IRP Modeling Advisory Group (MAG) on Draft 2025 Inputs and Assumptions (I&A) for the 2024-2026 IRP Cycle

February 27, 2025

Written Q&A Log

1. Andrea White: Hello, Andrea here from PCF. Is there a deadline for the informal comments?
   a. Informal comments are due next Friday, March 7th.
2. Tyson Siegel: The final Aliso Canyon decision D.24-12-076 listed the IRP proceeding as the proceeding capable of modeling the cost-effective replacement portfolio for Aliso Canyon. Will the 2025 I&A document be used for modeling of the Aliso Canyon replacement portfolio in addition to the PSP and TPP?
   a. We will generally use the 2025 I&A for all of our modeling work in this cycle. I'll note IRP staff will be having an upcoming MAG webinar in March on the development of our local capacity area version RESOLVE that could provide us additional analysis options for assessing issues around gas retirements. I'll also note that such specific studies will likely require development/inclusions of additional inputs/assumptions that would be reviewed/communicated as we developed such scenarios.
3. Hillary Hebert: Can you please clarify the overall schedule of the creation of portfolios for the 2026-27 TPP? These portfolios are typically provided for initial comment around October and then final versions are submitted to CAISO in February. I understand that this I&A doc will apply to those portfolios, but since the individual IRPs are not due until November 2026, I assume that data will not be part of the portfolios for the 2026-27 TPP?
   a. Yes, given the schedule it's unlikely for us to be able to use LSE plans for the 26-27 TPP. As we generally do for TPP portfolios/busbar mapping, we will work gather the most up-to-date contracting and procurement information we have and incorporate that into the portfolio develop.
4. Tom Beach: Does the new zonal topology in RESOLVE have a significant impact on the time to run the model? Are there other new RESOLVE changes that impact the runtime?
   a. We have not experienced significantly longer runtimes because of the zonal disaggregation alone, but combined with other modeling updates, it is possible to see additional runtime increase.
5. Kurtis Kolnowski: Good afternoon. I see that the I&A finalization timeline is May-June. Does this mean that a RESOLVE model for LSEs to use in their upcoming IRPs won't be available until at least then?
   a. We expect to release a version of RESOLVE as we release Filing Requirements guidance for the Jurisdictional LSEs. The exact timing of that release is not yet finalized.
   b. Correct, we are still working to update the RESOLVE model based on these still in development I&As and ensure it and the SERVM models are properly calibrated.
6. Joe Gosselar: Why use 12/1/2023 IRP Filings for existing and in development resources? Why exclude the incremental RDT updates?
   a. The issue is timing and the time that is needed to both amalgamate and review the Dec 2024 filings and the time needed to develop and align the baseline for use in both SERVM and RESOLVE. So while the Dec 2024 resources won't be in the baseline, staff will still seek to capture them in portfolio develop (e.g. we can force

in resources to the portfolios to align with the additional resources identified in the new compliance data)

7. Ryan Saraie: Why is the Commission using December 2023, rather than December 2024 IRP compliance filings to source in-development CAISO resources?
    a. The issue is timing and the time that is needed to both amalgamate and review the Dec 2024 filings and the time needed to develop and align the baseline for use in both SERVM and RESOLVE. So while the Dec 2024 resources won't be in the baseline, staff will still seek to capture them in portfolio develop (e.g. we can force in resources to the portfolios to align with the additional resources identified in the new compliance data)
8. Michael Quiroz - Ava Community Energy: Hi, was CAISO previously modeled as one zone, instead of being broken out into 3?
    a. Yes, up until this cycle, CAISO was modeled as a single zone.
9. Hillary Hebert: The tables on page 66 and 67 of the draft I&A doc provide breakdowns of resource potential by study area. Can you please help me figure out where Southern NV solar is represented? I see SCE Arizona solar but I do not see any reference to NV solar.
    a. Southern NV solar/wind are modeled as part of SCE East of Pisgah (EOP).
10. Joe Gosselar: For slide 26: Did staff consider using CAISO's PLEXOS model assumptions to break out RoR and dispatchable hydro? We noticed the MW quantities were different between CAISO and Draft I&A.
    a. We do not utilize the CAISO's PLEXOS model assumptions, we would like to be close to CAISO approximations but there will be discrepancies. as we work to align SERVM and RESOLVE assumptions with each other
11. Jon Martindill: Is there any plan to release additional servm datasets? I am particularly interested in hourly capacity factors and SERVM reliability outcomes.
    a. A large portion of the SERVM updates were included in the TPP25-26 portfolio SERVM results. Much of the underlying SERVM data including renewables shapes are already on that part of the IRP website. Hourly capacity factors is not a standard output and was not saved for the TPP25-26 studies. Can you please email us more details and rationale for needing this level of data? Along with reliability results, we could consider adding it as an output for our next round of SERVM results that go public.
12. Kurtis Kolnowski: Slide 16 shows that only PacifiCorp West is included in the "NW" zone. I believe PacifiCorp's IRP includes all 6 states (including PacifiCorp East). When Staff were looking at their IRP, how was capacity needed to serve PacWest disaggregated from PacEast (slides 28-29)? (appreciate the amount of effort it takes to comb all external IRPs by the way!)
    a. Pacificorp's IRP provides separate load and resource tables for the PacWest and PacEast that are used to inform the disaggregation.
13. Nick Pappas: Does the NW_Hydro_for_CAISO contribute to SB100 requirements? If so, what costs are incorporated to reflect the premium for GHG-free energy and increasing scarcity as HB 2021 (Oregon) and CETA (WA) take effect?
    a. Yes, it contributes to SB100. Other than hurdle rates for power flow from NW to CAISO, we currently do not model other scarcity adjustments. If there are additional data that you could provide, it would be helpful.
14. Nick Pappas: Regarding gas retention for local requirements, does the IRP modeling process assess cost-effective LCR unit replacements with new resources, e.g.

LDES/MDES/geothermal? Could this study be included as a requirement for Local RA CPE IRP filings?

    a. The RESOLVE model currently doesn't have the capability to capture the specific needs of LCR areas; however, IRP staff are developing a local area tool version of RESOLVE (we'll be having a MAG webinar on it next month), that is being developed to help better model the issues around such questions.

15. Nancy Rader: I am just flagging a question I sent to staff re I&A Table 19 for 2025, which shows 8,000 MW of baseline CAISO wind, which is higher than shown in CEC Almanac and DOE's wind turbine database.
    a. Our baseline CAISO wind includes both in-state and out-of-state wind generators contracted to CAISO LSEs. Most of the discrepancy lay in the inclusion of out-of-state wind contracted to CAISO in our total.
16. Nancy Rader: Can you explain why the CPUC is not interested in understanding how much BTM solar is cost-effective in the portfolio?
    a. See answer below to Andrea White. IRP staff takes BTM solar amounts as input assumption from the CEC's IEPR forecast to treat it consistently with the other components in the IEPR forecast.
17. Andrea White, PCF: Hi why is it that p. 84 refers to BTM storage as a candidate resource and not an optimizable resource?
    a. BTM storage is modeled as a load modifier, derived from the CEC IEPR forecast. This is described in the I&A report Section 2 and Section 7.1.3
18. Stephen Torres SCE: What is the rationale for expanding the potential of clean baseload resources and long duration storage? Which external public sources were used to inform these potential projections?
    a. The EGS and LDES technologies proposed for inclusion as Default Technologies were selected due to their technology readiness levels as well as active commercial development. The resource potential of LDES is uncapped, since the generic LDES archetypes are assumed to not have any significant project siting restrictions (similar to Li-ion batteries). The potential for EGS is based on the new methodology that was presented on Slides 67-69.
19. Stephen Torres SCE: Why is there a solar pv annual build limit through 2028 but not after that? What changes in 2029 in terms of interconnection and build limits?
    a. We have historically placed build limits on solar based on historical rates for the first three years of modeling reflecting near term limitations of what is already in pipeline for development, then allowing for increased deployment amounts beyond. If you have recommendations for different treatment, please do include that in your comments.
20. Stephen Torres SCE: Why is long duration storage a similar cost to li-ion batteries on a levelized basis? What are the key underlying assumptions underpinning this result?
    a. The cost assumptions for each of the representative technologies used in the LDES archetypes are PNNL Energy Storage Grand Challenge Cost and Performance Database, as well as recent whitepapers from the LDES Council and Form Energy. We encourage you to review the I&A report and provide recommendations for cost data sources in the informal comments.
21. Stephen Torres SCE: Considering resolve models 36 independent days, how are you accurately accounting for the benefits of multi-day storage during multi-day events and how are you ensuring adequate charging power?
    a. We have a section on this in today's presentation.

22. Stephen Torres SCE: Considering the high penetration of use-limited resources and the move of the RA proceeding to Slice of Day (SOD), why is reliability and contribution to hsn/ssn still being assessed with a flat annual factor?
    a. As we'll share shortly, we use SERVM based ELCCs that consider both energy and capacity needs over all hours of 23 simulated weather years. The contributions to hsn/ssn are based on the CAISO's whitepaper - they vary by resource and may differ b/t on vs off peak.
23. Stephen Torres SCE: When will ED publish full datasets, RESOLVE and results?
    a. Jared: We generally release the RESOLVE model and its supporting datasets with corresponding use case (e.g. with the filing requirements). What general datasets are you referring to?
24. Kanya Dorland: Under the Trump Administration can new solar projects still qualify for production tax credits? If not, should this IRP cycle not assume production tax credits for new solar projects?
    a. Unless/until new policy guidance is released, projects can still currently qualify for production tax credits.
25. Stephen Torres SCE: When will ED publish details of the E3 Recost model including inputs, calculations/ equations to arrive at cost results?
    a. This will be published early next week, stay tuned.
26. Orran Balagopalan EDF: The 2023 ALJ Ruling on the 2024-2025 TPP portfolios indicated staff was in the process of developing "new local area modeling capabilities" to aid in modeling the retirement and replacement of gas plants. From what we understand, this modeling will function as an “add-on” to RESOLVE. Is this the “local area tool version of RESOLVE” that Jared Ferguson just referenced in the Q&A?
    a. Yes, this is the local capacity modeling tool version of the RESOLVE model to model LCR areas staff will be discussing at a MAG in March.
27. Stephen Torres SCE: For Table 15 (p.24) on candidate gas resource costs (re: economic retention) was the cost justification informed by market prices?
    a. Table 15 applies specifically to baseline gas resources. These costs are derived from the CEC report cited in that section of the I&A report. In Section 8 of this slide deck, we will present alternative assumptions for these costs.
28. Nick Pappas: Would you be able to release the SERVM weather dataset in the form of hourly capacity factors for resources and zones? This will be important for stakeholder IRP review and is also important for ongoing benchmarking with RA methods.
    a. Yes, this seems like a reasonable ask. Staff will look into sharing and posting this information.
29. Nick Pappas: Would you be able to release more output and summary data for the LOLE study results, when complete? These are important for IIRP input benchmarking on shifting reliability risk and important for long term contracting and development for ELCC resources. The included heat map of summer/winter risk is very useful.
    a. Please email us a more specific request for outputs so we can have more dialogue on this. We can certainly consider adding more detailed results beyond the LOLE results and EUE heatmaps we have been sharing publicly.
30. Tyson Siegel: Table 35 lists ranges of WACC values developed for three risk classes. The majority of PSH projects are categorized as existing-reservoir projects. However, only the new-reservoir PSH category is shown on table 35 for PSH resources. Is the existing-reservoir PSH category the same risk class as the new reservoir PSH category?

    a. Existing reservoir projects are classified as Mid-Risk. Apologies for this omission in the report and slides; we will make sure all technologies are included in the final version of the report.
31. Hillary Hebert: Can you please clarify what is reflected by the red lines on slice 41? I understand that the blue line data comes from the averaging of multiple sources. What data is used to form the red line?
    a. The blue curve on slide 41 is directly adopted from NREL 2024 ATB "Mid" CAPEX trajectory (in real 2023$). The red curve is that same data, but adjusted to nominal dollars, to highlight the discontinuity in 2035.
32. Hilary Hebert: Can you please clarify what is causing the spike for solar starting around 2045 on slide 44? Does the new data all point to some change in costs at that point that was not forecasted in last year's data?
    a. The spike in 2045 is due to the assumed expiration of the tax credits. The IRP is assuming that the credits expire over 2046-2049.
33. James McGarry: Can staff please clarify how Diablo Canyon retirement will be handled? The Nov 2024 baseline list used for Jan 2025 IRP Proposed Decision on CAISO 2025-2026 TPP portfolios (BaselineGeneratorList_ExternalBuildCalibration_v20241125) appears to have Diablo retiring in October 2029 and October 2030. However, the 2025 draft I&A document states that Diablo will be assumed to retire in 2024/2025. Can staff confirm that Diablo will be assumed to be retired beyond November 1, 2024, or Unit 2 beyond August 26, 2025?
    a. Diablo will be assumed to retire on 11/1/2024 and 8/26/2025 for IRP modeling to comply with SB846.
    b. I want to provide some additional nuance, as SB 846 requires IRP for planning to assume Diablo retires in 24 and 25, but for other analysis that is conducted by SERVM (e.g. RA) there is no requirement. Thus for RESOLVE modeling we will have the 24, 25 retirement assumptions, but the general baseline used across IRP models may have Diablo with later dates.
34. Erik Better: Does the SCE EOP region include Esmerelda county?
    a. It does not currently; please include a discussion on this in the informal comments.
35. Kate Kelly - Defenders of Wildlife: Was the land use screen for PSH updated to include protected areas?
    a. We based the PSH candidates on the ones analyzed in the 25-26 TPP busbar mapping and excluded the potential sites with the highest protected layer flags (>70%) as well as the ones with level 5 flags for the other environmental screens.
36. Nina Robertson: What is the def of "biopower" in your slide 42 and how does it relate to biomass and biogas as presented in the main doc?
    a. Biopower is the technology class from NREL 2024 ATB that is used to represent candidate biomass resources in RESOLVE.
37. Erik Better: Regarding the solar potentials shown on slide 59, you have shown 16.9 GWs of potential for East of Pisgah; can you offer any more info about how you determined that as the potential?
    a. This potential was determined by applying the techno-economic and environmental land-use screens, as described on Slides 54-56, as well as the BLM 2024 WSP exclusions (Slides 57-58). The remaining areas are multiplied by a 30 MW/km2 area density factor to result in the reported MW value.

38. Nina Robertson: What is staff doing to address the discrepancy between the RESOLVE and SERVM GHG results? (Discrepancy was noted in the most recent decision and is significant.
    a. Staff is currently undergoing a process to calibrate RESOLVE and SERVM to better understand and work to correct what could be driving discrepancies between the models.
39. Orran Balagopalan EDF: In addition to changes to evaluating geothermal resource potential, is staff considering doing a more granular evaluation of geothermal resource costs? (e.g., using more than one resource type to determine cost assumptions; focusing on the resources available specifically to serve load in California, instead of relying solely on NREL).
    a. Currently all hydrothermal resources are using the Binary costs from NREL 2024 ATB with no additional granularity. Please provide any recommendations in the informal comments and we will evaluate any updates for the final I&A.
40. Tyson Siegele: For PSH resources the I&A defines cost class by "no existing reservoirs" or "at least one new reservoir." Can you discuss how those classes were selected?
    a. These definitions were made to align with the classes used in NREL 2024 ATB.
41. Joe Gosselar: Can staff please clarify which technology the 24-hour LDES costs reflect (slide 48)? The slide says it reflects thermal storage, but the I&A doc (p.41-42) says it reflects CAES. (Albeit both cite the same PNNL source.)
    a. Section 4.2 of the draft I&A report is erroneously referring CAES and will be corrected for the final I&A. Section 5.4.3 of the draft I&A is correct in referring to thermal storage.
    b. The technology should be Thermal Storage (from PNNL), which itself is an aggregation of multiple technologies that all employ thermal energy storage. Apologies for the inconsistency in the written report.
42. Tyson Siegele: One of the busbar-mapped resources in the most recent round of mapping has zero new reservoirs. Can you discuss the cost class assigned to that resource? Further if it is the same as the one-reservoir resources, can you discuss why there is a difference in assumed cost between 1 and 2 reservoirs but not a cost difference assumed between 0 and 1 reservoirs?
    a. Our cost assumptions were limited by the available categories from our sources. The NREL data had only cost assumptions for PSH with 2 new reservoirs or one existing reservoir.
43. Poonum Agrawal: Why has the Diablo Canyon Call area been removed?
    a. It has been excluded based on BOEM decision to hold it from moving forward several years ago as call area due to dept of defense concerns
44. Kanya Dorland: Will the Idaho wind availability date be effected by recent changes under the new administration such as DOE funding, on-going opposition to the Lava Ridge wind project in Idaho and recent FERC's denial of incentives for the SWIP-North project?
    a. In developing these draft I&A assumptions we did not explicitly factor those recent issues. I noted at the beginning we are monitoring these kinds of changes and working to see what changes will be lasting and what if any impacts they will have. And staff will be able to incorporate potential changes later throughout the cycle as needed.
45. Erik Better: With respect to slide 65, what was the methodology behind deciding where to interconnect the OOS geothermal?

    a. The interconnection locations for the OOS geothermal were informed by the existing high-voltage transmission system topology, and/or identification of substations at the CAISO system boundary near both existing and planned high-voltage infrastructure and the OOS geothermal field locations. Please provide any additional feedback on these assumptions in the informal comments.

46. Ryan Tracey: What is driving the mid-2030 first year assumptions for out-of-state hydrothermal (2035 for Nevada geothermal at Malin as an example)?
    a. These first available years are informed by development lead-times, both for the resource development and the transmission required to deliver those resources to CAISO. This was covered in a bit more detail in 5.5. We welcome stakeholder input on these assumptions.
47. Kanya Dorland: Believe the SWIP-North project is also slated for completion in 2028 so delivery of Idaho wind by 2027 may not be possible.
    a. In your informal comments can you please just provide a reference link for this assumption? We can make that adjustment.
48. Hillary Hebert: Why is out of state solar (e.g. AZ solar or S. NV solar) not included on the table on Slide 65?
    a. Those resources are included in the in-state resource potentials since they interconnect directly to the CAISO system; see slide 59, "SCE EOP" for Southern NV Solar and "SCE Arizona" / "SDGE Arizona" for AZ Solar
49. Ryan Tracey: Is the temperature model for deep EGS used to estimate cost as well as capacity? (for example: are hotter areas expected to cost less per MW). Or is a standard cost used for all EGS that meets the 80% threshold.
    a. A standard cost is used for all deep EGS, namely the Deep EGS Binary costs from NREL 2024 ATB. We explored applying a cost modifier based on reservoir depth (but not temperature). If you have recommendations for additional granularity on our EGS Deep resource costs, please provide them in the comments.
50. Kanya Dorland: Has CAISO reviewed the IRP methodology for determining the generic upgrade costs? Has CAISO approved of the cost for the seven generic transmission upgrades modeled in RESOLVE?
    a. IRP staff with its consultants have developed these assumptions, in developing them we've discussed with CAISO staff cost assumption sources (e.g. Per Unit Cost guides, and CAISO's own assumptions in the 20-year outlooks) that we used to implement these assumptions but have not explicitly asked the CAISO to study, analysis or approve these cost assumptions.
51. Nick Pappas: In CAISO's new modeling initiative (RAMPD), they are taking a distinct approach on VERs which is more stochastic than probabilistic. They have indicated a unifying dataset may be forthcoming from CEC in a few years. Are you in collaboration with CAISO to benchmark forward looking reliability results and methods? any comment on the CEC dataset?
    a. We are in regular dialogue with CEC for improving their load forecast and having them be the source for a stochastic weather year-based hourly load dataset. This will improve consistency with the IEPR forecast if CEC data becomes the source for both peak/energy forecast and the weather-based set of hourly shapes. We can't speak for CEC, but we hope the next IEPR will include a probabilistic set of weather-based hourly shapes (instead of just the current single hourly shape) to go with the forecast. We are also in regular dialogue with the CAISO modeling staff to compare our models and methods and investigate together when our results differ.

52. Kanya Dorland: Is there a reason why upgrade costs are higher in southern California versus northern California?
    a. The generic assumptions are based on a combination of the already identified CAISO white paper upgrades and PTO per unit cost guides. a key factor in the higher cost for the southern California area are the longer distances over more difficult terrain (including built up areas)
53. Ryan Tracey: How will upgrades to inter-IOU capacity limits (with the new topology) be modeled (cost and first year)? Will there be any TPD-based upgrades that will increase intra-IOU transfer capacity?
    a. The detailed assumptions and specifics are covered in an upcoming section. Feel free to submit a new question if it didn't answer your question.
54. Emil Rodriguez: Would the assumption that transmission transfer capacity from remote zones is capped at the nameplate capacity of the remote generators not account for existing or future interregional transmission constraints?
    a. The assumption that transmission capacity is capped at the remote generator nameplate capacity only applies to the pseudo "transmission line used for remote generators in RESOLVE (i.e. the bottom line in the diagram on slide 108). The full interregional transmission constraint is reflected in the simultaneous flow constraint that the remote generators, and other imports, are subject to."
55. Kanya Dorland: CAISO PTOs also provide per unit costs annually to the CAISO. Was the CAISO PTO per unit costs guide consulted to confirm the cost estimates for the generic transmission upgrades?
    a. Yes staff used a combination of already identified upgrade assumptions, CAISO's cost assumptions used in the 2023-2024 20-year outlook, and the per unit cost guides
56. Stephen Torres SCE: Can the interim RESOLVE results and model itself as it stands today be shared with stakeholders so stakeholders can review, validate and provide comments?
    a. We are still working to update the RESOLVE model both to include these new I&As and to ensure SERVM and RESOLVE are properly calibrated, so we won't be releasing an interim version of RESOVLE at this time. Additionally we believe it's important to have a lot of our assumptions established based on data independent of what those assumptions produce in the modelling results.
57. Nick Pappas: There is a lot of great work being done by ED and team. Will you consider hosting a longer workshop which permits more engagement?
    a. For the draft I&A, we're not currently planning another workshop and hoping the incorporation of comments can provide a detailed source of feedback for IRP staff to review and incorporate. Generally across our various IRP processes (e.g. busbar mapping, our upcoming local tool webinar) we are striving for more engagement but we are also still restricted by our cycle timeline requirements and staff limitations.
58. David MacMillan: 1) How do you ensure that the cross-correlations between wind and solar are properly represented in the modeling? e.g. a clear sunny day may have low wind whereas a cloudy stormy day may have high wind.
    a. Cross correlations between wind and solar are captured in our model since (a) National Solar Radiation Database reflects actual historical insolation across 2000 - 2022 and (b) velocity profiles which are either the basis of the velocity approach or the basis around which random Monte Carlo draws are resorted is based on the ERA5 reanalysis which captures historical hourly conditions.

59. David MacMillan: How do you ensure the cross-correlations between wind & solar on the one hand and load on the other hand are properly captured? (All are affected from specific weather patterns so will be cross-correlated. A Monte Carlo draw on wind needs to be matched to suitable solar and load for the assumed weather pattern in the Monte Carlo draw.)
    a. Load, solar and wind profiles capture historical correlations across time and space because (a) load profiles are based on historical temperature and dewpoint profiles and (b) solar and wind profiles also reflect historical hourly values. See prior QA reply for further details
60. Kailash Raman: Will interperiod state of charge linking be implemented within the RESOLVE capacity expansion model?
    a. The short answer is yes. We will have updates on this shortly.
61. Mason Wolfe: You've proposed transmission constraints tranches between SCE and PG&E load centers which include deliveries to the PG&E load centers north of Path 15. Wouldn't it make more sense to separate these constraints and have an SCE to Southern PG&E constraint and a Southern PG&E to Northern PG&E (Path 15) constraint?
    a. We currently disaggregate CAISO to three zones in RESOLVE to align with SERVM. CEC IEPR load data is also at the same granularity for PGE, SCE, SDGE areas. So, for consistency, path 26 represents the SCE and PGE power flow constraint. However, the path 26 expansion options (tranche 2 and 3) include options to expand Path 15 if it is found economic to expand.
62. Kanya Dorland: Are the cost estimates for the SCE Transmission Upgrades also from CAISO sources such as the PTO cost guide and recent projects?
    a. The generic upgrade costs assumptions were developed by IRP staff and our consultants but do rely on the various CAISO cost data for all areas of the CAISO modeled in RESOLVE.
63. Nick Pappas: Hi Patrick, thanks for your response. Regarding the CEC dataset, is there consideration of bringing forth a broader probabilistic modeling dataset which includes generation resources, similar to the SERVM approach? As a stakeholder I am trying to figure out how to identify alignment between agencies in the current paradigm vs a potential future unifying dataset.
    a. The demand forecast is CEC's responsibility so it is appropriate they also take on expanding the IEPR to include a probabilistic hourly load dataset including BTMPV and other demand modifiers. CPUC will continue to create a probabilistic hourly load dataset for non-CA areas as well as utility-scale wind and solar for all areas of the WECC. I don't think we can have one entity produce everything so CEC, CAISO, and CPUC staff have over the years collaborated and agency leadership has put in place some agreements on how to do so.
64. Kayla Dowty: Have you considered a remote resource for Northern California geothermal resources that are located outside of the CAISO BA?
    a. If you are referring to candidate geothermal, then no. Candidate resources will be modeled with firm transmission to provide both energy and RA. If you are referring to existing (baseline) resources, then any unit in Northern California that is contracted to serve energy to CAISO, but does not interconnect to CAISO or provide firm RA to CAISO, would be a remote generator.
    b. Adding to this - we are considering modeling a transmission deliverability cost adder for in-state geothermal that interconnects to non-CAISO BAs in northern

California. If you have additional thoughts here, please include them in the informal comments.

65. Christian Lambert: How did E3 determine if a specified import provides "firm RA" or not? Our review finds that multiple specified import resource IDs in addition to the six facilities of Hoover, Palo Verde, IPP and Sutter (and now SunZia and Cape Station) regularly provide CAISO RA.
    a. Generally, resources providing RA are those that are not dynamically scheduled and deliver directly to CAISO. This includes pseudo tie resources. Hoover and Palo Verde are modeled as if they are located within CAISO, which is an exception to this rule though it is notable that recently, Hoover has moved to pseudo tie classification. We make this distinction partially by whether the resource has a CAISO Res ID and whether that CAISO ID includes a suffix of DYN to indicate dynamically scheduled.
66. Ryan Tracey: Is the natural gas price assumed to be at the hub or power plant? Does the forecast used incorporate any assumption on decarbonization driving reduced utilization - which will need to spread the fixed infrastructure costs over less therms?
    a. It's at the hub. There is another input in the model for transportation rate, which is given on a unit specific basis.
    b. We use the median forecast from the IEPR NAMGas model, which is a median forecast of the impact of decarbonization on gas utilization.
67. Tyson Siegele: The sponsor of the only PSH resource that qualifies for consideration in AB 1373 procurement has reported cost estimates for its proposed PSH facility will exceed the cost of NREL ATB class-15 PSH resources. Will the IRP modeling team add a PSH class-15 candidate resource to enable evaluation of the single PSH scenario allowed in AB 1373?
    a. If there are recently public datasets that show starkly different cost assumptions than the data sources we have incorporated in this draft I&A please do share it via the comments. Additional IRP staff note that the AB 1373 statue do not explicitly name a single facility and that any facility meeting the set of parameters for PSH could qualify.
68. Emil Rodriguez: Why are all remote generators modeled as not providing firm RA?
    a. Emil, I think you are asking about remote generators that are not one of the six specified import exceptions. Remote generators are modeled as units outside CAISO and subject to transmission path limits and simultaneous import constraints. Thus their contribution to RA is represented by the 4 GW sim import constraint. See also Answer above to Christian Lambert's Question.
69. Zoe Harrold, GPI: Does the existing thermal fleet ELCC analysis include Diablo Canyon?
    a. No it does not since these ELCC studies were performed on a 2035 base portfolio, after Diablo Canyon was assumed to retire.
70. Tyson Siegele: Regarding Figure 13, 4-hr Li-ion battery prices, the mid- and high-cost assumptions appear to exceed manufacturers' currently advertised prices. Do currently advertised prices of li-ion batteries factor into the I&A battery cost range?
    a. There has been large variation in developer quotes for Li-ion batteries in recent months/years. The full range of Li-ion battery capital cost assumptions reflects this larger uncertainty. Manufacturer prices are referenced in some of the industry reports used in the analysis presented here. If you have more up-to-the-minute estimates of LI-ion battery costs, please share them via the informal comments and we can look to update our cost assumptions further.

71. Andrew Mills CalCCA: On slide 120, is the "multiplier" for 12h/24h/100h storage the same as saying a linear extrapolation of the 4h to 8h curve?
    a. No, the multipliers are not derived via extrapolation. They are derived by looking at specific points on the 3D surface and comparing the marginal ELCC of 8-hr storage to the marginal ELCC for 12/24/100 hr. This allows capturing the additional lower RTE impacts on LDES ELCC values.
72. Tyson Siegele: Slide 122 shows 100% ELCC for RESOLVE. There have historically been significant PSH outages during peak demand hours. Does 100% ELCC mean that the PSH outages are not considered in RESOLVE?
    a. PHS outage are not currently modeled in SERVM. Please provide relevant data and recommendations in your comments.
73. Nick Pappas: How are imports treated for RA validation with SERVM? Do SERVM runs limit imports to resources assumed to be under contract to CAISO similar to the RA LOLE study?
    a. The RA LOLE study for SoD applied the 4 GW cap in evening hours for all months. Further, the cap was tuned downward (tighter) to get reliability to 0.1. For IRP, SERVM will be configured differently and it will align with the Import slides that Aaron just presented. The ELCC surfaces were calculated using the IRP configuration so we expect that the selected RESOLVE portfolio will yield at least a 0.1 or better LOLE result when modeled in SERVM.
74. Joe Gosselar: Will CCS be included in the final I&A doc? Or if not, do you know why it's not included this cycle?
    a. We are currently not proposing having CCS as one of our selectable candidate resources, but RESOLVE does have the functionality/info to include it and we may consider sensitivities during the planning cycle that could include it
75. Joe Gosselar: Will staff be forcing in any other "planned resources"? E.g. any new resources beyond existing procurement for compliance with the 2019-2023 orders and 2023 LSE plans?
    a. It will depend on the scenario and use of the modeled portfolios. For past portfolios we have forced in various resources based on LSE plans, new in-development or contracted resources, assumed procurement of ordered resources. It will depend on the scenario and use case of the modeling
76. Paul Worhach: Can you provide more detail and step-by-step examples of how the LDES multipliers are developed?
    a. See response to Andrew Mills above. We take points on the surface representative of the years shown and then perform marginal ELCC calculations for 8/12/24/100 hr storage. The multipliers are the (X hr ELCC) / (8 hr ELCC).
77. Ed Kiolbasa: Will you share the metrics used to support the observation that there are marginal improvements above 40 representative days? The manner in which this is modeled would impact the observed improvements.
    a. The observation was based on RMSE (Root Mean Square Error) that the algorithm minimizes for clustering days.
78. Kurtis Kolnowski: Slide 131 shows demand response providing less value to peak reliability farther in the horizon. Can you clarify if this refers just to Shed DR or other DR types as well (e.g., shift).
    a. The multiplier shown is for shed DR.
79. Joe Gosselar: On p.35, it says that DRAM is included in the baseline resource assumptions. My understanding is that the DRAM pilot has been terminated. I'm guessing this was an oversight that carried over from 2023 I&A -- is that right?

    a. Staff will address and correct in the Final 2025 I&A.
80. Nicholas Sher: Per the "Resource Cost Data Sources for the 2025 I&A" slide (p. 165) CapEx costs for Li-Ion undergo a "custom" analysis to determine CapEx costs, while PSH costs, for example, are obtained from NREL ATB. First, please describe this custom analysis and how staff arrive at a "custom" CapEx cost. (Where can we get data on this custom analysis?) Second, do staff/does the RESOLVE model take into account limits on battery charging, discharging and degradation? How and where is the life of an asset accounted for?
    a. The custom analysis for Li-ion batteries is analogous to what was presented today on slides 40/41 for solar. Current-year CAPEX was benchmarked using additional data sources, and trajectories were updated to reflect greater uncertainty. The full methodology and summary data from this custom analysis is published in the I&A, and the full cost trajectories will be published in the Recost model next week. With regards to your second question, degradation costs of batteries, per NREL ATB documentation, are assumed to be included in FO&M. We model a minimum state-of-charge for all storage technologies, including LI-ion batteries. The lifetimes of each asset (used in the cost levelization calculation) are included in the I&A and available in the forthcoming Recost model.
81. Andrew Mills CalCCA: Did the finding that periods of risk changes to winter assume an import cap of 11 GW in the winter or 4GW like in the summer net peak hours?
    a. The import cap was only applied during the summer evening hours, not during winter. If winter imports were capped, we would see an earlier shift to winter risk (i.e. at lower solar/storage penetrations).
82. Kayla Dowty: Please note that for air cooled geothermal facilities, we typically install solar to support parasitic loading for the air coolers which greatly helps to level the generation profile. Ormat recently converted a water cooled facility to an air cooled facility in Imperial Valley (very high ambient temperatures) and have seen much success in overall generation.
    a. This type of information is very helpful Kayla. Please share it in your comments, along with your recommendations backed by these examples and quantitative data you can provide to support those recommendations.
83. Steve Metague: Can you give me an estimate of how much of the existing natural gas generation fleet will be 40 years old in 2035?
    a. Approximately 6% of the CAISO gas fleet would be 40 years or older in 2035. This would grow to nearly 50% by 2045.
84. Stephen Torres SCE: The joint IOUs request that informal comments deadline be postponed to allow parties to incorporate the workshop Q&A; we propose: 1. Written responses to Qs posted in the chat during the workshop today should be received within 2 weeks of the workshop. 2. CPUC staff should host an "office hours" after the responses are posted in order to give parties an opportunity to ask clarifying or follow-up Qs, if needed. 3. Informal comments should be due 2 weeks after responses to follow-up questions are posted.
    a. This question was answered verbally. Staff is posting the Q&A log a day after the workshop and released all draft I&A materials a week before the workshop in an effort to provide stakeholders with as much time as possible given scheduled needs of the IRP proceeding. We are still requesting that all stakeholders provide their comments by COB March 7, 2025 to aid IRP staff in meeting the required timeline. Comments coming in after that date will be considered, but IRP staff cannot ensure that they will flow into I&A updates needed for Filing Requirements modeling.

85. Ryan Tracey: Is staff also recalibrating the starting point for existing plant fixed O&M to reflect more recent data than the 2018 study? And for the 1% proposed escalation is that a 1% nominal or real $ increase?
    a. At this time, we have not proposed any change to the starting point of Fixed O&M. However, we encourage you and other stakeholders to comment or provide data if you believe this assumption should change. The 1% increase would be in real dollars, using the same dollar year assumption as our other costs (currently 2022).
86. Joe Gosselar: I have a series of questions on EV/VGI which wasn't covered in the presentation, so perhaps it's out of scope. But if staff do publish the Q&A log afterward, maybe they can still be answered in that format.
    a. Why does commercial/workplace (V1G_Com_TX, V2G_Com_TX) light-duty EV enrollment in V1G/V2G programs increase at a slower rate than residential (V1G_Res_TX, V2G_Res_TX) with increasing amounts of VGI incentives (Tables 76-77)?
    b. Are staff planning to distinguish between residential EV charging at single-family homes vs multi-unit dwellings?
    c. For the EV to charger ratios (1:1 for residential, 25:1 for workplace), does "charger" refer to a charging port (i.e., a single charger could have multiple ports and serve multiple vehicles simultaneously)?
    d. How are VGI use cases categorized?
        i. Is it correct to assume that EV managed charging program fits within V1G TOU rates category? This is controlling the charging of a vehicle to meet customer and grid needs.
        ii. Does the V2G model consider V2X use cases that are not discharged back to the grid? For example, using your vehicle to power your home or premise when rates are higher?
    e. Answer: There have been no changes since Staff released the 2023 I&A.