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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	Rulemaking 20-05-003

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN

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Pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan* ("Ruling"), Southern California Edison Company ("SCE") respectfully submits these comments to the California Public Utilities Commission ("Commission").

I.

INTRODUCTION

SCE appreciates the opportunity to comment on the proposed Preferred System Plan ("PSP"), the scenarios developed by Commission staff, and the questions in the Ruling.
SCE strongly supports the Ruling's recommendation to use a 38 million metric ton ("MMT") greenhouse gas ("GHG") target for the PSP. SCE's key recommendations are:

- SCE's capacity expansion ("CE") and reliability modeling of the 38 MMT Core Portfolio resulted in a loss-of-load expectation ("LOLE") metric of 0 (zero), indicating ***the portfolio has no hours of unserved load under all simulated cases***. This demonstrates the 38 MMT Core Portfolio is over-resourced due to the choice to maintain a 22.5% planning reserve margin ("PRM") through 2030, without sufficient studies to support the long-term use of a 22.5% PRM, combined with some unexplained modeling choices and outcomes. To avoid adoption of an overbuilt PSP that will unnecessarily increase costs for customers, SCE recommends the

Commission remove at least 3,500 MW of energy storage from the 38 MMT Core Portfolio by 2030 and not require any reliability-based procurement in excess of the procurement requirements in the mid-term reliability ("MTR") decision, Decision ("D.") 21-06-035, at this time. This will still result in a PSP that is significantly more reliable than the industry standard 1-in-10 LOLE, with an LOLE metric of 0 (zero).

- Prior to implementing a 22.5% PRM as a planning standard in the Integrated Resource Planning ("IRP") process, the Commission should establish a separate track or dedicated process in the IRP proceeding to evaluate and determine the appropriate stochastic input parameters (e.g., load scenarios, renewable production scenarios, outage rates, etc.) and proper reliability metrics (e.g., 1-in-10, 1-in-20, 1-in-50 LOLE) used to determine an appropriate PRM reliability planning standard. This process should weigh the need for a more stringent PRM and reliability standard against the costs of building a more reliable and resilient supply mix.
- With some modifications addressed herein, SCE supports the use of the 38 MMT Core Portfolio with the 2020 Integrated Energy Policy Report ("IEPR") mid-demand load forecast as the PSP ("38 MMT Core Portfolio with 2020 IEPR"). It is imperative the state plan for a higher electrification future. In doing so, planning assumptions for electrification cases should be transparent so scenarios can be sufficiently evaluated before adoption. Here, the 2020 IEPR high electric vehicle ("EV") load forecast included in the 38 MMT Core scenario with 2020 IEPR assumptions occurred without notice and an opportunity for advance review. Ideally, the high EV load forecast would have been released for review and vetted by parties and staff would have released production cost modeling ("PCM") and reliability analyses on this scenario. Without such information, it is difficult to opine on the appropriateness of the 38 MMT Core with high EV load forecast scenario as the PSP.

- SCE's PCM shows the 38 MMT Core Portfolio has GHG emissions of close to 30 MMT by 2030 despite being designed to reach a 38 MMT target. It is unclear how some of staff's modeling results were achieved. This warrants a transparent reexamination of staff's RESOLVE and SERVM modeling. The Commission should not require any clean energy procurement in excess of the MTR procurement requirements but should give load-serving entities ("LSEs") the flexibility to commence clean energy procurement according to their IRPs.
- The Commission should initiate a stakeholder process to evaluate and establish a clean energy procurement framework using a more programmatic approach to allocate procurement requirements, set program guidelines, compliance rules, and enforcement mechanisms or penalties for non-compliance.
- SCE urges the Commission not to use the current effective load carrying capability ("ELCC") methodology in determining the contribution of variable resources. The ELCC methodology continues to overestimate the contribution of variable resource capacity during early evening peak demand. Additionally, SCE has concerns with the lack of any opportunity for stakeholder review of staff's ELCC calculations for energy storage for MTR procurement compliance.

II.

SCE'S RESPONSES TO RULING'S QUESTIONS FOR PARTIES

1. Please comment on the individual IRP portfolio aggregation performed by Commission staff.

SCE appreciates the importance and difficulty of the analysis work needed to aggregate individual LSE plans into a single California Independent System Operator ("CAISO") system portfolio. While the 38 MMT aggregated LSE portfolio was found to "fall short" on both reliability and GHG targets,[1] there may be valuable insight on why that occurred and an

[1] *See* Ruling at 2, 9-10.

opportunity to avoid that result in future IRP cycles by making changes to IRP filing requirements. Specifically, SCE recommends the Commission prioritize the development of more robust planning standards and requirements to guide the development of LSEs' IRP filings. For instance, insufficient guidance was provided to LSEs in the current IRP cycle on how much they can rely on system power and existing resources in their plans relative to identifying the need for new resources that each LSE should be expected to procure. It is therefore not unexpected that the aggregate LSE portfolios may not include sufficient new resources to meet reliability or GHG targets, as staff discovered in the aggregation process.

SCE suggests the Commission provide guidance to LSEs similar to SCE's approach in its 2020 IRP, which was to limit the selection of shared system resources, existing transmission, and import and export capability to its customer share of overall system load. This was done to allow SCE's bundled portfolios to use system resources without over-relying on the system.
The Commission should require this or a similar approach for all LSEs to ensure shared resources (e.g., CAISO system resources, major transmission lines, and import/export lines) are not excessively used by any one LSE. Additionally, SCE generally limited candidate generation resources to its bundled load share to prevent over-subscribing the technical potential of economic resources. Using this approach would help avoid potential difficulties in combining all LSEs' portfolios into the PSP. SCE urges the Commission to add these filing requirements to prevent the portfolio aggregation issues encountered in this IRP cycle from being repeated.

3. Comment on the appropriateness of the scenarios and sensitivities developed in RESOLVE to be considered as the preferred portfolio. Suggest any alternative sensitivities or changes to the analysis.

SCE supports the focus on the 38 MMT scenarios and agrees "a 38 MMT target was a reasonable goal to set in the PSP."[2] Moving beyond the 46 MMT GHG target to a 38 MMT target is timely and will establish a more reasonable path to achieve California's Senate Bill ("SB") 100 goal to supply 100% of electric retail sales with renewable and zero-carbon resources

[2] *Id.* at 11.

by 2045. SCE agrees that a 38 MMT portfolio should be adopted as the PSP and the IRP process should focus on a 38 MMT 2030 GHG target going forward.

4. Comment on the SERVM analysis and results of the 38 MMT Core Portfolio.

SCE conducted independent modeling analysis on the 38 MMT Core Portfolio using the ABB CE model and evaluated the operational feasibility with PLEXOS PCM and calculated the LOLE to evaluate the portfolio's reliability performance.[3] SCE's modeling results are included as Appendices A and B. As explained below, SCE's modeling found the 38 MMT Core Portfolio recommended as the PSP is significantly overbuilt in the later years, with between 3,500 MW and 5,500 MW more resources than are needed for reliability or GHG reduction. Indeed, the 38 MMT Core Portfolio has a LOLE metric of 0 (zero)**, *indicating the portfolio has no hours of unserved load under all simulated cases***. Although it is designed to achieve a 38 MMT GHG target, the 38 MMT Core Portfolio also results in GHG emissions of close to 30 MMT in 2030. These likely excessive resource additions come at a significant cost to customers – an increase in costs of at least $450 million per year in 2030.

Based on SCE's understanding of the 38 MMT Core Portfolio and analysis results, SCE recommends the additional post-MTR resource additions of between 3,500 and 5,500 MW of energy storage be removed from the 38 MMT Core Portfolio because such resources appear to be unnecessary for reliability or GHG reduction. This will still result in a PSP that is substantially more reliable than the industry standard 1-in-10 LOLE reliability metric, with an LOLE metric of between 0 (zero) and 0.034. Moreover, the Commission should not require any reliability-based or clean energy procurement in excess of the MTR procurement requirements in D.21-06-035 at this time, due to the lack of a robust process, reliability studies, and economic analyses to determine the appropriate PRM, and unexplained SERVM modeling results

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[3] These models are further described in SCE's 2020 IRP. *See Integrated Resource Plan of Southern California Edison Company (U 338-E)*, September 1, 2020 ("SCE IRP"), at 21-27.

regarding reliability and GHG emissions. LSEs should have flexibility to commence clean energy procurement according to their IRPs.

As the Commission recognized in D.21-06-035, where it found that "[m]ore analysis is needed before revising the planning reserve margin for long-term planning in the IRP proceeding on a permanent basis,"[4] the stacking analysis used to justify the 22.5% PRM is insufficient for establishing 22.5% as the PRM used in the IRP process going forward. Commission staff should also review the SERVM model performance as that modeling seems to be underestimating the reliability of the proposed PSP portfolio and overestimating GHG emissions compared to SCE's and the California Energy Commission's ("CEC") reliability modeling. While the CEC did not do a GHG check, its MTR analysis showed the proposed PSP was significantly more reliable than what was shown in Commission staff's analysis – a 0.005 LOLE in 2026 (i.e., equivalent to a 1-in-200 LOLE) in the CEC's analysis compared to a 0.064 LOLE in 2026 (i.e., equivalent to a 1-in-15 LOLE) in Commission staff's SERVM analysis.[5]

CE Modeling Comparison

SCE performed CE modeling of the proposed PSP to replicate the 38 MMT Core Portfolio using assumptions, such as baseline and candidate resources assumptions, the GHG target, PRM constraints, and import assumptions, that are largely consistent with RESOLVE assumptions made available by Commission staff to develop the 38 MMT Core Portfolio with the following exceptions:

1) The 2020 IEPR hourly load forecast was directly applied and used to determine the energy need and 22.5% PRM requirement based on the managed load peak.
2) Consecutive years 2022 to 2030 were modeled in the planning horizon.

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4 D.21-06-035 at Finding of Fact ("FOF") 1. *See also id.* at 11-12, Conclusion of Law ("COL") 1.

5 *See* CEC, *Lead Commissioner Workshop, Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants*, August 30, 2021, at 33 (S1: PSP), available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=239554&DocumentContentId=72991; Ruling at 20.

3) For each month, the expected energy during the managed load peak hour was used to determine solar and wind resources' contribution to the PRM constraint instead of using the ELCC methodology.

SCE's modeling results show the 38 MMT Core Portfolio developed by the RESOLVE CE model includes an additional 3,538 MW of 4-hour batteries, 265 MW of demand response, and 22 MW of wind by 2030 compared to the portfolio built by SCE's ABB CE model while meeting the same PRM standard. The detailed resource build-out in nameplate capacity is provided in Table 1 below. SCE's ABB CE model selected 557 MW more solar than RESOLVE as economical resource additions to pair with battery storage, serve load, and reduce GHG emissions. Aside from solar and battery storage, SCE's ABB CE model did not identify additional resource needs exceeding the minimum resource build-out provided in RESOLVE based on the aggregated LSE IRPs. The overall higher resource build-out in Commission staff's 38 MMT Core Portfolio results in an increase in new resource costs of approximately $450 million per year in 2030 relative to SCE's 38 MMT Core Portfolio (a 12% increase).[6]

Table 1 – CE Build-Out Comparison in 2030 (Nameplate Capacity)

Resource Buildout by 2030	Unit	RESOLVE	ABB CE	Difference
Biomass	MW	134	134	-
Geothermal	MW	1,161	1,161	-
Wind	MW	5,053	5,031	22
Offshore Wind	MW	195	195	-
Solar	MW	14,457	15,014	(557)
Battery Storage	MW	14,086	10,547	3,538
Pumped Storage	MW	1,000	1,000	-
Shed DR	MW	441	176	265
Total Resources (Renewables + Storage + DR)	MW	36,526	33,260	3,266

A detailed resource net qualifying capacity ("NQC") comparison is provided in Table 2 to demonstrate how PRM constraints are met by the RESOLVE and ABB CE models for 2030.

6 The annual cost of new resources was calculated as the levelized cost of capacity in RESOLVE ($/kW-year), then multiplied by the selected new resource capacity in the portfolio (kW).

Table 2 – CE NQC Stacking Comparison

	RESOLVE NQC (MW)		ABB NQC (MW)		Diff (RESOLVE - ABB)	
	2026	**2030**	**2026**	**2030**	**2026**	**2030**
CCGT	15,853	15,853	15,717	15,717	137	137
Peaker	7,794	7,794	7,786	7,786	8	8
CHP	1,178	1,178	1,580	1,580	-403	-403
Thermal Subtotal	*24,825*	*24,825*	*25,084*	*25,084*	*-259*	*-259*
Hydro (small + large)	5,206	5,205	5,657	5,657	-451	-452
Hoover	0	0	822	822	-822	-822
Palo Verde	631	631	635	635	-4	-4
Pumped Storage	2,080	2,899	1,829	2,633	251	266
Hydro, Nuclear and Specified Imports Subtotal	*7,917*	*8,735*	*8,943*	*9,747*	*-1,026*	*-1,012*
Geothermal + Biomass	2,065	2,922	2,015	2,885	50	37
Variable Renewable ELCC (Solar + Wind) [1]	9,129	10,018	2,134	2,609	6,995	7,409
Renewable Subtotal	*11,194*	*12,940*	*4,149*	*5,494*	*7,045*	*7,446*
Unspecified Import	4,000	4,000	4,000	4,000	0	0
Demand Response	2,618	2,636	2,371	2,371	247	265
Battery [2]	12,851	14,291	11,628	12,312	1,223	1,979
BTM PV and other reliability adjustment [3]	-7,116	-7,937	0	0	-7,116	-7,937
Total Resource Contribution	**56,288**	**59,490**	**56,175**	**59,008**	**113**	**482**
Peak Load [4]	**47,501**	**48,545**	**47,133**	**48,170**	**368**	**375**
Actual Reserve Margin %	**18.5%**	**22.5%**	**19.2%**	**22.5%**	**-0.7%**	**0.0%**

[1] While RESOLVE used the ELCC methodology to determine solar and wind resources' contribution to the PRM, SCE used the expected energy from solar and wind during the managed load peak hour (hour ending ("HE") 19) for each month.
[2] RESOLVE assumes a declining PRM contribution from batteries when battery capacity increases, whereas SCE assumes 100% PRM contribution for batteries with a 4-hour or longer duration.
[3] RESOLVE includes unspecified imports (392 MW from Hoover) and negative adjustment primarily due to behind-the-meter ("BTM") solar and BTM storage in the category of reliability adjustment.
[4] Peak load difference: RESOLVE used 2019 IEPR with 2020 IEPR adjustment, ABB directly used the IEPR 2020 peak based on the IEPR 2020 Mid-Mid hourly load forecast.

As shown in Table 2, SCE's ABB CE model met the 19.2% and 22.5% PRM constraints in 2026 and 2030, respectively, with less resource additions than RESOLVE. The largest differences in the portfolios are in the amounts of batteries and variable renewables (solar and wind), and BTM solar resources – which SCE does not include in the supply stack. However, comparing resource additions in the portfolios highlights some of the questionable outputs from the RESOLVE modeling. The higher battery build-out in the RESOLVE portfolio results in about 1,200 MW and 2,000 MW higher NQC in 2026 and 2030, respectively.[7] But the RESOLVE portfolio also assumes significantly more NQC contribution from solar and wind resources than SCE's ABB portfolio with 6,995 MW higher in 2026 and 7,409 MW higher in 2030.

[7] The nameplate capacity battery storage built-out in RESOLVE is 12,552 MW in 2026 and 14,086 MW in 2030, whereas in ABB it is 9,872 MW in 2026 and 10,547 MW in 2030.

This NQC increase in RESOLVE is driven largely by the use of the ELCC methodology, which gives more credit for baseline or existing solar and wind contribution to system reliability by using an average monthly value, compared to SCE's ABB portfolio that uses expected energy contribution from solar and wind in the net peak load hour (HE19) for the month of September. SCE's approach provides a consistent estimate of expected capacity for solar and wind during the most constrained periods by accounting for these resources' contribution during the critical net peak load hour. These resources' NQC contribution to system reliability is overstated in critical hours in the ELCC methodology. In 2026 and 2030, 24% of the nameplate capacity of variable renewable resources are credited as NQC in RESOLVE.[8] The ELCC for solar and wind is higher than their expected contribution in HE19, which is now the most critical period. It is more prudent to plan to this critical hour to make sure sufficient dispatchable generation is available to meet system reliability needs when there are expected hours of low solar and wind generation. SCE recommends the Commission not use the ELCC method currently being used in determining the contribution of variable resources in staff's modeling, filing requirements, MTR procurement compliance, and Resource Data Templates.

Additionally, SCE used a 100% PRM contribution for batteries with a 4-hour or longer duration in its ABB CE modeling, rather than the RESOLVE ELCC methodology. According to SCE's LOLE analysis results, unserved loads occur in HE18 to HE20.[9] The duration of an unserved load event is never beyond three hours. As such, 4-hour batteries are sufficient to serve the load during the critical hours and have a 100% PRM contribution. SCE is also concerned with using ELCC calculations for energy storage for determining MTR procurement compliance without stakeholder review. Such calculations will have a significant effect on the amount of

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[8] The nameplate capacity of variable renewable resources in RESOLVE is 27,417 MW solar plus 10,523 MW wind (37,940 MW total) in 2026 and 30,874 MW solar plus 10,523 MW wind (41,397 MW total) in 2030. In 2026, 9,129 MW NQC/37,940 MW x 100 = 24%. In 2030, 10,018 MW NQC/41,397 MW x 100 = 24%.

[9] *See* SCE IRP at 35, 43, Appendix B.

MTR procurement required by LSEs; however, stakeholders had no opportunity for input on the ELCC calculations.

Finally, RESOLVE counts BTM solar and storage resources on the supply-side of the PRM constraint and adds the equivalent peak reduction (7,937 MW by 2030) to the need side of the PRM constraint on top of the IEPR managed peak. Applying the PRM to BTM resources in this way is non-standard, and with staff's decision to force a 22.5% PRM to account for the MTR resources, causes the RESOLVE portfolio to be larger than intended or needed. Even if this impact was intended, SCE believes this additional PRM requirement added in RESOLVE due to the BTM solar adjustment is not appropriate because BTM solar's generation during the net peak load hour (HE19) in September is near zero.

PCM Comparison

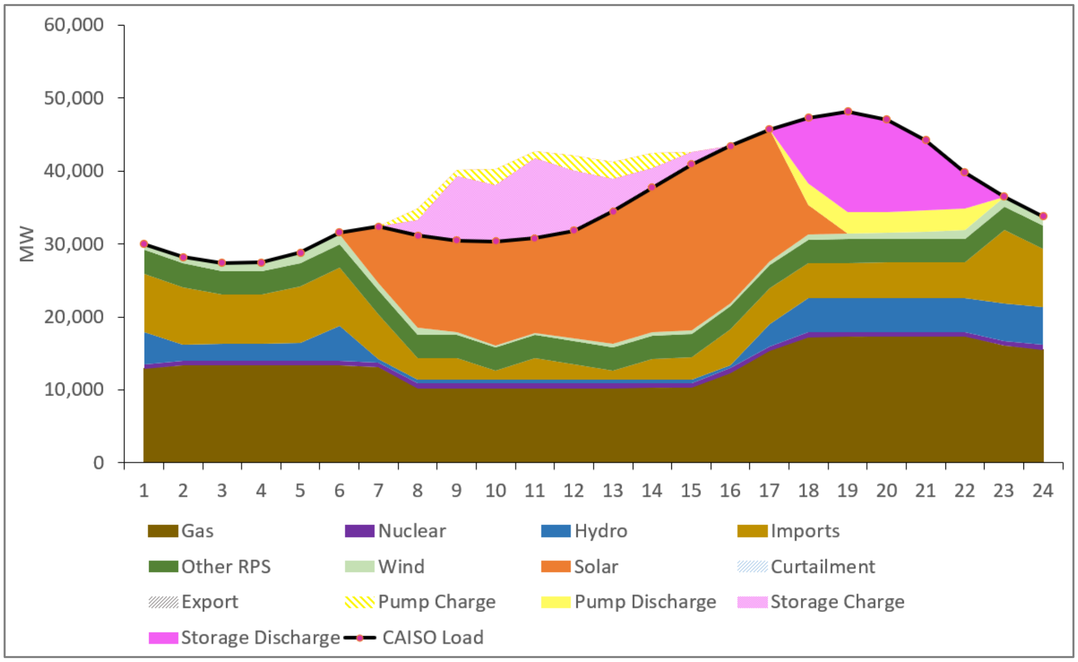
SCE also performed PLEXOS PCM to evaluate the operational feasibility and validate the GHG emissions of Commission staff's 38 MMT Core Portfolio for years 2026 and 2030. The PLEXOS simulation results show this portfolio is operationally feasible to meet demand and ancillary services requirements. However, SCE found the estimated GHG emissions in 2030 for this portfolio is 31 MMT,[10] much less than the 38 MMT target. The gap in GHG emissions between the two models seems to be driven by the significantly higher dispatch of gas resources in SERVM relative to SCE's PLEXOS model despite there being sufficient solar and energy storage for the system to rely less on gas resources.

As shown in Figure 1, SCE provides an hourly generation and load profile for the peak day in 2030 based on the PLEXOS production cost simulation results. On this peak load day in 2030, pumped storage and Li-battery are underutilized. On the peak load day shown in Figure 1 below, SCE found the pumped storage and Li-battery utilization rate is only 42% and 79%, respectively. These utilization values seemingly indicate both battery storage and pumped

[10] PLEXOS reported a total of 20.1 MMT GHG emission in CAISO compared to a 25.78 MMT GHG target in CAISO, excluding BTM combined heat and power GHG emissions for the 38 MMT Core Portfolio.

storage exceed the amount of resources needed by the system in 2026 and 2030. Overall, Commission staff's 38 MMT Core Portfolio exceeds system needs in 2030.

Figure 1 - 2030 Peak Day Load and Generation Profile



Further, SCE assessed the system reliability of Commission staff's 38 MMT Core Portfolio by performing an LOLE study using PLEXOS Monte Carlo simulations considering the uncertainties on load, wind and solar generation, and gas generation outages. The supply and demand data were developed using the 2019 IEPR mid Baseline mid Additional Achievable Energy Efficiency case and the Commission's 2019 SERVM load and renewables profiles. The extreme managed load peak simulated in SCE's LOLE analysis is 49,871 MW in 2030, which is close to the CAISO historical peak load of 50,271 MW occurring in 2006. A 7.5% forced generator outage rate was applied to gas generators. The simulation results show no unserved load existed at any time for 2026 and 2030, which equates to an LOLE metric of 0 (zero).

SCE's findings are consistent with the CEC's independent study of the 38 MMT Core Portfolio in its MTR analysis presented at an August 30, 2021 workshop, which shows a LOLE of 0.005 (i.e., equivalent to a 1-in-200 LOLE) in 2026.[11] SCE's and the CEC's study results lead to the conclusion that using a 22.5% PRM through 2030 in the 38 MMT Core scenario results in a portfolio with new resource additions that far exceed industry standards for reliability and therefore are more expensive than necessary.

With respect to past IRP portfolios, the Commission has noted Commission staff considered "sufficiently reliable to mean an LOLE of less than or equal to 0.1, which translates approximately to one day in ten years where the electric system would have to shed firm load due to insufficient generating capacity to serve load and hold critical operating reserves,"[12] and the IRP filing requirements refer to an LOLE of 0.1 as the industry probabilistic reliability standard.[13] An LOLE of 0 (zero) (SCE's analysis) or 0.005 (CEC's analysis) indicates Commission staff's 38 MMT Core Portfolio far exceeds this industry standard, which comes at a cost premium to customers with questionable added benefits.

Commission staff used the 22.5% PRM estimated from the MTR stacking analysis presented in D.21-06-035 for all years – essentially treating it as the long-term PRM to be used in the IRP process. However, while the Commission found the "PRM assumption of 20.7 percent, with the addition of several other assumptions and variables that effectively raise the PRM to approximately 22 percent, is appropriate to use for the medium-term to support the need for some procurement in order to support system reliability," the Commission also stated that "[f]or the long-term assumptions to be used for IRP planning purposes, we agree with the majority of parties who commented that more analysis is likely needed before revisiting our standards."[14] The Commission determined that "we will refrain, in this order, from setting new standards for PRM, LOLE, or weather variants of the demand forecast, and instead will continue

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[11] *See* CEC, *Lead Commissioner Workshop, Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants*, August 30, 2021, at 33 (S1: PSP), available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=239554&DocumentContentId=72991.

[12] D.20-03-028 at 22.

[13] *See Narrative Template*, June 15, 2020, at 17, available at: ftp://ftp.cpuc.ca.gov/energy/modeling/Narrative%20Template.docx.

[14] D.21-06-035 at 11, COL 3.

additional analysis and stakeholder engagement before making major changes" and that "[m]ore analysis is needed before revising the planning reserve margin for long-term planning in the IRP proceeding on a permanent basis."[15] The necessary analysis and studies to establish a PRM for long-term planning have not been completed. The Commission should not ignore its own guidance regarding such a major change to increase the PRM.

Rather than using a 22.5% PRM not supported by robust analysis for all years, SCE strongly recommends the Commission assess whether it is appropriate to reduce the PRM after the MTR resources are to come online (i.e., after 2026) to a level more in line with established reliability criteria. The Commission should also establish a track or process within the IRP proceeding to evaluate and determine the appropriate range of probabilistic planning inputs (i.e., demand forecast scenarios, variable generation output scenarios, outage rates, etc.); appropriate LOLE metric (e.g., 1-in-10, 1-in-20, 1-in-50, etc.); and suitable PRM to be used for IRP resource portfolios that balances changing reliability needs with customer affordability. This methodology and ultimate PRM result should continue to be updated as conditions change and aligned across agencies and with CAISO reliability assessments to ensure a consistent view on this important planning standard.

SCE used the iterative approach described in its IRP to address the reliability planning criteria discussed above.[16] Iterating the ABB CE model and PLEXOS PCM runs until an acceptable LOLE was achieved enabled SCE to identify an economic resource portfolio meeting both a 1-in-20 LOLE reliability requirement and the 38 MMT GHG target in 2030. SCE selected a 1-in-20 LOLE standard as illustrative of a scenario the Commission could evaluate in determining a suitable PRM. In this resource portfolio that meets an approximate 1-in-20 LOLE standard, the only difference from SCE's ABB CE results is the 4-hour energy storage build-out is reduced from 10,547 MW to 8,621 MW and the build-out quantities of all

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[15] *Id.* at 11, FOF 1.
[16] *See* SCE IRP at 21-28.

other resources are the same, resulting in a 18.5% PRM in 2030. The resource portfolio comparison is provided below in Table 3.

SCE believes this resource portfolio reaches a better balance of resource cost and reliability performance with about 5,500 MW less energy storage additions and $583 million per year savings by 2030 compared to the RESOLVE 38 MMT Core Portfolio, while meeting a 1-in-20 LOLE reliability requirement in 2030 with a 0.034 LOLE metric. In addition, the resource build-out identified in this portfolio is sufficient to meet the D.21-06-035 MTR procurement requirements. Given the lack of a sufficient reliability assessment or economic analysis to determine that a 22.5% PRM appropriately balances cost and reliability, SCE recommends that no additional reliability or clean energy procurement be required above the amounts in D.21-06-035 to meet system reliability or the 38 MMT GHG target at this time. The Commission should provide LSEs with the flexibility to procure clean energy consistent with their IRPs.

Table 3 – 38 MMT Core Portfolio Comparison with Lower PRM Requirement

Year 2030	RESOLVE - 38 MMT Core Portfolio	ABB CE - 38 MMT Core Portfolio	ABB CE - 38 MMT Core Portfolio with Lower PRM
PRM Requirement (%)	22.5	22.5	18.5
Reported LOLE by Plexos PCM in 2030	0	0	0.034
Battery Buildout by 2030 (MW)	14,086	10,547	8,621
Total Resource Cost per Year ($Billions)	4.17	3.72	3.59

As previously mentioned, SCE's PCM results found a much lower GHG value in 2030 for the 38 MMT Core Portfolio than RESOLVE and SERVM. To explore this topic further, SCE developed modeling output of the 2030 energy by resource type from RESOLVE, SERVM and PLEXOS. From aggregated energy balance results, summarized below in Table 4, it appears there are also some outlying values in the generation profile of SERVM results compared to PLEXOS.

Table 4 – 2030 Generation Output in GWh of RESOLVE, SERVM and PLEXOS

Aggregated Energy Balance	2030	Resolve	SERVM	Plexos
Nuclear	GWh	5,108	5,136	5,563
Hydro (Large + Small)	GWh	22,962	25,394	23,040
Hydro_NW_CAISO	GWh	11,284	11,000	11,687
Gas	GWh	41,252	**63,404**	38,344
Renewables (after curtailment)	GWh	133,470	132,186	**138,518**
Storage Losses	GWh	(5,740)	(6,112)	(5,391)
Curtailment	GWh	**(4,451)**		(1,544)
Imports (unspecified)	GWh	**23,832**	**26,486**	15,130
Exports	GWh	(7,030)	**(20,564)**	(5,228)
Total Generation	GWh	**225,138**	**236,930**	**221,662**

As shown in Table 4, many of the aggregated energy balance values of the resource types are consistent between RESOLVE, SERVM and PLEXOS, namely, nuclear, hydro (large, small and NW CAISO), and storage losses are reasonably aligned. But there are notable differences that may help explain the different 2030 GHG values that were identified by SERVM (38 MMT) and PLEXOS (31 MMT). Compared to SERVM, PLEXOS appears to dispatch the generation resources and storage devices in a more efficient manner resulting in higher delivered renewable energy and less exports and curtailment. PLEXOS has less reliance on unspecified imports, which have a higher GHG emission intensity than gas generators in the CAISO system.
The largest influence on the higher GHG value in SERVM could well be the high use of gas. SERVM results are 54% above the RESOLVE output and a 65% increase in gas use versus the results in PLEXOS. Moreover, significantly higher export power is also observed in SERVM results. All of these factors could play a role in the differences of the GHG calculations in 2030. It is not clear why there would be such discrepancies in the build-outs between the models.

The observations and discrepancies found in the modeling results described above indicate that additional procurement beyond the already ordered MTR procurement requirements would be premature at this time and should not be ordered by the Commission.

5. Comment on the appropriateness of the 38 MMT Core Portfolio as the PSP.

SCE supports the Ruling's recommendation to use 38 MMT as the 2030 GHG target for the PSP. SCE and many other parties to this proceeding support this more appropriate GHG target to help put California on a viable trajectory towards meeting its 2030 and 2045 decarbonization goals. Planning for the level of clean resources and grid investments needed through 2030 and beyond is necessary now and should span the next decade. It is critical to get the target right at the onset – the longer insufficient targets are being used to meet California's GHG objectives, the greater the challenge becomes to reach the state's decarbonization goals feasibly and affordably. For the reasons discussed in response to question 4, SCE supports using the 38 MMT Core Portfolio with 2020 IEPR as the PSP with adjustments to remove at least 3,500 MW of energy storage by 2030.

6. Comment on whether the load forecast assumptions should be adjusted to include higher load, particularly related to EV adoption or high electrification more broadly.

It is vital that California plan for a higher electrification future. SCE supports revisiting the load forecast assumptions to reflect a higher EV load forecast than what is assumed in the 38 MMT Core Portfolio (or the mid-case EV load forecast from IEPR), to ensure alignment with achieving the state's GHG emission reduction goals in 2030 and beyond, which will necessarily include substantial EV adoption. However, as to the inclusion of the 2020 IEPR high EV load forecast, there has not been sufficient information provided by staff to enable review of the assumptions and impacts in the 38 MMT Core scenario of inclusion of the high EV load forecast. The high EV load forecast should be released for review by parties, including PCM and reliability analyses on this scenario. Without such information, it is difficult to comment on the appropriateness of the 38 MMT Core with high EV load forecast scenario as the PSP and it would be premature to adopt it as the PSP without providing parties the opportunity to comment based on meaningful information regarding the scenario.

SCE's independent analysis of the 38 MMT Core Portfolio uses the CEC's IEPR mid-case demand forecast which projects only 3.2 million light-duty EVs by 2030 (as reflected by

2020 IEPR). The existing IEPR mid-case demand forecast does not reflect the level of high electrification that is needed to support California's long-term decarbonization and air quality goals. In contrast, the California Air Resources Board ("CARB") (from its Draft Mobile Source Strategy scenario analysis) estimates that almost 8 million zero-emission vehicles ("ZEVs") will be needed by 2030 to meet California's decarbonization goals.[17] The CEC's recent Assembly Bill 2127 Assessment also indicates significant levels of charging infrastructure are needed to support the Governor's 5 million ZEV goal by 2030 and 100% ZEV sales by 2035.[18] As the charging infrastructure expands and the adoption of EVs accelerates over the planning horizon, it is critical for IRP to adopt a load forecast that is reflective of the higher load driven by the accelerated electrification load growth and clearly define what a "high electrification" load forecast means in light of the CEC's and CARB's recent scenario assessment.

For future IRP cycles, it is important for the CEC to develop a robust "high electrification" scenario forecast reflecting the state's long-term clean energy policies through its stakeholder process as the first step. The Commission also needs to produce IRP analysis based on the CEC's policy-based scenario forecast and make such analysis available for meaningful stakeholder review and comment. Once the CEC establishes a "robust" high electrification scenario forecast and the Commission vets the associated IRP analysis with parties, the Commission, CEC, and CAISO should adopt the policy-based high electrification scenario forecast consistently across major proceedings that impact state's long-term planning.

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[17] *See* CARB, *Revised Draft 2020 Mobile Source Strategy*, April 23, 2021, available at: https://ww2.arb.ca.gov/sites/default/files/2021-04/Revised_Draft_2020_Mobile_Source_Strategy.pdf. While CARB's Draft 2020 Mobile Source Strategy is illustrative and not an actionable document, the levels of ZEVs put forward in that document align with the levels SCE believes should be included in the 2022 Scoping Plan and supporting policy and programs as it relates to ZEVs and associated infrastructure.

[18] *See* CEC, *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment, Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030*, July 2021, available at: https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127.

7. **Comment on the proposal to use the 38 MMT Core Portfolio as the reliability and policy-driven base case in the TPP.**

SCE supports the use of the 38 MMT Core Portfolio with 2020 IEPR and the modifications discussed in response to question 4 (to remove at least 3,500 MW of energy storage by 2030) as the reliability and policy-driven base case in the CAISO's next Transmission Planning Process ("TPP").

8. **Comment on the proposed policy-driven sensitivity portfolio for the TPP based on the 30 MMT GHG limit in 2030 with the high electrification load assumptions. Suggest any additional or alternative scenarios that should be analyzed as policy-driven sensitivities.**

SCE supports evaluating the 30 MMT GHG limit with high electrification load assumptions as a TPP policy-driven sensitivity portfolio. While there are many factors that need to be considered to establish a consistent policy-based high electrification scenario forecast that can be utilized in the IRP process and TPP as the PSP and base case, SCE supports prioritizing these issues and appreciates the cross-agency and stakeholder collaboration underway. Furthermore, SCE supports the continued assessment of transmission needs due to deep decarbonization of the California economy to identify: (1) the proper staging of new infrastructure with sufficient lead time for permitting and licensing, (2) inflection points of system needs (i.e., frequency response) with potential mitigation options, and (3) integration points with longer-term assessments, including SB 100 and the CAISO 20-year outlook.

9. **Comment on whether and how the Commission should act to encourage specific non-transmission alternatives to be built, if identified as part of the CAISO TPP process, both for the two specific projects identified in the 2020-2021 TPP, as well as in general for future such opportunities.**

SCE supports the identification of non-transmission alternatives through the CAISO TPP and other planning forums to inform potential locations where new resources can be sited and provide grid benefits beyond system capacity. These insights should continue to guide the IRP process and create more synergies with other initiatives such as local resource adequacy ("RA") planning and procurement. To successfully integrate use-limited resources in lieu of transmission upgrades, including the two specific storage projects identified, the desired operational characteristics of these resources must be flexible enough to function as market resources and be dispatched to meet the identified reliability need. Otherwise, overly constrained storage resources may be better suited as transmission assets to meet the need.

10. Comment on the options raised in Section 7.2 of this ruling to address procurement for system benefit more broadly. Suggest whether and how a particular cost recovery framework can be adopted quickly or discuss additional considerations that should be explored.

Any asset under the control of the CAISO as part of the transmission system would fall under Federal Energy Regulatory Commission ("FERC") jurisdiction with cost recovery and operations subject to the CAISO Tariff and FERC rate recovery mechanisms. Existing policies and mechanisms are in place for transmission assets and should be leveraged and applied, avoiding the need for the Commission to develop new policies and procedures for IRP procurement of assets for system reliability that benefit the transmission system. Additionally, the CAISO should be encouraged to continue the development of the Storage as a Transmission Asset rules to allow transmission rate recovery and market revenue recovery through the CAISO markets and FERC transmission tariffs. For procurement of assets that will be part of the CAISO's transmission system, the Commission should defer to the CAISO process.

11. Comment on the busbar mapping approach.

SCE commends the significant improvements to the busbar mapping approach and looks forward to reviewing the mapped resource portfolios. SCE acknowledges the challenges with conducting busbar mapping concurrently with finalizing the PSP and encourages that any resulting uncertainties and assumptions be raised and highlighted in the mappings.

SCE agrees with the utilization of the CAISO Local Capacity Technical Studies to help inform and drive the mapping of IRP resources within local capacity requirement ("LCR") areas. This includes considering the ability of those areas and subareas to accommodate battery storage (i.e., desired operational characteristics and system charging limitations).[19] In addition to LCR areas, SCE seeks clarification if the process also takes into consideration subareas such as Western LA Basin, and if resources will be mapped to busbars within those subareas. If not already incorporated, SCE encourages this moving forward as it is a natural step forward in planning for greater integration and maximized benefits of resources that meet multiple grid needs, including local RA.

12. Comment on whether the Commission should require the procurement of resources contained in the individual IRP filings and have LSEs face penalties and/or backstop procurement requirements with cost allocation arrangements, similar to those for D.19-11-016 and D.21-06-035.

In these first two IRP cycles, the Commission properly focused on establishing a GHG target to meet the state's 2030 and 2045 clean energy and GHG reduction goals. The Commission's IRP process helps facilitate the state's decarbonization goals with a 38 MMT GHG target for the PSP. The details on how the Commission intends to achieve that target should be clear and transparent; however, the Commission has not established a framework to adequately address clean energy need determination, allocation, and procurement compliance within this proceeding.

Such a framework should be developed within a subsequent track of this proceeding to ensure LSEs plan to procure to meet their respective shares of system reliability and GHG reduction needs and pursue the planned procurement. The Commission and parties should evaluate the need to mandate procurement based upon LSEs' individual IRPs with appropriate compliance, including considering the use of backstop procurement or establishing a more programmatic approach to clean energy procurement similar to the Renewables Portfolio Standard ("RPS") program that incorporates an established minimum requirement, clear compliance rules, and enforcement mechanisms or penalties for non-compliance based upon planning outcomes. SCE believes ultimately the Commission should move towards this

[19] For example, see Table 3.1-3 in the CAISO's *2026 Local Capacity Technical Study*, available at: http://www.caiso.com/InitiativeDocuments/Final2026Long-TermLocalCapacityTechnicalReport.pdf.

framework as part of a separate track of this proceeding. SCE's analysis shows the 38 MMT Core Portfolio meets system reliability and GHG targets through 2029 and clean energy requirements are not binding beyond the RPS until 2030 and later. Therefore, the Commission can take the time now to initiate a stakeholder process to develop a comprehensive planning and compliance framework with enforcement mechanisms to meet reliability and GHG goals.

SCE recommends taking a more programmatic approach for clean energy procurement. This framework should set the foundation for LSE planning so there are clear requirements on what is necessary to meet LSEs' share of system reliability and GHG reduction goals as they develop their IRPs. Until a framework has been established, SCE recommends the Commission authorize all LSEs, including the investor-owned utilities, to procure according to their approved IRPs but not mandate procurement.

13. Comment on whether you would prefer an approach where the Commission determines procurement need for GHG-free resources or the GHG-free attributes of resources at the system level and then uses a need allocation methodology to assign procurement to individual LSEs. If you propose this type of alternative approach, please address the following aspects:

- **Need allocation, by year**
- **How to address new and existing resources**
- **Whether procurement should be all-source or resource-specific**
- **Resource attributes required (MW, MWh, percentage of GHG-free energy, etc.)**
- **Duration (through 2030, 2032, interim milestones, etc.)**
- **Cost allocation**
- **Compliance, monitoring, and enforcement arrangements.**

The path to a decarbonized future requires thoughtful and timely clean energy procurement with clear objectives on how the Commission plans to reliably achieve the state's GHG and clean energy goals. Deliberate procurement decisions resulting from reliable modeling paired with a framework with clear compliance and enforcement mechanisms will help the Commission ensure LSEs plan to procure their share of clean energy resources. As noted above, the Commission should begin the development of a clean energy procurement framework now. This framework should allow LSEs to procure based on their IRPs but provide flexibility to adjust resource types and quantities based on market demand or operating variables such as hydro fluctuations due to drought years. Below, SCE provides concepts and ideas for a clean energy procurement program. The details will need to be defined and implemented through a stakeholder process in a subsequent track of this proceeding. In the meantime, the Commission's Clean System Power ("CSP") calculator can be used as an ongoing GHG tracking tool until clean energy targets and related requirements are established.

Need allocation, by year: SCE favors a need allocation approach based on a GHG target applied to each LSE as a percentage of clean energy in the portfolio. This approach is similar to how the RPS program functions in that there would be clear compliance requirements with implied annual targets, and the requirements should provide flexibility on a year-to-year basis through multi-year compliance periods to account for production variances such as potential hydro swings in drought years or low wind years. This would also enable a smooth transition from a renewables procurement target to an overall clean energy procurement target where GHG is the driving criteria and planning metric.

How to address new and existing resources: Both new and existing resources should be counted toward clean energy counting.

Whether procurement should be all-source or resource-specific: The Commission should not establish resource-specific technology carve-outs. These carve-outs result in inefficient procurement with increased costs. An all-source, technology agnostic approach to procurement is the more optimal approach and would provide some of the flexibility needed to ensure LSEs can procure the most cost-effective resources that meet their portfolio needs and attributes. Once the requirements are set, the market can play the important role of offering resources that can be selected based on cost and attributes. Each LSE should be responsible to meet the energy, GHG emissions targets, and reliability needs of their portfolio. This program could take on some of the attributes of the RPS, in that a broad authorization is given with end-term targets, but with flexibility and a process to allow for procurement deviations. The PSP can provide some guideposts on the directional path the clean energy procurement should take.

Resource attributes required (MW, MWh, percentage of GHG-free energy, etc.): Compliance with the clean energy program would rely on LSEs meeting or exceeding the GHG target required by all LSEs as a given percent of their portfolio by MWh. The portfolio would also continue to be required to meet all other requirements such as reliability and serving individual LSEs' load profiles.

Duration (through 2030, 2032, interim milestones, etc.): Similar to the RPS, SCE favors multi-year periods for compliance. This could be a "rolling window" of compliance years that covers the IRP planning period.

Compliance, monitoring, and enforcement arrangements: For the clean energy procurement program proposed by SCE, there will be a required GHG emissions target as a percent of MWh that each LSE must meet. If an LSE does not meet its GHG emissions target requirements with its portfolio, then the Commission can order that LSE to procure additional clean energy resources similar to the MTR procurement requirements for reliability and/or penalize the LSE. It will be important to have some rigor in the process to ensure alignment and consistency between LSEs. A form of the CSP Calculator will be needed to measure LSEs' compliance. This can be used to assess clean energy procurement progress on a level playing field between all LSEs and help the Commission decide on approval of LSEs' IRPs. Additionally, GHG-emitting resources need to be designated as system resources and allocated to all LSEs based on their selected portfolio as in the CSP Calculator. The CSP Calculator would allocate expected system GHG-emitting resources to LSEs based on a carbon intensity heat map driven by the Reference System Plan or PSP.

Other issues: There will be a need to address how to equitably address departing load as part of the clean energy program. Departing load and load migration present challenges to mandating procurement to specific LSEs. Rather, establishing benchmarks and a framework that would transfer the burden and risk along with the load will be needed. The clean energy program will also need to be flexible enough to accommodate the next generation of clean energy resources. This is one of the benefits of creating a clean energy standard instead of mandating a specific resource or plan. Lastly, a mechanism will be needed to address the residual need or identify system resources the Commission thinks are needed. While the goal should be to not have residual need, in this and future IRP cycles, an LSE's existing contracts should be considered when allocating any residual need.

15. Comment on whether and how much procurement required in D.21-06-035 should be accelerated to 2023 and/or suggest additional actions to facilitate additional resources in response to the Governor's Proclamation from July 30, 2021.

In support of the Governor's Proclamation, SCE is pursuing additional supply for summer 2022, including bilateral procurement opportunities from third-party providers, increasing the capacity/output of generation and storage resources already under contract, exploring opportunities to expedite any MTR projects to 2022, exploring the development of utility-owned storage, and procuring incremental imports that can help to mitigate reliability risks. The directives in the Governor's Proclamation are focused on 2021 and 2022, and do not address 2023. Moreover, the Commission's stack analysis in D.21-06-035 did not show a need in 2023 under any scenario,[20] and this is confirmed by the CEC's analysis showing reliability concerns from 2023 through 2026 should be diminished with the capacity ordered in D.19-11-016 and D.21-06-035.[21] Accordingly, to avoid unnecessary increased procurement costs and decreased procurement flexibility, SCE recommends the Commission not accelerate any more of the MTR procurement required in D.21-06-035 to 2023.

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20 *See* D.21-06-035 at 21, 25.

21 *See* CEC, *Lead Commissioner Workshop, Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants*, August 30, 2021, at 40, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=239554&DocumentContentId=72991.

16. **Comment on the CEC's MTR reliability analysis, the determinations regarding the need for fossil-fueled generation resources, and the actions, if any, that the Commission should take as a result.**

SCE agrees with the CEC's finding that 2023-2026 reliability concerns are sufficiently addressed by the preferred resource procurement ordered in D.21-06-035 and believes no additional fossil-fueled generation resources are needed for reliability. SCE notes, however, that the CEC's conclusion that the preferred resource portfolio is as, or more reliable than, an "equivalent" gas portfolio is largely driven by the methodology used to construct the equivalent gas portfolio. Specifically, this finding is influenced by the simplifying assumption that one MW of preferred resources, as determined on a marginal ELCC basis, is equivalent to one MW of gas, as determined on a nameplate capacity basis. Nevertheless, SCE recommends the Commission not order the procurement of any new fossil-fueled generation.

18. **Comment on the percentage of renewable hydrogen facilities that should be required, if any, and the timing of the transition from a blend to full renewable hydrogen combustion, including the option for inclusion of fuel cells. Discuss the feasibility and cost of achieving a 100 percent renewable hydrogen blend by 2036 in your comments.**

Low carbon fuels including hydrogen are anticipated to play an important role in the decarbonization of California primarily in the next decade. SCE's Pathway 2045 examines the energy implications and how California can evolve to reach carbon neutrality by 2045, and states that "[n]atural gas consumption in 2045 will decline 50% from today, and cost impacts on remaining gas customers will need to be managed. At least 40% of the remaining gas will need to be low-carbon fuels such as biomethane or hydrogen."[22] The Commission must develop a strategic plan to better understand the potential applications of hydrogen in the electric sector and other end use applications before making significant decisions about its use. Developing a California strategic plan would help define parameters around critical decisions such as

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[22] SCE, *Pathway 2045*, November 2019, at 2, available at: https://www.edison.com/home/our-perspective/pathway-2045.html.

optimal/most cost-effective percent of hydrogen, deployment timelines, and types of transport and storage that would be viable for California.

The CEC is currently conducting research on hydrogen-based power generation systems that can inform the state's decarbonization strategy.[23] Other research and pilot projects can help inform the development of a state-wide strategy that includes policies designed to incentivize investment. It is premature to provide recommendations on the details of what a California hydrogen economy would look like at this time without a more detailed overarching plan for how the state can incorporate hydrogen to help achieve decarbonization. Given the size of the current natural gas fleet and its critical role in electric system reliability, the Commission's plan should include details on how the state can cost-effectively optimize decision-making around the number of potential options for the state's future hydrogen economy including ongoing development of fuel cell technologies. SCE supports continued research and development to bring low carbon fuels to commercial viability at scale.

19. Comment on proposed measures regarding NOx emissions from facilities using renewable hydrogen.

Given the expected significant reduction in gas/hydrogen burn volumes in the future it might not be necessary to maintain or reduce emissions rates, but instead lower the daily/annual NOx limits. As the state considers moving to cleaner fuel sources by incorporating green hydrogen in its resource portfolio, the state should continue to also reduce criteria pollutants. It is reasonable to require facilities co-firing hydrogen to maintain their current permitted NOx rates, daily/monthly/annual NOx limits, or both.

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[23] *See* Resolution G-3584.

20. Comment on whether the Commission should take any initial actions on geographically-targeted procurement, particularly with respect to Aliso Canyon, or more broadly, and respond to the factors discussed in Section 12 of this ruling.

Specific procurement action with respect to potential closure of Aliso Canyon is premature at this time. Since there is currently no local capacity need in the LA Basin, the CAISO in its LCR study process would need to analyze the implications of Aliso Canyon closure on local capacity needs in that area. Without the appropriate LCR studies, targeting resources such as energy storage in the basin could in fact create local capacity issues if there is insufficient energy located in the local area to charge the storage systems. Additionally, deploying resources locally likely would have a higher incremental cost than deploying resources most economically throughout the system. Without a specific local need identified or finding of potential need due to the closing of Aliso Canyon, it is premature to require electric customers in SCE's Transmission Access Charge area to pay for these more expensive resources to be deployed locally.

21. Comment on whether and how the act to preserve transmission deliverability rights in the central coast area that could be utilized for offshore wind or other resources.

While there may be an opportunity for Diablo Canyon or other facilities to reserve transmission deliverability for a limited time following their decommissioning, there is not a mechanism to "reserve" transmission deliverability that may currently be available in the central coast for offshore wind or other resources. If there is available deliverability, it is generally allocated through the CAISO's deliverability study process for generators in the interconnection queue. The CAISO Tariff governs the allocation of deliverability subject to FERC's Open Access Policy and the CAISO operates the transmission system. However, the Commission could, through the IRP process, identify that resources should be procured from that area in the future, which could lead the CAISO to identify any potential policy-needed projects in that area if deemed necessary.

22. Comment on the amount of offshore wind, if any, that should be included in the 2022-2023 TPP base case. Comment on how the results of the 2021-2022 TPP offshore wind sensitivity case should influence this issue.

Ahead of preliminary results from the 2021-2022 TPP expected in November 2021, it is uncertain how much offshore wind should be selected, carried forward, and included in the 2022-2023 TPP base cases, particularly in the base portfolio for which transmission projects could be approved. The Commission should avoid technology carve-outs, and instead select resources with the required attributes and least cost needed to ensure reliability. Although there may be an early expectation that 8,000 MW of offshore wind would not trigger a significant level of new transmission, the economics of this offshore wind cannot be fully informed and confirmed without the finalized TPP scope and cost of transmission to deliver these resources. As such, no additional offshore wind should be forced into the TPP base case at this time.

23. Comment on whether and how the Commission should act to support the development of out-of-state ("OOS") renewables/wind and the transmission to deliver it. Be as concrete and specific as possible in your recommendations.

At this time, the Commission should not act to support the development of OOS renewables/wind or the new transmission infrastructure to deliver it. While the Ruling states that "[s]everal rounds of IRP RESOLVE modeling indicate the need for some amount of OOS wind resources from New Mexico, Wyoming, and/or Idaho,"[24] these resources were not selected on an economic basis. Instead, they were forced into the model and displaced less expensive in-state resources such as solar plus storage. Supporting the development of a specific resource as a carve-out that is above the cost of other equally satisfactory resources runs counter to the least-cost, best-fit planning and procurement principles that should drive resource planning and procurement decisions. The Commission should conduct a study that identifies when OOS wind will be selected on an economic basis, including the costs of new transmission. Then, the Commission can determine the lead time needed to develop OOS wind plus transmission

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[24] Ruling at 47.

resources and plan to begin development in time to meet that need. Forcing an expensive resource and transmission into the resource mix before its time is not consistent with least cost, best fit principles.

24. Comment on specific actions the Commission can take to ensure retention of existing resources needed both for reliability and/or GHG emissions purposes.

SCE agrees "there is a need to ensure that existing, efficient, and clean resources are available to the system on an ongoing basis."[25] At some point in the future, many of the legacy resources in the state will retire because their capabilities have been replaced with newer, cleaner, more efficient resources and are no longer needed. In the meantime, however, these resources will need to be retained and remain reliable to meet California's goals. The RA and RPS programs, qualifying facility contracts, and CAISO Reliability Must-Run contracts have been the means of resource retention in recent years. SCE urges the Commission to modify the RA program to better capture the reliability contribution of both existing and new resources. The updated RA program should consider net peak load contribution and ability of resources to provide capacity outside of the peak and net peak to facilitate energy storage. As covered in SCE's response to question 13, the Commission should also implement a program to measure clean energy contributions and incentivize LSEs to contract for clean energy resources. For now, these mechanisms should be able to retain the resources California requires for reliability and to achieve GHG goals.

25. For any of the potential procurement requirements discussed in this ruling, allocation of need to LSEs is a required step. Comment on how the methodologies should account for in-CAISO POU load and what steps the Commission should take to ensure those POUs bear their share of responsibility for reliability and GHG impacts.

Like LSEs within the Commission's IRP jurisdiction, publicly-owned utilities ("POUs") should be required to self-provide their share of needed reliability and clean energy procurement.

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[25] *Id.* at 49.

LSEs within the Commission's IRP authority should not bear the responsibility or cost burden of achieving the POUs' share of reliability and GHG reduction. The most straightforward approach to ensure POUs take their fair share of responsibility would be for the Commission, CEC, and CAISO to coordinate efforts and act to ensure the POUs in the CAISO system are indeed procuring their fair share of reliability and clean energy resources.

Respectfully submitted,

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Appendix A

SCE's Capacity Expansion Modeling Results

This workbook provides additional results from the SCE ABB Capacity Expansion modeling scenarios

The three blue tabs provide detailed information about the buildout by resource type

- Information includes RA contribution by resource and overall PRM need by year, as well as the RPS Sales share and Emissions total by year. These constraints drive the overall buildout, shown by resource type.

The Cost Comparison tab provides information regarding how the Core and Lowered PRM case compare in terms of annual resource cost in 2030 to the RESOLVE Core scenario.

Buildout	*Unit*	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas	*MW*	-	-	-	-	-	-	-	-	-
Biomass	*MW*	34	65	83	95	107	107	134	134	134
Geothermal	*MW*	14	114	114	114	184	184	1,160	1,160	1,161
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-
Wind	*MW*	1,645	1,719	2,049	3,360	3,419	3,419	3,419	3,419	5,031
Offshore Wind	*MW*	-	-	-	-	132	132	195	195	195
Solar	*MW*	3,094	6,549	7,750	10,564	10,833	10,833	12,730	12,730	15,014
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*		313	7,248	9,863	9,863	9,863	10,219	10,526	10,547
Pumped Storage	*MW*	-	-	-	-	196	196	1,000	1,000	1,000
Demand Response	*MW*	176	176	176	176	176	176	176	176	176
Gas Capacity Not Retained	*MW*									
Renewables	*MW*	4,963	8,623	10,173	14,310	14,852	14,852	17,815	17,815	21,712
Storage	*MW*	-	313	7,248	9,863	10,059	10,059	11,219	11,526	11,547

PRM	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load	MW	45,448	45,826	46,452	46,758	47,133	47,374	47,543	47,794	48,170
Reserve Margin Requirement	%	14.9%	14.9%	22.5%	19.9%	18.30%	18.3%	22.5%	22.5%	22.5%
Total Reserve Margin Requirement	MW	52,220	52,654	56,903	56,063	55,759	56,044	58,240	58,548	59,008
Firm Capacity	MW	42,517	42,621	39,690	36,754	36,583	36,575	37,452	37,452	37,453
CCGT	MW	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717
Peaker	MW	8,232	8,232	8,232	8,025	7,786	7,786	7,786	7,786	7,786
ST	MW	2,883	2,883	-	-	-	-	-	-	-
CHP	MW	1,627	1,627	1,627	1,580	1,580	1,580	1,580	1,580	1,580
Hydro (small + large)	MW	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479
Nuclear	MW	2,912	2,912	2,912	635	635	635	635	635	635
Coal	MW	480	480	480	-	-	-	-	-	-
Geothermal	MW	1,209	1,297	1,297	1,297	1,356	1,356	2,207	2,207	2,208
Biomass	MW	607	629	642	650	659	659	677	677	677
Demand Response	MW	2,371	2,365	2,305	2,371	2,371	2,364	2,371	2,371	2,371
PRM Import	MW	5,000	5,000	5,000	4,000	4,000	4,000	4,000	4,000	4,000
Storage	MW	3,311	3,711	10,646	13,262	13,458	13,458	14,617	14,925	14,945
Li-ion	MW	1,678	2,078	9,013	11,628	11,628	11,628	11,984	12,291	12,312
Pumped Storage	MW	1,633	1,633	1,633	1,633	1,829	1,829	2,633	2,633	2,633
Wind and Solar	MW	1,392	1,408	1,567	2,048	2,135	2,135	2,171	2,171	2,609
Total Available Capacity	**MW**	**52,220**	**52,740**	**56,903**	**56,063**	**56,175**	**56,168**	**58,240**	**58,548**	**59,008**
Reported Reserve Margin	**%**	**14.90%**	**15.09%**	**22.50%**	**19.90%**	**19.18%**	**18.56%**	**22.50%**	**22.50%**	**22.50%**

RPS Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
RPS Sales Share Modeling Result	%	45%	48%	51%	57%	58%	57%	62%	62%	65%
RPS Regulation	%	39%	42%	44%	48%	50%	52%	54%	57%	60%

Emission Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Modeling Result	MMT	26.04	24.41	24.02	24.78	26.59	26.96	23.26	23.46	21.29
Emission Regulation	MMT	45.81	43.24	40.68	38.11	35.54	32.98	30.41	27.85	25.28
Statewide Emission	MMT	31.75	29.77	29.30	30.22	32.43	32.88	28.36	28.62	25.96

Buildout	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas	MW	-	-	-	-	-	-	-	-	-
Biomass	MW	34	65	83	95	107	107	134	134	134
Geothermal	MW	14	114	114	114	184	184	1,160	1,160	1,161
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-
Wind	MW	1,645	1,719	2,049	3,360	3,419	3,419	3,419	3,419	5,031
Offshore Wind	MW	-	-	-	-	132	132	195	195	195
Solar	MW	3,094	6,549	7,750	9,721	9,990	9,990	11,887	11,887	15,014
Customer Solar	MW	-	-	-	-	-	-	-	-	-
Battery Storage	MW		313	5,390	7,572	7,892	8,176	8,317	8,615	8,621
Pumped Storage	MW	-	-	-	-	196	196	1,000	1,000	1,000
Demand Response	MW	176	176	176	176	176	176	176	176	176
Gas Capacity Not Retained	MW									
Renewables	MW	4,963	8,623	10,173	13,467	14,009	14,009	16,972	16,972	21,712
Storage	MW	-	313	5,390	7,572	8,088	8,372	9,317	9,615	9,621

PRM	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load	MW	45,448	45,826	46,452	46,758	47,133	47,374	47,543	47,794	48,170
Reserve Margin Requirement	%	14.9%	14.9%	18.5%	15.0%	15.0%	15.0%	18.5%	18.5%	18.5%
Total Reserve Margin Requirement	MW	52,220	52,654	55,045	53,772	54,203	54,481	56,339	56,636	57,081
Firm Capacity	MW	42,517	42,621	39,690	36,754	36,583	36,575	37,452	37,452	37,453
CCGT	MW	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717
Peaker	MW	8,232	8,232	8,232	8,025	7,786	7,786	7,786	7,786	7,786
ST	MW	2,883	2,883	-	-	-	-	-	-	-
CHP	MW	1,627	1,627	1,627	1,580	1,580	1,580	1,580	1,580	1,580
Hydro (small + large)	MW	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479
Nuclear	MW	2,912	2,912	2,912	635	635	635	635	635	635
Coal	MW	480	480	480	-	-	-	-	-	-
Geothermal	MW	1,209	1,297	1,297	1,297	1,356	1,356	2,207	2,207	2,208
Biomass	MW	607	629	642	650	659	659	677	677	677
Demand Response	MW	2,371	2,365	2,305	2,371	2,371	2,364	2,371	2,371	2,371
PRM Import	MW	5,000	5,000	5,000	4,000	4,000	4,000	4,000	4,000	4,000
Storage	MW	3,311	3,711	8,788	10,970	11,486	11,770	12,715	13,013	13,019
Li-ion	MW	1,678	2,078	7,155	9,337	9,657	9,941	10,082	10,380	10,386
Pumped Storage	MW	1,633	1,633	1,633	1,633	1,829	1,829	2,633	2,633	2,633
Wind and Solar	MW	1,392	1,408	1,567	2,048	2,135	2,135	2,171	2,171	2,609
Total Available Capacity	MW	**52,220**	**52,740**	**55,045**	**53,772**	**54,203**	**54,481**	**56,339**	**56,636**	**57,081**
Reported Reserve Margin	%	**14.90%**	**15.09%**	**18.50%**	**15.00%**	**15.00%**	**15.00%**	**18.50%**	**18.50%**	**18.50%**

RPS Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
RPS Sales Share Modeling Result	%	45%	48%	51%	55%	57%	56%	61%	61%	64%
RPS Regulation	%	39%	42%	44%	48%	50%	52%	54%	57%	60%

Emission Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Modeling Result	MMT	26.0	24.4	24.3	25.7	27.5	27.8	24.1	24.4	22.2
Emission Regulation	MMT	45.8	43.2	40.7	38.1	35.5	33.0	30.4	27.8	25.3
Statewide Emission	MMT	31.8	29.8	29.7	31.3	33.5	33.9	29.4	29.7	27.1

Buildout	*Unit*	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas	*MW*	-	-	-	-	-	-	-	-	-
Biomass	*MW*	34	65	83	95	107	107	134	134	134
Geothermal	*MW*	14	114	114	114	184	184	1,160	1,160	1,161
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-
Wind	*MW*	1,645	1,719	2,049	3,360	3,419	3,419	3,419	3,419	5,031
Offshore Wind	*MW*	-	-	-	-	132	132	195	195	195
Solar	*MW*	3,094	6,549	7,750	11,158	11,427	11,427	13,324	13,324	15,608
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*	-	411	7,410	10,063	10,063	10,063	10,523	10,861	10,915
Pumped Storage	*MW*	-	-	-	-	196	196	1,000	1,000	1,000
Demand Response	*MW*	176	176	176	176	176	176	176	176	176
Gas Capacity Not Retained	*MW*									
Renewables	*MW*	4,963	8,623	10,173	14,904	15,446	15,446	18,409	18,409	22,306
Storage	*MW*	-	411	7,410	10,063	10,259	10,259	11,523	11,861	11,915

PRM	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load	MW	45,498	45,924	46,584	46,925	47,336	47,604	47,792	48,067	48,470
Reserve Margin Requirement	%	14.9%	14.9%	22.5%	19.9%	18.30%	18.3%	22.5%	22.5%	22.5%
Total Reserve Margin Requirement	MW	52,278	52,766	57,065	56,263	55,999	56,315	58,545	58,882	59,375
Firm Capacity	MW	42,517	42,621	39,690	36,754	36,583	36,575	37,452	37,452	37,453
CCGT	MW	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717	15,717
Peaker	MW	8,232	8,232	8,232	8,025	7,786	7,786	7,786	7,786	7,786
ST	MW	2,883	2,883	-	-	-	-	-	-	-
CHP	MW	1,627	1,627	1,627	1,580	1,580	1,580	1,580	1,580	1,580
Hydro (small + large)	MW	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479	6,479
Nuclear	MW	2,912	2,912	2,912	635	635	635	635	635	635
Coal	MW	480	480	480	-	-	-	-	-	-
Geothermal	MW	1,209	1,297	1,297	1,297	1,356	1,356	2,207	2,207	2,208
Biomass	MW	607	629	642	650	659	659	677	677	677
Demand Response	MW	2,371	2,365	2,305	2,371	2,371	2,364	2,371	2,371	2,371
PRM Import	MW	5,000	5,000	5,000	4,000	4,000	4,000	4,000	4,000	4,000
Storage	MW	3,369	3,809	10,808	13,461	13,657	13,657	14,921	15,259	15,313
Li-ion	MW	1,736	2,176	9,175	11,828	11,828	11,828	12,288	12,626	12,680
Pumped Storage	MW	1,633	1,633	1,633	1,633	1,829	1,829	2,633	2,633	2,633
Wind and Solar	MW	1,392	1,408	1,567	2,048	2,135	2,135	2,171	2,171	2,609
Total Available Capacity	MW	**52,278**	**52,837**	**57,065**	**56,263**	**56,374**	**56,367**	**58,545**	**58,882**	**59,375**
Reported Reserve Margin	%	**14.90%**	**15.05%**	**22.50%**	**19.90%**	**19.09%**	**18.41%**	**22.50%**	**22.50%**	**22.50%**

RPS Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
RPS Sales Share Modeling Result	%	45%	48%	51%	57%	58%	58%	62%	62%	65%
RPS Regulation	%	39%	42%	44%	48%	50%	52%	54%	57%	60%

Emission Regulation	Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030
Modeling Result	MMT	26.27	24.72	24.47	24.94	26.86	27.33	23.69	23.96	21.85
Emission Regulation	MMT	45.81	43.24	40.68	38.11	35.54	32.98	30.41	27.85	25.28
Statewide Emission	MMT	32.04	30.14	29.84	30.42	32.76	33.33	28.89	29.21	26.65

Year 2030	RESOLVE - 38 MMT Core Porfolio	ABB CE - 38 MMT Core Portfolio	ABB CE - 38 MMT Core Portfolio with Lower PRM
PRM Requirement (%)	22.50%	22.50%	18.50%
Reported LOLE by Plexos PCM in 2030	0	0	0.034
Battery Buildout by 2030 (MW)	14,086	10,556	8,600
Total Resource Cost per Year ($Billions)	$ 4.17	$ 3.72	$ 3.59

Appendix B

SCE's Production Cost Modeling Results

Tab	Simulation Case	Description
2026 PCM	**2026 PCM for RESOLVE's 38mmt Core Portfolio**	**SCE perfomed production cost simulation (PCM) for RESOLVE's 38mmt Core Portfolio for year 2026. This tab summarizes the resource dispatch and GHG emission from 2026 PLEXOS PCM simulation.**
	Table 1 - 2026 Generation output in GWh of RESOLVE, SERVM and PLEXOS	This table compares 2026 RESOLVE, SERVM and PLEXOS aggregated energy balance results
	Table 2 - 2026 Reported Pleoxs Emission	This table reports emision from PLEXOS PCM for 2026 RESOLVE's 38mmt Core Portfolio
2030 PCM	**2030 PCM for RESOLVE's 38mmt Core Portfolio**	**SCE perfomed production cost simulation (PCM) for RESOLVE's 38mmt Core Portfolio for year 2030. This tab summarizes the resource dispatch and GHG emission from 2030 PLEXOS PCM simulation.**
	Table 3 - 2030 Generation output in GWh of RESOLVE, SERVM and PLEXOS	This table compares 2030 RESOLVE, SERVM and PLEXOS aggregated energy balance results
	Table 4 - 2030 Reported Pleoxs Emission	This table reports emision from PLEXOS PCM for 2030 RESOLVE's 38mmt Core Portfolio
	Figure 1 - 2030 Average Load and Generation Profile	This figure provides an hourly generation and load profile for 2030 annual average based on the PLEXOS production cost simulation results
	Figure 2 - 2030 Peak Day Load and Generation Profile	This figure provides an hourly generation and load profile for the peak day in 2030 based on the PLEXOS production cost simulation results
LOLE	**LOLE Study for RESOLVE's and ABB's 38mmt Core Portfolio**	**SCE assessed the system reliability of the Commission's 38 MMT Core porfolio by performing an LOLE study using PLEXOS Monte Carlo simulations considering the uncertainties on load, wind and solar generation, and gas generation outages. SCE then further perfomred LOLE study on ABB CE 38 MMT Core portfolio with 22.5% and lower PRM (18.5%).**
	Table 5 – Reliablity Study Comparsion for RESOLVE and ABB CE 38 MMT Core Portfolio	This table compares LOLE values from relibility assemsment for Commission's 38 MMT Core Portfolio and SCE's ABB CE 38 MMT Core Portfolio with 22.5% and lower PRM (18.5%)
	Figure 3 - Unserved Energy Event Duration Curve for ABB CE - 38 MMT Core Portfolio with Lower PRM	This table summarizes unserved energy event duration curve for ABB CE 18.5% PRM Case
	Figure 4 - Unserved Energy Event Occurred Months for ABB CE - 38 MMT Core Portfolio with Lower PRM	This table summarizes unserved energy event occured months for ABB CE 18.5% PRM Case
	Figure 5 - Unserved Energy Event Occurred Hours for ABB CE - 38 MMT Core Portfolio with Lower PRM	This table summarizes unserved energy event occurred hours for ABB CE 18.5% PRM Case

2026 Production Cost Simulation Results for RESOLVE PSP 38mmt Core Case

Table 1 - 2026 Generation output in GWh of RESOLVE, SERVM and PLEXOS

Aggregated Energy Balance	2026	Resolve	SERVM	PLEXOS
Nuclear	GWh	5,108	5,563	5,563
Hydro (Large + Small)	GWh	22,964	25,393	23,042
Hydro_NW_CAISO	GWh	11,324	11,000	11,779
Gas	GWh	55,084	69,689	50,821
Renewables (after curtailment)	GWh	112,408	114,718	117,292
Storage Losses	GWh	(4,226)	(5,327)	(3,743)
Curtailment	GWh	(1,989)		(191)
Imports (unspecified)	GWh	24,134	27,328	18,096
Exports	GWh	(3,877)	(16,041)	(2,326)
Total Generation	GWh	222,919	232,323	220,524

Table 2 - 2026 Reported Pleoxs Emission

PLEXOS Emission (MMT)	2026
Gas	18.15
Imports (unspecified)	7.74
Gas + Imports (unspecified)	25.89
CA Total Emission	38.14

2030 Production Cost Simulation Results for RESOLVE PSP 38mmt Core Case

Table 3 - 2030 Generation output in GWh of RESOLVE, SERVM and PLEXOS

Aggregated Energy Balance	2030	Resolve	SERVM	PLEXOS
Nuclear	GWh	5,108	5,136	5,563
Hydro (Large + Small)	GWh	22,962	25,394	23,040
Hydro_NW_CAISO	GWh	11,284	11,000	11,687
Gas	GWh	41,252	63,404	38,344
Renewables (after curtailment)	GWh	133,470	132,186	138,518
Storage Losses	GWh	(5,740)	(6,112)	(5,391)
Curtailment	GWh	(4,451)		(1,544)
Imports (unspecified)	GWh	23,832	26,486	15,130
Exports	GWh	(7,030)	(20,564)	(5,228)
Total Generation	GWh	225,138	236,930	221,662

Table 4 - 2030 Reported Pleoxs Emission

PLEXOS Emission (MMT)	2030
Gas	13.60
Imports (unspecified)	6.48
Gas + Imports (unspecified)	20.07
CA Total Emission	30.95

Figure 1 - 2030 Average Load and Generation Profile

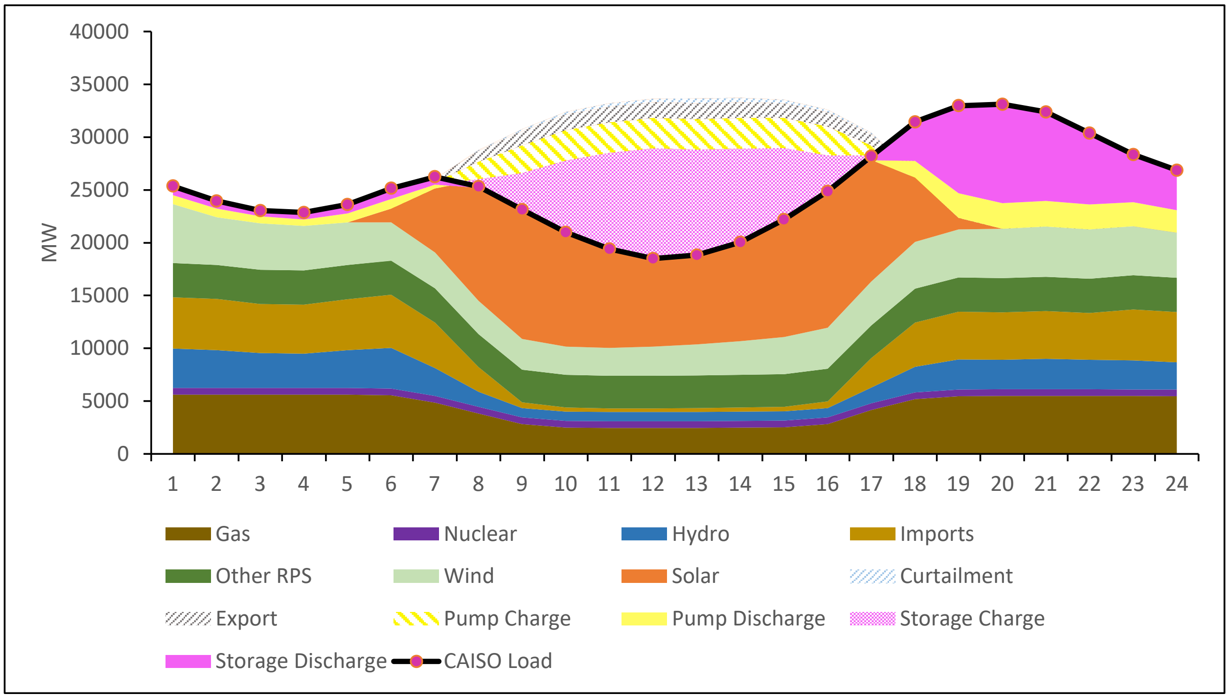
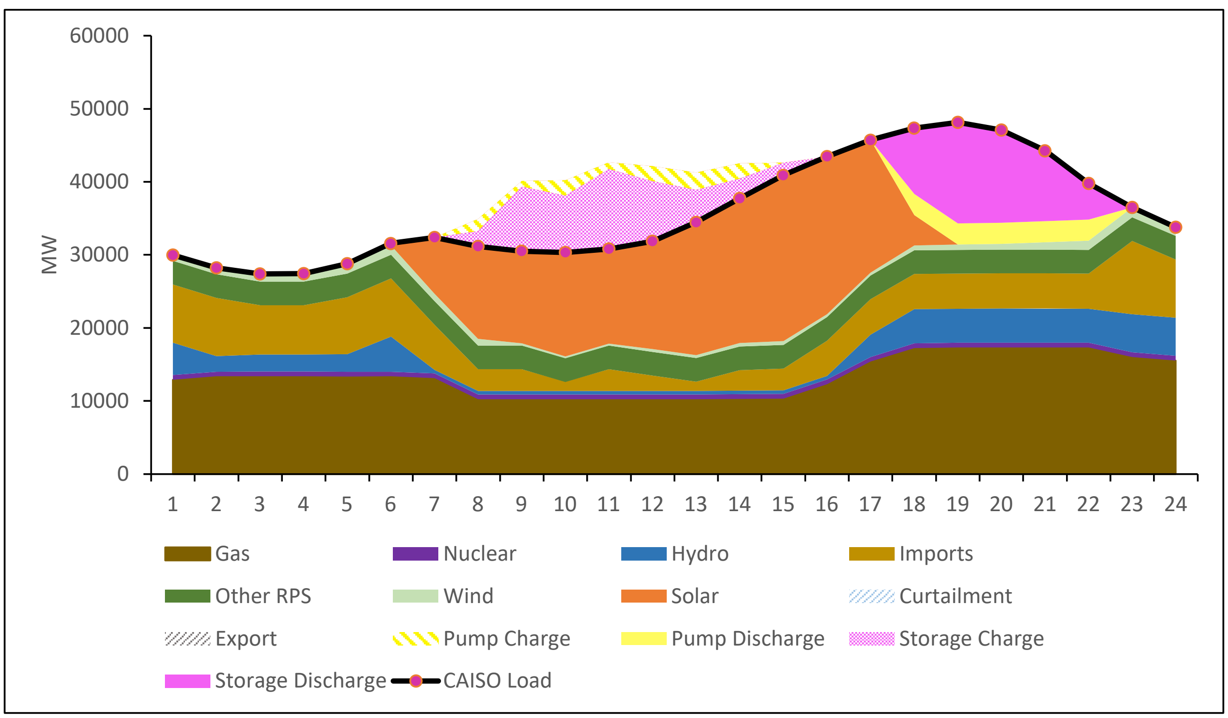


Figure 2 - 2030 Peak Day Load and Generation Profile



SCE's LOLE Study for 38mmt Core Portfolio

Table 5 – Reliablity Study Comparsion for RESOLVE and ABB CE 38 MMT Core Portfolio

LOLE Value	Study Year	
Case	**2026**	**2030**
RESOLVE - 38 MMT Core Porfolio	0	0
ABB CE - 38 MMT Core Portfolio (22.5% PRM)	N/A	0
ABB CE - 38 MMT Core Portfolio with Lower PRM (18.5%)	N/A	0.034

Figure 3 - Unserved Energy Event Duration Curve for ABB CE - 38 MMT Core Portfolio with Lower PRM

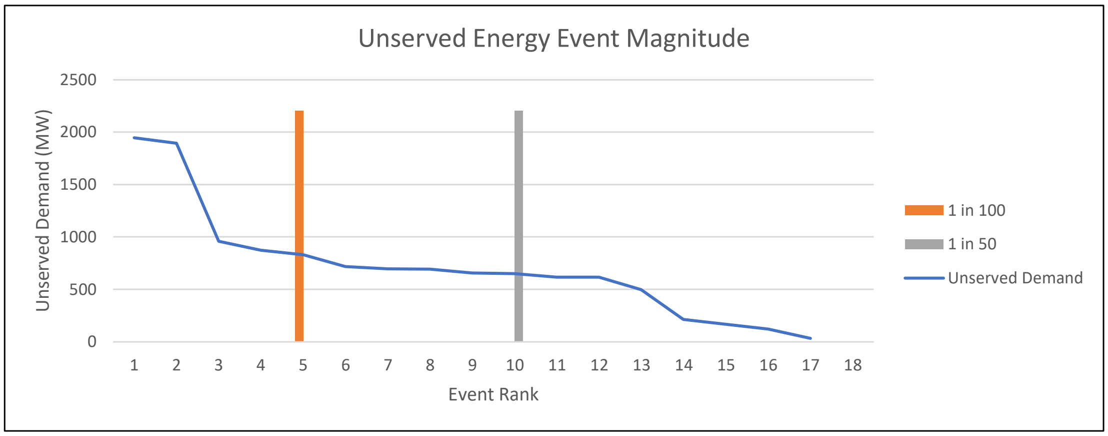


Figure 4 - Unserved Energy Event Occurred Months for ABB CE - 38 MMT Core Portfolio with Lower PRM

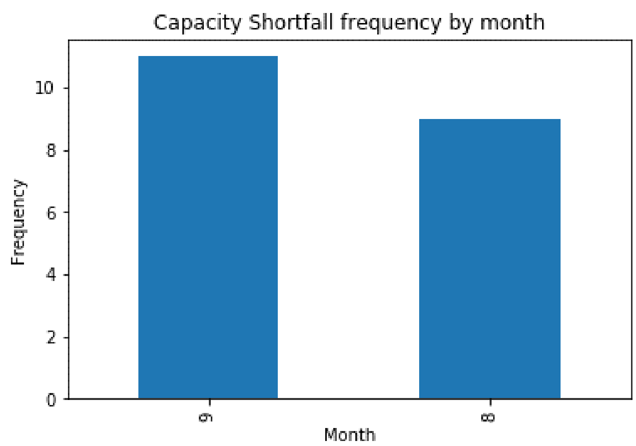


Figure 5 - Unserved Energy Event Occurred Hours for ABB CE - 38 MMT Core Portfolio with Lower PRM