PUBLIC UTILITIES COMMISSION
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May 21, 2021

Agenda ID #19549
and
Alternate Agenda ID # 19547
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 20-05-003:

Enclosed are the proposed decision of Administrative Law Judge Julie A. Fitch previously designated as the presiding officer in this proceeding and the alternate proposed decision of Commissioner Rechtschaffen. The proposed decision and the alternate proposed decision will not appear on the Commission's agenda sooner than 30 days from the date they are mailed.

Pub. Util. Code § 311(e) requires that the alternate item be accompanied by a digest that clearly explains the substantive revisions to the proposed decision. The digest of the alternate proposed decision is attached.

This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 3 days beforehand. When an RDM is held, there is a related ex parte communications prohibition period. (*See* Rule 8.2(c)(4).)

When the Commission acts on these agenda items, it may adopt all or part of the decision as written, amend or modify them, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision and alternate proposed decision as provided in Pub. Util. Code §§ 311(d) and 311(e) and in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed [15] pages.

Comments must be filed pursuant to Rule 1.13 and served in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to Commissioner Rechtschaffen's advisor Sean Simon at SVN@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/S/ ANNE E. SIMON_________
Anne E. Simon
Chief Administrative Law Judge

AES:avs

Attachment

Agenda ID #19549
and
Alternate Agenda ID # 19457
Ratesetting

ATTACHMENT

DIGEST OF DIFFERENCES BETWEEN ADMINISTRATIVE LAW JUDGE FITCH'S PROPOSED DECISION AND THE ALTERNATE PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN

This alternate differs from the proposed decision only in the area of eligibility and authorization for resources utilizing fossil fuels.

The alternate:

1. Directs procurement of 500 megawatts (MW) conventional fossil-fueled generation by the investor-owned utilities (IOUs) with the following conditions:
   a. Cannot be located in a disadvantaged community;
   b. Projects at mothballed or retired plants cannot qualify;
   c. The project must demonstrate greenhouse gas emissions benefits and incremental net qualifying capacity; and
   d. Contracts are limited to five years.
2. Authorizes procurement by the IOUs of 300 MW of eligible fossil-fueled resources that commit to using specified portions of green hydrogen fuel throughout the contract term.
3. Specifies that the procurement above will have its costs allocated via the cost allocation mechanism.

Adds that the proceeding's planning track will explore coordinated planning for resource buildout and resource retirement to inform an orderly and equitable path to Senate Bill 100 goals, optimizing for greenhouse gas reductions, reliability, and costs.

Decision **PROPOSED DECISION OF ALJ FITCH (Mailed 5/21/2021)**

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

DECISION REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY (2023-2026)

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DECISION REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY (2023-2026)

Summary

This decision addresses the mid-term reliability needs of the electricity system within the California Independent System Operator's (CAISO's) operating system by requiring at least 11,500 megawatts (MW) of additional net qualifying capacity (NQC) to be procured by all of the load-serving entities (LSEs) subject to the Commission's integrated resource planning (IRP) authority. The capacity requirements are adopted annually, beginning with 3,000 MW by 2023, an additional 4,500 MW by 2024, an additional 2,000 MW by 2025, and an additional 2,000 MW by 2026.

This procurement order is designed to achieve our ambitious greenhouse gas (GHG) emissions reduction targets for 2030 and to keep us on a clear path to meeting our ultimate goal of 100 percent zero-carbon electricity resources by 2045. In particular, the resources required in 2023-2025 are designed for purposes of replacing the capacity retiring from the Diablo Canyon Power Plant (Diablo Canyon), as well as several thermal power plants complying with the once-through-cooling (OTC) regulations of the State Water Resources Control Board (Water Board). We are specifically ordering that the resources from Diablo Canyon be replaced with at least 2, 500 MW of firm, zero-emitting resources. We also expect that almost all of the resources procured pursuant to this order will be zero-emitting.

The 2026 resources are required to be long-lead-time (LLT) resources, with half coming from long-duration storage and the other half from either firm (at least 85 percent capacity factor) or dispatchable (between hours 17 and 22)

zero-emitting resources, designed to replace the firm and/or dispatchable output of Diablo Canyon and the OTC facilities.

Contracted imported power may be used to count toward the capacity requirements in this order if the imports otherwise meet the requirements for firm imports in the resource adequacy program, are available during the duration of the time period for this order (2023-2026), and are contracted with new resources that have commercial online dates after the date of this decision.

Incremental capacity from fossil-fueled resources that represent efficiency improvements, upgrades, or repowering at existing sites may be used to satisfy between 1,000 MW and 1,500 MW of the total 11,500 MW requirements in this order, to be procured by the investor-owned utilities only by 2025. These resources are determined to be needed for system reliability overall and best procured by the investor-owned utilities (IOUs), and will therefore have their costs allocated to all customers via the cost allocation mechanism (CAM). In addition, we place additional restrictions and prohibitions on these resources if they are located in disadvantaged communities. All fossil-fueled projects will also be required to file a full application with the Commission for approval.

The total capacity procurement requirements are allocated to all LSEs in proportion to their overall load on the electric system, as adjusted by their peak load contribution, and all LSEs will be required to procure their proportional share other than the fossil-fueled resources described above.

LSEs will be required to submit procurement information twice yearly, consistent with Decision (D.) 20-12-044 requirements, to show progress toward the capacity procurement requirements in this decision. Backstop procurement to be conducted by the IOUs may be ordered by the Commission once yearly, with the costs allocated to the deficient LSEs and/or their customers. In addition, deficient LSEs will be subject to penalties for failing to deliver the capacity required in 2023-2025 at the level of the net cost of new entry (CONE). Penalties will not be assessed on any LSE failing to procure the LLT resources required in 2026; LSEs showing a good faith effort to procure these resources may be granted an extension until 2028 before facing potential penalties, due to the challenging nature of procuring these important LLT resources.

For the IOUs that must submit their contracts to the Commission for advance approval, Tier 3 advice letters must be submitted for all procurement, except, as mentioned above, for contracts with fossil-fueled resources, which will require full applications.

This proceeding remains open.

1. Background

On February 22, 2021, an Administrative Law Judge (ALJ) ruling (ALJ ruling) was issued seeking comments from parties on Commission staff analysis of mid-term (2024-2026) electric system reliability and proposed procurement requirements recommended based on the analysis. The ruling included a series of questions to which parties responded in comments and reply comments.

The following 46 parties timely filed comments on or before March 26, 2021, in response to the ALJ ruling: American Clean Power - California (ACP-CA); Advanced Energy Economy (AEE); Alliance for Retail Energy Markets (AReM); Bioenergy Association of California (BAC); California Biomass Energy Alliance (CBEA); California Community Choice Association (CalCCA); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Independent System Operator (CAISO); California Wind Energy Association (CalWEA); Calpine

Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); City and County of San Francisco (CCSF); Diamond Generation Corporation (Diamond); Eagle Crest Energy (Eagle Crest); Electrochaea Corporation (Electrochaea); Environmental Defense Fund (EDF); EDF Renewables, Inc. (EDFR); Fervo Energy Company (Fervo); Form Energy, Inc. (Form Energy); Geothermal Rising (GRC); Golden State Clean Energy, LLC (Golden State); Green Power Institute (GPI); GridLiance West LLC (GridLiance); Hydrostor, Inc. (Hydrostor); Independent Energy Producers Association (IEP); L. Jan Reid (Reid); Long Duration Energy Storage Association of California (LDESAC); Middle River Power, LLC (Middle River); Natural Resources Defense Council (NRDC); Ormat Technologies, Inc. (Ormat); Pacific Gas and Electric Company (PG&E); Protect Our Communities Foundation (PCF); Public Advocates Office of the California Public Utilities Commission (Cal Advocates); Powerex Corporation (Powerex); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (Shell); Silicon Valley Clean Energy Authority (SVCE) and Central Coast Community Energy (3CE), jointly; Small Business Utility Advocates (SBUA); Southern California Edison Company (SCE); Southwestern Power Group II, LLC (SWPG) and Pattern Energy (Pattern), jointly; The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); Vote Solar, the Large-Scale Solar Association (LSA), and the Solar Energy Industries Association (SEIA), jointly; Watson Cogeneration (Watson); and the Joint Environmental Parties, consisting of NRDC, UCS, CEJA, Defenders of Wildlife (DOW), EDF, Friends of the Earth (FOE), GPI, and Sierra Club, jointly.

The following 38 parties timely filed reply comments on or before April 9, 2021, in response to the ALJ ruling: ACP-CA; AEE; AReM; Brookfield Renewable Trading and Marketing, LP (Brookfield); CalWEA; CAISO;

Cal Advocates; CalCCA; Calpine; CBEA; CCSF; CEERT; CEJA and Sierra Club, jointly; CESA; Diamond; EDF; Form; Green Hydrogen Coalition (GHC); GridLiance; GPI; GR; Hydrostor; IEP; LDESAC; LS Power Development, LLC (LS Power); Middle River; Ormat; PCF; PG&E; PCF; Reid; SBUA; SCE; SDG&E; SEIA, LSA, and Vote Solar, jointly; SWPG and Pattern, jointly; TURN; Vistra Corp. (Vistra); and the Joint Environmental Parties.

2. Planning Standards

The February 22, 2021 ALJ ruling included an adjustment to the planning reserve margin (PRM) that is used to analyze integrated resource planning (IRP) scenarios. To account for the types of conditions that led to unplanned rotating outages in August 2020, as well as the high demands experienced in September and October 2020, a PRM of 20.7 percent was used as the basic assumption for the analysis leading to the recommended level of procurement. This included a revision to the operating reserve component of the PRM from 4.5 percent to 6 percent, as well as an additional 2,000 megawatts (MW) of generic capacity that was added in the last IRP cycle to cover perceived calibration differences between the two major models being used for IRP (RESOLVE and SERVM), but may have also included changing reliability conditions on the electric system.

Parties were asked to comment on the 20.7 percent PRM assumption, as well as whether a loss of load expectation (LOLE) metric would be preferable. The ALJ ruling also sought input on the appropriate weather variants of the demand forecast to be used. Currently, the IRP process uses the "1-in-2" weather variant of the demand forecast, which means that the expectation is that the forecast will be exceeded once every two years, on average. Parties were asked to weigh in on whether a 1-in-5 or 1-in-10 weather variant assumption would be more appropriate, and why.

2.1. Comments of Parties

Roughly half of the parties commenting on the planning assumptions made for the analysis in the February 22, 2021 ALJ ruling agreed, to a larger or lesser degree, that the 20.7 percent PRM assumption was appropriate for now. These parties included AEE, CAISO, Calpine, CESA, Golden State, Hydrostor, IEP, LDESAC, Middle River, NRDC, Ormat, SBUA, SEIA/LSA/Vote Solar, Shell, and Watson. Most of these parties also would have preferred a more complete or more robust analysis if there was or is time. Some also noted that the PRM may need to be even higher, given the composition of resources on the grid today, as well as due to the reliability challenges experienced in 2020.

Cal Advocates argued that the 1.5 percent additional operating reserves is appropriate, as well as approximately 1.1 Gigawatt (GW) additional capacity, which amounts to 2.4 percent. Together, these amounts would equal around 18.7 percent and could be rounded up to 19 percent as an assumption, rather than 20.7 percent.

GPI would prefer a modified demand level be used for modeling, but if using a PRM, GPI suggested that it be at most 1.25 times the 15 percent level, which would amount to 18.75 percent. GPI reasoned that this would serve as a middle ground between the existing 15 percent assumption and the higher 20.7 percent level.

CCSF and TURN argued that the PRM assumption for this round of analysis should be set at 17.5 percent, with CCSF arguing that this is the PRM level used in the extreme weather Rulemaking (R.) 20-11-003, while TURN pointed to the root cause analysis report from the events of August 2020. Both argued that the 17 percent level would be an interim assumption until a more complete study is conducted to set the long-term assumption.

AReM and Reid argued that a 15 percent PRM should be maintained for now, with a more complete analysis later. PCF argued that instead of revising operating reserves up to 6 percent, they should be moved down to 3 percent, with import limits increased by the 2,000 MW adder amount, since this would still be fewer imports during the peak demand period than assumed in earlier analyses.

The 20.7 percent assumption was actively opposed by several parties, including CEERT, CEJA/Sierra Club, EDF, SCE, and SDG&E. PG&E and CalCCA also opposed the 20.7 percent PRM assumption, but generally supported procurement requirements in the range of 7 GW (CalCCA) or 7.5 GW (PG&E), with additional analysis for setting the PRM in the future. PG&E was also concerned about transmission constraints and wanted more zonal analysis of procurement locations.

Almost all parties opposed using the 20.7 percent PRM assumption for long-term planning going forward without additional analysis.

Parties were quite divided on the subject of the appropriate weather variant of the demand forecast to use (1-in-2, vs. 1-in-5 or 1-in-10). A good number of parties supported maintaining a 1-in-2 forecast, including Cal Advocates, CEJA/Sierra Club, Gridliance, IEP, PCF, PG&E, SCE, SDG&E, and SBUA. Some parties argued that the 1-in-2 should remain, under the assumption that the PRM assumption is already being increased to 20.7 percent. Many of these parties supported using the 1-in-2 forecast for purposes of this order, but exploring other options for later planning, after considering further the effects of climate change.

Cal Advocates also suggested consideration of incorporating a 1-in-5 weather variant in developing the inputs and assumptions for the next cycle of the IRP process. CEJA/Sierra Club pointed out that the difference between a 1-in-2 weather variant and a 1-in-5 is related to air conditioning load, and as such, advocated that programs should be developed that directly target that impact.

Middle River argued that the weather variant used should either be higher than 1-in-2, with an average allowance for load forecast error in the PRM, or be 1in-2 with a high allowance in the PRM, but not both, since together these assumptions create a compound effect.

CEERT and Reid advocated that a 1-in-10 weather variant be used. CESA referred to recent California and Texas outages and suggested that even 1-in-10 may not be enough. Form advocated for 1-in-10 at a minimum, and preferably 1-in-20. ACP-CA suggested consideration of 1-in-35, while not advocating that this level be adopted now. GPI argued that the assumptions underlying the forecasts need to be recalibrated in light of expected weather pattern changes due to climate change.

CalCCA argued that using higher percentiles of the load distribution, different rainfall profiles for hydroelectric generation, or a 1-in-5 weather variant may well be warranted as part of an overall PRM analysis, and an LOLE analysis should be the ultimate guide. Hydrostor, referring to the amount of capacity that will need to be built to electrify the transportation sector and buildings, and NRDC, referring to the demand forecast and its accounting for climate change, also generally advocated for further study of these weather and demand forecasting issues.

Finally, CAISO pointed out that the CEC currently only produces hourly forecasts based on the 1-in-2 weather variant, and use of higher forecasts would have to be based off of those same hourly forecasts. Thus, further analysis would likely be needed to develop true 1-in-5 or 1-in-10 (or higher) weather variants. Overall, the CAISO basically argued that increasing the PRM or changing the demand forecast weather variant are interim measures that will uncover the minimum level of need, but should not replace more comprehensive reliability analysis for the long-term requirements. Many other parties, including CalCCA, CCSF, CEERT, CEJA/Sierra Club, GPI, Golden State, NRDC, PG&E, SCE, SEIA/LSE/Vote Solar, SWPG, UCS, and SBUA all stated this same basic conclusion in various and slightly different ways.

When addressing the assumptions that the Commission should use for the long-term in IRP, AReM insisted that both the PRM and LOLE assumptions are out of scope for the IRP proceeding, preferring to address these questions only in the resource adequacy context. The majority of parties argued that the PRM assumptions should be regularly updated, based on studies to determine how much of a PRM is required to maintain a 0.1 LOLE standard. These parties included CalCCA, CEJA/Sierra Club, NRDC, PG&E, SCE, SDG&E, TURN, UCS, CAISO, Shell, CCSF, and Watson. Calpine, SDG&E, Shell, CCSF, and Watson commented that the 0.1 LOLE standard should be maintained, while CalCCA, SCE, and CAISO argued that this standard should be revisited.

Several parties preferred that the IRP analysis use different metrics than just LOLE, including expected unserved energy (EUE), or loss of load hours (LOLH), instead of or at least in addition to an LOLE-based metric. Form and Reid made comments along these lines, and Form proposed a "net energy" planning standard to address reliability issues. Middle River commented that the IRP analysis should address local area reliability requirements that are no less stringent than in the resource adequacy program. SBUA commented that the Commission needs to relook at and potentially redefine both the resource adequacy and IRP reliability methods to address the current, more modern power system.

Many parties also commented about the continuing need for coordination between IRP and resource adequacy planning and compliance, including ACP-CA, PG&E, SVCE, CESA, and SEIA/LSA/Vote Solar. Cal Advocates specifically advocated that the PRM assumptions for IRP should be higher than the compliance standard in resource adequacy.

2.2. Discussion

For 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. The composition of the electric grid is changing dramatically, at the same time that the state is facing more extreme weather events driven, at least in part, by climate change. Therefore, we will refrain, in this order, from setting new standards for PRM, LOLE, or weather variants of the demand forecast, and instead will continue additional analysis and stakeholder engagement before making major changes. With respect to matters related to the demand forecast and the impacts of climate change, we will work closely with the CEC to determine if there are additional changes or analyses that they should make in the demand forecast that underpins a lot of other analysis by this Commission, the CEC, and the CAISO in driving reliability and environmental decisions affecting the electricity sector.

Should the Commission decide to continue to use an LOLE metric of 0.1, we agree that the PRM should be set at a level that accomplishes this reliability level, and the analysis should be regularly updated. Commission staff is currently conducting such an analysis, and additional analysis and discussion of these issues will be forthcoming in this proceeding. In the meantime, we will not make revisions to the long-term assumptions in this decision.

However, we do need to make a determination about the assumptions to use to support this interim procurement requirement for the medium term (2024-2026). For this purpose, we find that the 20.7 percent PRM assumption is a reasonable proxy for the potential changes that may be needed to the PRM, the load forecast, and LOLE standards. Though certainly not every party agreed with this PRM assumption, even on an interim basis, most parties did not object to the resulting magnitude of the capacity procurement. The 20.7 percent PRM level is higher than the assumption used in the extreme weather proceeding addressing 2021 reliability, which was 17.5 percent. However, in the context of this order, with the longer timeframe, it is reasonable to account for both some contingency, as well as both the reliability and environmental goals that drive the need for greater investment in development of new and improvement of existing resources.

3. Need Determination

To conduct the analysis of potential procurement needed during the mid-term (2024-2026) timeframe for purposes of the February 22, 2021 ruling, Commission staff began with the planning standards described above, which are the 1-in-2 managed peak forecast, plus the PRM.

The 2019-2020 IRP baseline generator list was updated to align with the CAISO Master File. Staff also accounted for additions to the IRP baseline using the contracted resources included in the individual IRP filings of all of the load-serving entities (LSEs) included in their filings from September 1, 2020 intended to meet the 46 million metric ton (MMT) greenhouse gas (GHG) target required by D.20-03-028. Resources in development that were identified in the individual IRP filings were added to the baseline if they had signed contracts that were approved by the Commission and/or the LSE's highest decision-making authority, as applicable, as of June 30, 2020. Also included were resources sufficient to meet 100 percent of the 3,300 MW of net qualifying capacity (NQC) needed to satisfy the requirements of Decision (D.) 19-11-016.

Each resource type had its NQC based on expected contribution to reliability. For wind and solar resources, Commission staff applied effective load carrying capability (ELCC) assumptions developed stochastically by year. For other resource types, staff applied the September NQC according to the Commission's 2021 NQC list, where available, and otherwise used technology-specific NQC multipliers consistent with the 2019-2020 IRP Inputs and Assumptions.[1] Once-through cooling (OTC) plant closures, and other planned retirements, were also taken into consideration.

Once all of these NQC values were calculated, they were added up and compared against the reliability need in each year through 2026.

Commission staff also analyzed a low-need and a high-need scenario, to bound the amount of effective capacity likely to be needed in the medium term. For the low-need scenario, staff removed the PRM adjustments, leaving it at 15 percent instead of 20.7 percent, and also removed project viability discounts on the resource additions to the IRP baseline. For the high-need scenario, approximately 815 MW of additional thermal plant retirements by 2026 were assumed. This was based on an estimate of the portion of the thermal generation fleet that will reach 40 years of operating life by 2026, which is an indication of the risk of plants being retired beyond those already announced. Also, for the

[1] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442459770

high-need scenario, unspecified imports were reduced from 5 GW to 4 GW. Finally, the PRM was effectively increased further to reflect an assumed effect of a one-degree Celsius temperature increase due to climate impacts over the next decade, with the impacts of the changed assumption applied beginning in 2024.

Table 1 below shows the key metrics and NQC need outputs for each scenario.

Table 1. Assumptions and Outputs of Need Scenarios Analyzed (NQC MW unless otherwise specified)

Item	Mid Need	Low Need	High Need
Assumptions (by 2026)			
PRM	20.7%	14.9%	22.5%
Operating Reserves (subset of PRM)	6%	4.5%	6%
Unspecified imports	5,000	5,000	4,000
OTC unit retirements	3,733	3,733	3,733
Diablo Canyon retirement	2,280	2,280	2,280
Additional thermal retirements	479	479	1,294
Outputs			
2024 NQC shortfall	4,146	1,520	6,571
2025 NQC shortfall (cumulative)	7,097	4,424	9,892
2026 NQC shortfall (cumulative)	7,410	4,715	10,432

The ALJ ruling recommended that procurement be required to address the mid-need scenario, which showed the need for 7,410 MW of NQC additions by 2026. This amount, when added to the 3,300 MW of NQC required by D.19-11-016, closely approximates the 18,000 MW of new nameplate capacity by 2026 included in the Reference System Portfolio (RSP) adopted in D.20-03-028.

3.1. Comments of Parties

Parties to the proceeding were quite divided about the reasonableness of the mid-need scenario. Parties generally supporting the recommendation in their comments on the ALJ ruling included Calpine, GridLiance, IEP, SWPG/Pattern, Watson, SBUA, SDG&E, PG&E, and CalCCA. SDG&E argued that this level of procurement is in line with the IRP load case used in the IRP RESOLVE modeling. These parties generally commented that this level of procurement appeared to represent a balanced analysis.

Parties preferring that the Commission order procurement based on the high-need scenario included ACP-CA, CEERT, EDF, CESA, Golden State, Hydrostor, LDESAC, SEIA/LSA/Vote Solar, Cal Advocates, and CAISO. ACP-CA argued that the high-need scenario is more reasonable given the number of uncertainties inherent in the analysis, including projected online dates for baseline resources, development uncertainty, weather events, interconnection issues, and the likelihood that the Commission will reduce the greenhouse gas (GHG) target. SEIA/LSA/Vote Solar, CEERT, CESA, and Golden State pointed out the requirements of Senate Bill (SB) 100 (DeLeon, 2018) requiring electric sector near-zero-carbon emissions by 2045, as well as the likelihood of load growth associated with electrification. EDF, CESA, CEERT, and Hydrostor argued that the high-need scenario is the least-regrets option, and CESA pointed out that this level of procurement is consistent with the CAISO's independent stochastic analysis.

CESA argued that the GHG target should be set at 38 MMT for the electric sector by 2030, and therefore the high-need scenario is more relevant. LDESAC and SEIA/LSA/Vote Solar argued that we should account for the additional units likely to retire during this period, beyond those already announced, and that increasing capacity constraints in the West in general will constrain imports further. SEIA/LSA/Vote Solar also argued that there is little risk in requiring additional procurement over the next four or five years, because tax credits are still available that will make the investments lower cost for ratepayers. Finally, in between opening and reply comments, Cal Advocates changed their position to advocate for the high-need scenario (from the mid-need) after reading the CAISO analysis and after accounting for additional coal retirements in the West.

Several parties, by contrast, argued that the low-need scenario is more appropriate and least regrets. AReM objected to the use of the 20.7 percent PRM for the mid-term analysis and argued that it does not equate to a 0.1 LOLE. Therefore, AReM reasoned that the mid-need scenario would lead to over-procurement and higher costs than necessary for all consumers. Reid pointed out that the California economy is in poor condition, and therefore cost should be a paramount consideration. TURN suggested that a lower PRM of 17.5 percent be used, similar to the assumption used in emergency procurement for 2021, which would result in procurement requirements similar to the low-need scenario. PCF argued that the import assumptions and the high PRM assumption will lead to excess procurement and cost.

CEJA and Sierra Club argued that at least 20,000 MW of procurement should be required by 2026, with 14,000 MW coming from solar and wind resources, with no gas capacity counting towards any of the requirements. CEJA and Sierra Club agreed with various other parties that the procurement requirement should be based on a lower GHG target, and also argued that the Commission cannot rely on the RPS requirements to meet the higher GHG requirements.

GPI did not support the high-need scenario, and Middle River stated that they could not comment on the appropriateness of the procurement amount because the analysis that led to the recommendation was not rigorous enough.

SCE argued that the Commission must take action now as a "no regrets" first step and require procurement of at least 5,400 MW to address the OTC and Diablo Canyon retirements, while resolving any additional procurement in a later decision.

CAISO conducted its own analysis and presented a summary of that analysis in its comments, calling for at least 10,000 MW of effective capacity by 2026. The CAISO also noted that it had reevaluated the Commission staff analysis and considered the need for additional capacity because the peak demand is shifting later in the day. CAISO, AReM, and SCE commented that the Commission staff analysis was more focused on gross peaks than net peaks, which currently are the most critical reliability periods.

Several parties also pointed out errors in the staff analysis that led to all of the need cases. First, AReM and CalCCA pointed out that there was 410 MW of small hydroelectric capacity that was inadvertently left out of the analysis. Hydrostor also pointed out an error in a ruling reference to the Navajo coal plant, noting that the plant retired in 2019 (this was reflected correctly in the associated spreadsheets). Finally, Cal Advocates noted that the updated CEC load forecast adopted as part of the Integrated Energy Policy Report (IEPR) in 2021[2] should be used, instead of the 2020 forecast, which would result in increased resource needs of at least 1,100 MW by 2026.

[2] Available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update

Finally, GPI and Watson raised the issue of ensuring that existing preferred resources that may be coming off contract in the mid-term are re-contracted, by increasing the amount of resources that are required to be procured in the medium term. This position was opposed, in reply comments, by CalCCA, on the basis that there is a significant probability that preferred resources with imminent retirement dates will be voluntarily recontracted by LSEs to meet other objectives, including the RPS and resource adequacy requirements.

3.2. Discussion

First, we agree with CalCCA and others that an error in the accounting for small hydroelectric resources should be corrected. This, combined with correction of erroneous counting of a specified import as thermal instead of solar,[3] results in a net reduction in the ultimate need under any scenario by approximately 327 MW.

Second, we disagree with the comments of the CAISO and others that our analysis does not account for the net peak periods. The model used for the analysis underpinning this decision uses the managed peak from the CEC's demand forecast as the basis for determining resource adequacy need, but in doing so accounts for the annual ELCC of renewables both in front of and behind the meter. This is done via the use of the ELCC surface model, derived from probabilistic analysis, that expresses the total ELCC of a portfolio of wind and solar resources as a function of the penetrations of each of those two resources on the grid. Using this, the model accounts for the impacts of renewables in shifting the gross peak to the managed peak, as well as the impact in shifting the

[3] This error was caught by Commission staff and described in a workshop held on March 10, 2021 describing the analysis.

managed peak to the net peak. The model captures the total ELCC and provides an estimate of the marginal ELCCs, thereby capturing the net peak challenges via an upstream probabilistic analysis rather than an hourly deterministic view.

Despite our confidence in the appropriateness of the Commission staff analysis taking into account the net peak impacts, we agree with those parties who argue that we should choose the high-need scenario as the basis for this procurement order. There are several reasons for this. In general terms, we have, for many years, tended to choose mid-level requirements in all procurement-related orders. It is likely partly due to a natural tendency to assume that the middle scenario is likely "just right," and represents the least-regrets choice. However, as the rotating outages required in August 2020 have demonstrated, we are not in a business-as-usual situation on the electric grid in California. The electricity market is changing rapidly in many respects, including the large number of new LSEs, the recent major shifts in the resource mix, a great deal of weather- and climate-change-driven uncertainty, as well as the increasing acceleration of electrification of building and transportation end uses.

In addition, our staff are currently aggregating the individual IRPs submitted to us in September 2020 by all LSEs, and we strongly anticipate the adoption of those plans that achieve the 38 MMT GHG limit by 2030, assuming that the aggregated portfolio of all LSEs achieves the necessary reliability levels. If that is the case, as pointed out by many parties, procurement of larger amounts of resources will be necessary compared to the current 46 MMT target, between now and 2030.

All of these factors, coupled with the increasing urgency of our climate goals, leads us to choose to adopt the high-need scenario here rather than the mid-need scenario. An additional benefit is that this comports with the CAISO's analysis of the need, even though the CAISO arrived at a similar conclusion using slightly different assumptions and analytical tools. But the similarity in results gives us confidence that this is in the ballpark of the level of requirements that will be prudent from a reliability perspective.

Under the high-need scenario, with the corrections made for small hydro projects and the adjustments to account for higher demand in the CEC's IEPR forecast adopted in February 2021, the procurement need identified is as follows:

- 2024: 7,361 MW;
- 2025: 10,816 MW; and
- 2026: 11,597 MW.

Finally, in response to the comments of GPI and Watson, with the concern about the need to re-contract existing preferred resources, we clarify that that is not the purpose of this order (or D.19-11-016). Our primary purpose here is to require the LSEs to develop new clean energy resources to address growing resource adequacy needs for new generating, non-generating, and hybrid resources. The risk of retirement of preferred resources is also important, but it is not something the Commission needs to act on here, given the roles of the resource adequacy program and the RPS program requirements, and the LSEs' ongoing requirements to satisfy those obligations. The need for additional Commission action is something the LSEs are required to address in their individual IRPs and also something we can consider when we analyze the preferred system portfolio later this year; we will also consider requiring additional procurement associated with meeting GHG, reliability, RPS, or other goals as part of the PSP.

4. Timing of Procurement

The February 22, 2021 ALJ ruling reasoned that because the current reliability electricity situation has been tight, there is risk in requiring procurement only for the exact amount of capacity identified as needed in any given year. Thus, the ALJ ruling proposed to accelerate procurement requirements by one year for 40 percent of the capacity identified as needed in each year. The ALJ ruling also rounded up the procurement requirements to round numbers to simplify the implementation.

The ruling also suggested that June 1 be the required online date in each year except 2023. The resulting capacity requirements are given in Table 2 below. This capacity is proposed to be in addition to the 3,300 MW NQC required in D.19-11-016.

The ruling also asked whether any contingency procurement should be ordered, to mitigate risk of contract delay or failure.

Table 2. Need Determination by June 1 of Each Online Year (MW NQC)

Need Determination and Required NQC	**2023 (Aug 1)**	**2024**	**2025**	**2026**	**Total**
System Resource Adequacy Need (cumulative)	-	4,146	7,097	7,410	7,410
System Resource Adequacy Need (annual additions)	-	4,146	2,951	313	7,410
Accelerated capacity requirement (approx. 40% by prior year)	1,658	3,668	1,896	188	7,410
Accelerated capacity requirement, conversion to round numbers *(recommendation)*	1,800	3,700	2,000	-	7,500

4.1. Comments of Parties

In comments in response to the February 22, 2021 ALJ ruling, parties were vocal about the issue of accelerating procurement, expressing concerns about increased costs and potentially less diverse resource selection, if procurement requirements are accelerated. CEERT, Diamond, GridLiance, IEP, PG&E, and SWPG/Pattern all generally supported the approach proposed in the ALJ ruling. AReM, Cal Advocates, CCSF, CESA, GPI, Hydrostor, Reid, PCF, SCE, Shell, SBUA, and TURN all generally opposed the accelerated approach. Several parties involved in resource development said that this timeframe is unreasonable and could result in more parties choosing existing thermal contracts or defaulting to solar and storage, to the detriment of resource diversity. PCF pointed out that battery costs are decreasing, making early procurement more expensive.

In replies, AReM, CCSF, Hydrostor, and SCE all reiterated their opposition to accelerated procurement. CAISO reiterated its support, in response to earlier questions, of early procurement to address OTC retirements. IEP suggested accelerating 20 percent of the annual procurement amounts instead of 40 percent, to produce some contingency without causing too much acceleration that could increase costs.

Several parties also commented on the ALJ ruling proposal to round up the annual requirements as an additional contingency. AEE supported this approach, while Reid and SBUA opposed.

With respect to contingency procurement, most commenting parties opposed (AReM, Cal Advocates, Calpine, CCSF, GPI, Reid, Middle River, PCF, PG&E, SCE, SDG&E, and SBUA), though TURN suggested that contingency procurement could potentially meet future obligations.

4.2. Discussion

We are generally in favor of requiring enough procurement ahead of the exact time when it is needed, because of the reliability risks, as well as potential costs, associated with "just in time" procurement. It is generally preferable to bring resources onto the system a little ahead of when they are needed rather than have an emergency situation in real time. Given that many LSEs are already procuring to meet the requirements of D.19-11-016, the additional procurement required by this order represents an increase that is somewhat large but still should be manageable within their operations.

Due to our selection of the high-need scenario, as discussed in Section 3, this provides a natural contingency for demand being higher than expected. Thus, we are slightly less concerned with the exact annual procurement amounts than we might have been if we were requiring only the mid-need scenario amounts. However, a countervailing consideration is the retirement of Diablo Canyon that will represent two large amounts of capacity retiring in short order in 2024 and 2025. Thus, we want to be sure to require enough new capacity to ensure reliability of the system during this period.

Another consideration is with respect to the desirability of requiring the procurement of some long lead-time (LLT) resources such as geothermal or long-duration storage. This is discussed in more detail in Section 5. However, for purposes of assigning the annual amounts of procurement required, we want to be sure to leave room for those resources being procured in a feasible timeframe, which most parties seem to agree is 2026 at the earliest.

Finally, we agree with parties that these measures offer sufficient hedging, and additional contingency procurement beyond this amount is not required.

Taking all of these factors into consideration, Table 3 below summarizes our determination of the annual procurement amounts that will be required from all LSEs as a result of this order.

Table 3. Adopted Aggregated Procurement Requirement by June 1 of Each Online Year (MW NQC)

Need Determination and Required NQC	**2023 (Aug 1)**	**2024**	**2025**	**2026**	**Total**
System Resource Adequacy Need (cumulative)	-	7,361	10,816	11,597	11,597
System Resource Adequacy Need (annual additions)	-	7,361	3,455	781	11,597
Accelerated capacity requirement (approx. 40% by prior year)	3,097	5,646	2,385	469	11,597
Accelerated capacity requirement, conversion to round numbers and similar annual requirements *(adopted amounts)*	3,000	4,500	2,000	2,000	11,500

5. Eligible Resources

The February 22, 2021 ALJ ruling proposed, due to the significant amount of capacity needed in the 2024-2026 timeframe associated with the retirement of Diablo Canyon and OTC plants, which are firm capacity resources, that at least some of the replacement capacity be similarly firm in nature. Longstanding concerns about resource diversity also led to this suggestion, along with the declining ELCC values of solar, solar plus storage, or standalone battery storage.

In addition, the RSP adopted in D.20-03-028 identified the need for some resources that have long development lead times (chiefly long-duration storage). Thus, the ruling proposed that at least 1,000 MW of geothermal resources and 1,000 MW of long-duration storage (defined as providing 8 hours of storage or more) be required to be part of the procurement requirement by no later than

2025. LSEs would be encouraged, but not required, to undertake joint procurement for their share of both the geothermal and long-duration storage requirements, under terms mutually agreed upon and not imposed by the Commission. If the LSEs did not show significant progress toward this procurement by the August 1, 2023 milestone reporting date, the ruling proposed that the Commission consider requiring large investor-owned utilities (IOUs) to procure these resources using the cost allocation mechanism (CAM) or forthcoming modified version of CAM.

Ultimately, the ruling proposed the procurement summarized in Table 4 below.

Table 4. Total Recommended Mid-Term Procurement Requirements (in NQC MW)

Type of Resource	2023	2024	2025	Total
Geothermal resources	-	-	1,000	1,000
Long-duration storage resources	-	-	1,000	1,000
Any type of resource	1,800	3,700	-	5,500
Total	1,800	3,700	2,000	7,500

In addition, the ALJ ruling proposed certain limitations on allowing natural gas-fired generation to qualify to provide the capacity in Table 4 above. The proposal was that fossil-fuel development at new sites be prohibited from qualifying to satisfy the requirements of this order, but that redevelopment or repowering at existing electric generation sites could be eligible, with some restrictions. The restrictions listed to elicit parties' comments included:

- Prohibiting modifications to existing fossil-fueled plants within disadvantaged communities unless they can demonstrate net reductions in greenhouse gases and criteria pollutant emissions.

- Requiring contracts to include dispatch constraints, such as limited generating hours, for fossil-fueled plants within disadvantaged communities.
- Allowing repowered or augmented fossil-fuel contracts to count if they are in effect only for a period of ten years or less.
- Requiring efficiency improvements or reductions in the rate of GHG emissions for any fossil-fueled plant repowering.
- For IOUs, allowing fossil-fueled capacity to count, but penalizing its valuation in the least-cost best-fit evaluation in some way.
- Also for IOUs, requiring any contract with fossil-fueled resources to be submitted to the Commission for approval via an application instead of an advice letter.
- Requiring fossil-fueled capacity used to count toward the procurement required to burn a percentage of green hydrogen (hydrogen produced with zero-emitting resources) or biomethane.

The ruling also mentioned, but did not propose, another alternative, which is to request further extensions of OTC compliance deadlines for existing natural gas plants.

Finally, the ruling did not specify if or how imports could count toward the potential capacity procurement requirements, but asked parties to comment on whether firm imports should be allowed to count, particularly if committed to California via pseudo-ties or dynamic scheduling. Parties were invited to suggest any other limitations on or requirements for imports to count towards the capacity requirements.

5.1. Comments of Parties

5.1.1. Long-lead-time resources

The majority of parties responding to the ALJ ruling suggestion for resource-specific procurement requirements for geothermal and long-duration storage resources were opposed to the proposed requirements for 1,000 MW of each by 2025. Opposition came from ACP-CA, AEE, AReM, BAC, Cal Advocates, CBEA, CCSF, SCE, PG&E, Diamond, Golden State, IEP, Middle River, SEIA/LSA/Vote Solar, PCF, Shell, SVCE, SBUA, and CalCCA.

Parties supporting the proposal for resource-specific requirements included Calpine, CESA, Form, GridLiance, Geothermal Rising, LDESAC, Ormat, and TURN.

Reasons for opposing the proposal included the idea that an order addressing *mid*-term reliability should not require *long*-term LLT resources. Parties also argued that there could be a risk of under-procurement due to the smaller pool of potential projects, as well as a risk of higher costs to ratepayers due to the smaller number of projects. SCE estimated a cost increase of 16 percent, before accounting for market power concerns.

SDG&E argued that geothermal resources cannot provide local or flexible resource adequacy value, which represents a lost opportunity for meeting multiple needs simultaneously with one resource, which will then mean that procurement is more expensive.

PCF argued that any carve-out for a particular type of resource violates Public Utilities Code Section[4] 454.51(a) which requires that the Commission specify resources for the IRP portfolio in a cost-effective manner. PCF also

[4] All further references to code are to the Public Utilities Code, unless otherwise indicated.

argues that it violates CCA rights to self-select resources as detailed in § 454.51(d).

PG&E argued that specific technology mandates belong in focused proceedings, citing the example of the bioenergy requirements in the RPS.

NRDC, with comments somewhat in favor of technology specification, argued that without it, the Commission risks not meeting the statutory requirements related to the retirement of Diablo Canyon.

Ormat was concerned that the Commission does not discourage the nearly 600 MW of geothermal collectively that was included in the LSEs' individual IRPs between now and 2030.

Other parties made specific suggestions for how to modify the proposed requirements, particularly around specifying the attributes of the types of resources needed without necessarily specifying particular technologies.

BAC recommended including all baseload resources. AReM suggested that the Commission define a resource performance profile (generation shape or resource flexibility) and then define the GHG emissions profile; any resource meeting those characteristics would then qualify.

PG&E agreed that the focus should be on operating characteristics. For example: contributing to needs during the net system peak, contributing to needs across all hours of the day, dispatchability, having certain ramping rates, or some combination of all of these.

Form suggested that the specifications should be for firm zero-carbon resources that are physically capable of and contractually guaranteed to deliver at least a 95 percent availability factor over a ten-year period, including during continuous 100-hour low-renewable-energy weather events and grid contingencies reflected in the 1-in-10-year standards.

CalWEA argued that the resources should be specified based on system integration needs, which requires flexible / dispatchable resources, not baseload. CalWEA also suggested aligning with the ongoing work in the resource adequacy proceeding (R.19-11-009) Track 3B. This comment relates to concern about battery storage experiencing too much wear and tear from regular cycling.

In general, the majority of parties argued in favor of the Commission defining criteria rather than resources. Many parties, including developers of these specific types of resources, expressed concern with the timetable being too fast for reasonable projects to compete. Calpine, CCSF, Ormat, SEIA/LSA,Vote Solar, and SWPG mentioned transmission and/or interconnection challenges. CalWEA was concerned about the potential for market power, while GPI was concerned generally with higher costs.

Some stakeholders recommended a market test of some type and/or the ability of LSEs to seek a waiver of the requirement if they are unable to find reasonable projects. Others, including EDF, felt that off-ramps or other mechanisms designed to mitigate risk could create other risks, such as creating additional market uncertainty.

Parties representing developers of long-duration storage, in particular, recommended relaxing the 2025 online date to ensure that some technology types of long-duration storage are able to compete.

SVCE also raised a concern about sending the wrong regulatory signal to LSEs that have already procured these types of resources, with the consequence of requiring them to procure even more of these types of resources that are already inherently difficult or costly to develop.

The reference in the ALJ ruling to joint procurement of LLT resources also caused some confusion among parties. Parties generally seemed to assume the reference was to some form of multi-party power purchase agreement with a resource, rather than having one LSE procure a resource and then sell portions to other LSEs. Parties had mixed interpretations, with some interpreting the proposal as mandatory while other saw it as an option if it helped to meet the LLT requirement. The following parties seemed to generally support the concept of voluntary joint procurement: Cal Advocates, Calpine, CCSF, CAISO, CEERT, CESA, GPI, CalCCA, and PG&E. AReM pointed out that antitrust laws do not allow ESPs to procure jointly. PG&E agreed and suggested allowing joint procurement but not mandating it. SCE would prefer that the IOUs procure the LLT resources, though they would prefer that the Commission not require these separate from the overall capacity requirements.

The CAISO supported the LSEs being given the option for joint or separate procurement of these LLT resources, but directing the IOUs to conduct backstop procurement if individual LSEs fail to procure by 2023, and suggested firm imports as a backstop option.

PG&E and SDG&E commented that the backstop timeline needs to be revised because there is not enough time for the IOUs to backstop LLT resources between 2023 and 2025. SCE would prefer that the IOUs front-stop the LLT resources, considering the time required to procure. CCSF agreed that 2 years is not realistic. CESA would prefer an earlier backstop trigger.

5.1.2. Fossil-fueled resources

Parties had mixed responses on fossil generation, many supporting a prohibition on new fossil-fueled procurement, some supporting restrictions, and others opposing any restrictions beyond limiting procurement to existing sites.

Parties arguing for prohibiting any incremental fossil-fueled generation to count toward the capacity requirements in this order included AEE, CEERT, CEJA/Sierra Club, CESA, EDF, GPI, Hydrostor, Joint Environmental Parties, NRDC, PCF, SEIA/LSA/Vote Solar, TURN, SWPG/Pattern, and UCS. PCF argued that the Commission is legally obligated to support the cleanest, most reliable, and most affordable resources, and that studies have shown that solar and storage are cleaner and more reliable than new gas generation.

GridLiance, Golden State, PG&E, SDG&E, and SBUA supported allowing some incremental fossil-fueled generation, with additional restrictions.

AReM, Calpine, Diamond, Electrochaea, IEP, Middle River, Shell, and Watson wanted fewer or no restrictions. Most reiterated their views that existing and incremental fossil-fueled generation should be eligible at all existing sites, though not at new sites.

BAC supported requiring renewable natural gas as a fuel. Cal Advocates argued that any requirements for green hydrogen are premature, while GHC supports green hydrogen requirements.

Finally, very few parties commented on the idea of any additional OTC extensions as an option. Cal Advocates opposed any extensions to OTC compliance deadlines beyond those already granted.

5.1.3. Diablo Canyon replacement

The Joint Environmental Parties, who originally entered a settlement with PG&E for the retirement of Diablo Canyon and the plan to replace its power, have continued to argue that the Commission has not done enough to ensure that the retirement of Diablo will not result in an increase in GHG emissions. The Joint Environmental Parties requested that the Commission order specific procurement of resources to replace the Diablo Canyon zero-emissions resource to ensure continued GHG-free delivery of energy beginning in 2024 and 2025.

5.1.4. Imports

The most common comment by parties on the topic of whether firm imports should be allowed to count toward the capacity requirements in this order was that the rules should simply follow the resource counting rules of the resource adequacy program. Parties generally supporting this approach included SWPG, SDG&E, Middle River, Ormat, CESA, CalCCA, AReM, and Golden State.

Cal Advocates and SCE advocated for slightly stricter rules than in the resource adequacy program, allowing the inclusion only of firm imports with pseudo-tie or dynamic scheduling arrangements. SCE noted that the resource adequacy program is considering changing the import counting rules to be stricter as well.

Some parties, including Brookfield, while generally agreeing that the resource adequacy rules should be used, also argued against restricting import eligibility to dynamically-scheduled or pseudo-tied facilities because it would artificially restrict the availability of imports. TURN, Powerex, Geothermal Rising, and CEJA/Sierra Club argued that firm imports should be required, but there should not be additional requirements for pseudo-ties or dynamic scheduling, also to avoid unnecessarily restricting imports.

ACP-CA argued that firm imports should be allowed from specified resources, while noting that discounting imports because of transmission risks is unfair, because in-state resources also have transmission risks that are not typically accounted for.

EDF, Shell, and CEERT advocated that firm imports with specified resources and firm transmission into the CAISO should be eligible, with EDF suggesting additional requirements for carbon-free certification. CEERT advocated for a requirement for both a specified generation source and firm transmission rights.

PG&E advocated for a maximum percentage of an LSE's allocation that could come from imports. AReM explicitly opposed this concept in reply comments. PCF advocated for requiring pseudo-ties and also using the "bid cap" proposal from resource adequacy to limit the amount of imports, similar to PG&E's proposal to limit the percentage of imports allowable.

Calpine suggested using the same import eligibility requirements as D.19-11-016 (which required pseudo-ties or dynamic scheduling), and also recommended allowing imports procured for D.19-11-016 compliance purposes to have their contracts extended to be counted for the requirements of this order. CalCCA agreed with the idea of contract extensions for imports under contract previously to count toward the new requirements.

BAC argued that no imports should be allowed to count towards the requirements, because they do not provide as many benefits to California as in-state development. LDESAC argued that imports could be allowed only if they come from new capacity from specified resources.

Finally, CAISO proposed that non-dynamically-scheduled resource-specific imports could be allowed to count, in additional to pseudo-tied and dynamically-scheduled resources, if they meet the following specific requirements: 1) they can show firm transmission to the CAISO border; 2) they are available for a minimum of 16 hours per day, seven days per week; and 3) they provide attestation and source specification sufficient to show underlying resources dedicated to serving CAISO load.

5.2. Discussion

5.2.1. Long-lead-time resources

We understand the points of parties who ask that we specify attributes of resources rather than specific resources that need to be delivered to meet mid-term reliability needs. At the same time, our experience is often that we need to seek specific resources in order to spur their development. In past experience, specific orders have been needed from the Commission in the areas of solar, biomass, and storage, to name a few. While we generally prefer to be technology-neutral, there are instances where too much of a least-cost option leads to its own set of challenges. We are facing this situation now due to the confluence of several factors: an abundance of solar energy, the impending loss of a large chunk of nuclear capacity, and the retirement of a number of OTC thermal plants. This means a reduction in the system's ability to supply firm and/or dispatchable energy when the grid needs it most.

Therefore, this order still specifies a requirement for a minimum of 2,000 MW of LLT resources in 2026, one year later than originally proposed, to allow additional development time, as suggested by a number of parties.

The requirement will be in two categories: a minimum of 1,000 MW of long-duration storage, and a minimum of 1,000 MW of dispatchable and/or firm resources with zero or de minimis emissions, as further described below.

First, we note, as several parties did in comments, that long-duration storage is already a resource-neutral designation that may be met by a number of different technologies. We have specified that long-duration storage must be able to discharge over at least an eight-hour period, though we also note that 12 hours or even multi-day storage options may be even more favorable, given the grid needs. LSEs should bear these considerations in mind when evaluating proposals to deliver long-duration storage.

For the other 1,000 MW of specific resources, we would still like to see a large amount of geothermal development in this category, due to the resource diversity, as well as economic development, benefits that additional geothermal could bring to certain regions of California, in addition to the grid benefits. However, we will broaden the description of the attributes we are seeking in this second category of resources to include either firm (with a capacity factor of at least 85 percent) and/or dispatchable (during hours 17 and 22 daily) energy delivery. This represents the characteristics of the major nuclear and OTC plants that we are seeking to replace in the medium term. This second category must be from resources with zero or de minimis emissions. Fossil-fueled resources will not be allowed to qualify in this category.

Both the long-duration storage category of 1,000 MW and the clean firm (and/or high-capacity factor and dispatchable) category of 1,000 MW will be required for compliance in 2026 and not earlier in the procurement period of this order, to acknowledge the comments of many parties that noted the need for longer lead times for these resources. We also acknowledge the challenge associated with development of these types of resources in this timeframe, even with a one-year delay from the original proposal. We are aware that the commercial interest shown thus far in diverse and LLT resources that can be online by 2026 may be limited.

As described further in Section 10 below, we will grant LSEs an opportunity for an extension of the compliance date for these LLT resources to 2028, if they show documented evidence of good faith efforts to procure the resources and that they can still be online by 2028. In addition, we reserve the right to impose cost allocation for these resources on all LSEs if they are not procured by some, consistent with state law, since we find that they are needed for system reliability.

In response to the comments of SVCE about LSEs that may have developed these types of resources early and now would be asked to do more, we will allow any long-duration storage, firm, or dispatchable resource that was developed for compliance with D.19-11-016 to count early for the 2026 requirements for 2,000 MW of these types of resources, so long as the LSE can show that other resources were also developed to meet the total capacity requirements of D.19-11-016 and/or this order, such that all obligations are met. For example, if an LSE had a 2 MW obligation to procure firm and/or dispatchable resources in 2026, but already acquired that amount of geothermal by 2023, then the LSE could procure an additional 2 MW of solar in 2023 and count the geothermal procurement toward its 2026 obligation.

With respect to the option included in the ALJ ruling to encourage joint procurement by multiple LSEs, we clarify that we will adopt this as an option but not a requirement, acknowledging that some LSEs (chiefly ESPs) may be unable to undertake such joint procurement. Other LSEs simply may not want to undertake joint procurement. However, other purchase and/or sale configurations are possible between LSEs to meet these obligations.

As suggested in the ALJ ruling, we will use one of the compliance filing milestones as a triggering check-in point to determine if backstop procurement of these LLT resources will be required. Since the compliance date for LLT resources to be online will be June 1, 2026, we will use the February 1, 2023 compliance filing date as the time to check the status of LLT resource procurement. Each LSE should be able to show the presence of contracts and other milestone requirements (including site control, interconnection agreement, and notice to proceed) to meet its 2026 LLT obligations by February 1, 2023, or show that an extension to 2028, if granted, will allow the resources to come online.

If neither of these circumstances is present, the Commission will consider at that time instituting a backstop requirement for IOUs to procure the resources and have the costs allocated to the deficient LSEs via the modified CAM mechanism that is still to be finalized for procurement associated with D.19-11-016 and this order. We understand that this will likely mean a delay in the resources being able to be online, but we find this preferable to the proposal of SCE to have the IOUs simply procure all of the LLT resources from the beginning (as "front-stop"). Procurement of diverse resources is an important skill and obligation for all LSEs if we are to achieve the state's long-term reliability and environmental goals.

5.2.2. Fossil-fueled resources

With respect to the question of whether fossil-fueled resources should be allowed to count toward the capacity requirements in this order, this is the most difficult choice we must make in this decision. We understand and sympathize with the views of the many environmental parties that ask us to prohibit the ability of new fossil-fueled generation to be used for compliance with the capacity requirements in this decision. We take very seriously the zero-emission goals for the electric sector by 2045 and for the state in general. We are also very concerned about the continuation of or potential increase in air pollutant emissions in local communities that bear more than their fair share of environmental burden to keep the electricity grid operating.

At the same time, we face the responsibility to ensure that the delivery of electricity remains reliable in the face of massive changes in the resource mix over the next few decades. We emphasize that the volume of renewable energy in the mix in California already exceeds the percentages on any other grid anywhere in the world that is of similar scale. We are also simultaneously seeing a huge proliferation of battery storage resources, also at a scale not seen anywhere else.

We are confident that we can reach our long-term environmental goals while keeping an acceptable level of reliability of electricity service. However, we are less confident about the shorter-term operational realities during the transition period and maintaining the reliability of the system in the interim. The middle of this decade represents an inflection point and a transition we need to make it through successfully in order to realize our goals.

The potential for a destabilized electric grid and unreliable service if we fail to plan appropriately for the transition is a very serious threat to our ability to realize our long-term goals. Already with the rotating outages in August 2020, the Commission was blamed for focusing too heavily on our environmental goals to the detriment of reliability. Although this explanation is inaccurate, as demonstrated by the lengthy interagency root cause analysis that explains the multivariate reasons for the outages in August 2020 (and documents the steps the energy agencies are taking to address the problems that occurred), the challenge remains that outages and reliability problems can seriously erode public confidence in our environmental goals for the electric sector. To ensure that we remain on track without reliability problems, we need to retain some insurance that we will be able to keep the lights on if we encounter operational difficulties during our ongoing transition to zero-emissions resources.

As we have already experienced with emergency procurement for Summer 2021 in R.20-11-003, we have limited options when we must conduct procurement for potential reliability challenges less than a year away. To avoid such circumstances in 2023-2026, we need to plan now to ensure resources are online as insurance in the event of tight supplies and/or higher-than-anticipated demand. As recent experience has shown, when we must procure within a one-year timeframe, the fastest resource to deploy is likely demand response, which may, in an emergency situation, sometimes come with some of the least favorable environmental options of all: backup generators, which are often diesel-fueled. These have far worse local environmental impacts than any new utility-scale natural gas turbine would have, but are sometimes among the only alternatives available to maintain reliability in a very short timeframe.

We also note that much of the recent longer-term procurement in the past few years has been for battery storage capacity. While that represents significant deployment progress for this relatively new resource, it is important to point out that batteries do not themselves produce energy. There must be capacity and energy available from generation resources to charge the batteries, even if they can be optimally discharged at the time the grid needs their resources the most. We also note that battery storage operations are still evolving and likely still require additional experience and possibly policy guidelines to ensure they are optimized for grid use during the most extreme weather and grid events. This progress is evolving and moving in the right direction, but it is still very new, and on an unprecedent scale, as already mentioned above.

As we have also already noted, many of the resources retiring in the 2023-2026 timeframe are either firm or dispatchable resources, which are not easily replaced by as-available variable renewables in terms of their capacity factors and values, as well as their impact on grid operations. We recognize that renewables paired with storage are part of the solution, but also involve increasing reliance on battery storage at a large scale.

Many of the fossil-fueled generators currently on the grid have been developed within the past 20 years and are relatively clean and efficient, with the exception of two types of resources: the OTC resources that are scheduled to retire, and some combined heat and power (CHP) units under legacy qualifying facility (QF) contracts.

Consistent with the recommendation in the ALJ ruling, we are not recommending any extensions to the compliance deadlines for the OTC regulations of the Water Board in this order. There is very little advocacy for this solution, and due to the age and emissions from these OTC plants, we would prefer to see cleaner resources developed rather than continue to rely on the retiring OTC generators.

With respect to the CHP generators, they represent a class of resources that will need long-term contracts in order to upgrade their efficiencies, or otherwise they may find it more economic to retire the facilities. However, in recent years, for reliability reasons, the CAISO has needed to designate a number of them as reliability must run (RMR), often because of their importance for local grid reliability. To the extent that they are necessary for reliability of the system, we would prefer that they receive long-term contracts to upgrade their heat rates, instead of continuing to run older units.

One further important point with respect to fossil-fueled resources is that the best-case scenario is that we may need these types of resources for capacity purposes and to remain on standby, but if we have enough renewable and zero-emissions generation in the system, the fossil-fueled resources ideally will not have to run much or produce much energy, and therefore will have very few emissions. Having them available, but running at their minimum levels or not running at all, still acts as an insurance policy during the operational transition to more renewables and energy storage on the system, as we make steady and significant progress towards the SB 100 decarbonization goals for 2045.

When considering all of these factors, we are faced with a series of difficult choices. On balance, we find that allowing some incremental and efficient natural gas generation at utility scale or at CHP facilities, at existing sites, is preferable to the public safety risks posed by widespread outages or allowing the proliferation of diesel backup generators in an emergency. It is also preferable to retaining inefficient CHP or OTC plants that have outlived their useful lives and are significantly higher-emitting than their newer alternatives.

We also note that the risks are asymmetrical: failure to provide insurance to keep grid reliability is a far greater threat to public confidence and public health than running state-of-the-art fossil-fueled generators a few extra hours a year. In addition, adding a small amount of efficient natural gas capacity will not necessarily lead to an increase in the generation from fossil-fueled units overall, but rather will likely lead to less dispatch of the higher-emitting and less efficient units.

Because of this hierarchy of less-than-ideal choices, we will allow some fossil-fueled resources to count toward the capacity requirements of this decision, with some limitations as we describe further below.

First, as we did in D.19-11-016, we will limit the counting of fossil-fueled capacity to existing sites where electric generation is already sited. No development of new sites for fossil-fueled electric generation is contemplated or authorized by this order.

Next, we examine the types of modifications to existing sites that could result in the ability of incremental fossil-fueled generation to count toward the capacity requirements in this decision. We note that the CEC, as part of the IEPR, has been assessing this same question, and may define the options slightly differently than we do here. The five categories for modifications to existing power plants fueled by natural gas that we define here are as follows:

1. **Category 1:** Efficiency improvements: These changes involve upgrades to improve heat rates of turbines, and may or may not increase NQC substantially. Better efficiency of a turbine or plant will decrease the rate of GHG and criteria pollutant emissions. To qualify as part of the capacity required by this order, a plant would have to decrease its heat rate, reduce its rate of GHG emissions, and increase its NQC value. The emissions improvements associated with this category could also be accomplished by converting fuel use to green hydrogen.[5]
2. **Category 2:** Uprates/upgrades: These changes provide more capacity from the same plant and may also improve heat rates compared to the existing plant. The purpose is to get more peak output from a plant. These types of improvements could also include hybridization by adding storage using existing or expanded interconnection capacity.
3. **Category 3:** Expansions: These changes involve adding NQC at the same site, potentially by adding turbines, but within the existing permitted limits.
4. **Category 4:** Repowering at an operating facility: These changes involve changing out less efficient turbines for more efficient ones. This would be done to an existing plant that is delivering energy/capacity currently, but would be improved by a turbine changeout. This type of

[5] Green hydrogen refers to green electrolytic hydrogen, as defined in Public Resources Code Section 400.2, or any subsequent California law that defines "green hydrogen."

project would also likely reduce GHG emissions significantly.

5. **Category 5:** Repowering at a mothballed or retired plant: These changes involve changing out less efficient turbines for more efficient ones in a mothballed or already-retired plant. After the repowering, the plant would come back into service with newer and more efficient turbines.

Though the RESOLVE modeling leading to D.20-03-028 did not suggest the need for any new fossil-fueled resources through 2030, the SERVM modeling to check reliability gives us less confidence in this result. In addition, while most of the fossil-fueled resources on the system are shown to be needed through at least 2030, there is a reasonable amount of improvement that could be made to the existing fleet to make it more efficient and reduce its GHG impacts further, without increasing the total amount of natural gas generation on the system.

For the mostly-qualitative reasons already discussed in this section, we are convinced that we should require between 1,000 and 1,500 MW of incremental natural gas resources that can be dispatched and also generate energy as an insurance policy to ensure reliability through the transition in the middle of this decade. We choose this level because it represents roughly 10 percent of the procurement required by this decision, which is a reasonable insurance policy against reliability challenges, and also allows for the retirement of less efficient fossil-fueled generation in favor of more efficient and less-emitting technology, which is also favorable. This amount also closely approximates the amount of feasible capacity expansion identified by the CEC as part of their recent IEPR inquiries.

The CCA community has made it clear that they are focused on non-fossil-fueled resources, and the ESPs are less likely to make these investments due to their shorter customer commitment timelines. Therefore, we find it reasonable to ask the IOUs, collectively, to seek between 1,000 MW and 1,500 MW of incremental natural gas resources as part of their allocations in this order, by no later than 2025. The costs of these resources will be allocated using the CAM mechanism, because we find the resources needed for system reliability reasons. The allocations are based on load share within the entire IOU territory (including other LSEs serving load in their areas), and are as given in Table 5 below.

Table 5. Natural Gas NQC Procurement Requirements
for IOUs, Cumulatively, by 2025

Utility	Minimum Natural Gas Procurement (NQC MW)	Maximum Natural Gas Procurement (NQC MW)
PG&E	420	630
SCE	480	720
SDG&E	100	150
Total Requirement	1,000	1,500

We will allow any project in the five categories listed above to count towards these obligations if the project is not located in a disadvantaged community. As discussed further below, the IOUs must bring us applications for any projects in this category and must show how each project satisfies the definition of one of the five categories listed above. In addition, we particularly encourage strategies to repower legacy CHP facilities, use more than 30 percent green hydrogen fuel, and/or hybridize facilities by adding storage.

If the project is located in a disadvantaged community, as defined by being in the top 25 percent of communities with the highest environmental burden, as given in the most recent version of the CalEnviroScreen tool maintained by the California Office of Environmental Health Hazard Assessment, then we impose the following additional requirements.

If a project is located in a disadvantaged community, as defined above, then the following categories of projects, as defined in this decision, will not be eligible to qualify to meet the compliance obligations of the IOUs for this procurement:

- Category 3 (Expansions).
- Category 5 (Repowering at mothballed or retired facilities).

In addition, if a project is in any other category, it must show that the project will improve (reduce) the rate of GHG emissions at the project location. Beyond that, Category 1 (Efficiency improvements) must include a commitment to use at least 30 percent green hydrogen by the fifth year of operation. This is to ensure dramatic GHG emissions improvements accrue to the disadvantaged community. If a project is in Category 2 (Uprates/Upgrades) and located in a disadvantaged community, then it must include hybridization by adding energy storage to improve its GHG profile. And finally, if a project is in Category 4 and located in a disdvantaged community, it must reduce its rate of GHG emissions compared to existing operations.

These requirements, taken together, are designed to ensure reliability of the system overall, while providing appropriate protections to communities already burdened with emissions associated with production of energy on behalf of the system as a whole.

5.2.3. Diablo Canyon replacement

D.19-04-040 contains an extensive discussion of our planning for replacement of the capacity of Diablo Canyon, and we will not repeat all of it here. The most important elements, however, are that the expectation that Diablo Canyon will retire in 2024/2025 has been included in all IRP analysis conducted since 2016, and other long-term procurement analysis prior to that, and we are satisfied that LSEs have been in the process of securing replacement capacity for some time. In addition, nearly all of the procurement that has been conducted to meet IRP requirements thus far has been from renewable or zero-emission resources, and we expect approximately 90 percent of the resources procured as a result of this order to be in those categories.

Nonetheless, to ensure no ambiguity, we will require that at least 2,500 MW of the resources procured by the LSEs collectively, between 2023 and 2025, be from zero-emission resources that are firm, to replace Diablo Canyon. These are expected to be largely incremental renewables paired with storage that can deliver firm power, at a minimum, during hours 17 through 22 every day. To make this requirement attribute-based, this means that the resources must be incremental, available every day during hours 17 through 22, and for every 1 MW of incremental capacity, able to deliver at least 5 megawatt hours (MWh) of energy during these time periods.

We anticipate that this requirement is unnecessary, because LSEs are mostly procuring these types of resources anyway, and their overall requirements from this order are much greater than this minimum. In addition, we are requiring 2,000 MW, in addition, from long-duration storage resources and zero-emitting firm and/or dispatchable resources with higher capacity factors by 2026.

In an abundance of caution and to make it crystal clear that the retirement of Diablo Canyon is not resulting in an increase in GHG emissions, we will include this requirement for no less than 2,500 MW zero-emitting firm replacement power, which is consistent with our implementation of SB 1090 (Monning, 2018), as further discussed in D.19-04-040[6] and D.18-02-018.

5.2.4. Imports

As a starting point, we are reluctant to set new and different rules for the counting of imported power each time we adopt procurement requirements in IRP. We are also sympathetic to those parties who advocate for consistency between the resource adequacy program and IRP procurement, and find no compelling reason to deviate from the basic resource adequacy rules for counting imports here. We avoid citing the specific resource adequacy rules here, because those rules for imports in resource adequacy are constantly evolving and may change again during the compliance period of this order. Therefore, here, we simply state that imports may be counted toward compliance with the requirements of this order if they comply with the import rules associated with the resource adequacy program in place at the time that compliance must be shown, between 2023 and 2026 for purposes of compliance with this order.

In addition, we add one additional requirement, consistent with the overall purpose of this order. That is, imports used for compliance with the capacity requirements of this order must show that they are associated with a new resource with a commercial online date after the date of this order, and under a long-term contract of at least ten years. This will ensure that the imports will be from truly incremental resources.

[6] *See*, especially, D.19-04-040, at 147-149.

5.2.5. Conclusion

To sum of all of the requirements included in this section (5) of this decision, Table 6 below gives the full set of requirements for procurement in particular years of specific types of resources.

Table 6. Total Minimum Mid-Term Procurement Requirements (in NQC MW)

Type of Resource	2023	2024	2025	2026	Total
Firm zero-emissions resources	-	2,500	-	-	2,500
Firm and/or dispatchable zero-emitting resources	-	-	-	1,000	1,000
Long-duration storage resources*	-	-	-	1,000	1,000
Maximum fossil-fueled resources (IOUs only, by 2025)**	-	-	1,500		
Any other type of non-fossil-fueled resource	3,000	2,000	500	-	7,000
Total	**3,000**	**4,500**	**2,000**	**2,000**	**11,500**

**LSEs may request an extension by February 1, 2023 up to 2028 for the LLT resources.*

***Fossil-fueled resources meeting the requirements in this decision may be used to satisfy the IOU obligations in any of the years 2023, 2024, or 2025, and may not total more than 1,500 MW.*

6. Need Allocation to LSEs

D.19-11-016 allocated procurement responsibility to LSEs on the basis of their proportional load share at the time the requirement was adopted. The February 22, 2021 ALJ ruling proposed to improve upon that approach by taking into account the contract positions of individual LSEs relative to one another and to the overall procurement need identified. This would be done by calculating each LSE's load and resource balance for each year to determine their resource shortfall, if any, and then apportioning their responsibility for the overall procurement need based on that shortfall relative to that of the other LSEs.

Contract data would be extracted from the September 1, 2020 IRP filings of the individual LSEs, reflecting contracted resources by year, measured in

September NQC amounts, for existing resources and those in development as of June 30, 2020. This approach was expected to mitigate the need for the use of cost allocation mechanisms such as CAM or the power charge indifference adjustment (PCIA), while enhancing the ability of electric service providers (ESPs) and community choice aggregators (CCAs) to control their own resource portfolios and costs, by more accurately assigning responsibility for physical capacity procurement to the entities serving the load.

The ruling also suggested that one way to handle load migration during the compliance period would be to utilize the PCIA process, for the 2023-2025 vintage of contracts, or alternatively, reflecting the date when this order is issued.

6.1. Comments of Parties

Among parties' comment on these issues, the CCAs and ESPs generally preferred the peak share allocation method, while the IOUs, ratepayer advocates, and some industry and environmental group preferring the contract position method. Among the groups supporting the contract position method, however, nearly all parties recommended modifications, the most significant of which called for allocating the resource adequacy attributes of PCIA resources pro rata to all LSEs paying PCIA, based on vintage load share, when setting the need allocations.

In general, the contract position method was supported by Cal Advocates, Calpine, CalWEA, EDF, GPI, NRDC, PCF, PG&E, SDG&E, and TURN. Most of these parties recommended modifications to the method proposed in the ruling. Calpine would prefer to set requirements as long-term system resource adequacy requirements where LSEs are obligated to procure sufficient capacity to meet their projected load. However, Calpine supports the contract method if this order only focuses on procurement of incremental capacity.

AReM, CalCCA, Shell, and SVCE/3CE all supported the peak share method. SCE would prefer the contract method proposed in the ALJ ruling, but accepts using the peak share method for this order while the details are worked out for modifying the contract method for future procurement orders. Both Cal Advocates and SCE support further exploration of these issues after this order is issued, with particular focus on allocating procurement based on whether each LSE has sufficient net peak load capacity, sufficient energy to meet net load, and sufficient energy to charge storage resources.

CalCCA and PCF argued that LSEs should be given a pro-rata allocation of all contracts for which they pay the PCIA. They argue that any other approach is unfair because under the PCIA, non-IOU LSEs pay for IOU contracts while IOUs hold the resource adequacy credit. They argue this puts non-IOU LSEs at a disadvantage on need allocation by creating a situation where LSEs pay for the resources that only the IOUs can count toward their IRP obligations.

Responding to this in reply comments, AReM stated a preference for handling PCIA issues in the PCIA proceeding (R.17-06-026). PG&E argued that whatever happens in the PCIA working group 3 outcome should be reflected in need allocation here, while SDG&E similarly argued that the PCIA proceeding will address this issue. SCE argued that any of these proposals should be vetted and considered only for future procurement orders.

PG&E also commented that the obligation should be based on the LSE's share of the 2026 shortfall, in particular. PG&E also felt that the load share should be based on draft 2022 resource adequacy year-ahead forecasts, while SDG&E argued that the basis should be energy forecasts for 2024-2026.

SCE argued, if the peak share method is adopted, that the resource adequacy year-ahead forecasts alone be the basis, because energy-based allocations are inequitable. PG&E also requested that all LSE allocations be published, similar to D.19-11-016. And several LSEs sought an opportunity to review and comment on their allocations prior to their being finalized, including CCSF.

With respect to the ALJ ruling suggestion of using PCIA vintaging to deal with load migration issues, the IOUs supported this suggestion. PG&E and SDG&E preferred a PCIA vintage tied to the year of the load share forecast used to allocate procurement need, while SCE preferred the PCIA vintage tied to the date this order is issued. In reply comments, Cal Advocates supported these positions using PCIA vintaging.

CalCCA, CCSF, and EDF opposed using PCIA, and CalCCA and CCSF recommended that the Commission create a cost recovery mechanism that all LSEs can use, that would apply when customers move between any type of LSE. Shell would support adjusting procurement obligations up or down annually to track load migration.

AReM argued that all of this mid-term reliability procurement should be handled in the context of resource adequacy, with those requirements changing as load changes. They argued that extending system resource adequacy requirements three years forward will properly incentive longer-term resource adequacy contracting.

EDF recommended allowing for “fractional assignment” where contracts could be broken up and moved to new buyers, as needed. Finally, PCF recommended that IOU contracts be limited to three years.

CalWEA advocated for distinguishing between system resource adequacy and system integration needs, implying that system integration resources help with ramping and moving energy across days. Therefore, CalWEA recommends setting procurement obligations for each type of resource and allocating them across LSEs.

6.2. Discussion

Ideally, we would be inclined to prefer the contract position method in the long term, because, in theory, it would be more equitable to all LSEs and would take into account the LSE causing any system integration shortfalls.

We note that Assembly Bill (AB) 1584 (Quirk, 2019) requires us to "develop methodologies for allocating electrical system integration resource procurement needs to each load-serving entity…based on the contribution of the load-serving entity's load and resource portfolio to the electrical system conditions that created the need for the procurement and for determining any costs resulting from a failure of a load-serving entity to satisfy its allocated procurement needs."[7]

Consistent with these requirements, to date we have allocated procurement requirements to all LSEs based on load share, and have not made any findings that any LSE has created any differential need for system integration resources. Should we make such a determination in the future, we would need to develop methodologies to allocate the responsibilities differentially.

However, as proposed in the ALJ ruling and as discussed in several party comments, including CalWEA's, allocating procurement based on contract position is not a self-executing methodology and has many complexities that are based on distinctions between types of resources that are not readily obvious. Many parties pointed out issues with the contract position method that would

[7] Codified as Public Utilities Code Section 397.

need to be resolved in order for us to adopt it for the procurement required in this decision. We will need to do more work to design and vet the finer points of a methodology taking into account contract positions of all LSEs, not the least of which will be related to confidentiality of contract data and valuing the long-term capacity attributes of IOU contracts for which other LSEs pay the PCIA. These are issues that will need to be worked through in a process to be conducted later in this proceeding.

In the meantime, we will utilize the same basic method of assigning procurement allocations to LSEs based on load share, and implemented in a similar manner to the procurement obligations assigned in D.19-11-016. This methodology complies with the requirements of AB 1584, because, at present, the system integration needs are not attributable to any particular LSE as distinguished from any other LSE. By allocating procurement responsibility to all LSEs, we are ensuring fair distribution of costs across the customer base, for system integration resources.

The method we will use is basically a hybrid allocation method, utilizing both year-ahead peak load and energy load forecasts of individual LSEs. The hybrid allocation avoids using energy load forecasts that are considered confidential by ESPs. For the procurement required in this order, for IOUs and CCAs, we will use the 2021 year-ahead resource adequacy forecasts and the 2021 energy forecasts that were adopted via ALJ ruling on May 20, 2020 in this proceeding, for use in the current cycle of IRP. For ESPs, we will use only their 2021 year-ahead resource adequacy forecasts. Then, load migration for existing IOU customers will be handled by vintaging the PCIA costs to the date of this order, which will also be in 2021.

This procurement allocation approach has several advantages. First, it allows us to publish all procurement obligations for all LSEs individually, except for ESPs, whose class obligation will be published, but individual ESPs will be given their allocations confidentially. This sets us up better for understanding progress toward the obligations, along with our general preference for making obligations public wherever possible.

Using the 2021 vintage of forecasts for both energy and peak load also allows us to avoid PCIA implementation challenges that would be associated with using later energy forecasts (like 2024-2026). In addition, 2021 vintage forecasts will mean that new LSEs that begin serving load next year, but which did not have a 2021 forecast, will not have an obligation under this order. This effectively allows new LSEs to opt out until their procurement operations are more mature. (See further discussion in the next section of this decision about opt-out options.)

Finally, if the Commission later develops and adopts a methodology for procurement obligations based on the contract position of individual LSEs, LSEs that have procured to meet the obligations herein will have an advantage in that they will be better positioned relative to future obligations. Thus, the allocation based on hybrid peak/energy forecasts adopted here will facilitate a potential transition to a more sophisticated and equitable method in the future.

A different approach is being taken for ESPs because their 2021 energy and peak demand forecasts are both confidential, meaning that even under the hybrid peak/energy approach, individual ESP procurement obligations would have to remain confidential. Thus, the hybrid approach offers no transparency advantage for ESPs, so their requirements will be set based on peak share alone.

The individual LSE obligations, based on these determinations, are given in Table 7 below.

Table 7. Individual LSE Procurement Minimum Obligations (in NQC MW)

LSE	2023	2024	2025	2026 (LLT resources)	Firm, zero-emitting resources by 2024*	Total
PG&E Bundled	569	853	379	379	474	2,180
PG&E Direct Access (Aggregated)	118	177	79	79	98	453
Clean Power San Francisco	47	71	31	31	39	180
East Bay Community Energy	102	153	68	68	85	391
King City Community Power	1	1	-	-	1	2
Marin Clean Energy	84	126	56	56	70	322
Monterey Bay Community Power Authority	84	126	56	56	70	322
Peninsula Clean Energy Authority	55	82	36	36	46	209
Pioneer Community Energy	18	26	12	12	15	68
Redwood Coast Energy Authority	10	14	6	6	8	36
San Jose Clean Energy	68	102	45	45	57	260
Silicon Valley Clean Energy	61	91	41	41	51	234
Sonoma Clean Power Authority	36	54	24	24	30	138

LSE	2023	2024	2025	2026 (LLT resources)	Firm, zero-emitting resources by 2024*	Total
Valley Clean Energy Alliance	12	18	8	8	10	46
SCE Bundled	1,064	1,596	709	709	886	4,078
SCE Direct Access (aggregated)	130	194	86	86	108	496
Apple Valley Choice Energy	4	5	2	2	3	13
Baldwin Park, City of	4	6	3	3	3	16
Commerce, City of	3	5	2	2	2	12
Pomona, City of	6	9	4	4	5	23
Clean Power Alliance of Southern California	177	266	118	118	147	679
Desert Community Energy	9	13	6	6	7	34
Lancaster Clean Energy	8	13	6	6	7	33
Pico Rivera Innovative Municipal Energy	4	6	3	3	3	16
Rancho Mirage Energy Authority	4	6	3	3	3	16
San Jacinto Power	2	4	2	2	2	10
Santa Barbara Clean Energy	3	5	2	2	2	12
Western Community Energy	24	36	16	16	20	92
SDG&E Bundled	201	301	134	134	167	770

LSE	2023	2024	2025	2026 (LLT resources)	Firm, zero-emitting resources by 2024*	Total
SDG&E Direct Access	43	64	29	29	36	165
Clean Energy Alliance	2	3	2	2	2	9
San Diego Community Power	50	74	33	33	42	190
Total*	**3,003**	**4,500**	**2,001**	**2,001**	**2,500**	**11,505**

**The amount in this column is a subset of the 2023 and 2024 columns, and is therefore not also added to the total for each LSE.*
***Totals are affected slightly by rounding to whole number requirements for individual LSEs, resulting in a few extra MW in some years.*

7. Backstop Procurement and Associated Cost Allocation

For the capacity required by D.19-11-016, the Commission allowed LSEs to opt out, up front, of self-providing capacity to meet the requirements. Any LSE could elect to have the IOUs procure the capacity on their behalf, and have the costs assigned to them and/or their customers. The February 22, 2021 ALJ ruling did not propose that option, and instead proposed that all LSEs be required to procure the capacity assigned to them by the Commission.

The ruling also addressed the possibility that LSEs could try but fail to procure the required capacity, creating a possible reliability shortfall for the system as a whole. To address this situation, the ruling proposed that the aspects of D.19-11-016 associated with backstop procurement, recently adopted in D.20-12-044, be continued for the procurement addressed in this order. In broad terms, this means continuing the biennial compliance filing requirements (currently scheduled on February 1 and August 1 of every year) through at least

2026, and triggering backstop procurement to be performed by the IOUs after each February showing, to the extent LSEs do not show enough progress toward meeting the capacity requirements for the upcoming summer season. There would also be an additional summer trigger point, to occur after the final compliance filing associated with the new procurement requirements.

The cost allocation methodology associated with backstop procurement related to D.19-11-016 requirements (which has yet to be decided) would then also be utilized for the procurement associated with the requirements in this order.

7.1. Comments of Parties

Parties' comments were mixed on whether the option to opt out of self-providing capacity should be preserved from D.19-11-016 or removed, as proposed by the ALJ ruling. Cal Advocates, GPI, PCF, PG&E, SCE, SDG&E, SEIA/LSA/Vote Solar, and Shell supported the ruling's proposal not to allow LSEs to opt out. AReM, CCSF, CESA, and TURN would prefer to preserve the option for individual LSEs to opt out of self-provision and instead pay for the capacity provided by the IOUs. CalCCA commented that it would be a good idea to allow CCAs formed after January 1, 2021 to opt out because it may be likely that their procurement operations have not yet reached maturity and they should be given a chance to transition into the role.

In reply comments, a number of parties emphasized the particular need to allow opting out for resource- or attribute-specific procurement requirements, and/or for new LSE entrants to the energy markets. AReM and TURN supported allowing all non-IOU LSEs to opt out, and to use the cost allocation method (CAM) for LLT resources. CalCCA recommended that the IOUs should not be required to procure the LLT resources, and therefore CAM should not be used unless there is an opt-out option, or if backstop procurement is triggered. CESA recommended allowing LSEs to opt out if they are new entrants and for LLT resources. SCE recommended that the IOUs should serve as front-stop providers of LLT resources, and not just backstop. CalWEA and SDG&E commented that self-provision should be required with no exceptions.

With respect to the backstop provisions, in the event that individual LSEs fail to procure their requirements, most parties were supportive of continuing the backstop provisions in D.20-12-044 and requiring the IOUs to provide the backstop procurement, if needed. AReM, Cal Advocates, CESA, GPI, LDESAC, PG&E, SCE, SDG&E, SEIA/LSA/Vote Solar, Shell, and TURN all filed generally supportive comments. Some (GPI, PG&E, and TURN) distinguished between what makes sense for this order and what might be preferable in the long term, such as an independent central procurement entity (CPE).

PCF opposed the use of the backstop mechanism and Hydrostor opposed backstop procurement provisions for purposes of LLT resources. SDG&E supported the backstop mechanism but preferred the CPE be the largest LSE in a service territory, rather than automatically the IOU. Cal Advocates also argued that the Commission should adopt rules, for this procurement context, similar to those established in resource adequacy in D.20-12-006 to ensure competitive neutrality by the IOUs acting in a CPE capacity for backstop procurement.

PG&E, in its comments, proposed early dates for LSEs to show compliance, in order to give time for backstop procurement to come online on time. In reply comments, GPI warned that pushing up the procurement deadlines to allow more time for backstop procurement could further risk resource diversity. Hydrostor, in contrast, pointed to the need for longer timeframes, particularly for long-duration storage.

7.2. Discussion

In general, we favor self-provision of required resources by all LSEs individually for their proportional share. Procurement of diverse resources is an important skill and obligation for all LSEs if we are to achieve the state's reliability and environmental goals. We continue to endorse the basic principles of load-proportional procurement and procurement being a core function of serving load, except in instances where there are specific reasons that self-provision is unworkable or unlikely to succeed. Therefore, we will adopt the ALJ ruling recommendation that LSEs will not be given the option to opt out up front from providing their proportional share of the capacity required by this order.

One specific exception was discussed earlier, with respect to entities that were not yet serving load as of January 1, 2021. For those entities that are beginning to serve load after this date, they have not been given an allocation in this order for the mid-term period. Therefore, effectively, those LSEs have been automatically opted out of self-providing their required capacity, and the costs of providing the capacity for customers migrating to their service will be handled through the PCIA vintaging as of the date of this order.

We also extend the self-provision requirement to LLT resources. As proposed in the ALJ ruling, LSEs are encouraged to continue to work together and/or transact with one another, brokers, or other market participants, to procure the resources meeting these requirements, but ultimately each LSE is responsible to show contracts to meet its individual allocation. However, because the procurement of the LLT resources may be more of a challenge for individual LSEs in the timeframe we adopt here, we will not include a penalty provision for now for LSEs that can show that they attempted to procure the LLT resources in good faith, but were unable to do so in the timeframe required. In the future, we will consider what to do in this situation, once we see more information about the market and feasibility of these LLT resources.

In addition, we see no reason to make major changes to the backstop procurement provisions just recently adopted in D.20-12-044. As adopted in that order, LSEs will be required to report twice a year on their progress toward the procurement requirements in D.19-11-016 and now this order. Beginning after the August 1, 2023 biennial reporting deadline, the reporting and trigger dates will move to June 1 and December 1, instead of August and February. Beginning in 2023, backstop procurement may be triggered on December 1 for the following year's procurement requirements. If backstop procurement is triggered, the administrative and procurement costs of the IOU conducting backstop procurement shall be recoverable in rates and subject to the forthcoming modified CAM.

We also will not make changes at this stage to the timeline for triggering or bringing online backstop procurement. We understand that if backstop procurement needs to be triggered, it will take longer to bring the resources online than the original deadline for the self-providing LSEs. Our hope is that minimal, if any, backstop procurement is required. We are also erring on the side of selecting the high-need scenario, partly in order to ensure adequate resources even if a small amount needs to be backstopped due to contract or other failures.

Table 8 below gives the applicable dates where compliance filings are due and when backstop procurement may be triggered.

Table 8. Compliance Filing and Backstop Trigger Dates

Date	D.19-11-016 Action	Action resulting from this decision
August 1, 2021	Compliance filing	None
February 1, 2022	Compliance filing/ Backstop procurement trigger	Extension request for LLT resources
August 1, 2022	Compliance filing	None
February 1, 2023	Compliance filing/ Backstop procurement trigger	Compliance filing/ Backstop procurement trigger
August 1, 2023	Compliance filing/ Backstop procurement trigger (final)	Compliance filing
December 1, 2023	None	Compliance filing/ Backstop procurement trigger / LLT backstop procurement trigger
June 1, 2024	None	Compliance filing
December 1, 2024	None	Compliance filing/ Backstop procurement trigger
June 1, 2025	None	Compliance filing
December 1, 2025	None	Compliance filing/ Backstop procurement trigger
June 1, 2026	None	Compliance filing/ Backstop procurement trigger (final – not extended)
Dec 1, 2027	None	Compliance filing
June 1, 2028	None	Compliance filing/ Backstop procurement trigger (final – LLT extended)

8. Approval Process

The February 22, 2021 ALJ ruling proposed that the LSEs that require Commission approval of their procurement, which are the IOUs, file Tier 3 advice letters for Commission approval. At their discretion, they would also be authorized to file a separate application. And in instances where they propose fossil-fueled resources, the ALJ ruling recommended that a full application would be required.

8.1. Comments of Parties

The majority of parties commenting on this topic supported the proposal of a Tier 3 advice letter filing by IOUs for procurement required in this order. Those parties included CEERT, CEJA/Sierra Club, Geothermal Rising, LDESAC, PG&E, SCE, and SEIA/LSA/Vote Solar.

CESA and SDG&E recommended Tier 2 advice letters for all procurement except fossil-fueled resources. CESA and Hydrostor recommended that applications not be required for LLT resources. Cal Advocates requested that the protest deadlines on the Tier 3 advice letters be automatically extended from 20 days to 30 days, and that the IOUs be required to include bid and valuation information in their initial advice letters. Cal Advocates also recommended that a limited common resource valuation methodology (CRVM) be adopted to support this procurement. CEJA and Sierra Club recommended that IOUs be required to include total GHG and local air emissions information, as well as project impacts on disadvantaged communities, in their advice letters or applications.

GPI and PCF, on the other hand, requested that the Commission require full applications for all IOU contracts signed in response to this order.

In reply comments, the IOUs opposed the suggestion for a CRVM to be adopted, because it would require more robust stakeholder engagement and analysis. CESA supported a Tier 2 or Tier 3 advice letter process, while Cal Advocates opposed the use of Tier 2 advice letters. Cal Advocates endorsed the CEJA and Sierra Club recommendations on air emissions, GHG emissions, and disadvantaged community impacts.

8.2. Discussion

After reviewing the comments and experience to date with Tier 3 advice letters facilitating IOU procurement to meet IRP reliability needs, we will maintain a Tier 3 advice letter requirement for all procurement associated with this order. Tier 3 advice letters are a familiar tool, both in the IRP and the RPS context, and provide the best balance between efficiency and stakeholder engagement for clean or preferred resources. If an IOU procures resources that would count toward both their IRP and RPS procurement goals, the IOU should make only one request for PPA approval through a single Tier 3 advice letter, served on both the RPS and IRP proceeding service lists.

There are two exceptions to the Tier 3 advice letter approach. The first is related to any procurement of fossil-fueled resources. For fossil-fueled resources, the procuring IOU will be required to submit a full application that shall include, as recommended by CEJA and Sierra Club, a full set of information about the GHG, local air emissions, and disadvantaged community impacts of the procurement.

The second exception to the Tier 3 advice letter process requirement for IOU procurement is that the IOUs must file a full application for the long-duration storage contracts to meet their 2026 requirements as detailed in Section 5 of this order. This is because it is likely that those long-duration storage projects will raise other environmental issues besides the GHG emissions and local air quality impacts and will likely represent new technologies or configurations that will require additional scrutiny and deliberation.

This order declines to specify whether LLT resources other than long-duration storage will require an application, but we expect the IOUs to consult with Commission staff and allow the fact-specific circumstances to determine the appropriate regulatory approval path.

9. Compliance

The February 22, 2021 ALJ ruling proposed that LSEs demonstrate compliance with the required procurement by showing evidence of long-term (10 year or more) contracting with eligible resources. The resources would have to be shown to be incremental to the baseline used in need determination, meaning it would need to be contracted and approved by the Commission and/or the LSE's highest decision making authority after June 30, 2020. The 2019-2020 IRP RESOLVE/SERVM baseline generator list that includes all online and in-development resources would be made available and serve as the baseline for the procurement proposed in this ruling.

The ruling proposed that any resource used to satisfy an LSE's procurement obligation under D.19-11-016 or the storage mandate would not be eligible to satisfy the requirements of this order. However, resources eligible under the rules of the renewables portfolio standard (RPS) program may be eligible, if they remain online for the required time period. Even though some baseline and other mandated resources may not count toward compliance, they would still be included in the calculation of an individual LSE's portfolio contracting position.

According to the ALJ ruling proposal, each LSE would be required to demonstrate that the contracted new resource is online and contributing system resource adequacy on or before the online date required. The ruling also proposed that new resources be required to contract for at least ten years forward from the compliance date required.

Compliance would be measured based on NQC calculations using marginal ELCCs calculated by the Commission for each resource type for each future online year.

9.1. Comments of Parties

Parties had mixed responses to the idea of requiring minimum 10-year contracts to support the procurement in this order. Numerous parties wanted to prohibit long-term contracts for fossil-fueled resources. Other parties felt that there should not be minimum requirements and that LSEs should be able to choose contract lengths that work for their portfolios.

Parties supporting the ten-year minimum included ACP-CA, CalWEA, CESA, Golden State, GPI, Hydrostor, LDSEC, Ormat, SCE, SEIA/LSA/Vote Solar, SWPG, and TURN. CEJA/Sierra Club, Hydrostor, and PCF argued that ten-year contracts should be prohibited with fossil-fueled resources. EDF supported a five-year maximum for fossil-fuel contracts, and a clean replacement plan which details how the LSE intends to replace the fossil capacity with clean new resources once the contract expires.

CESA also commented that longer-term (longer than 10 years) contracts are likely required for long-duration storage projects.

Parties opposing ten-year contract requirements entirely included AReM, CCSF, CEERT, Diamond, IEP, Middle River, PCF, SDG&E, and Shell.

Several parties expressed concerns in comments about the confidential nature of some data in the baseline generator list. ACP-CA and AReM argued that in-development contract data should be held confidential at least for some period of time. Shell recommended that some in-development generator list data, including resource name, developer and/or seller, and contract details such as quantity, should be confidential until a project or procurement is publicly announced. Shell stated that other information, such as resource type, size, and location can be made public.

CCSF supported making data public as long as it does not reveal individual positions for specific LSEs. CEJA/Sierra Club supported making as much data public as possible, with the burden of proof on LSEs to prove why any data should be confidential. LDESAC voiced general support for public sharing of data and transparency. CAISO asked for clarity from the Commission on making the following data public, at a minimum: resource type; MW size and duration, if applicable; expected commercial online month and year; CAISO participating transmission owner and interconnection queue number; locational description such as county; and utility footprint.

Most parties generally supported the use of marginal ELCCs for compliance accounting, including AReM, CAISO, CalCCA, Cal Advocates, Calpine, CalWEA, CEERT, GPI, Hydrostor, PG&E, SDG&E, Shell, TURN, UCS, and SBUA. ACP-CA, while supporting use of a marginal ELCC methodology for planning purposes, argued it is important that the IRP procurement compliance accounting process align with how resources are actually valued in the resource adequacy program and recommended waiting for longer-term reform in that program. A handful of parties would prefer that average ELCC values be used, referring back to the resource adequacy proceeding. Those parties included CESA, Golden State, PCF, and SEIA/LSA/Vote Solar.

9.2. Discussion

Because this decision contemplates the use of new/incremental resources to satisfy the capacity requirements, as shown in the staff analysis that led to the

ALJ ruling, the baseline will consist of existing resources online or in-development and contracted and approved by the Commission and/or the LSE's highest decision making authority as of June 30, 2020.

On the matter of confidentiality of data in the baseline generator list, and particularly data about in-development resources, we agree with the CAISO that the following information should be publicly available without any risk of revealing confidential or market-sensitive contractual information: resource type; MW size and duration, if applicable; expected commercial online month and year; CAISO participating transmission owner and interconnection queue number; locational description such as county; and utility footprint in which the resource is located. If an LSE submits an adequate request for confidential treatment, other information should be made available publicly once the contract is publicly announced, by the individual LSE, and/or by the Commission, in keeping with our own confidentiality rules with respect to contract price and terms, as governed by D.06-06-066 and its related successor decisions.

Commission staff should work with LSEs to improve procurement progress data collection so that baseline update for future IRP modeling and potential procurement action contains sufficient detail.

By no later than 60 days after the effective date of this order, Commission staff will post to our web site a final baseline list, so that parties may know exactly what resources are included in the baseline. The final baseline list will be the same as the baseline list included in the need determination model that was posted on the Commission's website on February 22, 2021,[8] but with the added detail describe above of in-development resources. It is worth noting that LSEs

[8] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442463413

should already know which resources they contracted with before the June 30, 2020 cutoff date, and therefore need not wait on the posting of the final baseline list before commencing their procurement processes.

Consistent with D.19-11-016, as well as § 454.51(d) requirements surrounding long-term commitments to renewable integration resources, we also find that it is necessary to require long-term contracts for the procurement specified herein. Long-term is defined as at least ten years. This is also in the interest of ratepayers, since the purpose of this order is to develop new resources. In order to induce developers of resources to make large capital investments and finance their projects, it is likely that at least a 10-year contract is necessary. Shorter-term contracts for new resources will likely just lead to higher annual costs, because the total costs will need to be amortized over a shorter period of time.

We also expect that the Commission will need to consider the necessity of further action, including possible revisions or expansions to the existing resource adequacy program, to require that these tranches of new clean energy resources stay online after they come online. LSEs should expect there will be some kind of ongoing obligation to maintain the new resources brought online as a result of this order.

The same issue applies to any investments made to fossil-fueled assets allowed to be counted toward the capacity required by this order, as discussed further in Section 5 above. If the resource is eligible to count toward the requirements herein, we see no reason to raise annual costs by requiring shorter contracts. Likewise, requiring fossil-fueled resources to have shorter contract terms could create a disincentive toward investing in cleaner resources, which would be undesirable.

Thus, all resources used to satisfy the requirements of this decision shall be procured using contracts that are at least ten years in length.

In terms of the ELCC values that should be used to calculate individual resource contributions to the required capacity, we will utilize marginal ELCC values as recommended by the February 22, 2021 ALJ ruling. These aim to ensure LSEs develop resources that will meet the reliability needs of the system identified in this decision. We will ask Commission staff to finalize the marginal ELCC values that will be used to count the procurement required to be online in 2023 and 2024 by no later than August 31, 2021. This first set of marginal ELCCs will be provided for energy storage at various durations, solar, solar plus storage of various durations and configurations, and wind in various regions, in order for LSEs and developers to be able to rely on those values for the 2023 and 2024 capacity required in this order.

In addition, Commission staff will provide guidance on what resource counting LSEs should assume for geothermal, long duration storage, out-of-state wind, and offshore wind for online years through 2028. For all other resource types, counting will be in accordance with the system resource adequacy NQC counting rules at the time the resource comes online.

For some resource types, the marginal ELCC will only be accurate up to a certain level of additional procurement of that resource, and depends on factors including the type and amount of other resources serving load in the future. Accordingly, Commission staff may provide indicative ELCCs for energy storage, solar, solar plus storage, and wind for online years beyond 2024, and then may update those values to final compliance ELCCs for those years as updated data on LSEs' resource additions becomes available. Commission staff will likely utilize the inputs and assumptions process of future IRP cycles to finalize marginal ELCCs for the capacity required online by this decision beyond 2024. This will include taking stakeholder feedback before finalizing the marginal ELCC values.

10. Penalties for Noncompliance

The February 22, 2021 ALJ ruling proposed that, in addition to the backstop provisions in the event that an LSE fails to procure its required capacity, there would be a financial penalty to the individual LSE. The penalty would be set at the cost of new entry (CONE) figure published annually by the CEC, for any required capacity (in MW) that the LSE failed to procure. LSEs would also be subject to citations for failure to comply with the overall reporting requirements that will also apply to the procurement required herein.

10.1. Comments of Parties

In comments, parties generally recognized the need for a meaningful deterrent to non-compliance with incremental capacity requirements. Most parties supported an appropriate penalty, alongside backstop procurement costs, to be assessed to LSEs that do not meet procurement requirements and/or to their customers.

Several parties, including GPI, Cal Advocates, PCF, and Shell, supported using CONE as the basis for a penalty structure.

The IOUs and CalWEA generally recognized the need for a penalty and did not object to CONE, but sought more details on how a penalty would be applied. SCE also emphasized that penalties should not be applied to LSEs that make good faith efforts to procure, but have project delays or failures that are truly outside of their control.

IEP supported a sufficiently high penalty, but believes that CONE is likely excessive because it would effectively require a non-compliant LSE to pay twice for new capacity. Hydrostor opposed use of a generic CONE value, and instead suggested referencing costs of the resource that failed to be procured, such as long-duration storage.

CalCCA and AReM both opposed penalties for LSEs that fail to procure. CalCCA argued that any penalty in the short term is unreasonable, due to the limited availability of resources and limited time to conduct procurement, "coupled with the myriad reasons that could produce non-compliant outcomes despite conducting best efforts procurement." AReM stated that the backstop procurement obligation should provide sufficient incentive for LSEs to perform.

10.2. Discussion

Consistent with the recommendations in the ALJ ruling, we will set up a penalty structure for LSEs that fail to comply with the procurement requirement in this order that includes both the threat of backstop procurement by IOUs (with associated costs assigned to the relevant LSE and/or its customers), as well as a further penalty per MW of capacity not procured.

After consideration of parties' comments, we agree that CONE may be a high penalty, and will instead set the penalty at the level of "net CONE." The "net" portion refers to CONE, net of estimated energy market and ancillary services revenues. The net CONE value shall be based on the cost of a new battery storage facility, which is a technology that is highly likely to be procured as part of the requirements of this order. We consider this level of penalty appropriate but not excessive.

This estimate is already regularly updated for purposes of battery storage procurement, using RESOLVE inputs and outputs. The most recent estimate of net CONE is embedded in our Avoided Cost Calculator for demand-side resources, which was last updated in D.20-04-010 as part of the integrated distributed energy resource (IDER) proceeding.

For purposes of the procurement required herein, we will issue a potential penalty for failure to procure resources once, shortly after the June 1, 2025 milestone compliance date. This will take into account accrued penalties for each year where backstop procurement may have been triggered in 2023, 2024, and 2025, so that LSEs will still have an opportunity and incentive to catch up to their total requirement by the June 1, 2025 milestone compliance date.

If an LSE failed to achieve its share of the capacity procurement in this decision by the June 1, 2025 milestone, for all capacity required between 2023 and 2025 by this order, the LSE will be subject to an assessment of a penalty for each year that the LSE has been non-compliant. The penalty will be set at the level for net CONE specified in the Avoided Cost Calculator.

As noted earlier in Section 5, we will allow LSEs to request an extension up to 2028 for the 2,000 MW of required LLT resources to be procured by 2026, unless the LSE does not submit evidence of a good faith effort to effect such procurement. If requesting an extension, LSEs must submit this evidence, including evidence of having held a solicitation, contract documentation, bid data, other documentation or affidavits from developers about timing considerations, interconnection agreement, site control, and notice to proceed, by the February 1, 2023 milestone date. The Commission will then make a determination about whether to grant an extension, or alternatively, authorize backstop procurement. Much of this data may be submitted confidentially, but should be provided at the milestone date in order to show documentation of the good faith effort to procure these LLT resources. If an LSE can show by

February 1, 2023 that it can bring the LLT resources online by 2028, no penalty will be imposed and no backstop procurement will be required.

11. Relationship to Central Procurement Entity

The February 22, 2021 ALJ ruling also included suggested clarification of the relationship between an individual LSE and the hybrid central buyer framework and central procurement entity (CPE) adopted in D.20-06-002 for the procurement of local resource adequacy capacity.

The ruling proposed the clarification that if an LSE procures a resource to meet its IRP procurement requirements and then chooses to show or sell the capacity of this resource to the CPE (which would not have an IRP procurement obligation), the LSE could still count this resource towards meeting its IRP compliance requirements for D.19-11-016 and any subsequent requirements in this order.

The ruling stated that this clarification should not be viewed as creating a compliance product or unbundling an IRP compliance attribute. Rather, it is intended to clarify the accounting for IRP compliance only.

11.1. Comments of Parties

Parties that commented on this issue included Cal Advocates, Calpine, CCSF, CEJA/Sierra Club, CESA, GPI, LDESAC, Middle River, PCF, PG&E, SCE, and Shell. Most commenting parties generally supported the clarification in the ALJ ruling. Middle River and Shell sought further clarification on the CPE, with specific reference to how the Commission would treat compliance for an LSE that sells resource adequacy to another LSE.

11.2. Discussion

As proposed in the ALJ ruling, we clarify that if an LSE procures a resource to meet its IRP procurement requirements and then chooses to show or sell the capacity of this resource to the CPE (which would not have an IRP procurement obligation), the LSE could still count this resource towards meeting its IRP compliance requirements for D.19-11-016 or this order. In response to Shell's comment, an LSE may retain the IRP compliance attribute of an incremental resource it procured, even if it sells that resource to another LSE within the CAISO territory. The buyer of this resource will not be able to show the same resource for IRP procurement compliance purposes, but can purchase the resource adequacy attributes.

Simply put, only one LSE may show a particular resource for IRP compliance and retains that attribute so long as the resource remains within the CAISO. LSEs will continue to have the ability to transact for excess procurement from another LSE, as long as that procurement has not yet been shown for IRP compliance by the first LSE.

12. Alternative Compliance Regimes to Address Longer-Term System Reliability Requirements

Commission staff are in the process of aggregating the individual LSE IRPs filed on September 1, 2020, in order to determine if additional procurement may be warranted out to 2030 to address both reliability and environmental goals. In their individual IRPs, LSEs were required to provide proposed resource portfolios to meet the 2030 GHG targets of both 46 MMT and 38 MMT. As stated in the ALJ ruling, it is likely that additional procurement will be necessary to meet the 38 MMT target, which the Commission is evaluating and strongly inclined to adopt in a decision later this year. This may result in the requirement for additional procurement action, in addition to the capacity required by D.19-11-016 and in this order. As noted in the ALJ ruling, there is also procurement required to address resource adequacy requirements (in

R.19-11-009), as well as the extreme weather event reliability proceeding (R.20-11-003). And of course, there is also procurement related to the ongoing RPS requirements.

As stated in the ALJ ruling, this sets up an increasing level of complexity to determine compliance with all of these separate resource procurement requirements in many different venues. The ruling sought party input on whether it would be preferable to institute a forward system resource adequacy requirement similar to the one for local capacity in the resource adequacy program. Similar concepts are already being evaluated in R.19-11-009.

12.1. Comments of Parties

Parties have disparate views on this complex topic. Several parties, including CAISO, Cal Advocates, CCSF, Middle River, and SCE, urged that the Commission continue to consider these topics in this proceeding. AReM, on the other hand, preferred that these topics be addressed in resource adequacy.

TURN, CESA, Hydrostor, IEP, and Vistra encouraged greater alignment between resource adequacy and IRP proceedings on planning and procurement in general. IEP's comments included specific suggested distinctions between IRP long-term analysis and need determinations compared to capacity monitoring and enforcement under the resource adequacy program.

A number of parties, including AReM, CCSF, IEP, SBUA, Shell, TURN, and Calpine, urged the Commission to explore the possibility of enforcing IRP-based procurement mandates through longer-term forward resource adequacy compliance obligations.

Middle River suggested the IRP and resource adequacy processes incorporate mechanisms to ensure that generation needed for reliability is retained over the procurement horizon in an effective manner. Middle River is concerned that the assumption that existing merchant resources will continue to exist and be available in the long term may be flawed, without structural changes to either the resource adequacy and/or IRP structure.

IEP and PG&E also suggested a joint IRP and resource adequacy workshop to review common issues.

12.2. Discussion

These are complex issues and parties are obviously correct to point out the ongoing need for coordination between the long-term planning being undertaken in this proceeding and the compliance regime represented by the resource adequacy program. We will continue to explore opportunities for greater alignment with, or expansion of, resource adequacy program obligations and compliance to accommodate IRP long-term objectives, as recommended by several parties.

As noted by many parties in their comments, this will require additional examination and vetting by the Commission and parties. Thus, it is not something we can accomplish in this decision immediately. However, we do commit to continuing to explore these issues in this proceeding, in coordination with the resource adequacy proceeding. We will also consider holding a joint workshop in the near future to further explore the ideas brought forward by parties in response to the February 22, 2021 ALJ ruling. We will also continue to explore the ideas presented in the Staff Proposal on Resource Procurement Framework issued via ALJ ruling on November 18, 2020.[9]

Meanwhile, for the capacity procurement requirements in this order, we will allow LSEs to show procurement that they have conducted to support the

[9] *See* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K577/351577446.PDF

Commission's orders or requirements in the context of the RPS program, as well as for emergency reliability purposes in R.20-11-003, as compliance toward the requirements herein. As stated earlier, procurement to support the requirements of D.19-11-016 are considered in the baseline and will not count towards the requirements of this order, unless the amounts are in excess of the LSE's obligation under D.19-11-016, in which case they may be counted toward the capacity requirements herein if they otherwise qualify.

13. Comments on Proposed Decision

The proposed decision of ALJ Fitch in this matter was mailed to the parties in accordance with Pub. Util. Code section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________.

14. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

Findings of Fact

1. More analysis is needed before revising the planning reserve margin for long-term planning in the IRP proceeding on a permanent basis.
2. The purposes of the resource adequacy program requirements and the IRP long-term planning assumptions are sufficiently distinct that the PRM used for each need not be identical.
3. The analysis conducted by Commission staff to analyze the need for procurement addressed in this decision includes addressing the net peak by utilizing ELCC values that were developed in a probabilistic manner.

4. The electricity market in California is changing rapidly in many respects, including the large number of new LSEs, the major shifts in the resource mix, weather and climate uncertainty, and increasing acceleration of electrification of building and transportation energy use.

5. The electric grid within the California Independent System Operator's balancing authority requires at least 11,500 megawatts of incremental net qualifying capacity compared to resources online, or contracted and approved to come online, as of June 30, 2020, in order to maintain grid reliability.

6. The resources required by this order will contribute to meeting a 38 MMT GHG emissions limit in the electricity sector by 2030.

7. Requiring 2,500 MW of incremental procurement of firm, zero-emissions resources by 2024 will further ensure that there is no increase in GHG emissions as a result of the closure of Diablo Canyon.

8. Import availability has been on the decline in recent years, for many reasons, including retirement of fossil-fueled resources in the West, warming climate, increasing loads, and lower availability of hydroelectric resources.

9. Procurement conducted within a year or two of the actual system need is likely to result in higher costs and lower resource diversity than procurement with more lead time.

10. Acceleration of procurement requirements one year ahead can help mitigate cost and reliability risks.

11. Procurement must begin now to ensure delivery of LLT resources by mid-to-late in this decade.

12. LLT resources will provide important resource diversity, renewable integration, and system reliability benefits.

13. Specification of long-duration storage and firm (at least 85 percent capacity factor) and/or dispatchable (available between hours 17 and 22 daily) zero-emissions resources as LLT by 2026 will help diversify the grid resources and improve reliability and renewables integration.

14. The OTC units still on the electric grid represent some of the oldest and least efficient fossil-fueled units.

15. CHP units operating under legacy contracts or extensions as QFs can benefit from upgrading or replacement if they are needed for reliability, to improve heat rates and reduce GHG emissions from their locations.

16. Allowing incremental fossil-fueled or natural gas capacity to count toward the NQC requirements of this decision will likely result in replacing existing capacity with more efficient and lower-emitting resources.

17. The Reference System Plan adopted in D.20-03-028 did not show a requirement for new natural gas capacity by 2030, but did not analyze whether replacement of existing, inefficient natural gas capacity with newer, more efficient gas would contribute to system reliability and renewables integration.

18. Replacement capacity for Diablo Canyon has been in the process of being procured since 2018.

19. Imports are an important part of the resource mix in California to ensure reliability.

20. Section 397 of the Public Utilities Code requires the Commission to allocate procurement needs to each LSE based on load and resource portfolio considerations. The Commission has not found that any particular LSE's portfolio has a differential impact on system reliability at this time.

21. Using the power charge indifference adjustment process, vintaged to the date of this order, will address any future load migration away from IOU service.

22. D.20-12-044 adopted the milestone dates for compliance filings and triggers for backstop procurement associated with D.19-11-016.

23. The Commission utilizes Tier 3 advice letters to approve cost recovery for numerous low-emission and clean energy procurement programs, including for the RPS program.

24. Calculating the system reliability benefits of specific resources will be more accurate if marginal ELCCs are used.

25. Net CONE represents the cost of new entry for new battery storage resources, net of estimated energy market and ancillary service revenues, which is a technology highly likely to be procured in response to this order.

Conclusions of Law

1. The Commission should conduct additional analysis to finalize the appropriate planning reserve margin to use for long-term planning in this proceeding.

2. The Commission should continue to work with the CEC on issues affecting the demand forecast, particularly around weather variants and the impacts of the changing climate.

3. The PRM assumption of 20.7 percent is appropriate and conservative to use for the medium-term to support the need for some procurement in order to support system reliability.

4. The Commission should adopt the 38 MMT GHG limit for 2030 when considering the aggregated IRPs of all LSEs when we consider the PSP later this year as long as the resource mix results in a reliable system with a 0.1 LOLE or less.

5. The Commission should use the high-need scenario analyzed by Commission staff to form the procurement need required in this order.

6. The Commission should require a significant amount of resources to be procured and come online at least one year prior to their being needed for reliability, in order to provide insurance against imperfect analysis, contingency for procurement failure, and the costs of lack of reliability leading to unplanned outages in real time.

7. The Commission should require all LSEs, in aggregate, to procure the resource amounts in the timeframe given in Table 3 of this decision.

8. The Commission should require the procurement, in aggregate, of at least 1,000 MW of long-duration storage resources by 2026, with the option of an extension to 2028 for compliance, if good cause and a good faith effort to procure are shown.

9. The Commission should require the procurement, in aggregate, of at least 1,000 MW of firm (at least 85 percent capacity factor) and/or dispatchable (between hours 17 and 22 daily) resources that have zero or de minimis emissions by 2026, with the option of an extension to 2028 for compliance, if good cause and a good faith effort to procure are shown.

10. The Commission should allow the procurement of long-duration storage resources, or firm or dispatchable zero-emissions resources, that has occurred since D.19-11-016 was issued, to count toward the obligations for these LLT resources in this order, as long as the total resource obligation by LSE is still met.

11. Joint and/or coordinated procurement of LLT resources by multiple LSEs should be encouraged but not required.

12. If individual LSEs are unable to procure the required LLT resources in this order, it is reasonable for the Commission to allow an extension and/or to require the IOUs to procure the LLT resources to backstop other LSEs, and have

the costs allocated according to the modified CAM that will be forthcoming in this proceeding.

13. The Commission should not request from the Water Board any further extensions to OTC compliance dates for the affected units.

14. Allowing incremental natural gas capacity to count toward the procurement in this order will not necessarily result in increased GHG emissions, but will assist in retiring older, less-efficient units and help insure reliability during the transition to a cleaner grid by 2030.

15. The Commission should have stricter requirements for any incremental natural gas generation used to count toward the procurement requirements in this decision that are located in disadvantaged communities compared to other areas.

16. The Commission should require the incremental natural gas resources required in this order to be procured by the IOUs only, with the costs allocated via the CAM.

17. To ensure no ambiguity about the emissions profile of replacement capacity for Diablo Canyon, the Commission should require that a minimum of 2,500 MW of incremental NQC be from firm, zero-emitting resources, that are available every day between hours 17 and 22, and can deliver 5 MWh of energy during each of those periods for every MW of incremental capacity used to comply with the requirements of this order.

18. The Commission should maintain consistent rules for counting of imported power for both this order and the resource adequacy program.

19. Requiring imports to be associated with a new resource with a commercial online date after the date of this order will ensure the resource is incremental.

20. It is reasonable and in compliance with §397 to allocate procurement responsibility to LSEs based on a hybrid of their 2021 energy forecasts and 2021 year-ahead resource adequacy forecasts, except for ESPs, where we will use only the resource adequacy forecasts and convey their individual allocations confidentially.

21. It is reasonable to continue a similar compliance filing and milestone trigger system for backstop procurement to the schedule adopted in D.20-12-044 for procurement associated with D.19-11-016. Therefore, the dates given in Table 8 of this decision are reasonable and will facilitate orderly compliance monitoring.

22. The Commission should require the IOUs procuring in response to this order to file their non-fossil-fueled projects seeking cost recovery via Tier 3 advice letters.

23. Fossil-fueled resources and LLT long-duration storage resources involve more complex and potentially controversial environmental issues and therefore should require the filing of a full application by the IOUs procuring these resources as described in this order.

24. The Commission should use marginal ELCC values provided by Commission staff to estimate the reliability contributions of various resources to be procured in response to this order.

25. It is reasonable to set the penalty for non-compliance with the procurement required in this order at the level of net CONE included in the Avoided Cost Calculator, after assessing compliance after the June 1, 2025 compliance filing date.

26. It is reasonable to allow LSEs to count resources that were procured in compliance with D.19-11-016 or this order toward the requirements of these orders, even if the LSE subsequently shows or sells the capacity to the CPE.

27. It is reasonable to allow resources procured to support the requirements of D.19-11-016 that are in excess of the compliance requirements to be used to satisfy the requirements of this order.

O R D E R

IT IS ORDERED that:

1. Procurement of 11,500 megawatts (MW) of incremental net qualifying capacity shall be conducted over the course of four years, with 3,000 MW online by August 1, 2023, an additional 4,500 MW online by June 1, 2024, an additional 2,000 MW online by June 1, 2025, and an additional 2,000 MW online by June 1, 2026.

2. Long lead-time resources required by this order shall be defined as at least 1,000 megawatts (MW) of long-duration storage (able to deliver for a least eight hours) and at least 1,000 MW of firm (at least 85 percent capacity factor) and/or dispatchable (between at least hours 17 and 22 daily) zero-emissions resources by June 1, 2026.

3. All load-serving entities named in Table 7 of this order shall procure the net qualifying capacity amounts given in Table 7, and shall file and serve on the service list of this proceeding or any successor proceeding compliance filings according to the schedule given in Table 8 of this order.

4. All load-serving entities named in Table 7 of this order shall submit evidence of a good faith effort by February 1, 2023 to procure long lead-time (LLT) resources defined in Ordering Paragraph 2. The Commission will decide after the February 1, 2023 milestone filing whether to allow an extension up to

June 1, 2028 for the LLT resources to come online, or whether to order backstop procurement of the LLT resources. Evidence of a good faith effort shall include, but may not be limited to, at least two of the following:

(a) Evidence of a solicitation;
(b) Evidence of bids in a solicitation;
(c) A contract;
(d) Evidence of site control;
(e) An interconnection agreement; and
(f) A notice to proceed.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall procure the amounts of natural gas net qualifying capacity given in Table 5 of this decision, collectively the range of minimum 1,000 megawatts (MW) and maximum 1,500 MW, by no later than 2025, as a portion of their overall procurement required by this decision in Table 7. The natural gas capacity costs shall be allocated to all benefitting customers in each service territory using the cost allocation mechanism established by the Commission for purposes of allocating the costs of resources needed for reliability and renewables integration purposes. If the natural gas capacity is located in a disadvantaged community, as defined by being in the top 25 percent of communities with the highest environmental burden, as given in the most recent version of the CalEnviroScreen tool maintained by the California Office of Environmental Health Hazard Assessment, then the following requirements also apply to the categories of projects as defined in Section 5 of this decision:

(a) The project may not be in Category 3 (expansions).

(b) The project may not be in category 5 (repowering at mothballed or retired facilities).

(c) If a project is in Category 1 (efficiency improvements), it must include a contractual commitment to use at least

30 percent green hydrogen by the fifth year of operation.

(d) If a project is in Category 2 (uprates/upgrades), it must include hybridization by adding storage to improve its emissions profile.

(e) If a project is in Category 4 (repowering at operating facilities), it must reduce its rate of greenhouse gas emissions compared to existing operations.

6. Collectively, to ensure that the capacity retiring at the Diablo Canyon Power Plant is replaced entirely with firm, zero-emitting resources, the load-serving entities shall collectively procure a minimum of 2,500 megawatts (MW) of incremental firm, zero-emitting capacity out of the total of 11,500 MW required in this decision. This firm, zero-emitting capacity shall have the following characteristics:

(a) Be available every day from hours 17 through 22, at a minimum; and

(b) Be able to deliver at least 5 megawatt-hours of energy during each of these periods for every megawatt of incremental capacity claimed.

7. Any imports used to show compliance with the procurement required by this order shall follow the eligibility and counting rules of the resource adequacy program and shall be associated with a new resource with a commercial online date that is after the date of this order.

8. All resources, including imports, used to satisfy the requirements of this procurement order shall be contracted for a minimum of 10 years.

9. To the extent that any resources procured in response to this order are subject to allocation using the power charge indifference adjustment, the date of that adjustment shall be vintaged by the date of this order.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall each file Tier 3 advice letters to

request cost recovery for any procurement conducted as a result of this order, except if the procurement is associated with a fossil-fueled resource or a long-duration storage resource, a full application is required.

11. Commission staff shall publish on our web site marginal effective load carrying capability values to be used for the 2023 and 2024 compliance dates in this decision by no later than August 31, 2021 and for the 2025 and 2026 compliance dates by no later than December 31, 2022.

12. Any load-serving entity (LSE) that procures a resource for purposes of the requirements of this order or Decision (D.) 19-11-016 and subsequently shows or sells the attributes of the resource to the resource adequacy central procurement entity may still count the resource for purposes of compliance with this order and D.19-11-016. Any resource (or a portion thereof) may only be used to show compliance with this order or D.19-11-016 once by one LSE.

13. Any load-serving entity that procured resources to comply with Decision 19-11-016 in excess of their minimum requirements may use those resources to satisfy the requirements of this decision, as long as the resources are contracted, approved, and come online after June 30, 2020.

This order is effective today.

Dated ______________________, at San Francisco, California.