticipated cycling rate (i.e., ~2% capacity factor) as described by E3. AIC would be glad to provide reference performance characteristics if requested based on previous/prior analyses.

2.3 What feedback do you have on the proposed base case cost assumptions for mature technologies (including solar, wind, lithium-ion storage, and gas)?

AIC offers the following observations:

Consistent treatment of market conditions: The treatment of current market conditions across resource types appears inconsistent. 'Market conditions' include both supply-demand constraint driven price levels as well as external, potentially transitory policy choices such as tariffs. Elevated gas turbine costs reflect a supply-demand imbalance driven by the data center buildout wave, which is likely to ease as equipment demand stabilizes in the early 2030s. Renewable energy costs similarly reflect current tariff and supply chain conditions but are assumed to alleviate quite rapidly in the 2030s. AIC does not take a position on whether any individual market effect is transitory or structural, but believes the same and consistent analytical framework and treatment should be applied across all resource types. In short, there should be a very high burden of evidence to claim renewable market conditions and tariffs are alleviated while turbine dynamics persist.

Tariff uncertainty: Tariff magnitudes and duration are highly uncertain and deserve treatment as a critical sensitivity across all cases/scenarios. The current regime could persist, escalate, or be substantially rolled back, whether under this administration or the next. Given the material impact of tariffs on capital costs for solar, wind, and storage equipment, this uncertainty should be treated as a key input variable and tested through sensitivities rather than embedded as only a fixed assumption.

Storage tax credit treatment: The proposed storage cost assumptions appear to embed an unrealistic expectation regarding PFE and domestic content bonus credit qualification. Current supply chain conditions make it unlikely that all storage projects will meet domestic content requirements, and assuming universal qualification for the additional 10% ITC adder will systematically understate the net cost of storage. Furthermore, the initially proposed structure links PFE-compliance with domestic content criteria satisfaction. These are not inextricably linked concepts. For example, a Korean-sourced cell (52% of system cost in Treasury guidance MACRS) would satisfy PFE compliance for the 30% ITC but fail the domestic content criteria. Even more critically, it may be aggressive to even assume 30% ITC achievement. Roland Berger estimates that through the early 2030s (based on existing announcements and capacities) US supply of battery cells from PFE-compliant actors cannot satisfy expected ESS demand. As a result, the firm expects that even 20-25% of domestic ESS demand are unlikely to be satisfied by PFE-compliant cells and materials. Full achievement of the full 30% ITC is therefore potentially aggressive. The safe-harbor assumption of still achieving some level of ITC credit in 2039 or 2040 is also aggressive as Treasury guidance and reasonable expectations hold that most developers will not break-ground and hold a project for 4+ years after doing so.

AIC strongly recommends that partial qualification of both the base ITC and domestic be reflected in the base case inputs, or at minimum that a sensitivity testing reduced qualification be applied across all scenarios. Secondarily, AIC recommends the safe harbor window in the base case be limited to 2 years from start of construction for battery assets.

Renewables siting constraints: Local siting and setback rules in Illinois materially limit the buildable potential for high capacity factor wind sites. The National Lab of the Rockies (formerly NREL) has several studies that chart and characterize resource potential, inclusive of set backs and other local zoning constraints. The study's 'Reference' case allots a maximum potential of 170-180 GW of wind and 50-60 GW of solar are buildable within Illinois. AIC notes that these numbers are not additive, but heavily overlapped. The 'Limited' case truncates available resources to 65 and 20 GW for wind and solar respectively. The IRP should reflect these constraints and the capacity-factor characterized supply curves to ensure that selected portfolios are practically achievable, rather than assuming unconstrained access to resource potential that may not be available for development.

Cost of capital: The proposed cost of capital assumptions may not fully reflect the financing environment for resources developed outside the regulated utility framework. Illinois operates a restructured electricity market in which a significant share of generation investment is merchant-developed, typically at higher equity financing costs and different cap-structure than what is often observed with regulated utility WACCs. Broad order of magnitude, the WACCs provided in the initial inputs appear to reflect regulated utility conditions rather than the merchant conditions we'd likely expected in Illinois. Applying a uniform utility WACC to all resource types would understate the cost of merchant-developed resources and could distort portfolio selection. AIC recommends that E3 more clearly characterize how it derived the WACCs that will be used and thereafter adjust the figures to represent financing assumptions that reflect the market context we would expect in Illinois.

2.4 What feedback do you have on the proposed base case cost assumptions for emerging technologies (including nuclear and long duration storage)?

AIC has two concerns related to the costs and performance characteristics linked to nuclear:

Cost reduction trajectory: The current cost reduction curve for advanced nuclear (SMR) assumes a global build-out of approximately 23 GW, or roughly 76 BWRX-300 units, by 2050, based on a 15% cost reduction for every doubling of installed capacity. IEA deployment scenarios suggest materially faster build-out trajectories, reaching 40-120 GW by 2050 depending on the policy environment. Roland Berger has also provided guidance similar to expected cost declines in IEA's modeling based on existing deployments and plans for both Gen III + reactors and Gen IV SMRs expected beyond the Darlington plant (i.e., Duke Energy, Palisades' adjacent plant new build, the TVA). Applying the same learning rate to these higher deployment volumes would result in SMR capital costs 6-18% lower than ICC/E3 assumptions by 2040. AIC recommends that the Advanced Technology Acceleration scenario reflect a cost curve consistent with a higher deployment trajectory, and intends to provide supporting data to E3 and the Agencies.

Nuclear useful life: E3 proposed a 50-year asset life for new nuclear resources. NRC licensing supports a 60-year operational life through the established 40-year initial license plus 20-year renewal framework. License renewals can happen multiple times – Several sites including Clinton and Dresden have already relicensed for 60 years and have received approval from the NRC to extend to 80 years. 60 years is now the common assumption observed in other IRPs and planning processes and the existing Illinois nuclear fleet is expected to operate at least on 60-year cycle with several others extending to 80 years.[1] Use of a 50-year useful life will overstate the levelized cost of nuclear generation and may bias portfolio selection. AIC recommends adopting a 60-year useful life consistent with NRC practice, other IRPs, and broader Illinois operating experience.

Long-duration energy storage: AIC has minimal comments regarding the assumptions linked to long-duration energy storage. Although there are a range of technologies that may fit, many are still early stage and the company understands the 'representative' approach. However, two topics come to mind. The 2.1% capacity factor implies roughly two cycles from the LDES asset per year. This appears reasonable for a 100h asset. However, the other underlying assumptions around round-trip efficiency (i.e., likely under 50%) and charging cost (should be non-zero and based on wholesale rates) need further clarification. The capital costs per kW appear grounded at a baseline level, the cost decline does appear potentially aggressive and steep – Most LDES batteries are comprised of existing technologies (e.g., steel piping, pumps, and other balance of system hardware) that are unlikely to see significant real cost declines that outpace inflation.

2.5 What feedback do you have on the proposed commercial availability timelines shown on Slide 18?

At this time AIC mainly has comments for commercial availability related to nuclear assets, both Gen III+ and advanced nuclear SMRs. Based on guidance we see in the market and from Roland Berger, AIC proposes to have maintain a Gen III+ timeline at 2037 solely on the basis of expected site control requirements, permits, and long-lead time items. It's expected that 2035-36 would be the earliest timeline for a new light-water reactor in Illinois assuming key early and long-lead items could be secured in later 2026 or early 2027. Current development trajectories with other utilities such as the TVA, Duke, Southern, and at Palisades in the US and OPG in Canada should bring sufficient scale to have more earlier availability than proposed for advanced nuclear SMRs in 2045. AIC proposes that SMRs be available in 2040 in all scenarios and not just an 'accelerated technology' case. There are clear market signals and analogues that an asset could be developed in Illinois 13-14 years from today based on expected trajectory and investments other regulated entities have underway.

2.6 Please refer to the approach to modeling VPPs in this IRP on Slide 29. Are there any targeted refinements you would recommend to improve the robustness of this approach and the results?

AIC's primary concern is the proposed approach will attempt to model a single representative VPP consisting of multiple DER building blocks. Each building block (e.g., BTM solar, BTM storage, managed EV charging, smart thermostats, water heater controls, commercial building controls) should be modeled as a distinct resource option if possible. Even if they are combined, the mutually exclusive understanding of these resources' behaviors independent of each other is critical to understanding how they may act when bundled together.

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[1] https://www.constellationenergy.com/news/2025/12/nrc-renews-operating-licenses-for-clinton-and-dresden.html

These technologies differ materially in realistic potential (total available MW), cost structure (program administration, participant incentives, event dispatch costs), performance characteristics (reliability, response duration, notification requirements), and availability profile (seasonal, time-of-day, and weather-dependent variation). Combining them into a single unified average VPP risks masking these differences and producing a composite resource whose modeled cost and performance does not correspond to any real-world deployment pathway.

Additionally, each building block exhibits a supply curve dynamic: initial capacity is relatively inexpensive to acquire, but costs rise as participation deepens and harder-to-reach customers must be recruited. For example, we see subsidies are often included in other utilities characterization of DR or VPP costs. A 0% subsidy may be sufficient to garner an initial level of early heat pump adoption, but existing AGF analysis should over a 50% subsidy on heat pump capex is required to shift a majority of residential heat sources to a heat pump. These considerations must be reflect in the individual resources' capacity cost within the VPP. Ideally, the IRP would reflect this by modeling multiple tranches for each technology, with increasing marginal costs at higher penetration levels. Bearing the complexity of doing so, it highlights the criticality of at least separating the underlying resources.

AIC has developed proposed cost benchmarks and accreditation inputs for key VPP building blocks and intends to share these with E3 following submission of these comments.

(1) Capacity costs = Customer enrollment + Capacity-based incentives
   a. Customer enrollment = (One- time enrollment cost * # new customers) + (Program planning cost)
   b. Capacity-based incentives = (Total accredited capacity) * (Capacity cost) <u>or</u> (Annual cost * # customers)

(2) Variable costs = (Energy delivered) * (Performance cost)

(3) Accreditation = (Availability nameplate capacity) * (Enrolled in VPP %) * (Critical coincidence %) * (Event participation %) * (Technical and Customer Limitation %)

E3's own proposed approach appears similar, focusing on issues such as available capacity, frequency and duration of events linked to technologies, and costs. AIC seeks to share existing and ongoing analyses with benchmarks for each of the component pieces that can supplement the Agencies' approach moving forward.

2.7 Please rank which VPP building blocks you believe are most important to include in a representative VPP.

AIC does not support using 'building blocks' to create a representative VPP. As previously discussed, it would obscure cost and accreditation structure and potentially risk over-representing available nameplate capacities. However, the most relevant to include would be BTM rooftop solar (based on existing legal requirements), BTM storage for residential and commercial, and smart thermostats and controllable appliances. Other residential and commercial options are likely less prevalent. Although more advanced industrial options may be available, they could be too heterogenous to include in this particular study on the given timeline. If the Agencies and E3 seek to treat industrial VPP activity as load flexibility at large sites such as datacenters, that may be an option. However, the demand flexibility/curtailment of those sites should reflect a mix of costs and emissions from energy storage, fossil recips, or turbines in order to achieve the target flexibility.

Prioritized technology list to be modeled:

- BTM rooftop solar – AIC acknowledges and understand that E3 will model these separately as resources similar to how they were treated in the Resource Adequacy (RA) study in 2025.
- BTM residential and commercial energy storage
- Electric vehicles with managed charging (V1G capabilities only)
- Smart thermostats
- Controlled/smart appliances

  - Electric or hybrid heat pumps
  - Electric or heat pump water heater

De-prioritized technology list to not be modeled in the VPP:

- Industrial demand response
- Electric vehicles with V2G capabilities
- Controlled/smart appliances
  - Electric dryers
  - Electric stoves

2.8 Slide 30 identifies key VPP parameters that will inform the representative VPP to be modeled in the IRP. Please provide specific assumptions where possible.

AIC intends to provide detailed VPP parameter assumptions, including composition, available capacity, duration and frequency, and cost information, for each respective underlying resources (or, 'building block') to the Agencies and E3 as a supplement to these comments. These inputs are grounded in an ongoing benchmarking of existing VPP programs in other jurisdictions and adapted to Illinois-specific conditions. AIC has been supported by Roland Berger to characterize it's approach to both cost and accreditation covered in a previous question. Generally speaking, AIC recommends the VPP approach should capture total available nameplate capacity of each resource. The relevant nameplates available in a given year then have varying enrollment percentages (e.g., 10-11% for smart thermostats) and deployment costs, both fixed and variable. Using the enrolled nameplate capacities of each resources, they can then be treated with an accreditation approach that considers critical coincidence (or, ELCC – potentially seasonal), event level participation, and technical or customer limitations (e.g., depth of discharge on home batteries).

E3 and the Agencies have characterized that the modeling approach will likely be a 'generic' VPP wherein the "benefit" value of avoided capacity can be inferred. This modeling approach given the timeline is understandable but less than ideal. The results will thus then only imply the potential "what must be true" cost level VPPs must attain in order to be beneficial for ratepayers. Although the IRP will answer the thresholds of $/MW or $/MWh that VPPs may provide ratepayer value, how to subsidize, structure, or support certain underlying resources will still go unanswered. AIC stresses to the Agencies that the results of the IRP must therefore be directly compared to external benchmarks before any policy recommendations around programs, incentives, subsidies, or ascribed VPP costs can be communicated to other policymakers.

2.9 Do you have any feedback to provide on the Assumptions workbook separately posted?

AIC has reviewed the Assumptions workbook and requests the ability to provide additional comments in the future. However, several key topics are of importance.

Main and secondary assumption transparency: Many of the underlying assumptions or calculations are not available. AIC recommends further details are provided beyond the current workbook with the aspiration of broader alignment amongst stakeholders. For instance, it is quite unclear what capital structures, debt and equity %s, or risk adders have been used to derived the WACCs. Furthermore, for solar, wind, and storage resources it is not clear what underlying assumptions have been made for augmentation to manage degradation, mid-life capex refreshes, or over-builds for depth of discharge limitations (for batteries). For both lithium-ion energy storage and long-duration energy storage, AIC anticipates that the modeling of charging cost and dispatch will be market-based rather than a static figure or potentially $0/kWh. At this time, the process is unstated. The ELCC/critical coincidence considerations for all resources, seasonal treatment, and evolution over time is not stated, although AIC expects this is covered in a coming workshop and managed through 8760 modeling. AIC recommends that the Agencies support E3 in providing the underlying assumptions and data to these figures for the benefit of all stakeholders.

Solar Inputs: The useful life appears to be longer than industry standard with no clear connection to potential mid-life capex refreshes or extensions. The capacity factor is above that typically observed or available in Illinois. If some mid-life capex or extensions are included, the starting point for capital costs appear reasonable. More broadly however, the rapid decline as a result of alleviated market conditions and tariffs appears aggressive for base case treatment if not well correlated to what is occurring for other assets such as gas.

Wind inputs: Potential concerns and considerations are similar to that of solar.

Nuclear inputs: The useful life of 50 years is misrepresentative of other IRPs, operating reality in Illinois, and common practice. AIC recommends the use of 60 years for a useful life parameter. Furthermore, the cost decline is very conservative against other expected cost curves from the IEA and Roland Berger. AIC has provided a cost curve to the Agencies and E3 based on expected/announced nuclear developments both globally and by other regulated entities (e.g., Duke, Southern, TVA) with an expected cost per kW linked to units produced and installed. Order of magnitude, Roland Berger and the IEA expect USD 6-7k per kW installed by 2040 vs. nearly USD 8k assumed by E3. Against the expected supply and production curve, E3's cost would represent 1/6 to 1/3 of IEA's expected global development and production by 2050.

Gas inputs: AIC proposes to treat gas capex development consistently and similar to the market expectations linked to supply-demand and tariffs as other resources rather than having high costs persist. If supply and demand pressures ease, it would be reasonable to expect capital costs for gas assets return to reasonable real levels between $1,500-2,000/kW with appropriate inflation treatment and technology declines already considered.

Storage inputs: AIC proposes clearer and more grounded treatment of the base ITC and domestic content adder (10%) for storage assets by allowing for 'partial' qualification across the installed base (e.g., 20% achievement of ITC vs. 30% based on 1/3 of the units not being PFE-compliant). The company also advocates for limiting the safe harbor period to 2 years from start of construction. Both of these treatments should apply in the base case and have been covered elsewhere in these comments.

Transmission: E3 has already indicated that out of state resources will be considered, including transmission charges. It is not yet clear how these transmission costs will be attributed either independently or on top of out of state resources. AIC requests further clarification from the Agencies and E3. Even if the IRP is not a transmission study, even a clear methodology on simple cost estimates for out of state resources informed by the REAP process and other studies will be valuable for all stakeholders. If the IRP anticipates selecting an out of state resource, two methodological questions are critical. First, the aforementioned cost allocation of transmission – For example, higher capacity factor wind from KS could appear attractive vs. in-state wind but would need a transmission charge to be compared apples to apples. Secondly, the emissions attributes of the exporting grid or out of state resource must be considered. Should imports to Illinois be backed by either renewables or gas respectively, the imported electrons should have attributed emissions from the original resource. Although E3 has indicated this emission artifact will be considered, further detail on emissions factors is warranted.

2.10 If CCS is considered as an added, co-paired technology with natural gas resources in a scenario, what is a likely timeframe and reasonable costing?

AIC does not have detailed comments on CCS timelines or costing at this time but notes that commercial availability and cost remain subject to significant uncertainty. AIC would support a conservative treatment of CCS in the base case, with more optimistic assumptions reserved for the Advanced Technology Acceleration scenario.

For the base case, previous analyses conducted by Roland Berger in conjunction with Ameren support a USD 8-12/ton sequestration cost in Illinois. Several operational realities also need to apply to capital expenditures and rated capacity. First, equipment capital expenditures figures linked to additional CCUS equipment on a

CCGT would likely be USD 1,100-1,500/kW based on prior national laboratory research.[1] On a 1 GW unit, about 100-150 MW would either need to be added (e.g., uprated to 1.1 or 1.15 GW) or subtracted from available capacity – The carbon capture system has a 'parasitic load.' In addition, observed downtime challenges should be included in potential downrates in accreditation based on maintenance and failure intervals (i.e., - 5 to 10% lower accreditation vs. CCGTs). Finally, for availability and timing, AIC proposes to utilize 2035 at the earliest. The permitting and construction of necessary pipelines will be a lengthy process despite recent federal efforts to ease the burden. Ameren and Roland Berger highlighted this in a 2023 brief to the EPA related to carbon pollution standards – Although the EPA's originally anticipated 7-8 year timeline to permit and construct CO2 pipelines, feedback from market participants and experts indicated an upper bound with an additional 4-5 years due to delays and expected execution issues. The modeling should conservatively expect at least 9-10 years from today.[2]

2.11 Please provide a recommendation for a different carbon sequestration percentage if 100% is deemed operationally unlikely.

Typical practice in IRPs often assumes a 90% capture and sequestration percentage. However, both capture and sequestration have proved challenging. In the first several years of operation, Saskatchewan Power Co's Boundary Dam CCS site captured between 50-90% of emissions annually, largely as a result of mechanical and chemistry issues that spurred long shutdowns of the CCS equipment. Illinois has already seen its own sequestration issues as well.[3] ADM's sequestration site near Decatur, IL was shut down for nearly a year after leaking 8,000 metric tons of CO2 the company attempted to sequester in the Mahomet Aquifer. Although the EPA and DOE are supportive of CCS projects, AIC recommends the IRP effort carefully reflect likely downtimes and challenges in both CCS resource accreditation and capture/sequestration percentages around 75-85% rather than the typical 90%. 90% could be potentially assumed in the Advanced Technology Acceleration case that considers society's broader ability to solve these challenges with a more mature version of the technology.

3. Conclusion

Ameren Illinois appreciates the Agencies' and E3's efforts to develop transparent resource cost and performance inputs for the IRP. AIC's comments focus on ensuring that these inputs reflect current market conditions, observable benchmarks, and the practical realities of resource development in Illinois. The Company intends to provide supplemental data on large load forecasting, nuclear cost benchmarks, energy storage, and VPP inputs in the coming weeks and looks forward to continued collaboration as the IRP process advances.

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[1] National Energy Technology Lab (NETL) resources for carbon capture, utilization, and sequestration

[2] Comments of Ameren Corporation – EPA New Source Performance Standards For Greenhouse Gas Emissions From New, Modified,And Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; And Repeal Of The Affordable Clean Energy Rule; Docket ID No. EPA-HQ-OAR-2023-0072; 88 Fed. Reg. 33,240 (May 23, 2023); Submitted on regulations.gov; August 8, 2023

[3] Saskatchewan Power Co.; "Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities" by Brent Jacobs a , Puttipong Tantikhajorngosola , Keith Hillb , Jonathan Ruffinib , Sarah Wilkesb , Wayuta Srisanga , Yuewu Fenga , Doug Daverne a , Conway Nelsona,* aThe International CCS Knowledge Centre, 198 – 10 Research Drive, Regina, Saskatchewan, Canada S4S 7J7 bSaskPower, 2025 Victoria Avenue, Regina, Saskatchewan, Canada S4P 0S1