CPUC IRP Inputs and Assumptions (I&A) Webinar

June 7, 2023

WebEx Q&A Log

Q: The I&A report was expected in Q4 2022. Curious to know the reason for the delay.

A: Competitive priorities in IRP and availability of some data sources. This document needs to be finalized for the PSP/TPP development which gave us some flexibility in terms of timing.

Q: It sounded like the only information retained from the LSE IRP plans is their "in-development" resources, but not their planned generic resources. Why not retain their preferences for location and technology type?

A: The I&A defines the baseline. We use the LSEs planned resources in developing the PSP/TPP portfolios with the details that LSEs provided in their IRPs.

Q: What is the timeframe over which historical annual hydro production is determined? Have there been any effort to include the impacts of climate change on forecasted hydro production?

A: Hydro production is modeled for all historical years simulated in SERVM (1998-2020). Climate change is factored into the latest modeled hydro production via removal of the declining capacity and energy trends seen over the past 20+ years. e.g. more distant historical production data is reduced more than that in recent history.

Q: Can you comment on the decision to use NREL and not Lazard for li-ion? What are the differences in estimates?

A: In addition the NREL 2022 ATB being available for several months before the release of Lazard LCOE+, review of industry data on quotes for new Li-ion battery storage projects (including Tesla MegaPack cost quotes) suggested that the NREL cost value more closely reflects current reality. The main difference between NREL and Lazard is that Lazard models more of its technology costs on Fixed O&M, relative to NREL.

Q: Re slide 66's OOS resource potentials, the slides are not explicit here about what is limiting OOS CAISO-interconnected solar and wind.

A: So we are only limiting in-CAISO wind and solar resource by the environmental and land-use screens, just like in-state resource.. For the OOS resources we are using the same WECC data set we've used previously, since CEC data sets are currently only for the state.

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Q: Was only 99% post-combustion capture considered (versus 90% and 95%)?

A: Yes, for post-combustion CCS, we are only considering 99% capture. At this time, we do not have sufficiently differentiated cost data to differentiate 90, 95, 99% CCS

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Q: When looking at hydrogen to power, do you only consider the combustion pathway or also a case where fuel cells are used?

A: For this cycle, we are not planning to consider fuel cells at this time for hydrogen consumption.

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Q: It would seem like the I&A team has removed flow batteries from the list of candidate resources, is this correct? Why?

A: We are not aware of more recent flow battery cost data (for example 2018 was the last year in which Lazard's LCOS included flow battery projections). In the I&A draft document (section 5.3.2), Staff are requesting any input stakeholders may have on newer cost data. If no new data is available, Staff proposes making the same cost adjustments as described for Li-ion

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Q: The I&A draft document indicates in section 5.2.4, page 65 of the I&A draft report states: “Existing & New Tx with Limits is the default screen for the 2022-2023 IRP. Under this screen, the default potential for out-of-state wind is limited to 5,000 MW by 2035 to reflect the likelihood that high-voltage transmission lines to each of these wind resources could be built.” The draft I&A document does not offer the same explanation for solar but do include a solar limit in the same section’s table.

A: The 5,000 MW only applies to the OOS, out-of-CAISO wind, i.e. Idaho, New Mexico, Wyoming, and Utah. We aren't modeling any OOS, out-of-CAISO solar, those solar limits for Southern Nevada and Arizona are from the land-use screens.

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Q: Do I understand this correctly that the transmission is capping the potentials? Why would you place a hard cap on potentials when the transmission limitations have the ability to measure whether a transmission build out is cost effective?

A: We are only capping the OOS, out-of-CAISO wind at 5,000 MW before 2035, afterwards RESOLVE could build out to the resource potential limits, though still having to account for in-CAISO transmission capacities and upgrades.

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Q: Does including CCS affect the baseline resource list in any way or is CCS effectively treated as a new candidate resource?

A: At this time, we are considering CCS as a separate candidate resource and not as a retrofit

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Q: You are using land use screens for OOS in-CAISO wind and solar?

A: We are applying land-use screens for OOS, in-CAISO wind and solar, and we don't have a cap placed on them based on estimated transmission upgrades like the 5,000 MW near-term cap on OOS, out-of-CAISO wind. Transmission constraints are applied to OOS, in-CAISO resources the same as in-state in-CAISO resources.

Q: Can you clarify if Diablo Canyon is added back into the baseline?

A: In this draft I&A, DCPP is assumed to go offline as previously scheduled (in 2024-25). There might be differing interpretations re: exactly what SB 846 allows (or doesn't allow) planning exercises such as IRP to do re: characterizing DCPP in modeling analysis. A strict interpretation could lead to only modeling it as going offline at previously scheduled dates (2024-25). A less strict interpretation could be that it would allow analysis of DCPP extension, but perhaps not the adoption of policy based on that. There could be even less strict interpretations. Would be very curious re: stakeholders thoughts. For reference, I am looking at SB 846's changes to 454.53(b)(5).

Q: Slide 26: can you please provide more detail on the rational for not modeling paired solar/storage? Is it because staff does not believe developers will pursue paired configurations now that storage can charge from the grid?

A: That's essentially correct. With the IRA, standalone storage projects can receive the ITC, and consequently the main driver for developing paired solar/storage no longer exists. Additionally, the cost savings (e.g. interconnection costs) from co-locating these technologies is not viewed as significant enough to warrant modeling hybrids in RESOLVE. We expect that some paired solar-storage resources will be developed in the future. While RESOLVE won't explicitly model these paired resources, we believe that the cost and capability of independent solar and storage resources is similar enough to paired resources to not warrant a different treatment in capacity expansion modeling. There is a significant model runtime benefit to simplifying the representation of solar and storage (i.e. not modeling paired explicitly), which allows us to model other parts.

Q: Do the hydrogen costs also include the costs for the power to produce the hydrogen and the costs to control NOx if hydrogen is combusted?

A: The cost for the power to produce hydrogen will be endogenously captured in Resolve

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Q: Thanks Jared for the clarification. Even though there is a lot of info available on these regions adjacent to CA, including data that has been filed with the CPUC and CEC, the CPUC does not wish to consider this info for IRP?

A: This is more of a CPUC and CEC staffing and timeline constraint that has limited our ability to update OOS land-use screens. Due to that, we are still using the WECC based screens previously used.

Q: The potentials seem very low for those non CA, but in-CAISO, areas. Is there any more info available for us to understand the findings?

A: So for both Southern Nevada (80 GW solar, 2 GW wind) and Arizona (84 GW solar), those don't cover the whole states, just the areas within reasonable interconnection distance of the in-CAISO system. For geothermal we are still using the 2008 USGS study, due to lack of publicly available more recent data. Geothermal is also still conventional geothermal. Enhanced geothermal is discussed in the emerging tech part of the I&A but those potential values are not a default candidate resource.

Q: Can you clarify if the post-combustion CCS is only on new-build facilities or if it is representative of CCS retrofits to existing gas facilities?

A: At this time, we are modeling only new-build facilities. We would appreciate comments if stakeholders have recommendations for cost and operational characteristics for retrofits

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Q: Could you comment on what existing commercial CCS projects are actually delivering at costs that low? I confess I haven't followed that space, but I haven't heard of any CCS projects that were either 99% effective or that cheap. What we're seeing in the commercially viable clean firm space is mostly geothermal, I believe.

A: The cost for 99% CCS was determined by applying a cost adder to the NREL 2022 ATB costs for CCGT 90% CCS. This cost adder was adapted from a report (Feron et. al.) on the cost of additional liquid amine-based carbon capture. The citation for this source is provided in the CPUC IRP Pro Forma workbook. We welcome additional data sources on the cost to develop commercial 99% CCS resources.

Q: How do the emerging low (but not zero) generation technologies count towards the SB100 and other decarbonization goals?

A: 99% CCS is the only non-zero GHG emissions emerging technology we're modeling, and under the SB100 language this technology qualifies. So we're following this qualification.

Q: What does this modeling assume related to Aliso Canyon?

A: The assumptions in the I&A do not include any specific assumptions regarding Aliso Canyon availability.

Q: will emerging technologies be included in "core" modeling scenarios? or only in sensitivities?

A: Sensitivities. However as mentioned, during each IRP portfolio development, staff evaluates the non-default candidate resources based on these guiding principles and determines if a resource meets the criteria to be a default candidate resource

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Q: Are there assumptions made in relation to community solar that considers the incentives in the IRA and AB 2316?

A: No explicit assumptions are made. Community solar developed in open greenfields are subsumed by the geospatial analysis for utility-scale solar. There is also geospatial data for Distributed_Solar optimized candidate resource, which includes commercial in-front-of-meter solar. IRA incentives are modeled for these resources, but no explicit assumptions are made for community solar.

Q: If we provide data on enhanced geothermal in commercial operation and additional cost estimates, then you'd consider incorporating that?

A: Yes. Please provide those data in your comments with ref. Thank you.

Q: The I&A document (e.g., Figures 15 and 17) and at least one of the supporting spreadsheets includes values for 90% capture in addition to 99% capture. Are you planning to use only the 99% capture values?

A: Yes, we are planning on only modeling 99% capture. References to 90% capture will be fixed in the final I&A document

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Q: Biomass and biogas are absent from Sections 3.2, 3.4, and 3.6.. They should be considered in all of these sections.

A: Biomass is considered by RESOLVE as a candidate resource. We actually don't show the full spectrum of the candidate resources available to the model in those charts, but instead focused on particular ones. Generally, the biomass costs that we've considered in IRP have stayed stable over the last several years, so that resource type wasn't highlighted today.

Q: Re slide 81 about Build and Dispatch constraints, Regarding these new build and dispatch constraints, where/when can we get the detailed information about these? For example what specific constraints will be implemented?

A: So the draft I&A document has this discussion starting on page 59. The table 37 starting on page 61 shows what constraints affect what resources regions+tech

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Q: Also regarding these new constraints, is the team far enough along to confirm that RESOLVE will still reasonably solve with this added detail?

A: One of the main motivations for creating separate build and dispatch resource representations is to keep model runtime reasonable. While we are significantly adding to the number of build decisions in the model by subdividing resource potential based on transmission constraints, we are removing dispatch decisions from the optimization by aggregating the build resources to the larger dispatch resources. We expect this tradeoff to have a minimal impact on runtime, or perhaps even a decrease in runtime.

Q: Can you confirm that the CAISO will be providing an updated Transmission Constraint White Paper in time for the PSP development? Can you share a timeline for the release of the updated White Paper?

A: We expect the draft white paper to be released by CAISO at end of June/early July , which will enable use to utilize the white paper in the modeling efforts for PSP and TPP development.

Q: Would you consider hybridizing peakers with onsite short duration storage (1hr) to improve emissions decrease of the peaker, but having peakers stay online for primarily reliability purposes?

A: Please provide more information on this suggestion through informal comments for consideration.

Q: On Slide 85 - why are some candidate resources not included in the transmission constraints analysis?

A: Candidate thermal and emerging technology resources are not assumed to have a locational resource potential, so modeling them on transmission constraints may introduce false precision to the model. For the candidate emerging technology resources, we may re-examine this assumption if significant amounts of these technologies are selected in the emerging technology sensitivities.

Q: On slide #86, you have indicated that "The known transmission constraints and available upgrades as reported by the CAISO may be insufficient to permit enough resource additions to meet system needs through the planning horizon (2045)." However, it appears that the resource additions have exceeded transmission capabilities much earlier.

A: Agreed, we see it in the busbar mapping analysis but not the RESOLVE results much earlier. These updates are designed to try to capture those details in RESOLVE.

Q: For example, my analysis of the CPUC busbar mapping spreadsheet that was used in the development of CPUC's 2035 Base portfolio (provided to the CAISO 2023-2024 TPP) of FCDS resources exceeds the FCDS capability of not only the existing system FCDS capacity, but also exceeds the incremental FCDS capacity offered by the additional area delivery network upgrades (ADNU) identified by the CAISO. In particular, out of twenty-nine (29) different transmission constraints, for thirteen (13) constraints, the CPUC-provided Base portfolio of resources in the year 2035 exceeded the FCDS capability of the existing plus the ADNUs identified by CAISO. It is not clear what transmission cost was assumed in selecting the additional resources in those areas. In other words, the question is, "If the portfolio resources could not fit within the existing capabilities and defined expansions, then what assumptions were used about the relative costs of additional expansions to map the remaining resources?" It is unclear from this presentation (slide #79) what your plans are for the current IRP cycle. Please provide some clarity.

A: In busbar mapping, additional detailed analysis is done to downscale the resources to the busbar level. In the mapping effort CPUC, CEC, and CAISO incorporate an array of additional information that RESOLVE does not capture such as development interest, more land-use analysis and additional constraint and upgrade information provide from staff level assessments. This does result in shifts of resource between constraints that are not captured and cannot be capture by the RESOLVE version. These updates are designed to capture more of the constraints seen in busbar mapping in the RESOLVE model itself to better capture the cost implications. RESOLVE is still a higher level analysis than busbar mapping, so it won't capture all the effects, but staff expect these updates to be a significant improvement,, as in previous version the transmission assumptions were much more simplified compared to the actual constraint info.

Q: Can you clarify slide 86's bullet: 500MW per year of incremental capacity is made available starting 2037. Is that statewide?

A: 500 MW is made available on each of the eight Generic Transmission Upgrade Zones, per year, beginning in 2037. In aggregate, this would mean that 4 GW of incremental transmission capability is made available per year.

Q: On slide 91/92: How are imports from variable resources with dynamic schedules treated in terms of the 4000 MW import limit? E.g. how do you treat New Mexico wind with a dynamic transfer to the CAISO system?

A: In RESOLVE, we model a 11,041 MW simultaneous import limit to CAISO (with additional true-ups for the Specified Imports on Slide 92). Baseline renewables (e.g. SW_Wind), including both those which are contracted to sell energy to CAISO, and those which RESOLVE chooses to import as part of its dispatch algorithm, will contribute towards this value on an hourly basis. All remote generators, including both firm and variable generators, those with specified imports to CAISO, and unspecified imports, are assumed to provide 4,000 MW of firm capacity counting towards the PRM. Candidate out-of-state variable wind resources (e.g. New_Mexico_Wind) include resource costs for extending new transmission lines to those regions to directly interconnect resources to the CAISO system. Those candidate resources provide RA to CAISO, do not count against the 11,041 MW simultaenous hourly import constraint, and are not represented by the 4,000 MW PRM from imports.

Q: Can you confirm my understanding that the model will only count 4000 MW of imports towards the reliability margin but will allow an additional ~4400 imports based on the simultaneous import constraint numbers just shown?

A: Yes. On an hourly basis, up to 11,041 MW can be imported from other zones (including the specified remote generators highlighted on Slide 91). All imports to CAISO, in aggregate, will only contribute 4,000 MW towards the reliability margin.

Q: Re Wy wind treatment in RESOLVE, with TWE being a CAISO PTO project, is TWE-interconnected WY wind going to be treated as being in-CAISO - for example as opposed to other WY wind which is off CAISO?

A: So Wyoming wind assumptions include resource costs and estimated new transmission costs (or wheeling cost for other OOS winds) to get to the CAISO border. All candidate OOS, out-of-CAISO resources that could get selected we treat as requiring in-CAISO transmission headroom from the intertie point reflecting a MIC expanding requirement). This means that the modeling treats Wyoming wind PTO/transmission line agnostic.

Q: Have you updated BTM solar and storage projections per the CPUC's NEM reform decision? Is that in the materials somewhere?

A: BTM solar and storage (non-optimized resources) in the I&A come from IEPR. The IEPR hasn't incorporated the NEM in the 2022 vintage.

Q: Following up on Shannon's question, why does transmission built not start until 2037?

A: These are the generic transmission upgrades only that can't come online until 2037. CAISO identified constraint upgrades are allowed to be selected based on their estimated construction time online year. Generic tx upgrades are not allowed earlier because they are zeroth-order approximations of transmission costs and capacity, so we want to limit their selection in the near term where CAISO identified upgrades have more confidence and certainty in costs and capacity.

Q: Are lifecycle emissions consider in the GHG values? Is the additional power to operate CCS and the power to produce hydrogen included in the GHG values?

A: We do not consider full lifecycle emissions of resources in our zero-emissions resources. We would welcome any additional information stakeholders have on how CCS reduces plant efficiency. Power to produce hydrogen will be included in GHG accounting to the extent that emitting resources are used to power the electrolysis

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Q: When do you expect more information on programmatic approach will occur?

A: IRP staff are expecting Q3 this year

Q: Re TWE wind, are you assuming that TWE-interconnected wind will require MIC? And am I tracking your agnostic point in that you assume the wheeling costs and transmission rates will be essentially equal? And, what about the treatment of the max import constraint? Will it apply to TWE-interconnected wind?

A: MIC, as I understand it, is essentially reserved in-CAISO transmission capacity for the resources to ensure deliverability. We don't explicitly have MIC in RESOLVE but we treat the out-of-CAISO selected resources as requiring in-CAISO transmission capacity to ensure deliverability. This can be roughly translated as requiring MIC. Thus whether TWE is in the CAISO or not RESOLVE modeling will require the resources to have in-CAISO transmission capacity

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Q: Will the local capacity module be able to be integrated into the PSP development process?

A: We are seeking to do so, but development of that tool is occurring on a separate track. Hopefully more from us in Q3 on that.

Q: Ok. To summarize re TWE...No changes in RESOLVE are planned as a result of TWE becoming a PTO, in-CAISO, transmission line. Correct?

A: Correct

Q: If RESOLVE uses PCAP PRM and at the same time, residential solar and BTM storage are modeled as load modifiers rather than as supply (please correct if I am misinterpreting this change), is there an issue with applying the PRM on gross peak rather than managed?

A: While BTM PV is a "non-optimized" resource as presented, we do need RESOLVE to account for its reliability contribution in a consistent way as all other resource types - i.e., using its ELCC.

Q: Have you considered reporting reliability definition that tracks the RA 24 hour approach? This would keep the IRP from drifting away from the RA definitions and provide a stronger depiction of the actual hourly needs, I would think.

A: ELCC studies consider the reliability contribution of resources across all hours. No, we haven't considered adding Slice of Day reporting in RESOLVE at this stage - I imagine once the compliance rules have matured we would also need to think through the feasibility and merits of adapting what is an LSE by LSE compliance requirement to system level modeling.

Q: By conducting reliability modeling to a 0.1 LOLE in days/year, is that synonymous with modeling to an LOLE of 2.4 hrs/yr?

A: No, 0.1 days per year LOLE is equal to 1 day of load shed in 10 years. The corresponding LOLH (hrs/yr) will depend on average duration of load shed simulated in the model. 2.4hrs/yr would imply that the average duration of the load shed event is 24 hours. The actual LOLH when tuning to 0.1LOLE will be lower than 2.4hrs/year.

Q: Why is ID wind absent in reliability modeling? Specifically, why isn't Idaho wind included on slides 118 or 127 along with WY and NM wind?

A: Based on trade off between data availability, modeling priorities, and materiality for MTR procurement. Something we're monitoring for future. On the table we showed in the MTR section, ID wind is included within WY wind, so it is accounted for.

Q: What is the trajectory of projected gas retirements included in these ELCC studies?

A: For the purpose of modeling the entire solar/storage surface, thermal resources were retired based on in service date with the oldest units being retired first and replaced with perfect capacity resources to maintain the system at 0.1LOLE. Then the different combinations of solar/storage penetrations were added which reduces LOLE below 0.1. PCAP is then removed to calibrate the system back to 0.1LOLE and the amount of PCAP removal is equivalent to the ELCC value.

Q: Is there any modeled interactivity between solar, storage, and DR? Noting 7GW CEC load shift goal by 2030, is that reflected in the current load forecast?

A: Slide 131 addresses how we propose to model shed DR on the solar + storage surface. The very recent CEC load shift goal was not included in the ELCC analysis presented here. Please provide this in your comments as we seek updates/improvements.

Q: would it be fair to say that ELCC of storage is mainly impacted by additional capacity available on the grid to allow it to charge fully, not particularly with Solar, however the I&A simply paired solar with storage for policy reasons?

A: Our studies have found storage ELCC is most sensitive to penetration of storage and solar.

Q: do the revised technology costs also include any additional TX delivery costs to the CA border? in prior Resource Cost and Build excel workbooks this additional cost ($/kw-yr) was added to the total cost calculation. however, this charge doesn't appear to be included in the latest workbooks posted yesterday evening. thank you

A: Our apologies as this table including the out-of-state transmission upgrade and deliverability costs was excluded from the Resource Cost and Build workbook. We will post an updated v2 of this workbook with those costs included in the Supply Curve. *(note – v2 is now posted)*

Q: Re 4-hour vs 8-hour battery representation in RESOLVE, does RESOLVE select storage between 4-hour or 8-hour? Or does RESOLVE rather select some generic 1-hour storage battery and essentially stack them to get the optimal duration of battery?

A: New in this IRP cycle, we are explicitly modeling fixed-duration 4-hr and 8-hr Li-ion batteries as separate candidate resources. The motivation for this change is to more accurately model the ELCCs of candidate storage resources on the ELCC surface. By selecting a portfolio of 4-hr and 8-hr Li-ion batteries, RESOLVE can still achieve a net portfolio Li-ion storage duration of anywhere between 4 and 8 hr.

Q: Are you still planning to examine the air quality (AQ) impacts of different portfolios? Have there been any updates? I don't see any information about the AQ inputs and assumptions in the presentation.

A: Yes. That will be provided as part of PSP/TPP analysis, and we use the inputs/assumptions that are already developed. Please provide this point in your comments if you suggest any updates to those.

Q: Is there a secondary cost impact of needing to build additional transmission to accommodate large solar buildout to be able to charge the storage, if not co-located at the same site, rather than using other technologies, eg wind or geothermal, charge the same amount of storage?

A: So utility scale solar, wind, and geothermal are all modeled as requiring transmission capacity and the cost of any transmission expansion needed to accommodate solar buildout would be captured by those functionalities in RESOLVE.

Q: It is good to see the shift from NQC to ELCC for thermal resources. Could you elaborate on the inputs assumptions used for thermal resource correlated outages and ambient derates?

A: For thermal resources we model maintenance and forced outages and those contribute to the ELCC calculation. We are exploring ambient derating of thermal resources (from high temps) and plan to study sensitivities with ambient derate included as part of 2023 PSP modeling.

Q: Are the non-optimized BTM PV and Storage and LDES then modeled on the solar/storage ELCC surface?

A: The non-optimized BTM PV and utility-scale storage are modeled on the solar/storage ELCC surface, as are LDES resources. The exception is BTM storage, which is not explicitly given an ELCC in RESOLVE, but is modeled as a load modifier.

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Q: Do you consider methane leakage from the upstream natural gas system associated with the CCGT with CCS (99%)?

A: We do not consider this.

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Q: are there different ELCC values for different years/load profiles? asking b/c I believe we're expecting LOLE events to shift from summer to winter over the next couple decades, which could presumably impact ELCC values.

A: RESOLVE's solar+storage ELCC surface, and the various wind curves, are a function of resource penetrations rather than year/load profile. However the SERVM ELCC studies that informed these do take into account load profiles as they are projected to change in the IEPR. For RESOLVE in this round of IRP ELCCs reflect a 2030 load year. It will be important to conduct ELCC studies periodically as load profiles change and as we see more winter LOL events.

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Q: Adding 1,213 MW of non-CAISO CCGT and 209 MW of non-CAISO geothermal brings the total of firm non-CAISO MWs to 2,812 MW. That leaves 1,188 MW for other imports to count against the 4,000 MW PRM contribution limit. Do non-firm, non-CAISO resources not count, and if so, for what reason? If not, can you share the amounts of non-firm NQC by non-firm resource type? Is there a data source for the assumption that unspecified RA imports fall to no more than 1,188 MW and remain there indefinitely?

A: The 4,000 MW PRM contribution value from imports was determined from historical observations of the amount of imports that can actually be delivered to CAISO during system peak hours. It's not a question of which resources "contribute" to the 4,000 MW value, but rather an observation from historical data that this is the amount that can be sourced from imports when the system needs to.

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Q: Slides 131 - 141: can you please provide more detail on the rationale for why you are using the 2022 IEPR forecast rather than the ATE forecast since that's what was used for the most recent TPP? Sorry if I missed it.

A: IRP uses the latest available IEPR. ATE was from 2021 IEPR. The 2022 IEPR is now available.

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Q: How are you discounting the queue for delays in order to gain a more realistic sense of resources?

A: We do not use the CAISO IC queue to determine resource baseline. In-development generators in the Resource Baseline come from the November 2022 LSE filings. We currently do not discount those planned capacity additions, either.

Q: Can you provide more detail on how interconnection requests serve to meet the commercial interest criteria?

A: So that is accounted for in the busbar mapping process for TPP portfolios. The details of the last busbar mapping effort for the 23-24 TPP can be found at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

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Q: Are outages modeled randomly or as a function of temperature / other inputs?

A: Forced outages are random subject to a "time to fail" distribution assigned to a given unit. Lengths of outages are random subject to a "time to repair" distribution assigned to a given unit. The distributions are developed from GADS data and thus are based on historical performance by class.