Integrated Resource Planning (R.20-05-003)

Preferred System Plan Workshop

Questions & Answers

This document covers the questions and answers during the Integrated Resources Planning (IRP) workshop on the Ruling proposing a Preferred System Plan. This workshop was held on September 1, 2021. The purpose of the workshop was to help stakeholders understand the analysis and proposed Commission actions that were made available by the Administrative Law Judge's (ALJ) Ruling dated August 17, 2021.

1. **Regarding bus bar mapping, can someone please comment on process? Is mapping happening now? Or will the CPUC wait until a decision is issued on the ruling's portfolios, and if so when the mapping will likely happen? Any estimated timelines for mapping, stakeholder engagement on mapping, and results would be appreciated.**
   Staff made a number of improvements to RESOLVE as well as to the methodology to address party comments we weren't able to fully address last cycle. We hope that these improvements will reduce the need for revisions to the methodology at this stage. However, we encourage parties to submit comments if they have any concerns with the proposed methodology or have suggestions for how to improve it. Staff is beginning busbar mapping now and we will do our best to incorporate any suggested improvements prior to the finalization of the busbar mapping for the Proposed Decision.

2. **Are any changes to the 2021-22 TPP expected based on the midterm procurement order?**
   Answered verbally: We recommend tracking CAISO's TPP process to see if any changes are made.

3. **Slide #72: Why wouldn't the Reliability and Policy-Driven Base Case Portfolios submitted for the 2022-2023 TPP take into consideration the transmission scope and cost information for In-CAISO transmission, OOS Wind and Offshore wind developed as part of the 2021-2022 TPP (which is expected to be available by November 2021)? The currently proposed portfolios including the 38MMT Core portfolios likely lack that information. Afterall, the 2022-2023 TPP portfolios need to be transferred to the CAISO by Feb-22.**
   Answered verbally: Disconnect in when final 21-22 TPP results will be available (February 2022) and the work required to transmit the portfolios to CAISO by the deadline for the 2022-2023 TPP. In order for the CPUC to map a portfolio(s) with the working group, write a report, and take the results through the procedural process including a proposed decision followed by comments and a final Decision, staff need to begin the mapping work now.

4. **Is there any cushion built-in to allow for the impact of CAISO's open access tariff? Depending on the interconnection queue, it's possible a different set of resources gets deliverability first and capacity is not left for the PSP's desired resources (example: solar taking-up capacity that was planned for geothermal). How is this risk incorporated into the PSP and TPP?**
   If you have any suggestions on how to handle this issue, please submit in comments. Staff have partially attempted to address this risk by using the interconnection queue and particular projects with executed interconnect agreements as a criterion in deciding where to map resources, but it definitely doesn't fully address the risk

particularly for resources like geothermal that doesn't have an established queue presence. CAISO staff collaborate with us on the busbar mapping process so we would definitely welcome any suggestions on this risk in comments

5. **Will you be announcing opportunities for input as proposed in the Ruling? Will there be an opportunity to observe busbar mapping results before they are published?**
Parties can comment by the deadlines stated in the Ruling. This includes commenting on the methodology. The busbar mapped base case portfolio will be released in conjunction with a report and attached to the Proposed Decision. Parties will have the opportunity to observe the results of busbar mapping at that time and will have the opportunity to comment.

7. the IRP team distinguishing between OOS wind and OOS wind w/ new transmission? In your presentation you said that some LSEs included NM wind on existing transmission in their plans but none requiring new transmission (and the ALJ ruling states the same) but in reality all NM wind is being delivered on both existing and new transmission.

One of the resources that was modeled in the 2019-2020 RSP and was included in the LSE plans is tagged SW_Ext_Tx_Wind. It represents wind resources in the New Mexico area that are using existing transmission connections to the CAISO border and do not require a new transmission line. This resource has a 500 MW capacity limit. This resource is different from the New_Mexico_Wind resource which is considered to require a new transmission line to connect to the CAISO border and has the additional cost of this new transmission line embedded in the resource cost. There is a similar treatment for resources from the Northwest and Wyoming. There is a NW_Ext_Tx_Wind resource (1,500 MW capacity limit) which represents wind resources in the Washington area that are using existing transmission connections to the CAISO border, and there is a Wyoming_Wind resource which represents wind from Wyoming requiring a new transmission line to connect to the CAISO border

Although the LSE plans did not include any wind requiring new transmission, due to the updated CAISO transmission limits constraining the build out of wind resources on existing transmission, the CPUC made OOS wind on new resources eligible for selection to meet the LSE plans.

8. **Have you considered hybridizing CT fleet with 1 hour storage to reduce the emissions of the CTs to help achieve the 38MMT portfolio instead of adding other types of resources to achieve the same emissions goals.**
We have not explicitly considered gas hybrids with 1 hour storage in our modeling to date. We welcome recommendations on inputs and assumptions that may also us to better consider how these resources might contribute to GHG reduction goals.

9. Why not include biogas as well as renewable hydrogen in any requirement for renewable/low carbon gas?

There are competing uses for the limited supply of in state biogas (including transportation fuels under CARB's LCSF standard program, and industrial processes) that need to be further evaluated, whereas renewable hydrogen produced from solar or wind is not so limited. Transitioning to renewable hydrogen in fuel cells would have further benefits by eliminating local air pollutant emissions. We will consider party comments on this issue.

10. Is there information on when infrastructure would be available to transport hydrogen for thermal resources to use to meet the recommendations of utilizing hydrogen within X years?

Large volumes of hydrogen are currently used in industry and delivered in tanker trucks and dedicated pipelines. Onsite storage uses large above ground cylinders. Huge volumes may be stored in underground pipelines that ideally would connect a powerplant to a nearby hydrogen production facility. Creating demand for renewable hydrogen is the first step in facilitating development of the production and delivery infrastructure, but it is hard to say how long it will take. We invite parties to provide what insight they have on infrastructure needs and development timelines for use of hydrogen.

11. Can you clarify the 50% H2 number given that current gas pipelines cannot accommodate a blend that high?

The proposal is 50% of facilities procured would immediately utilize 30% green/ renewable hydrogen. 60% green/renewable hydrogen would be required by 2031 and 100% by 2036. We welcome your feedback on this proposal.

12. It would be helpful for Staff to outline how the hydrogen target %s were derived.

To achieve the desired magnitude of carbon-free electricity on the grid, we need to transition gas plants to 100% renewable H2, rather than continuing to use a lower percentage blend. This is because the volumetric energy density of natural gas compared to hydrogen is roughly 3:1. As a result, using H2 does not offset an equal amount of natural gas; rather, an increased volume of natural gas is required when using an H2 blend to produce the same kwh of electricity. Accordingly, the carbon reduction benefit from using blended hydrogen is significantly lower than the percentage of hydrogen in the blended fuel. For example, using a 50 percent hydrogen blend reduces GHG emissions per kWh by about 20 percent and a 75 percent blend reduces GHG emissions by about 50 percent. See a General Electric Technical White Paper, "Hydrogen as a fuel for gas turbines" available at: www.ge.com/power/future-of-energy/, page 5, Figure 3: "Relationship between CO2 emissions and hydrogen/methane fuel blends (volume %)."

13. **How did you/ RESOLVE separate out the shadow costs for capacity and GHG for resources that provide both value streams? Also, are shadow prices in your graph in nominal $?**
    Shadow prices for individual constraints are standard outputs of linear programs (the type of optimization RESOLVE relies on). Conceptually, the model is calculating the cost of meeting an infinitesimal increase in the requirement (the greenhouse gas or planning reserve margin requirement), while also accounting for all of the other constraints and costs in the model. GHG and PRM requirements are enforced each year, so the shadow price reflects the cost to increase the requirement in a specific year. The cost to do takes into account the net cost of meeting the requirement. If a resource such as storage is added to meet the requirement, the optimization is evaluating all of the benefits that that resource brings to the system in both the current and future years, and nets those benefits off of the costs. Costs are in real $2020, not nominal $.

14. **How was the 15 MMT target for 2045 established? This seems inconsistent with direction of AB32 and Executive orders, as well as the science, that would require we achieve zero emissions on the 2040-45 time frame.**
    The 2045 target is the same used in the 2019 RSP RESOLVE modeling. It comes from the CEC 2018 Deep Decarbonization Pathways analysis based on an 80% economywide reduction by 2050. This level of 2045 emissions is generally consistent with the "High Carbon Dioxide Removal" scenario from E3's Carbon Neutrality report for CARB.

15. **What does "shadow price" mean on the GHG costs chart?**
    Shadow prices for individual constraints are standard outputs of linear programs (the type of optimization RESOLVE relies on). Conceptually, the model is calculating the cost of meeting an infinitesimal increase in the requirement (the greenhouse gas or planning reserve margin requirement), while also accounting for all of the other constraints and costs in the model.

16. **Are the selected new OOS wind resources subject to the "MTR persistence" 4,000MW import constraint during the tightest hours?**
    The new OOS wind resources are not subject to the 4,000 MW import constraint, because that constraint only limits the amount of unspecified resources that can be counted towards meeting the RA requirement. The OOS wind resources are considered to be specified imports.

17. **Why is the incremental cost of the 30 MMT Core sensitivity only nominally more than the 38 MMT Core despite fairly large increases in capacity?**

First, the costs across all scenarios are similar because most of these costs are associated with maintaining the existing electric system (distribution, transmission, generation, and other costs) that do no change between RESOLVE scenarios. Approximately ~80% of the total resource cost falls into this category. In other words, most of the total current and projected costs of operating the electricity system would occur absent state policy initiatives and are unrelated to the choice of the 2030 GHG target. Second, many new investments that will be needed to ensure reliability even without any RPS or GHG targets, including those needed to reach the 22.5% and the pumped storage and geothermal added for MTR. Third, the 2030 GHG target primarily impacts resource needs in 2030 and the years close to it; the near-term (before the GHG target binds) resource needs and the very long-term (by 2045, when all cases use the same GHG target) are the same. Across GHG targets, there are factors exerting both upward and downward cost pressures. The investments needed for the higher resource buildouts stemming from lower GHG targets put upward pressure on the TRC. But the associated operating (fuel) savings that result from a lower GHG target (reduction of 17,000 GWh of gas generation from 46 to 30 MMT target) puts downward pressure on costs and helps moderate ratepayer impact. Finally, resource prices (e.g. solar, storage, offshore wind) also changing over time, which impacts the costs associated with front-loading vs. delaying a portion of the very large 2045 system needs.

18. **can you tell us where we can see more info on how the non-jurisdictional LSE plans were folded into the portfolios and can you confirm if, and how, COOPs' info was included given that they don't file plans with CPUC or CEC?**
    Answered verbally

19. **In determining GHG emissions and reductions for each portfolio, is the CPUC considering the lifecycle emissions of each resource type or just avoided emissions from fossil fuels?**

    Answered verbally

20. **As mentioned in the ALJ Ruling, LSE plans included New Mexico and Pacific Northwest wind resources on existing transmission, but no OOS resources requiring new transmission. (p.48). Given this, why are you forcing OOS wind resources requiring new transmission in the scenarios, such as 38MMT Core and 46MMT Core, which are based on the LSE plans? In other words, why are you relying on RESOLVE to add resources that the LSE IRPs have determined to be uneconomical?**
    Answered verbally

21. **You stated that RESOLVE found it economical to select OOS wind (WY) resources more economical than In-State wind resources. While doing so, did RESOLVE**

consider the internal CAISO transmission upgrades/costs OOS wind may trigger when it is delivered at the Eldorado substation?
Answered verbally

22. **Could you explain why GHG emissions don't decrease very much over the course of the next decade, despite huge amounts of resource additions? is it just because of load growth and Diablo Canyon's retirement? any other factors?**
    Answered verbally

23. **Would you please provide some insights into why the 38 MMT No MTR Persistence scenario results in some gas capacity not being retained?**
    Answered verbally

24. **The trajectory of procurement of new resources is different in the PSP Scenario from the Procurement Scenario as modeled by the CEC for their Midterm Reliability Assessment. Which scenario more accurately reflects LSE plans?**
    Answered verbally

25. **The PSP assumes incremental NQC of 2753 MW in 2022. Does the Commission staff believe this amount of new resources for 2022 to be realistic?**
    Answered verbally

26. **Slide 27 shows 38MMT Core requires very little upgrades to transmission through 2032. Can you explain when the CPUC plans to build the needed transmission into Location Constrained urban load centers to eventually retire the gas generation those urban area?**
    Answered verbally

27. **Why is there still nuclear generation in 2030 on slide 44?**
    The Palo Verde nuclear plant stays online through out the modeling period.

28. **Why do you believe that LSEs will have difficulty procuring from existing renewables?**

    Answered verbally

29. **How does the modeling determine whether to retain natural gas? It appears it is limited to fixed costs. Are other costs related to retaining natural gas beside the fixed costs considered such as variable O&M, increased energy costs related to market power, the costs associated with increased air emissions and GHGs, etc.?**
    RESOLVE considers both operating (variable O&M, fuel costs) and fixed O&M costs of natural gas versus the system value of those resources as the GHG target declines.

RESOLVE is a cost-based model so market power is not modeled. GHG emissions cost is captured by the declining GHG target. System capacity needs and declining battery ELCC generally drive gas retention even as the gas is operated less frequently.

30. **Slide 29 shows the increase to typical residential electric bill in 2032 with 38 MMT core, and the 30 MMT Core portfolios. Bills would be less than 1% higher for the 30 MMT core. Since cost to customers is almost identical, why do you recommend 38 MMT?**

    the March 2020 RSP asked LSEs to submit 46 MMT and 38 MMT plans. You're right that RESOLVE showed modest cost differences between a 38 and 30 MMT target. But it's also important to recognize that we don't have LSE plans for 30 MMT and the portfolio has not been subject to reliability modeling in SERVM. IRP staff views the build-out in the in the 38 MMT core as ambitious and challenging to achieve in the timeframe. We welcome comments from parties on alternative portfolios that should be considered

31. **It seems the CEC Mid-Term Reliability Anlysis presented on Monday assumes that the proposed PSP is not inclusive of the procurement already directed in D.19-11-016 and D.21-06-035. However, the proposed PSP ruling explicitly notes that the 38 MMT Core scenario includes resources associated with D.21-06-035. Could you clarify this situation?**

    We can confirm that the 38 MMT Core includes resources sufficient to meet both IRP procurement orders. This is true in the CPUC and CEC analyses of the proposed PSP.

32. **Did you evaluate the cost and capacity impact of increasing the PRM to 22.5% for the PSP?**

    The ruling does not propose adopting a new PRM as part of forming the PSP. By assuming the MTR order is fully met, the proposed PSP uses the 22.5% PRM from 2024 through 2026 but does not propose adopting it on an ongoing basis. The slide deck does not include a cost anlaysis specific to the MTR order.

33. **Did the resources in LSEs' plans count toward the procurement required in the MTR decision, or were the MTR resources considered entirely additional to the LSEs' plans?**

    Yes LSEs' resources count towards the MTR. RESOLVE added only what was necessary to meet the reliability requirements etc.

34. **The LOLE analysis performed by the CPUC and CEC show that the PSP leads to LOLEs far below the 0.1 target. Track 3B.1/4 of the RA proceeding stated that further LOLE analysis is needed before considering changes to the current 15% PRM. Instead of having a PSP with a 22.5% PRM, would staff consider further analysis that optimizes**

the PRM to reduce cost while still meeting reliability and GHG goals, where the 11.5 GW of MTR procurement is maintained but not necessarily incremental to LSE IRP plans?

LSEs' planned resources count towards the MTR requirements. RESOLVE only adds additional necessary to meet the MTR order. Pls restate your question if that still leaves queries in your mind.

35. **Regardless of if the LSE planned resources "count" or not for MTR, it appears the 11.5 GW was added to the IRP baseline just to meet the 22.5% PRM. My question really boils down to the fact that a 22.5% PRM appears to overprocure--would staff model a lower PRM that still meets reliability and GHG requirements and that could also inform the RA Track 3B.1/4 proceeding? If the PSP requires that LSEs procure all resources in the plan, it will de facto raise the RA requirements.**

    We took the principle that we should assume full compliance with the MTR order in forming the PSP. It is a matter for later stakeholder and analytical process in IRP and RA proceedings to conduct reliability modeling to assess the PRM (as stated in the MTR decision CoLs and dicta).

36. **Has a scenario in RESOLVE been run with no transmission constraints to understand what the fleet would look like in comparison to the 38 MMT Core? My concern is that some of the upgrade options are fairly limited (example: 57 MW option for Humboldt wind) and I am curious if the resource mix would be much different if there were a broader set of transmission options.**

    We have not yet run a scenario that does not utilize the available transmission upgrade limits provided by the CAISO in the new whitepaper. We were limited in the number of scenarios that could be analyzed for this PSP and this was not considered. Additionally, the 20-year transmission study that the CAISO is beginning to conduct, which is taking a more expansive and wholistic look at what transmission is needed, will hopefully help address areas where there are very limited existing possible transmission upgrades.

37. **How is future deployment of BTM PV being forecasted? Is BTM PV (+storage) being considered candidate resources and selected based on cost? How are the rate impacts of NEM tariffs being evaluated?**

    BTM PV and storage are incorporated based on the latest CEC IEPR forecast. Distributed solar and storage are considered as candidate resources but not selected incrementally on top of the IEPR amounts included. RESOLVE's average CAISO residential rate in the Results Viewer includes NEM impacts on the residential rate class via declining sales, but not on differences between customers within the residential rate class.

38. **Is there a 30 MMT with "medium" Electrification Sensitivity Portfolio available? Would that be the "30 MMT Core" portfolio? If not, is there a separate portfolio that captures the medium level of electrification?**
    we ran a 30 MMT with the 2019 IEPR mid-mid forecast and the high electrification forecast that Karolina described. There is some amount of electrification in the 2019 IEPR mid-mid forecast, such as ~4 million ZEVs. But we do not have a load level between those two forecasts for the 30 MMT. I imagine the resource build-out amounts would be somewhere between those two portfolios.

39. **If the GLW constraint implicates the geothermal/LLT resources that are due under the MTR for 2026 with extension to 2028, does the base case portfolio's assumption that the LLT resources are online in 2028 comprise a signal that MTR LLT-related transmission upgrades may not be in place for 2026? Is this assumption consistent with the principle (see Q&A) that LSEs are fully compliant with MTR, i.e., LLT online in 2026?**
    The 2028 online year assumption for the LLTs simply assumes LSEs will seek the extension afforded by the MTR decision if they meet various conditions. It is not based on the specific risk you call out. Your further thinking on that in comments would be welcome.

40. **What portion of the selected storage in the 38 MT Core portfolio is assumed to be paired with solar by co-locating the solar and storage?**
    RESOLVE modeling with the new transmission constraints suggest that siting of solar and storage in similar parts of the grid may be useful for maximizing utilization of the transmission system. However, the final level of co-location with more granular siting will be developed during the busbar mapping process. RESOLVE does not currently explicitly model co-located solar and storage (such as specific co-locating cost reduction benefits and operational limitations).

41. **From Slide 85: "D.21-06-035 requires 2,000 MW NQC by August 1, 2023. Should a higher amount (e.g., 4,000 MW NQC) be required?" Questions: The CEC found a LOLE for 2023 for the PSP scenario of less than 0.01, correct? Then why do we need any additional procurement for 2023?**
    Addressed verbally

42. **Do we have a sense of when the modeling showing how different levels of the PRM translate into loss of load expectations?**
    Addressed verbally

43. **From Slide 86: Li-ion batteries are a commercial technology, whose performance can be covered under warranty. So, what performance uncertainty is the CPUC really discussing here? Is it continued fear of lack of energy available to charge the**

batteries? Is the CPUC claiming it has not adequately modeled the performance of Li-ion batteries in its system modeling, and if so, what is the plan to address this?
Both capacity expansion modeling and reliability modeling consider energy sufficiency for charging storage. As part of this are assumptions about how responsive storage will be to charge and discharge in the CAISO market. IRP modeling tends to assume high responsiveness, without the benefit of that being supported by real life evidence at the scale contemplated in the next few years. Comments very welcome on how to analyze summer 2021 CAISO storage fleet performance, to help inform this.

44. **From Slide 86: What leads the CPUC to know the thermal capacity is needed throughout the period versus being cost-effective throughout the period compared to alternatives that can provide the same reliability benefits? How does the CPUC know that replacing thermal resources with alternatives is impossible or unreasonably costly?**
RESOLVE's conclusions on thermal plant retention are based on the input assumptions used for thermal plant retention costs, declining storage ELCCs, growing electrification loads through 2045, the total reliability need of the system (peak load + PRM), and the alternative reliability resources currently considered. In addition to planned retirements, RESOLVE does include ~1 GW of unplanned thermal retirement by 2026 and the retirement of the CHP fleet between 2031 and 2045.

45. **What leads the CPUC to support green hydrogen without any RESOLVE modeling of green hydrogen?**
Addressed verbally

46. **What is the general timing for a Commission incremental procurement order? Would it only occur after the CEC reliability analysis and the adoption of the PSP?**
Addressed verbally

47. **Were the upgrades on slides 66-73 used to inform the PSP or only the 2022-23 TPP portfolios? Can you confirm if OOS wind on new tx is capped at 1,500 in or by 2030? I would expect to see more in the 30MMT scenarios.**
The OOS wind resource was capped at 1,500 MW for Wyoming Wind and New Mexico Wind only through 2030. Beyond 2030 the caps were removed. The updates were used to inform the 2021 PSP analysis. Like is mentioned in slide 72, the PSP portfolio is being proposed as the base case portfolio for the 2022-2023 TPP

48. **How was the cost of new transmission needed to support OOS wind in RESOLVE estimated if the CPUC has not identified any specific transmission projects needed to support out of state wind development? Was there a proxy project cost used?**

The cost of new transmission lines are based on assumptions developed for the CEC's Renewable Energy Transmission Initiative 2.0 (RETI 2.0) analysis. The RESOLVE Inputs and Assumptions documentation for the 2019-2020 RSP contains more details.

49. When you refer to "GHG Reduction-driven Procurement" are you talking specifically about Energy Only projects or is this a more general concept?

We aren't referring narrowly to EO projects. You could think of it much more generally, such as procurement for GHG-free energy. One way of thinking about it could be similar to how LSEs currently procure for RPS requirements. We are hoping to leverage party thinking on what such a regime could look like within IRP.

50. Is Energy Division open to exploring cost sensitivities such as higher storage costs given worldwide supply chain concerns with batteries?

we ran a senstivity that included high solar and battery costs. It was called 38 MMT High Solar + Storage Costs. You can read more about it in the ruling and Attachment A of the ruling.

51. Regarding the new transmission constraint model, can someone please comment on two parts: (1) are the RESOLVE multipliers for the impacts on constraints of resources based on RA deliverability counting, ELCCs etc? Or are they based on transmission topology shift factors? or both? Can you please explain? (2) the charts released in Appendix C of the ruling – those showing mapping of resources to constraints – often show no constraint impact from solar resources. Can someone please explain why?

(1) the RESOLVE multipliers for the impacts on constraints by resources are based on the output factors estimates the CAISO provide in their July 2021 updated Transmission capability white paper. The ISO provide percentages of nameplate MWs for each resource type output factors used for both FCDS and EODS tx capability estimates. (2) to limit the number of resources RESOLVE had to model solar and battery resources were modeled in larger areas which are then mapped to more precise locations via busbar mapping. Thus for both Solar and battery resources they are generally included in only the most geographically expansive constraints or the constraints that apply specifically to the larger solar area. In the busbar mapping process, all the constraints will be applied as the solar and battery resources are mapped to substations.

52. Are there plans to incorporate land use considerations and limitations in the busbar mapping process in coordination with the work the CEC is doing?

Yes, this is described in more detail in the busbar mapping methodology document released with the ruling, but in short, CEC staff are conducting land-use and environmental assessment as part of the busbar mapping work

53. 1) Please direct me to a resource on the RESOLVE model's transmission cost assumptions and estimates or can you explain the RESOLVE transmission cost estimates. 2) Please confirm whether or not the RESOLVE model's out-of-state wind transmission analysis considered transmission costs from Wyoming wind farms to California load centers.

1) The CAISO transmission white paper: http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf provides the details of the in CAISO transmission upgrades. 2) The CPUC's 2019 RSP Inputs and Assumptions document provides info on the OOS transmission costs assumed by RESOLVE

54. Can you clarify on slide 73 what is meant by "partial upgrade selected"? You stated verbally that full upgrades would need to be built in order to achieve the space shown by the dotted brown lines, but the model only selected a partial upgrade?

One of the limitations with the RESOLVE model is that it currently cannot optimize building the fix transmission amount of the project. It's limited to assessing partial buildouts of Tx upgrades proportional to the amount of resources it selects needing the upgrade. That is why we assess during the busbar mapping process if these Tx upgrades are actual optimal and cost-effective for meeting reliability and policy goals. In busbar mapping we may relocate resources to not trigger the upgrade .

55. Is re-allocating projects to avoid Tx upgrades a Tx avoidance strategy?Why do you know that such re-allocations are reasonable?

As part of the busbar mapping process, which we do in coordination with the CEC and CAISO, we look to assess if the transmisison upgrade triggered by RESOLVE is actually necessary or optimal. RESOLVE has limitations and one is that it cannot build Tx upgrades as concrete blocks. The CPUC, CEC, and CAISO staff busbar mapping group is able assess if the upgrade is actually needed and helps meet reliability and policy goals.

56. What info on OOS transmission solutions expected with current TPP?Select a panelist in the Ask menu first and then type your question here. There's a 512-character limits?

For the best summary I recommend looking at the CAISO's most recent update on the study. I'm sharing the link to their presentation from their July 27 stakeholder call. The OOS wind study update begins on slide 66.
http://www.caiso.com/Documents/Presentation-2021-2022TransmissionPlanningProcess-Jul27-2021.pdf

57. Can staff estimate the year in which the GHG constraint in RESOLVE becomes binding, over the RPS constraint? And what is the magnitude in 2030 of selected "additional" RPS nameplate capacity needed over the minimum RPS compliance level, exclusive of LSE plan amounts? Alternative phrasing: Rulling Attachment A shows a small solar build needed in 2030 on top of LSE plans for GHG reductions, but how much of the LSE plan aggregation represents RPS build above LSEs' minimum RPS compliance builds?

See slide 25 from this workshop. When the shadow price is >0, the constraint is binding. The 38mmt core case shows this happening starting in 2030. Per the RESOLVE Results Viewer, the 2030 RPS level reaches 69% RPS (or 9% above the SB100 minimum). The RPS minimum is exceeded in every year modeled for the 38mmt core case.

58. The CEC's mid term analysis shows 0.012 LOLE, whereas the CPUC's analysis shows 0.064. Would you be able to share why there is such a difference between the two analysis that seems to use the same level of resource build out?

The CPUC's analysis uses SERVM to perform (probabilistic) PCM to check the portfolio's reliability and GHG emissions. The CEC's analysis uses PLEXOS to conduct some probabilistic analysis on load, solar, and wind variability, and forced outage risk, using only resources included in the MTR Need Determination with several sets of resource additions, to check the reliability of various portfolios. The CPUC and CEC analyses share common inputs where applicable and practical.

59. The CEC's mid term analysis shows 0.012 LOLE, whereas the CPUC's analysis shows 0.064. Would you be able to share why there is such a difference between the two analysis that seems to use the same level of resource build out?

We have two different models and methodologies involved and we are continuing to analysis deltas where we can.

60. Is there a plan to compare the EUE metrics in the modeling done with SERVM by the PUC and with Plexos by the CEC?

We are continuing to compare the results. Pls see a similar question and response about how the LOLE results compare.

61. Does the PSP model include the social costs of carbon?

The RESOLVE cases shown here do not include a social cost of carbon input

62. Enforcing the 2026 procurement could also result in significantly higher cost since allowing two extra years could widen the pool of available LLT projects to be developed. Has the CPUC conducted any analysis comparing these claimed benefits against the increased costs?

The capacity expansion modeling scenarios in the deck do not explore that. We will touch on the topics like this that the ruling seeks comments on in the reliability procurement portion of the workshop soon.