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?

Overall, we appreciate that the study focuses on the existing and most likely resources for this first iteration of the IRP, recognizing that future updates can accommodate new information (new promising technologies, updated cost trajectories, changes in policy). We suggest reconsidering the potential to consider hydrogen-fueled power plants or fuel cells as part of viable technologies that mature within the study period. We considered geothermal, but it does not appear to have much potential in Illinois based on available research (e.g. see https://www.nlr.gov/docs/libraries/gis/high-res-images/geothermal-identified-hydrothermal-and-egs.jpg?sfvrsn=94d5211_1).

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?

We have no additional resources to consider beyond those considered in question 1, though we do want to confirm the modeling will consider the expansion of DERMS by ComEd to address potential status quo limitations around renewable penetration. Given the degree of turnover we see in projects applying for RECs under the RPS, we also recommend the study consider the cost and assumed timeline implications for the average resource attempting to connect to the transmission system.

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.

Below are ComEd's observations on the assumptions noted throughout the materials and/or workbook:

- The 17-26% solar capacity factor strikes us as high for at least the ComEd territory, as NREL data reflects 23.9% for Northern, IL for utility scale and 13.8% for residential, per NREL ATB2024 (ComEd Zone 8). We also note there does not appear to be a distinction between residential and community solar.
- Suggest including assumptions for distributed storage and other forms of distributed solar (e.g. community solar, larger C&I installations).
- The 10.5% WACC for long-duration storage seems high – if the assumption is that the technology is commercially mature enough to be a resource, we would expect it to be more akin to the WACCs for short-duration storage, and so perhaps it's intending to capture technology risk. However, it will be important to ensure the risk is only captured once (either in cost / operational parameters or in the discount rate).
- Are the changes in WACC and capex costs for wind and solar in 2031 solely tariff-driven? Would be helpful to understand why there's an impact to WACC if so.
- Please explain the drop in solar cost from 2030 to 2031.
- From the "Data Sources" tab in the assumption book, it looks like the timing for the tax credit phase out for nuclear and storage is the same. However, given the significantly different construction timeline for the two assets and safe harbor availability, we would expect the installed cost implications to be different for the two from a timing perspective (e.g. the impact of credit phase-out for nuclear should drive up costs later than that for batteries).
- We suggest considering an alternative inflation benchmark versus just a generic CPI inflator given the pronounced inflation in large capital equipment in particular. Consider whether one of the inflation sub-indices from FRED may be more relevant.
  - For example, see: https://fred.stlouisfed.org/tags/series?t=industry%3Binflation%3Bmanufacturing&ob=pv&od=desc

Beyond the above, we suggest using TVA's 2026 IRP as a reference. While there may be slight regional differences, it provides a comprehensive set of assumptions that are contemporaneous and seem to be relatively consistent with market. Focusing on the table on slide 20 of the IRP update dated 03/12/2026:

- https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/environmental-stewardship/integrated-resource-plan/2026-irp/presentations/march-12-2026-public-briefing-presentation.pdf

Question 4

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

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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.

We understand the timelines indicated on slide 18. We would note a potential enhancement to consider a limited number of opportunities for the model to select earlier stage resources if the circumstances might merit (e.g. there are some long-duration storage and even SMRs that are currently contracted in other parts of the country).

We would also note that historical experience has been that some uprates have been able to be implemented in less than the implied 8-9 year timeframe, so clarifying any assumptions there might be helpful (e.g. some uprates are already underway, which may or may not be part of the 2026-2030 fixed additions).

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?

While the approach to including VPPs in the modeling was unfamiliar to us in practice, we believe that it can provide a nimble and practical way to represent that resource, recognizing the limitations associated with the time allotted to conduct the IRP.

We do want to confirm that the modeling of VPPs will be consistent with the requirements of CRGA. Per the law, the minimum required service is to provide grid services opportunities for each eligible technology that customers and aggregators may provide, which shall include, at a minimum, reducing the utilities' applicable capacity and transmission obligations and capturing daily wholesale energy arbitrage opportunities through provision of grid services.

The model should also reflect the understanding and timing associated with the proposed tariff filing for June 1, 2026 (which references the SDVPP); smart thermostats and EV's are not included in the assumptions, though smart thermostats are separately covered in a proposed tariff filing in front of the Commission. However, it is anticipated that the full VPP framework tariff due by December 2027, which would require Commission approval, would likely include those resources.

We also want to confirm that the value of the VPP will be determined by comparing a state of the world with and without the VPP in isolation (i.e. ensure no other resources, such as incremental energy efficiency, will differ in the counterfactual approach).

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 storage; BTM solar; Managed EV charging; 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?*

a) The PLR Load Flexibility potential study should provide insight to all of these questions, but we recognize such information will not be available in time to support this first version of the IRP. Our initial impression is that storage only, solar plus storage, and smart thermostats would likely have the highest percentage based on impact. See also our response to question 6.

b) Generally, all resources would be new, as there are no existing programs stood up yet for ComEd, and we do not believe the VPP program is expected to extract material incremental value from the existing installed base of distributed flexible and/or generating resources.

c) We believe there is significant potential for continued customer adoption of both distributed solar and storage given the supportive policy and savings potential for customers, particularly in elevated supply cost environments. That should be the primary driver of penetration of VPP-eligible resources. Beyond the assumed forecast of those resources, based on an assumption for a potential smart thermostat program that could be based on BYODLR, ComEd estimates the following forecast reflecting growth over the next 4 years and beyond.

d) The duration of a VPP would be dependent on the grid service. We would expect for peak load reduction grid service, the resource would need to provide at least 2-3 hours in a given day, and we would expect 10-30 events per year in summer months. For SDVPP, the current expectation is that it would be 2-3 hrs a day, every weekday June through September (or 88 days). The parameters for a fully-developed VPP program will be determined in 2027-2028.
e) The cost would be dependent on incentive and scope, and we do not have a cost for VPP yet.

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.

We believe our feedback has been adequately captured in the response to question 3. However, we would note that it would be helpful to understand other key assumptions associated with the analysis (including – if in the event the analysis intends to leverage assumptions from related analyses like the resource adequacy study – whether all relevant assumptions will ultimately be provided in a consolidated workbook):

- Size (MW) constraints of assets (by resource, by year, by zone, cumulative)
- Commodity prices (e.g. natural gas)
- Transfer limits
- Fixed build / retirements in 2026-2030
- Firm gas costs
- As it pertains to ELCCs, does the IRP analysis intend to iterate the RECAP and PLEXOS models to adjust ELCC's for the different portfolios of resources? Will the initial assumed ELCCs be based on the PJM/MISO estimates or E3's? Are they system-wide and single estimates by technology by year? And how are they being determined for DR and VPP resources?

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.*

Our understanding from EPRI is that there have been no natural gas CCS plants built at scale yet; there are only small pilots. It is difficult to predict timelines for first-of-a-kind deployments, but we expect that they will be long. And we expect market or regulatory demand is needed to drive any future deployments forward.

As it pertains to costs, the National Laboratory of the Rockies (formerly NREL) has an Annual Technology Baseline which is a good source for this type of data. For a new natural gas CCS plant assuming 95% capture rate, costs in their moderate case (for an F-frame 2-on-1 CC plant) fall from $2,789/kW in 2027 to $2,032/kW in 2047

(Source: https://atb.nrel.gov/electricity/2024/fossil_energy_technologies with data excerpt here: https://public.tableau.com/shared/YGPJJSWF2?:toolbar=n&:display_count=n&:origin=viz_share_link&:embed=y)

Another Dept of Energy reference is this report: https://www.osti.gov/biblio/2580491 with this online tool: https://netl.doe.gov/NETLVol1BaselineTool

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.

Per the National Laboratory of the Rockies, for a new natural gas CCS plant, "capture rates of 95% or greater are technically feasible and increasingly economically favorable compared to lower capture rates." For retrofits, they use 90-95% range.

(Source: https://atb.nrel.gov/electricity/2024/fossil_energy_technologies)

We also found additional information provided by EPRI's expert (Abhoyjit Brown). With regard to percentage capture, it's more economic to capture 90-95+% CO2 from a slipstream (and not treat the remaining flue gas) as opposed to capturing a lower percentage from the entire flue gas flow. CO2 storage would then be designed for all the CO2 captured, not as a fraction of that which is captured. For large-scale CO2-mitigation, geological storage appears to be the only viable option. CO2 utilization options may exist in limited cases, such as enhanced oil recovery, but overall, there is currently a much larger supply of CO2 than there is demand for productive uses for anything other than capture to be a practical option in the context of this IRP.