IPA Integrated Resource Planning Workshop #2: Candidate Resources

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Question 1

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

A firm, controllable interregional transmission / HVDC import resource is not clearly captured in the current framework.

- The proposed resource categories do not include controllable interregional HVDC transmission. This resource type is distinct from in-state generation, generic transmission, or pool market imports — it delivers firm, controllable energy across an RTO seam with an independently validated ELCC. Under the current framework, this resource type is not likely to emerge unless it is explicitly represented or tested as a pre-specified case. If the framework has no category for it, it is invisible to the model regardless of its cost or reliability value.
- Beyond bulk energy and capacity, HVDC provides grid stabilization benefits using Advanced Transmission Technology — voltage support, frequency response, and power flow control — at minimal incremental capital cost. These services have real system value that the current resource categories do not capture. As the grid transitions to higher penetrations of inverter-based resources, controllable HVDC becomes more valuable for network stability, not less.
- The IRP should distinguish between pool-based market imports (variable, uncontrolled, subject to seam scheduling limitations) and firm controllable imports via dedicated infrastructure. These have fundamentally different capacity value, dispatch characteristics, cost structures and value for ratepayers.
- Note that in the report "Illinois Decarbonization Study: Climate and Equitable Jobs Act and Net Zero by 2050" prepared for Commonwealth Edison (ComEd) in December 2022, Energy and Environmental Economics, Inc. (E3). Noted that the modeled resources "includes approximately 2,000 MW of new SOO Green transmission from (MISO)," and that the "SOO Green transmission line was modeled as a clean firm resource" to "serve load in ComEd region, with the imported energy qualified for RPS under CEJA."

Question 2

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

SOO Green recommends adding a resource category for “firm controllable interregional import”. Key parameters that differentiate this category from existing resource types include:

- Dispatch and power flow: Fully controllable power flow that can be ramped up or down to meet demand instantaneously and with a high degree of dispatchability across the MISO-PJM seam. The line can be dispatched to serve Illinois load during stress events and can reverse flow to support the broader grid when Illinois is not capacity-constrained, maximizing system-wide value.
- Reliability and availability: HVDC underground cable has significantly higher availability and reliabilitythan overhead AC lines — not exposed to weather, wildfire, or vegetation-related outages. Long asset life relative to many other resource options.
- Network reinforcement costs: HVDC connects at defined converter stations; it may help reduce the cascading network upgrade costs that new in-state generation often triggers through the interconnection queue.
- ELCC: Project-specific, independently validated (92% PowerGEM SERVM / 87.3% IPA 2024 Policy Study), not a generic technology average.

Question 3

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

Please indicate which specific assumption you are commenting on, describe the reason for your feedback, and provide any alternative data source or supporting materials that you would like us to consider to support your recommendation. Please provide a link or share via email.

- Solar and wind: E3’s resource cost workbook shows utility solar LCOE dropping from about $88/MWh (2030) to about $64/MWh (2031) even as tax credits roll off under the base-case policy assumptions. By contrast, IPA’s Indexed REC procurements — real competitive Illinois procurement outcomes for renewable projects — cleared at an average strike price of about $84/MWh in December 2025, with tax credits reflected in bid pricing. While the Indexed REC strike price is not a direct LCOE equivalent, it is useful market evidence of the revenue level developers require to move projects forward in Illinois. Recent Illinois market outcomes therefore suggest a materially higher cost path than the model assumes, which warrants a market-grounded post-2030 sensitivity.
- Battery storage: Battery cost assumptions should be cross-referenced against actual market experience, including augmentation requirements, degradation over time, and evolving domestic-content and supply-chain requirements that may affect future battery costs and availability. A sensitivity around these assumptions would be useful.

- Gas: Given CEJA's emissions reduction requirements, the IRP will need to evaluate how gas-fired generation fits into Illinois's long-term resource mix. Iowa's generation mix is already over 60% wind, with additional baseload nuclear capacity expected to return — meaning the emissions intensity of a MWh imported via controllable HVDC is materially lower than a MWh from new gas in Illinois. To the extent the model evaluates gas as a reliability resource, it should also evaluate firm interregional imports as a lower-emissions alternative with comparable reliability characteristics.

Question 4

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

Please indicate which specific assumption you are commenting on, describe the reason for your feedback, and provide any alternative data source or supporting materials that you would like us to consider to support your recommendation. Please provide a link or share via email.

SOO Green does not have specific comments on nuclear or long-duration storage cost assumptions. We note that high uncertainty around these technologies' costs and timelines reinforces the value of including proven, near-term alternatives — such as firm interregional HVDC imports — so the model can evaluate the full range of available solutions.

Question 5

What feedback do you have on the proposed commercial availability timelines shown on Slide 18? Please identify any technology timelines you believe should be revised, why you think it should be revised, and any supporting data or materials you have to support your recommendation.

SOO Green notes that the slide does not provide stakeholders with much actionable value as currently presented. The timeline is oversimplified — it shows technology readiness without indicating potential MW contribution from each category. A technology that is "available" but can only contribute a few hundred MW has very different planning value than one that can deliver 2,000 MW of firm capacity. Without scale context, the slide does not tell the full story. More specific feedback:

- Add HVDC / interregional import: The timeline should include controllable HVDC as its own category, with availability starting in the 2032 timeframe if the agencies intend to evaluate solutions that could come online within the IRP planning horizon, particularly the shorter horizon for the mitigation plan.
- In-state resource timelines: Assumed availability timelines for in-state solar, wind, and storage should be reconciled with actual interconnection queue data and historical completion rates. Resource availability timelines should also reflect ongoing lead-time pressures for key interconnection and balance-of-system equipment, including transformers, which can slow project delivery across multiple resource types. LBNL data shows that interconnection and development timelines remain lengthy: the typical

project built in 2024 took 55 months from interconnection request to commercial operation, and larger projects took nearly 5 years. Queue withdrawal rates also suggest that a material share of queued projects never reach commercial operation. The model's assumed annual build rates should be benchmarked against historical installation data and interconnection completion rates to ensure the resource plan reflects what the market can realistically deliver.

Question 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?

The current approach seems reasonable as an initial approximation, but not necessarily as a basis for drawing strong conclusions about investment value for Illinois ratepayers. Slide 29 appears to indicate that the process accepts VPP submissions without a feasibility screen or proof of need. There should be an additional step after data collection where only DERs with a demonstrated needs case are included in modeling. MISO and PJM should have an opportunity to validate whether submitted VPPs are feasible and address identified system needs. Otherwise the IRP risks modeling a portfolio of hypothetical DERs that may never materialize, which would overstate the contribution of distributed resources to reliability.

Question 7

As shown on Slide 29, this IRP will model one representative VPP made up of multiple DER building blocks. Please rank which VPP building blocks you believe are most important to include in a representative VPP. (BTM solar, BTM storage, Managed EV charging, Residential smart thermostats, Water heater controls, Commercial building controls, Others).

BTM solar; Managed EV charging; BTM storage; Residential smart thermostats; Water heater controls; Commercial building controls; Others

Question 8

Slide 30 identifies key VPP parameters that will inform the representative VPP to be modeled in the IRP. Please use the parameter categories shown when responding to the following questions. Please provide specific assumptions where possible with supporting data sources and/or program examples, where available.

- *Based on the building block rankings you provided in your response to the previous question, please specify the percentage of total VPP nameplate capacity you recommend assigning to each building block.*
- *Of those building blocks, how would you distinguish between existing and new resources in your proposal?*
- *What available capacity should be assumed for this VPP? How should it be assumed to vary over the year?*

- *How long may this VPP sustain the response? How frequently?*
- *What may this VPP cost?*

SOO Green does not have a strong view on VPP parameter assumptions. We would note that whatever capacity value is assumed for VPPs should be subject to the same ELCC rigor applied to other resource types — particularly given that VPP availability and sustained response duration are less well-established than for utility-scale resources.

Question 9

Do you have any feedback to provide on the Assumptions workbook separately posted? Please note the specific assumption, your recommendation, and any data or supporting materials to support your recommendation.

- Solar LCOE trajectory: The Output Tables sheet (Nominal $/MWh LCOE section) shows utility solar dropping from about $88/MWh (2030) to about $64/MWh (2031) — a sharp year-over-year decline. Recent IPA Indexed REC procurement outcomes suggest a materially higher Illinois market cost path than this trajectory implies. While Indexed REC clearing prices are not directly equivalent to LCOE, they are relevant market evidence for project economics and should inform a market-grounded alternative cost sensitivity, including a case that holds renewable costs flat in real terms post-2030.
- PTC/ITC assumptions: The Data Sources tab confirms PTC is assumed for projects reaching COD through 2030 with a 4-year safe harbor. Given evolving federal safe-harbor rules and tax-credit availability, the workbook should include a sensitivity case where tax credit availability is more limited than currently assumed— particularly for batteries, where ITC eligibility is assumed to persist past 2030.
- Missing resource type: The workbook does not include cost or performance parameters for controllable HVDC. If the framework cannot represent controllable HVDC directly, the workbook should at minimum support testing it as a pre-specified alternative alongside existing options.

Question 10

If CCS is considered as an added, co-paired technology with natural gas resources in a scenario:

- *What is a likely timeframe for when this technology could be reasonably expected to be commercially operational and accessed?*
- *What is reasonable costing for this technology to be included in modeling and analysis? Include data and reports to support your answer.*

No specific comment. To the extent CCS faces significant commercial readiness uncertainty, the IRP should ensure the resource option set includes proven, commercially available alternatives for lower-emission firm capacity — including interregional imports — so the model is not forced to choose between uncertain emerging technologies and continued fossil operation.

Question 11

While current policy expects that CCS would fully sequester all carbon emissions to comply with CEJA (i.e. 100% carbon sequestration), a lower percentage of carbon sequestration may be more likely (e.g. 80% or 90% of sequestered carbon, i.e. 10-20% carbon emissions). Please provide a recommendation for a different percentage if 100% carbon sequestration is deemed to not be operationally likely during the term being modeled (2027-2047). If a different percentage is proposed, please support your recommendation.

No specific comment. If 100% sequestration is not operationally achievable, this reinforces the importance of evaluating lower-emission firm capacity alternatives in the resource mix.