Decision **PROPOSED DECISION OF ALJ FITCH (Mailed 9/12/2019)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007

DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

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DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

Summary

In this decision, the Commission takes a number of steps to address the potential for electricity system resource adequacy shortages beginning in 2021. The Commission's concern is to ensure safe and reliable electric service, in a manner that keeps the electricity sector on a path to the 2030 greenhouse gas (GHG) emissions goals articulated in Senate Bill (SB) 350 (DeLeón, 2015), SB 100 (DeLeón, 2018), and Commission Decision (D.) 18-02-018. The electricity resources required in this decision are necessary to continue to integrate the growing amount of renewable energy delivering to the electric grid.

First, this decision recommends that the State Water Resources Control Board (Water Board) extend of the once-through-cooling (OTC) compliance deadlines for the following units currently slated to retire by December 31, 2020, for the time periods specified: Alamitos Generating Station, Units 3-5, totaling approximately 1,200 MW, for up to three years; and Huntington Beach Generating Station, Unit 2, approximately 200 MW, for up to three years; Redondo Beach Generating Station, Units 5, 6, and 8, approximately 850 MW, for up to two years; and Ormond Beach Generating Station, Units 1 and 2, approximately 1,500 MW, for up to one year. In addition, we request a temporary extension for the Moss Landing facility to meet its obligations under the OTC requirements, though this does not result in additional capacity being available. These requests are to ensure electric system reliability with the expectation that these OTC units will have low capacity factors, and therefore low emissions and low use of seawater for cooling. The Commission remains committed to OTC compliance, for which California has made substantial

progress in the last decade, and requests this schedule adjustment purely to ensure electric system reliability.

Second, the decision requires incremental procurement, beyond the baseline resources assumed for the Year 2022 and included in the Preferred System Plan adopted in D.19-04-040 (as adjusted in this decision), and in addition to the OTC retirement extensions described above, of system-level resource adequacy capacity of 3,300 MW, by all load-serving entities (LSEs) serving load within the California Independent System Operator balancing authority area. The resources shall be required to come online at least 50 percent by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. LSEs are encouraged to exceed these minimum requirements to help minimize or eliminate the need for the OTC compliance extensions requested. LSEs are also encouraged to conduct their procurement with an eye toward grid resiliency, the need for which has been recently demonstrated with the experience with wildfires and power shutoffs. The Commission intends to further explore resiliency needs in its de-energization and microgrid rulemakings.

Procurement shall be conducted on an all-source basis, including both existing and new resources (except new gas-only resources), and may include LSE-owned resources when justified. The IOUs shall present their proposed contracts in a Tier 3 advice letter, with other LSEs providing summaries of their resource procurements, accompanied by an attestation from a senior officer that they will meet the requirements for the electric capacity.

All LSEs will also provide an activity progress report by February 15, 2020. They will also be required to include updated contractual data both in their 2020 individual integrated resource plan (IRP) filings, and in response to a standing data request to be submitted on May 1 of each year in which individual IRPs are not required to be filed, according to templates developed and disseminated by Commission staff.

The Commission will continue to consider clarifications or changes to the resource adequacy rules for imports, as well as the capacity values for hybrid resources, in the resource adequacy Rulemaking (R.) 17-09-020.

Additional procurement for longer term resource adequacy purposes will continue to be considered in the next IRP cycle, which is already underway.

This proceeding remains open.

1. Background

Our inquiry into the potential for near- or medium-term reliability issues began with a November 16, 2018 joint Assigned Commissioner and Administrative Law Judge (ALJ) Ruling seeking comment from parties on policy issues related to reliability. Comments and reply comments filed in November 2018, among other things, led to the initiation of the "procurement track" of this rulemaking, as ordered in Decision (D.) 19-04-040, to explore possible actions the Commission could take to address potential reliability or other procurement needs while the next Integrated Resource Plan (IRP) planning cycle is underway.

To further the exploration of potential reliability issues and spur the development of possible procurement options, another assigned Commissioner and ALJ Ruling was issued on June 20, 2019. The June 20, 2019 Ruling initiated the procurement track of the proceeding and offered a straw proposal for how potential near-term electricity system resource reliability issues could be addressed. The proposal was based on a "stack analysis" by Commission staff of available electric capacity as soon as 2021, as described in more detail in the ruling.

Comments in response to the June 20, 2018 assigned Commissioner and ALJ ruling were filed on or before July 22, 2019 by the following 44 parties or combinations of parties: Alliance for Retail Energy Markets (AReM); American Wind Energy Association California Caucus (AWEA) and Large-Scale Solar Association (LSA), jointly; Bonneville Power Administration (BPA); Golden State Water Company on behalf of its Bear Valley Electric Service Division (Bear Valley); California Independent System Operator (CAISO); California Community Choice Association (CalCCA); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Large Energy Consumers Association (CLECA); California Public Advocate's Office (Cal Advocates); California Wind Energy Association (CalWEA); Californians for Green Nuclear Power (CGNP); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); City and County of San Francisco (CCSF); Cogeneration Association of California (CAC); CPower and Enel X North America, Inc. (Enel X), jointly (Joint Demand Response Parties); Defenders of Wildlife (DOW); Department of Market Monitoring of CAISO (CAISO DMM); Environmental Defense Fund (EDF); First Solar, Inc. (First Solar); Form Energy, Inc. (Form); Green Power Institute (GPI); Hydrostor, Inc. (Hydrostor); Independent Energy Producers Association (IEP); LS Power Development, LLC (LS Power); Middle River Power, LLC (Middle River); Natural Resources Defense Council (NRDC); NRG Energy, Inc. (NRG); Pacific Gas and Electric Company (PG&E); Powerex Corporation (Powerex); Protect Our Communities Foundation (POC); Public Generating Pool (PGP); Range Energy Storage Systems, LLC (Range); San Diego County Water Authority

(SDCWA); San Diego Gas & Electric Company (SDG&E); Solar Energy Industries Association (SEIA); Southern California Edison Company (SCE); Sunrun, Inc. (Sunrun); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); Vote Solar; Wellhead Power Solutions, LLC (Wellhead); and Western Power Trading Forum (WPTF).

Reply comments were filed on or before August 12, 2019 by the following 36 parties: Advanced Energy Economy (AEE); AReM; AWEA and LSA, jointly; CAC; CAISO; CAISO DMM; Cal Advocates; CalCCA; Calpine; CCSF; CEERT; CEJA and Sierra Club, jointly; CESA; CLECA; DOW; EDF; GPI; Hydrostor; IEP; LS Power; Middle River; NRDC; NRG; PG&E; POC; Powerex; Small Business Utility Advocates (SBUA); SCE; SDG&E; SEIA; Sunrun; TURN; UCS; Vote Solar; Wellhead; and WPTF.

2. Threshold for Procurement Action

The June 20, 2019 Assigned Commissioner and ALJ Ruling contained a description of Commission staff analysis of available near-term supply for system resource adequacy. The analysis was based on system needs identified in the Integrated Energy Policy Report (IEPR) adopted by the California Energy Commission (CEC) in February 2019, for a 1-in-2 peak California Independent System Operator (CAISO) coincident forecast.

Analysis of the supply stack available to meet these forecasted system needs was based on the CAISO Net Qualifying Capacity (NQC) list, which reflects megawatts (MW) currently available to the bilateral market.[1] The CAISO produces this list annually, but updates it monthly to reflect new resources that have reached commercial operation, as well as existing resources that have

[1] Located on CAISO's reliability requirements website at: http://www.caiso.com/Documents/NetQualifyingCapacityList-2019.xlsx

increased their capacity. The NQC list, however, does not include new resources that are not yet online, nor does it reflect intra-year or future resource retirements.

To account for near- to medium-term retirements, the CAISO also maintains a list of mothballed and retired resources,[2] which includes resources that have retired or are expected to retire, as well as units that are in the process of mothballing or considering retirement. The June 20, 2019 ruling summary of the supply stack did not include resources that were already retired but did include those that have been mothballed or proposed to do so.

The supply stack was also adjusted by the recently-adopted effective load carrying capability (ELCC) values adopted in the resource adequacy Rulemaking (R.) 17-09-020.[3] Supply resources under development and expected to be online by 2024 were also included, including resources explicitly authorized by the Commission.[4] The analysis preceded the development of the baseline set of resources for use in the 2019-2020 IRP planning cycle posted in late June 2019 for purposes of modeling of the next Reference System Plan (RSP).[5]

An analysis of maximum import capability (MIC) and the potential contribution of imports toward system capacity was also included. In addition, estimates for hydroelectric contributions were included, though not adjusted for annual variations or uncertainty. The June 20, 2019 ruling also noted that the

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[2] Located at: http://www.caiso.comDocuments/AnnouncedReitrementAndMothballList.xlsx

[3] *See* D.19-06-026 at 42-49.

[4] These resources include, but may not be limited to, those referenced in D.13-02-015, D.14-03-004, D.15-11-041, D.14-02-016, DS.15-05-051, D.18-05-024, Resolution E-4397, and Resolution E-4949.

[5] 2019-2020 baseline assumptions are available at the following link: https://www.cpuc.ca.gov/General.aspx?id=6442461894

stack analysis shows that based on current knowledge, by 2021 the system could end up relying on all available resources, including nearly all of the available MIC, which is roughly double the historical usage of imports for system reliability purposes.

Based on this look at the supply and demand situation in 2021, the June 20, 2019 Ruling proposed to require all load-serving entities, on a pro-rata basis of load being served, to procure 2,000 MW of new resources, and for Southern California Edison (SCE) to procure 500 MW of existing resources, by August 1, 2021, to avoid a potential system emergency. The ruling also proposed to seek an extension of deadlines for some once-through-cooling (OTC) generation units to comply with requirements of the State Water Resources Control Board (Water Board). This aspect is discussed further in Section 3 below.

2.1. Comments of Parties

The majority of parties filing comments in response to the June 20, 2019 Ruling agree that there is at least a potential for system reliability issues as early as 2021. Where parties differ is in their recommendations for what the Commission should do to address the potential for reliability challenges. Comments generally fall into two categories: parties who believe the Commission should do more detailed study of the supply situation, and those who believe that time is already too short and additional procurement should be required starting immediately.

Leading the parties seeking more detailed study are AReM and CalCCA. AReM's central arguments are that the Commission and the CAISO need to coordinate their detailed analyses to determine if there are indeed any near-term reliability requirements that cannot be met through the continued operation of the existing resource adequacy program. In particular, AReM points to a number of unresolved resource adequacy and load forecasting issues that they argue need to be resolved, including the potential that the investor-owned utilities (IOUs) are holding onto resource adequacy capacity in excess of their needs.

CalCCA also argues that further analysis is needed because the uncertainty level of a stack-type analysis is very high. CalCCA argues that a more rigorous examination is needed of the pace and magnitude of resource retirement, the availability of import supplies, and the likely contribution of already-contracted new resources coming online between 2021 and 2025. In addition, they point out that there have been additional analyses by the CAISO that should shed light on the reliability situation beginning in 2021. In particular, they argue that the CAISO Sensitivity Study from the 2019 Summer Loads and Resources Assessment[6] concludes that the CAISO balancing area is unlikely to face a substantial reliability deficiency event, except if there is a confluence of several exceptional circumstances placing stress on the electric system.

CalCCA also points to the CAISO 2020 Local Capacity Technical Report[7] that concludes that planned transmission projects make any need in 2021 supply temporary. Finally, CalCCA points to the analysis done in this proceeding to support the Reference System Plan (RSP) in 2017 (leading to D.18-02-018) and particularly the adopted Preferred System Portfolio (PSP) in 2018 (leading to D.19-04-040), arguing that this type of analysis is more rigorous and necessary to support any procurement determination made in the context of IRP. Thus, CalCCA concludes that the Commission should conduct additional reliability

[6] http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf

[7] http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf

studies before requiring additional procurement beyond what is already happening naturally to satisfy renewables portfolio standard (RPS) or other resource adequacy requirements.

CCSF directly argues that the simpler stack analysis contained in the June 20, 2019 Ruling undermines the IRP process that the Commission has been carefully developing over the past few years in this proceeding. However, in reply comments, CCSF does support the Commission taking some "least regrets" actions for procurement through the resource adequacy framework.

GPI comments that there is no need to panic, and suggests temporarily relaxing the planning reserve margin (PRM) and/or focusing procurement requirements in the near term on existing, baseload renewables. Middle River expresses concern that ordering procurement in IRP may disturb reforms of the resource adequacy program that are underway, and therefore suggests we not do it. POC similarly suggests that reliance on imports should be enough, and therefore additional immediate procurement is unnecessary.

WPTF argues that the analysis is flawed, but if procurement is ordered, it should be for more than just storage resources.

Finally, SDG&E argues that procurement is not yet necessary, and that shortages are unlikely because the CAISO's analyses are very conservative. They argue that if there is an emergency, the CAISO has both the reliability must run (RMR) designation process, as well as the capacity procurement mechanism (CPM).

At the other end of the spectrum, the parties most strongly weighing in in favor of immediate procurement requirements were the CAISO and SCE. In its opening comments, the CAISO states that without action, there will be system resource adequacy capacity shortfall in 2021. CAISO presents its own analysis leading to similar conclusions as the June 20, 2019 Ruling. CAISO sees a shortfall of at least 2,300 MW by 2021, and 2,200 MW in 2022. CAISO recommends that the Commission direct load-serving entities (LSEs) to prioritize the procurement of existing and new resources capable of serving load in the after-peak hours in the absence of solar generation. This comment was backed up by an updated analysis included in its reply comments, suggesting that in addition to a resource adequacy capacity shortfall, there could be an "operational" capacity shortfall of closer to 4,400 MW by 2021. This analysis is predicated on the system peak period being experienced over a period of up to four hours instead of just the one peak hour normally utilized for determining resource adequacy capacity. This distinction becomes important as the peak period shifts later in the day and solar power cannot be counted on as much, later in the day or later in the year, to provide operational support to the system.

SCE's comments are even stronger than the CAISO's, suggesting that the CAISO system is confronting a significant system resource adequacy shortfall by 2021 unless expedited action is taken to develop new clean energy resources and potentially extend existing natural gas-fired generation resources on an interim basis. SCE presents analysis that suggests that the system resource adequacy reliability shortfall in 2021 could be as much as 5,500 MW, continuing over the next several years after that. SCE characterizes the reasons for this shortfall as a combination of the retirement of a large amount of OTC capacity, the potential for additional retirements of non-OTC thermal generating units, shifting peak load, reductions in ELCC values of solar and wind, reliance on an uncertain level of imports, and shrinking CAISO system capacity margins.

IEP supports the Commission exercising its authority to order procurement. Cal Advocates is also in support.

Several parties, including Calpine and Wellhead, support immediate procurement authorization, but argue that it is more appropriately done in the context of system resource adequacy requirements in the resource adequacy proceeding, with multi-year system requirements.

AWEA and LSA, as well as CESA, continue to argue that the Commission should order procurement soon because of the imminent decline in federal tax credits that California should take advantage of. CalWEA argues that it will be necessary to repower existing wind facilities in order to continue to meet the GHG targets at reasonable cost. CEERT and DOW generally support a procurement authorization, with a focus on preferred resources. CAC, meanwhile, supports a procurement requirement in order to retain efficient combined heat and power (CHP) facilities.

CEJA and Sierra Club, as well as UCS, support the Commission requiring procurement, but do not support any OTC extensions or contracting with additional natural gas generation resources.

SEIA supports some additional procurement, suggesting it be done through the renewable auction mechanism (RAM). Sunrun is interested in additional procurement to support solar-storage hybrid distributed energy resources (DERs). Vote Solar would support additional analysis before ordering procurement, but also supports solar-storage hybrid participation, as does Sunrun.

TURN's comments express uncertainty about whether a reliability need really exists, but suggest that if procurement is required it should be for storage. TURN would also prefer that the Commission develop a backstop procurement mechanism first before proceeding to order additional procurement. Finally, TURN also disfavors any OTC deadline extensions.

Finally, Form Energy advocates for the Commission to address the long-term needs of LSEs for renewable integration resources, and suggests an attribute-based set of requirements to ensure that portfolios are able to support the increased renewable resources in the overall system portfolio.

2.2. Discussion

First, to avoid any further confusion as reflected in the comments of some parties, our decision here is entirely about resources for system reliability, which means resources that qualify to meet system resource adequacy requirements. The June 20, 2019 Ruling was focused on concern about the potential for a system-level (not local or flexible) reliability shortfall by 2021. Since there is just a one-year-ahead requirement for system resource adequacy, such a potential shortfall would not be picked up by the regular system resource adequacy processes until late 2020. If there is indeed a shortage of available system capacity, that timing would likely be too late for the development of any new resources to help address the shortfall.

We acknowledge that the CPM and RMR mechanisms of the CAISO are designed for emergency situations, but they do not necessarily represent the most economic options for ratepayers. They also cannot be used to produce additional new resources able to come online in time to meet system reliability shortfalls. Thus, the question is really whether this Commission should take action to prevent the need for those mechanisms to be triggered to some degree by 2021 and shortly thereafter.

Before addressing the particulars of any procurement, first we must grapple with whether the analysis before us is sufficient to prompt us to make additional procurement requirements for all LSEs in the context of this proceeding. We acknowledge that there are activities occurring in the resource adequacy rulemaking (R.17-09-020) that have impacts on our thinking in the context of the IRP process, including rules about the counting of import resource adequacy and the development of a central buyer framework.

In addition, several parties, particularly those representing CCA and ESP interests, argue that our analysis in this proceeding, in the context of the development of the RSP and the PSP in the past two years, has been more sophisticated than the stack analysis contained in the June 20, 2019 Ruling. Our most recent analysis to develop the PSP adopted by D.19-04-040 did utilize both capacity expansion modeling and production cost modeling, with loss of load expectation (LOLE) analysis, but the latter was only conducted for the year 2030. That is because the context of that analysis was to determine if the optimal resource portfolio being adopted for 2030 was a reliable choice to be used as the target for LSEs to utilize in their ongoing planning and procurement decisions. In developing the PSP adopted in D.19-04-040, production cost modeling was not conducted for interim years of 2022 or 2026, let alone for each year in the planning period.

Meanwhile, new analysis for IRP planning purposes is underway for the development of the RSP for the 2019-2020 IRP cycle. We intend to conduct additional production cost modeling reliability checks on the development of the new optimal portfolio for the next and future IRP cycles, with interim year reliability checks. However, given the imminence of the 2021 system reliability needs, there is not time to complete that analysis, allow additional input and vetting from parties, and still have procurement take place in time to meet a potential shortfall in the timeframe of Summer 2021.

Therefore, we view the requirement for additional procurement now as a "least regrets" strategy, since electricity shortages would most certainly lead to regrets. This is consistent with the Commission's responsibility to ensure that customers have safe and reliable electric service. Procurement of the exact "right" amount of system power is never possible, and requires a balancing act of reasonableness. Too few system resources could lead to actual shortages or and/or market manipulation opportunities for owners of system resources. This leads to the risk of additional ratepayer costs. On the other hand, too much system capacity represents unnecessary ratepayer costs as well. Our job is to weigh these tradeoffs and find a reasonable path forward to achieve an appropriate balance of risks and ratepayer costs.

With this balancing role in mind, we find that there is sufficient information to authorize incremental system reliability procurement and to recommend an extension of the retirement dates of some OTC resources to serve as a bridge until these incremental system resources can be brought online. The later sections of this decision analyze in greater detail the amount and type of procurement we find necessary.

We will continue to conduct analysis in the development of the RSP for the 2019-2020 IRP cycle. New and better information is always becoming available as time progresses, but at this stage we are sufficiently concerned about the system reliability challenges facing us in 2021 that we are not inclined to wait until another round of analysis is completed and vetted. There will still be many steps between our procurement authorization today and the eventual delivery of power by new resources.

While there are many factors that have an impact on the thinking of all parties about the likelihood of system emergencies in 2021 or shortly thereafter, the one most critical to where parties weigh in about ordering procurement or not in this context appears to be the level of comfort with additional reliance on imported power. We will address the particulars about import counting later in this decision, but for purposes of whether or not to pursue near-term reliability procurement, this decision reflects the Commission's heightened concern about the reliance on imports without firm contractual obligations to meet peak demand reliability needs. This also plays into concerns about the potential for contract or resource shuffling, where the potential exists for hydroelectric generation to be used to serve California load without actually displacing any other emitting resources in the Western Electricity Coordinating Council (WECC) region.

Reliance on imports also represents a separate set of risks that is different from the risks associated with in-state resources, because California has less control over the resources. We discuss imported power issues further in Section 4 below.

3. Once Through Cooling Issues

The June 20, 2019 Ruling contained the recommendation that the Commission pursue the potential for OTC deadline extensions from the SWRCB. The Commission is a member, along with the California Energy Commission (CEC), CAISO, and several other state agencies, on the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS), which advises the Water Board on OTC policy. The suggestion in the June 20, 2019 Ruling was for a one- or two-year delay request, for perhaps a subset of units that are slated for retirement in the next several years. This was suggested as a temporary and short-term bridge strategy only.

The specific generation resources within the CAISO footprint that are scheduled to retire by December 31, 2020 that could potentially have their compliance dates extended are: Alamitos Generating Station (Alamitos), Units 3-5, totaling approximately 1,200 MW; Huntington Beach Generating Station, Unit 2, approximately 200 MW; Redondo Beach Generating Station (Redondo), Units 5, 6, and 8, totaling approximately 850 MW; and Ormond Beach Generating Station (Ormond Beach), Units 1 and 2, totaling approximately 1,500 MW.[8] Together, these resources represent approximately 3,750 MW of system capacity,[9] all within the transmission access charge (TAC) area of SCE.

3.1. Comments of Parties

As already summarized above, many parties are against the concept of extending any OTC compliance deadlines for environmental, and in some cases environmental justice, reasons. Parties opposing OTC extensions include CEJA and Sierra Club, DOW, and TURN. CEJA and Sierra Club point out that as recently as March 8, 2019, SACCWIS published a report concluding that no compliance deadline extensions should be necessary.[10]

Some other parties, such as GPI, favor pursuing OTC extensions instead of ordering additional procurement immediately.

PG&E, SCE, and SDG&E all suggest at least pursuing temporary OTC compliance date extensions, with CalCCA and CESA suggesting that the CAISO conduct additional analysis prior to further Water Board consideration.

The IOUs all also suggest utilizing the reliability must run (RMR) contracting process through the CAISO tariff to procure any OTC units whose compliance dates are extended. In reply comments, the CAISO argues that

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[8] *See* https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/, at 13.

[9] Note that the NQC values are different than the capacity values listed.

[10] *See* http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sac2019fnl.pdf at 26.

procurement should first occur through the resource adequacy program with LSEs contracting bilaterally and directly. They argue that the RMR authority is intended as a backstop only.

The CAISO's comments also contain an analysis that suggests that three of the Alamitos units (units 3, 4 and 5, with a combined capacity of approximately 1,120 MW) are the best candidates for an OTC compliance deadline extension. This is because those units provide both system resource adequacy and local capacity. The CAISO argues that Alamitos units 1, 2, and 6 must retire by the end of 2019 in order to allow a repowering project scheduled for their locations, and therefore are not good candidates for OTC extensions.

The CAISO also suggests in its comments that the owner of Redondo Beach is in the process of selling the property in anticipation of the OTC compliance deadline, and therefore this plant may not be a candidate for an OTC compliance deadline extension. IEP is similarly concerned about reversing OTC compliance deadlines after owners of retiring plants may have made other business decisions in anticipation of required retirement dates.

Many parties caution that OTC compliance deadline extensions should not be suggested lightly, and that the Commission should consider this option very carefully in light of the many environmental concerns associated with the OTC policy. Cal Advocates expressly refers to the idea of extending some OTC plant deadlines as an insurance policy. CESA recommends consideration of OTC deadline extensions only as a "stopgap" measure.

In reply comments, CEJA and Sierra Club especially oppose any extension to OTC compliance deadlines for Ormond Beach, due to its proximity to communities overburdened with pollution. NRDC also opposes extensions with OTC plants that are known to impact disadvantaged communities. They also argue generally that extensions with high-emissions plants are inconsistent with California's environmental goals.

3.2. Discussion

We state directly that requesting OTC compliance deadline extensions is not our first choice, but it may be necessary. We are committed to OTC policy compliance as soon as possible. However, we are also extremely concerned about the timeframe between now and approximately 2023 when a cluster of OTC retirements will converge at a time when additional recent procurement has not had time to result in additional operational capacity online to address reliability challenges. This is especially a concern in Southern California, where all of these OTC retirements are expected to take place.

It is also the case that if we do not ask for OTC compliance deadline extensions for these plants now, they will definitely not be available if we need them starting in 2021. However, it is also possible that we may not need them. Extension requests are an insurance policy against the possibility that we may have power shortages in this timeframe.

Many factors will impact the pace and timing of the commercial online dates for the new procurement authorized in this decision, including, but not limited to: time needed to run solicitations, especially for some LSEs who may be running solicitations for the first time; whether and where selected resources are within the CAISO interconnection queue; and the type of resources selected, which in turn impacts permitting and construction schedules.

In addition, a significant number of resources are counted as existing resources in the baseline, but are actually still under development, and may encounter delays to their commercial online dates. For all of these reasons, it is impossible to predict the size and length of a bridge we may need retiring OTC units to provide, and it seems most prudent to make the OTC units available to the resource adequacy program for the next several years to let the markets answer these questions.

Consistent with the resource adequacy program three-year forward local procurement requirements and our commitment to retire all OTC units in IOU territories in an orderly manner that does not jeopardize electric reliability, we recommend that SACCWIS pursue with the Water Board up to a three-year extension of the available Alamitos and Huntington Beach units, totaling approximately 1,400 MW of capacity. Of the units available, these offer the potential for the least detrimental impact to their communities and to the sea life affected by the OTC units.

Though the proposed decision also recommended extensions for the Ormond Beach and Redondo Beach power plants, we were persuaded by the comments of parties that these plants create more harm in their communities and/or would interfere with other plans already underway to redevelop their sites for community use. To mitigate against those effects, we will request that the SACCWIS pursue with the Water Board an extension of up to two years for the Redondo Beach units (approximately 800 MW) and an extension of up to one year for the Ormond Beach units (approximately 1,500 MW). These provisions are intended to appropriately balance the potential need for capacity from the OTC units, while also remaining committed to ramping down OTC unit reliance while additional resources come online.

The CAISO, in comments on the proposed decision, also recommended that we seek a temporary extension for the Moss Landing power plant, which is in the process of upgrading to comply with OTC requirements, but may not be certified in compliance by the Water Board in time to meet its December 31, 2020 compliance date. An extension for these units would not result in the retention of additional capacity, but would allow a bridge strategy to allow continued contracting with the facility during its upgrade period. We will also make this request to SACCWIS for consideration by the Water Board.

Our reasons for pursuing the OTC unit extensions are as follows. Mainly, we are concerned about the operational issues raised by the CAISO, related to the shifting of the peak hours to both later in the day and later in the year, such that additional renewable resources, particularly solar, do not provide the type of capacity needed to ensure system reliability in real time. For similar reasons, hydroelectric capacity, within California and in the Northwest, is in increasingly higher demand and may be less able to meet system peaks that occur later in the year.

We also note that in recent years, the capacity factors of all of these OTC units have been well under 10 percent, thus minimizing the marine environment impact of these facilities, since they are not actually running and using sea water for cooling the vast majority of the time.[11] This also minimizes GHG emissions from these facilities. The state has also made a great deal of progress in the past decade retiring OTC units from service. We expect to continue that progress, with this timing adjustment to ensure system reliability.

Finally, as explained later in this decision, we are also concerned about the tightening of market conditions in the West in general, not just in California, such that imports may not be able to provide as much real-time capacity for reliability purposes as in the past. As such, we see a need to extend the 2020 OTC

[11] *See*, for example, the SACCWIS analysis of actual water usage of OTC plans, available at: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/20180305_saccwis_an_rpt.pdf, at 8.

compliance deadlines for up to three years to allow time for additional procurement of new resources to take place. If procurement proceeds in a timely fashion, all three years of the extensions may not be needed.

In addition to the procurement that we order as a result of this decision, we expect our current cycle of IRP planning analysis may identify the need for additional procurement. If additional procurement is deemed necessary, the soonest the additional authorization or requirement could come, however, would be early 2020, which is too late to address 2021 needs.

We are also aware that the authority for OTC compliance deadline extensions ultimately rests with the Water Board. In order to demonstrate our commitment to OTC retirements generally, we understand that the Water Board will also want to see the Commission taking additional actions to ensure that the OTC units will not be needed beyond the maximum three-year period requested, and one and two years for Ormond Beach and Redondo Beach, respectively. We also understand that the Water Board may not agree that retirement dates for all units should be postponed.

The remainder of this decision addresses how we intend to require additional procurement actions in order to ensure that any OTC extensions granted will not be needed beyond a temporary and maximum three-year period.

In addition, with respect to the need to ensure revenues for the OTC units whose retirement dates may be extended, while we agree with PG&E and SCE that utilizing the CAISO's RMR process may appear to be the simplest and most expedient approach, we would prefer first to allow the market to attempt to procure these resources.

The existing annual system and multi-year resource adequacy requirements will continue to include a need for existing resources, including OTC resources, to meet individual LSE resource adequacy requirements. This will help ensure that OTC resource procurement is considered alongside the expected commercial online dates of new resources that the LSEs will be procuring to meet resource adequacy needs.

Therefore, we will look to the resource adequacy market to help determine which, how much, and for how long the OTC units will need to be contracted (provided the extensions are approved by the Water Board), with the expectation that this will result in the right amount of procurement and time needed for these units. In response to comments on the proposed decision, we clarify that procurement of any OTC units with deadlines extended by the Water Board are not eligible to count toward the incremental capacity procurement requirements discussed later in this decision.

We also recognize, in response to comments from several parties on the proposed decision, that we need to waive the provisions of D.12-04-046 that bar utilities from signing power purchase agreements with OTC units where the term of the agreement extends beyond the compliance deadlines, even if the deadlines are later extended, and we do so here.

In the event that LSEs fail to meet their resource adequacy program requirements and/or the reliability procurement requirements associated with this decision, then the OTC units needed to meet reliability can be procured through the CAISO RMR mechanism, which as the CAISO points out, is the intended purpose of this mechanism. We recognize that if the OTC units fail to be procured then we will need to ensure that the CAISO is able to designate these resources as RMR through their designation process. In order to ensure that no additional actions are needed, we will monitor the procurement of OTC units and new resources through the LSE annual data requests described later in this decision. This will help us identify the magnitude of the OTC resource procurement relative to the amount of new generation procurement and its timing. If we see issues with OTC procurement relative to new generation procurement, we can take additional action.

4. Reliance on Imports

The June 20, 2019 Ruling pointed out that the tightening of system resource adequacy beginning in 2021 is also associated with an increasing likelihood of needing to rely on imports to meet reliability requirements. In addition, much of the historical reliance on imported power has been from the Northwest hydroelectric resources, which are both seasonal and weather-dependent, and increasingly necessary to serve Northwest load, creating the potential for additional risk for California relative to in-state capacity.

To mitigate this additional risk, the June 20, 2019 Ruling suggested an option to allow additional reliance on firm imports, with the suggestion of discounting the counting of that capacity by up to one-third.

4.1. Comments of Parties

Easily the party expressing the most concern about increased reliance on imported power is the CAISO DMM. In particular, their comments express concern about increased reliance on imports, as well as in-state resources, that have limited capacity availability and value during critical system and market conditions. CAISO DMM points out that if import capacity is not scheduled in the day-ahead market or residual unit commitment process, these resources have no further obligation to bid into the real-time market, and thus may end up providing no real benefits in terms of either system reliability or market competitiveness.

CAISO DMM encourages the Commission, CAISO, and stakeholders to consider changes to resource adequacy import rules to increase both system reliability and overall market competitiveness. Recommended changes include creating rules or guidelines that require imports to be backed by specific resources, extending the must-offer obligation of resource adequacy imports beyond the day-ahead market and into the real-time market, and/or encouraging import capacity to be "bundled" with an energy sales contract. CAISO DMM then offers a number of examples and rules from other ISOs around the country that address these types of issues.

CLECA also comments that these types of issues are coming up in the resource adequacy proceeding, and should be addressed in more detail there.

The CAISO is also concerned about increased reliance on non-firm imports, arguing that the Commission should require that imports be firm and backed by physical resources or at least a specific balancing authority, not subject to recall from another balancing authority, and have firm transmission. The CAISO also opposed the simplistic discounting (of up to one-third) for imported power suggested in the June 20, 2019 Ruling.

In fact, every party commenting on the suggestion that firm imports should be discounted by some percentage to account for the additional risk, except AWEA and LSA, rejected this idea completely. Most parties directly opposed the potential for distorting the import market with an arbitrary assumption.

WPTF argues that imports could be similarly reliable to in-state resources if they are resource-specific or dynamically scheduled. In addition, WPTF argues that a discount would raise the effective price of imported power by 50% for LSEs, which is neither fair nor efficient. Finally, WPTF suggests that these issues are better addressed within the resource adequacy Rulemaking (R.) 17-09-020), with respect to imported power requirements for the resource adequacy program.

BPA comments directly that a one-third discount on imported power is discriminatory. PGP and Powerex both also comment that better resource adequacy rules for imports would be a more appropriate solution than an arbitrary discount. PGP further argues that discounting of clean imports is inconsistent with California environmental objectives.

Powerex comments that while California is facing tightening capacity markets, so are other entities in the Western region, which may ultimately affect California's ability to secure surplus capacity. Powerex points out that many western states are retiring coal resources and adding significant amounts of renewables. Thus, California can no longer assume that it can rely on residual capacity in day-ahead or real-time markets. Thus, forward contracting may be needed to secure needed imports.

CalCCA relatedly argues that an increased reliance on imports, at least temporarily, may be a fine and wise approach until new in-state resources come online. In addition, they argue that historical import levels do not necessarily reflect maximum supply, and that new contracts may be negotiated in the future, particularly on a forward basis, to secure additional supply of imported power. CalCCA also points out that MIC calculations by the CAISO suggest that there is potential for increased imports, with more analysis needed to determine if the potential is real. CalCCA, like all other parties commenting, suggests that any action in this proceeding be coordinated with activity in the resource adequacy rulemaking.

NRDC and EDF also concerned about reliance on imports, especially when more western states are implementing their own clean energy targets and RPS requirements. They also worry about the potential for resource shuffling. EDF specifically suggested that all imported power should be specified, and should only be imported if there is reasonable assurance that there are sufficient clean energy resources to meet the lost capacity from the exporting state.

4.2. Discussion

We are concerned with interpretation and implementation of the current resource adequacy rules related to imports. Additional reliance on unspecified imports with no obligation to provide power in the real-time markets puts CAISO system reliability at greater risk.

After consideration of the comments of all parties, we agree that the resource adequacy proceeding is already appropriately working on clarifying the rules about imports in the context of the resource adequacy program. An Assigned Commissioner's Ruling on this topic was issued for comment on July 3, 2019 and a decision affirming the resource adequacy import rules was issued on October 17, 2019.[12] Therefore, we will leave any further consideration of clarified or modified rules for imported resource adequacy capacity to R.17-09-020 or a subsequent proceeding.

We also explicitly reject the suggestion from the June 20, 2019 Ruling that firm imports be discounted in any manner, because of the potential for market distortionary effects. It will be far better for the Commission and the CAISO to

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[12] The decision is D.19-10-021 and is available at the following link: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M317/K931/317931103.PDF.

address the rules for imported resource adequacy, rather than adopt a rule-of-thumb measure in this proceeding and risk a negative impact on the availability or cost of imported power.

We also encourage LSEs to explore options for forward contracting of firm imported power with counterparties with available power to commit. We continue to have reservations about the GHG impacts of such contracting, such as whether the commitment could represent resource shuffling rather than incremental GHG-free production. But from the standpoint of reliability, firm forward contracting for clean imports will improve the reliability situation for California in the short term.

5. Need for Procurement

The June 20, 2019 Ruling proposed two tranches of procurement:

- 2,000 MW, procured on an all-source basis by all LSEs for their pro-rata load share, for new peak capacity; and
- 500 MW, procured by SCE, from existing capacity that is currently uncontracted.

The main rationale for the proposed volume of procurement was related to keeping the assumed level of imports at or near historical levels, thus ensuring approximately the same level of in-state capacity within California.

5.1. Comments of Parties

To the extent that many parties support requiring additional reliability procurement at all, most agree with the approximate amount suggested. Those parties include CAISO, Cal Advocates, and PG&E. SCE, on the other hand, presents an analysis suggesting that up to 5,500 MW may be needed as soon as 2021, with additional capacity needed in the next few years after 2021.

CLECA points out that although they were unable to replicate the analysis of staff, there should be concern about the lack of forced outage rates being reflected in an NQC analysis, meaning that the actual reliability impacts could actually be more problematic than represented by the staff analysis.

Most other parties did not offer alternative suggestions for the amount of capacity that should be acquired in the near-term.

Numerous parties, however, object to breaking down the types of procurement into separate categories of "new" and "existing" capacity. Many parties, including IEP, LS Power, Middle River, NRG, and WPTF, argue for all-source procurement, including both new and existing capacity in the same solicitation framework.

Further, some parties, including TURN, CLECA, and WPTF, argue that limiting procurement of existing capacity to units that have already announced intentions to retire, would serve to distort incentives for owners to declare such intentions in order to be able to take advantage of a procurement mandate.

5.2. Discussion

We note generally that the purpose of the procurement we are considering in this decision is to ensure a safe and reliable electric system, while also moving the electricity sector towards the GHG emissions reduction targets articulated in SB 350, SB 100, and D.18-02-018. All of the resources we are considering are necessary for keeping the electric sector on a path toward the 2030 GHG emissions reduction targets and our clean energy future in 2045 and beyond. Our success to date with procurement of renewable energy necessitates consideration of renewable integration needs to ensure reliability while continuing the transition to 2030.

We take seriously the comments of many parties concerned about perpetuating the state's recent emphasis on new resources, while assuming that existing resources also in need of contractual commitments will continue to be around and available to support system reliability and renewable integration.

An important consideration is the fact that, all else being equal in an all-source solicitation, existing resources should be able to be provided more economically than new resources, since at least some of their capital investment should have already been covered by previous contracts.

Therefore, we see no reason to restrict any all-source solicitations to "new" resources only.

At the same time, if we are to address potential reliability challenges brought on by the retirement of OTC units, we need some way to identify capacity as incremental to capacity already procured and serving load currently. Otherwise, we will have done nothing to address the potential reliability problems.

Therefore, we will need to compare any additional capacity commitments against a baseline. The most logical baseline is the baseline resources utilized in our most recent IRP modeling analysis used to produce the PSP adopted in D.19-04-040. The baseline for the year 2022 most closely approximates the likely need in the timeframe relevant for this decision. Already included in this baseline is a portion of the approximately 1,325 MW of storage that is slated to come online by 2024 due to storage development activities already underway.[13]

Several parties, in comments on the proposed decision, sought clarification of exactly what generating units are in this baseline, since some resources, such as the storage requirement, are represented generically and not specifically.

[13] The baseline resources can be found on the following page utilizing the link titled "42MMT Core Portfolio updated to 2017 IEPR demand forecast:" https://www.cpuc.ca.gov/General.aspx?id=6442451973.

In addition, UCS and CAISO pointed out that the treatment of imports is unclear with this baseline identification, because the assumptions in the PSP assumed that all of the maximum import capability (MIC) identified by the CAISO annually was utilized in the PSP modeling. The CAISO suggests, instead, that any imports that are above the average level of 5,340 MW of annual resource adequacy-based imports analyzed by the CAISO, should be considered incremental and count toward the procurement required by this decision. However, it is unclear how an individual LSE would show that its import contracts were incremental to this amount.

In addition, we are aware that imports are rarely contracted more than one year out, because the CAISO only identifies the MIC annually; this would conflict with other provisions of this decision with respect to contract lengths, to meet the incremental procurement obligations identified herein. While the CAISO recommends that we develop a methodology to differentiate baseline from incremental imports, we do not have enough information to do so in this decision.

In comments on the revised proposed decision, several parties suggested practical approaches to allowing some types of imports to count as incremental for purposes of the procurement obligations in this decision. This issue was raised in some manner by at least the following parties: AReM, CAISO, Range, UCA, CalCCA, Cal Advocates, Pattern, AWEA, and the Southwestern Power Group II, LLC (SWPG). To address the spirit of these comments, we will make the following provisions to allow some imports to count as incremental for purposes of the procurement requirements. Incremental imports may count for up to 20 percent of each LSE's total procurement requirement by 2023, as long as the imported power is tied to a specific and identified generation resource and dynamically transferred or pseudo tied to the CAISO system. This incremental import capacity must also be tied to a contract of at least three years in length. The imported power must also meet all of the other resource adequacy requirements associated with imports.

Particular power plants were also identified by several commenters, including the Sutter plant, which is not within the CAISO footprint, Moss Landing, which is being upgraded, and the Inland Empire Energy Center, which recently submitted a decommissioning and demolition plan.

We clarify the baseline as follows:

- Imports are included in the baseline at the MIC level.
- Storage resources that have projected online dates prior to the end of 2022 and have a long-term contract as part of the utility storage target of 1,325 MW are included in the baseline.
- The Sutter Power Plant is not included in the baseline and is also not considered an import, for purposes of this decision.
- The Inland Empire Energy Center is also not included in the baseline.
- Moss Landing is included in the baseline.

We also delegate to Commission staff to post on the Commission's web site and share with the service list of this proceeding, by no later than December 2, 2019, the baseline list for purposes of this decision, consistent with the description above. Parties may file comments on the list, no later than December 9, 2019. Thereafter, we delegate to the assigned ALJ to finalize the baseline list via a ruling issued in this proceeding.

The selected baseline should allow procurement that has been occurring since those baseline assumptions were created to count toward the identified need, as suggested by CalCCA. In particular, CalCCA presents in its comments a list of additional incremental procurement that has already taken place in the past year or so. Our intention is that those resources, and any others not already required or approved by the Commission separately, should count towards the requirements adopted in this decision.

We also note that due to the successful procurement by numerous LSEs of renewable resources delivering to the system, the system resource adequacy resources that we are considering in this decision are necessary for renewable integration purposes, as defined under Public Utilities Code Section[14] 454.51. Section 454.51(a) requires that the Commission "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."

That leaves the question of how much procurement of incremental system resources should be required at this time in order to support system reliability beginning in 2021. We believe that the original June 20, 2019 Ruling suggestion of 2,500 MW of system resource adequacy capacity is still appropriate based on the identified need and to balance against both the potential for some OTC retirement date extensions not to be granted by the Water Board and also against the potential for the tightening of the import market for California.

However, because the proposed decision originally sought OTC compliance deadline extensions for a larger amount of capacity, and this amount has now been reduced considerably and scaled down over time, we see a need for additional procurement at the system level. As discussed further below in this decision, we are also modifying the decision to require that all LSEs procure to meet this system need. In addition, as already stated, procurement of resources is not an exact science.

[14] All future references are to the Public Utilities Code, unless otherwise noted.

For all of these reasons, we will adopt a requirement for 3,300 MW of incremental system resource adequacy capacity procurement, utilizing the resource adequacy counting rules, above and beyond any resources included in the baseline assumptions for 2022 in the PSP adopted in D.19-04-040. The baseline was further clarified above and in the baseline list to be issued by Commission staff no later than December 2, 2019, and finalized by the assigned ALJ in a ruling after considering one round of comments from parties filed and served no later than December 9, 2019, as the required level of capacity procurement for system resource adequacy and renewable integration purposes ordered in this decision.

We have revised the total capacity procurement requirement downward, as suggested by CalCCA in comments on the revised proposed decision, to account for the changes to the baseline articulated in this decision and because we are prioritizing early procurement action over conducting additional analysis of the exact number that needs to be procured. We intend to further assess the need for additional capacity procurement almost immediately in this proceeding with the analysis of the next Reference System Portfolio and expect that additional procurement requirements may be necessary. But given the impending retirement of additional resources, including Diablo Canyon, we still assess that at least 3,300 MW of system resource adequacy capacity will be needed in the timeframe as a least regrets strategy.

6. Responsibility for Procurement

Next we turn to the question of who should procure the 3,300 MW of incremental capacity identified as the need in Section 5 above. The June 20, 2019 Ruling proposed that 2,000 MW of capacity be procured on a pro-rata basis by all LSEs, on the basis of their respective load shares. The remaining 500 MW was suggested to be procured by SCE on behalf of all benefitting system customers, with costs allocated based on the cost allocation mechanism (CAM), across the ratepayers of all IOUs and not just SCE.

6.1. Comments of Parties

PG&E, in its comments, points out that at least some of the IOUs are long on system capacity due to the load departing or already departed to CCA service. Therefore, in the context of the procurement charge indifference amount (PCIA) proceeding, proposals are being considered for allocating away from some IOUs their current resource adequacy capacity, because they have no further need to hold it or to acquire additional capacity, since their loads are dropping. PG&E submits that it makes no sense to require an IOU in that situation to procure additional capacity in IRP when it is not needed to serve its customers, and at the same time that it is considering selling capacity in another venue.

SCE comments that while procuring on behalf of all other customers in the state is not its first choice, it would be willing to take on that responsibility with the appropriate requirements and cost recovery structure from the Commission.

TURN strongly suggests that the Commission needs to develop a backstop procurement structure first, before ordering any procurement by anybody in this proceeding. While TURN supports requiring LSEs to procure on behalf of their own load first, they are most concerned with what happens if an LSE fails to fulfill that obligation, and the state is left with a shortfall. Bear Valley supported concurrent development of a backstop mechanism, as did Cal Advocates.

Some parties, including Middle River and PG&E, are concerned that action here in the IRP proceeding not disturb discussions occurring in the resource adequacy proceeding, especially with respect to the design of a central buyer framework. PG&E, however, advocates that the central procurement entity framework, once in place, be used as a backstop to procurement in IRP if LSEs do not fulfill their obligations. WPTF is similarly focused on developing that mechanism in the resource adequacy proceeding.

6.2. Discussion

We are sympathetic with the view of TURN that it is important for the Commission to develop a mechanism for backstop procurement, in the event that the LSE with the primary obligation for capacity procurement fails to live up to its obligation. We note that the central procurement entity discussion for purposes of local resource adequacy procurements in the resource adequacy proceeding is ongoing, and could be used as a model mechanism for system resource adequacy as well. Thus, we do not wish to prejudge that outcome until those discussions have had time to conclude. The mechanisms adopted in this decision are intended to apply only to the procurement required in this decision, and not to any other procurement that the Commission may require in the future.

This decision represents the first time since the beginning of the IRP process in 2016 that the Commission is taking a step to require incremental procurement related to system reliability and renewable integration outside of either the resource adequacy or the RPS framework.

We note that the Commission has the authority, articulated in § 451.51(c), to direct the IOUs to procure renewable integration resources on behalf of the electricity system as a whole and allocate those costs on a non-bypassable basis to all benefitting customers. As already articulated in D.19-04-040,[15] the

[15] *See* D.19-04-040 at 136-137.

Commission also has the authority under § 454.51(d) to permit procurement of renewable integration resources by CCAs to fulfill their portion of the renewable integration requirements, and to require long-term commitments to such resources.

We prefer to assume at the outset that the LSEs with procurement obligations for system reliability and renewable integration would prefer to conduct their own procurement to fulfill their individual requirements. We also note that in many venues for many years, many parties have expressed some degree of dissatisfaction with the CAM, utilized to allocate costs of procurement done by IOUs on behalf of customers of ESPs and CCAs. In response to these criticisms, we will implement a preference that each LSE, regardless of whether it is an IOU or an ESP or CCA, is responsible for its own share of the incremental reliability and renewable integration resources identified herein as needed.

Our preference is that a cost allocation framework where IOUs procure on behalf of other LSEs in their territories be used as a backup plan, in the event that the LSEs with the primary responsibility fail to fulfill their obligations. We may need to utilize the CAM or a similar mechanism, as TURN and other parties suggest, but for the primary procurement responsibility, we prefer to assign responsibility where we believe it should be, with the LSEs directly. We also clarify, in response to comments on the revised proposed decision, that we are intentionally allowing both CCAs and ESPs to elect to self-provide the capacity required by this decision, even though statutorily the option is explicit only for CCAs.

In response to comments on the proposed decision from numerous parties seeking clarification on the backup plan, or alternatively seeking identification of an enforcement mechanism, we clarify that we will utilize the authority given to us in § 451.51(c) to require IOU procurement on behalf of non-performing LSEs, or those that elect not to self-provide renewable integration resources, with associated non-bypassable cost allocation to that LSE's customers for that procurement, should it become necessary.

We recognize that election not to self-provide capacity and failure to provide the capacity after electing to do so, are fundamentally different situations, as pointed out by SCE in comments on the revised proposed decision. This, coupled with the fact that some LSEs electing not to self-provide capacity while others do, will likely require further development and differentiation of the cost allocation mechanism by the Commission, since the current mechanism is implemented through distribution rates and applied to all customers, whereas the new mechanism would need to be applied to LSEs' customers proportional to the amount of new reliability or renewable integration resources that they were responsible for but did not procure. For CCAs and ESPs who elect not to self-provide, we will require that they notify the Commission in their progress reports due by February 15, 2020. We also recognize that by the time we determine noncompliance from any other LSEs that do not procure, time will be extremely short to procure and bring online the needed reliability resources, and this type of "just in time" procurement is typically quite expensive. For these reasons, we hope that such steps will not be necessary. But if they are, the Commission will take the appropriate steps to ensure this outcome and will ensure that all costs incurred by the IOUs to undertake procurement on behalf of customers of other LSEs will be compensated. Likewise, the benefits of any such procurement will be shared with all customers who pay for the capacity, in keeping with longstanding Commission policy, as pointed out by AReM in comments on the revised proposed decision.

As discussed earlier in this decision, the procurement ordered herein is intended as a "least regrets" strategy against the potential for system reliability challenges beginning in 2021. For reasons articulated by many parties, the severity of this reliability challenge is uncertain, due to our inability to predict perfectly the demand, the level of imports that may be available to California, the amount of capacity that may come online in the meantime, and how the system will actually perform during and after the retirement of OTC units.

This is also an appropriate place to test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP. As pointed out by numerous parties in response to the proposed decision, the procurement identified herein as necessary is for system resource adequacy, and it is for incremental resources beyond those already present in the CAISO system. Therefore, there is a collective responsibility among all of the LSEs to develop these additional incremental resources.

In the proposed decision, the rationale for requiring procurement from LSEs within the SCE TAC area was related to the OTC retirements planned for that geographic region. But as many parties pointed out, if the need identified is at the system level, it should be able to be met by LSE and/or resources located anywhere on the CAISO system. As such, we are persuaded that the procurement responsibility should be shared by all LSEs, and not just those in the SCE TAC area.

The procurement requirement will be shared by all LSEs (CCAs, ESPs, and IOUs) that serve load in the CAISO footprint, on the basis of projected load share for 2021 in gigawatt hours (GWh) identified in Form 1.1c, "California Energy Demand Update Forecast 2018-2030, Mid Demand Baseline Case, Mid Additional

Achievable Energy Efficiency and Additional Achievable Photovoltaics," of the 2018 IEPR, which was adopted by the CEC in February 2019.[16] The IEPR forecast represents the most recent adopted and publicly-available source of load forecasts for these LSEs. However, to address the comments from AReM and others in response to the proposed decision about the differential impact of load shapes on the obligations identified for each LSE, we have utilized the 2020 year-ahead forecasts for resource adequacy capacity, aggregated by class of LSE, to first allocate the capacity by LSE type before further differentiating within LSE type by public load share. The peak capacity responsibility by LSE type is 66.5% to IOUs, 24.5% to CCAs, and 9.0% to ESPs for the 2020 resource adequacy year.

We prefer to utilize publicly-available information whenever possible to ensure clarity, transparency, and future potential enforcement options should LSEs not meet their obligations. In addition, it may be difficult for newly formed entities to take on this procurement obligation in the near-term. Our expectation is that analysis in the current cycle of IRP will help identify if additional obligations by new LSEs may be needed.

Table 1 below summarizes the obligations and the responsible entities outlined in this decision. The ESP obligations are presented in aggregate due to the confidential nature of their load forecasts, but Commission staff will inform each ESP individually of its obligation within 10 business days of the adoption of this decision.

[16] Detailed forecast information is available at: https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_LSE-BAF.php

Table 1. LSE Responsibility for Incremental System Resource Adequacy Procurement

Load Serving Entity	**2021 Load Forecast (GWh)**	**Adjusted Share of Total Load, after Peak Allocation by LSE Type (%)**	**System Resource Adequacy Incremental Procurement Requirement (MW)**
PG&E (Bundled)	34,895	21.73	716.9
PG&E Direct Access (Aggregated)	9,520	3.46	114.0
Clean Power San Francisco	3,414	1.73	57.0
East Bay Community Energy	5,965	3.02	99.6
King City Community Power	41	0.02	0.7
Marin Clean Energy	5,237	2.65	87.5
Monterey Bay Community Power Authority	3,439	1.74	57.4
Peninsula Clean Energy	3,292	1.67	55.0
Pioneer Community Energy	1,105	0.56	18.5
Redwood Cost Energy Authority	642	0.32	10.7
San Jose Clean Energy	4,644	2.35	77.6
Silicon Valley Clean Energy	4,024	2.04	67.2
Sonoma Clean Power	2,595	1.31	43.3
Valley Clean Energy Alliance	753	0.38	12.6
SCE (Bundled)	57,662	35.90	1,184.7
SCE Direct Access (Aggregated)	11,710	4.25	140.3
Apple Valley Choice Energy	227	0.11	3.8
Clean Power Alliance of Southern California	11,786	5.97	196.9
Lancaster Clean Energy	565	0.29	9.4
Pico Rivera Innovative Municipal Energy	156	0.08	2.6
Rancho Mirage Energy Authority	285	0.14	4.8
San Jacinto Power	166	0.08	2.8
SDG&E (Bundled)	14,256	8.88	292.9
SDG&E Direct Access (Aggregated)	3,562	1.29	42.7
City of Solana Beach	63	0.03	1.1
Total	**180,004**	**100.00**	**3,300.0**

7. Requirements for Consideration of Resource Types

The June 20, 2019 Ruling proposed that at least the first 2,000 MW be from an all-source solicitation approach, where all types of resources, including demand-side resources and storage, should be able to count toward the obligation. The June 20, 2019 Ruling also discussed considering resources without current contracts that extend through the relevant timeframe.

7.1. Comments of Parties

CEERT strongly supports conducting procurement with eligibility limited to preferred resources, prioritizing local capacity areas that have either a need or lesser levels of excess local capacity. DOW advocates at least a preference for the cleanest technologies.

Several parties are concerned that demand-side resources be able to count toward an all-source procurement obligation. Parties particularly concerned about demand-side resources include EDF, Cpower and Enel X, CEERT, POC, Sunrun, and SEIA. Cpower and Enel X suggest that the Demand Response Auction Mechanism (DRAM) contract be explicitly endorsed as the contractual starting point for demand response resources, to avoid negative experiences of the past where demand response resources were unable to compete due to the particular contract requirements that were more applicable to supply resources, such as resource response times.

PG&E and SDG&E comment that while they support allowing all resources to count toward the procurement obligation, there is a particular concern to ensure that demand-side resources are truly incremental, and not just supplanting projects that would otherwise have been accomplished through demand-side programs already planned and budgeted.

Cal Advocates suggests allowing LSEs to count procurement of demand-side resources either toward the procurement requirement here or to decrease its load forecast, thereby reducing its obligation to procure, depending on the type of project.

Some parties are also focused on preventing short-term resource procurement from potentially crowding out long-term resources, including Range, Hydrostor, and SDCWA, which advocate that some longer-term storage options should begin to be developed now.

An additional group of parties is focused on ensuring the ability for hybrid projects, including renewables and storage, to count towards the procurement requirements. Those parties include Sunrun and Vote Solar.

Wellhead would like a particular target for hybrid projects utilizing both storage and generation technologies. CAC advocates for continuation of existing combined heat and power (CHP) contracts, to allow those resources to continue to support system resource adequacy beyond their currently-contracted periods.

7.2. Discussion

Like most parties, we support solicitations being conducted in an all-source manner, allowing all types of resources to count toward the 3,300 MW requirements we implement in this decision. This includes everything: new and existing, preferred and conventional, CHP, and demand-side resources; as long as the resource is incremental to the 2022 PSP baseline resources.

However, we will adopt the prohibition on new fossil-fueled resources suggested by CEJA, Sierra Club, and DOW in their comments. Specifically, any new development of fossil-fuel-only resources, at sites without previous electricity generation facilities, will not be considered to count toward any of the procurement obligations outlined in this decision. Another way of saying this is that all new resources should all be from preferred sources, or hybrid technologies, and not fossil-fuel-only sources. If there are existing fossil-fueled resources that may have the ability to make modifications or produce incrementally more to serve reliability needs, those may still be considered, even if the units were part of the baseline, but only for the incremental capacity added.

We will not prescribe the exact metrics to be used to compare different types of resources, but will require the IOUs to conduct their solicitations in a non-discriminatory manner, treating all resources on a level playing field as long as they deliver equivalent value. Clearly, resources with different costs and benefits may be evaluated differently, so long as similar attributes are valued similarly. The exact metrics for bid comparison should be presented in the advice letters required for approval of the contracts, as detailed further below in Section 10.

We agree that for demand response resources that are bidding into a solicitation, the standard DRAM contract should be the starting point for negotiations, but may be modified by mutual agreement. For all demand-side resources, we also reference the incrementality principles adopted in D.16-12-036[17] as a starting point.

In addition, we anticipate that hybrid generation and storage projects will fare well in competitive solicitations for system reliability resources and should be strongly considered. However, we decline to make a particular MW requirement for these types of projects. Instead, we prefer to consider the results of the solicitations. We also note that there was a September 27, 2019 motion filed in this proceeding and simultaneously in the resource adequacy rulemaking

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[17] *See* D.16-12-036 at 18-20.

(R.17-09-020), seeking a determination from the Commission about the capacity value of hybrid resources. The motion was filed jointly by Enel X, Sunrun, Tesla, CESA, CEERT, and Vote Solar. Numerous parties filed comments in support of the joint motion. We understand the desire to have a determination about how such resources will be valued when participating in the solicitations likely to follow from this decision. The Commission intends to take up this motion in the resource adequacy rulemaking, where traditionally capacity counting issues have been handled. Therefore, the motion is denied procedurally for purposes of this proceeding, but will be taken up substantively in R.17-09-020.

We also remind all of the LSEs of their obligations, in the design and conduct of their solicitations, to minimize impacts of localized air pollutants and GHGs on disadvantaged communities, as required by § 454.52(a)(1)(H).

Finally, as stated earlier, all resources, regardless of particular technology or fuel, must be able to show that they are incremental to the year 2022 baseline assumptions utilized in the PSP adopted in D.19-04-040, and to be clarified in a baseline posted by Commission staff no later than December 2, 2019, with comments filed by parties and the final baseline issued via an ALJ ruling in this proceeding, in order to receive a contract.

8. Timing of Procurement

The June 20, 2019 Ruling suggested that an August 1, 2021 online date should be set for any new procurement ordered under this framework. The Ruling was silent about whether additional capacity procurement should be required to extend for a particular period of time.

8.1. Comments of Parties

TURN, in particular, advocates that the online date requirement should begin with the summer season, which in the past has typically been June 1 and not August 1, to ensure availability throughout the peak summer months. TURN also states that June 1, 2022 may be more practical than 2021, both for LSEs and for resource developers.

Most other parties accept the August 1, 2021 date and provide no other suggestions.

However, numerous parties, including the IOUs and the CAISO, also express concern that the potential for a system resource adequacy shortfall exists not just for 2021, but also at least through 2023, according to current analysis. Thus, they argue that the requirement for incremental capacity should not just be for one year beginning in 2021, but should extend at least three years out.

Many of the parties representing renewable interests also point out that this procurement timeframe would still allow California ratepayers to take advantage of the federal tax credits (investment tax credit (ITC) and production tax credit (PTC)) that are winding down in the next several years. Parties emphasizing this point include AWEA, CESA, SEIA, and CalWEA. CalWEA also continues to raise the concern that the assumptions about retiring resources fail to take into account the large volume of wind power that will either need to be retired or repowered in the next few years.

SEIA also suggests that the Commission could utilize the renewable auction mechanism (RAM) process to expedite project development.

8.2. Discussion

We agree that the reliability concerns beginning in 2021 do not end in 2021, according to the stack analysis included in the June 20, 2019 Ruling. While this decision is on an expedited track because of the proximity of the 2021 date to today, we do not wish to simply postpone the emergency just one year by creating an obligation only for 2021.

Since most parties commenting on this issue appear to support at least a three-year obligation, we will require that the 3,300 MW incremental resource requirement of this decision stay in place at least through the end of the resource adequacy summer months of 2023.

In addition, because 2021 is so soon, we find it reasonable to allow for some ramp up of the obligation, in case not every resource bidding in a solicitation is able to come online by August 1, 2021. The original proposed decision ramped up the requirement from 60 percent in 2021, to 80 percent in 2022, and 100 percent in 2023. In response to numerous comments from parties on the proposed decision and continuing concerns about the revised proposed decision, we have modified the ramp slightly to ensure that the ramp, coupled with the total capacity requirement, does not result in too much of a seller's market, raising costs for ratepayers. Therefore, as suggested by SCE in its comments on the revised proposed decision, we will now require that at least 50 percent of each LSE's portion of the 3,300 MW obligation be online by August 1, 2021, with 75 percent by August 1, 2022, and 100 percent by August 1, 2023. We also encourage LSEs to offer bonuses or other incentives for resources that can come online for 2021.

In addition, all contracts to support these incremental resources are required to be for at least ten years in length, if the contracts are for new resources, and three years for existing resources, if they were not included in the baseline. If the contract is for an energy efficiency resource, the contract must be for at least five years, as suggested by SCE in comments on the proposed decision. In addition, any contracts negotiated with the OTC units addressed in Section 3 of this decision, if entered into by an IOU, may not be for any longer than the period requested for the OTC extension, and must be submitted for approval along with the other contracts required by this decision.

The purpose of these provisions is to avoid a "cliff" where resources drop off of contracts again in the early part of the next decade, creating another system reliability challenge.

To ensure that each LSE's obligation is clear, Table 2 below details the minimum cumulative incremental procurement amounts that are required to be delivering energy by August 1 of each year required by this decision.

Table 2. LSE Responsibility for Incremental System Resource Adequacy Procurement by 2021, 2022, and 2023

Load Serving Entity	**Minimum By August 1, 2021 (MW)**	**Minimum By August 1, 2022 (MW)**	**Minimum By August 1, 2023 (MW)**
PG&E (Bundled)	358.5	537.7	716.9
PG&E Direct Access (Aggregated)	57.0	85.5	114.0
Clean Power San Francisco	28.5	42.8	57.0
East Bay Community Energy	49.8	74.7	99.6
King City Community Power	0.3	0.5	0.7
Marin Clean Energy	43.7	65.6	87.5
Monterey Bay Community Power Authority	28.7	43.1	57.4
Peninsula Clean Energy Authority	27.5	41.2	55.0
Pioneer Community Energy	9.2	13.8	18.5
Redwood Coast Energy Authority	5.4	8.0	10.7
San Jose Clean Energy	38.8	58.2	77.6
Silicon Valley Clean Energy	33.6	50.4	67.2
Sonoma Clean Power	21.7	32.5	43.3
Valley Clean Energy Alliance	6.3	9.4	12.6
SCE (Bundled)	592.3	888.5	1,184.7
SCE Direct Access (Aggregated)	70.1	105.2	140.3
Apple Valley Choice Energy	1.9	2.8	3.8
Clean Power Alliance of Southern California	98.4	147.7	196.9
Lancaster Clean Energy	4.7	7.1	9.4
Pico Rivera Innovative Municipal Energy	1.3	2.0	2.6

Rancho Mirage Energy Authority	2.4	3.6	4.8
San Jacinto Power	1.4	2.1	2.8
SDG&E (Bundled)	146.4	219.7	292.9
SDG&E Direct Access (Aggregated)	21.3	32.0	42.7
City of Solana Beach	0.5	0.8	1.1
Total	**1,650.0**	**2,475.0**	**3,300.0**

Finally, we note SEIA's suggestion of utilizing the RAM mechanism to expedite procurement. While we will not require RAM procurement by the IOUs for their obligations, we encourage all LSEs to consider using the RAM mechanism, where it may be useful.

9. Utility-Owned Resources

The June 20, 2019 Ruling did not make a proposal about whether the additional resources counting towards an incremental procurement requirement should have any particular ownership characteristics.

9.1. Comments of Parties

In comments on the June 20, 2019 Ruling, SCE proposes that at least some of the incremental capacity that would count toward a procurement requirement should be allowed to be utility-owned.

LS power, on the other hand, fears that the expedited timeframe being contemplated here will become an excuse for utilities to propose self-build projects and crowd out third-party resources. LS Power suggests, at a minimum, that the Commission require a demonstration of competitive procurement and least cost to ratepayers, using the template included in Appendix A of D.19-06-032, which adopted SDG&E's storage investment plan.

9.2. Discussion

The issue of utility ownership of generation or storage resources has been raised numerous times over the past decade in the context of procurement required by the Commission. We are not averse to allowing utility ownership of some of the resources that would count towards the procurement requirement ordered in this decision. The difficult issue has always been about how to compare accurately bids received from third parties against a utility ownership cost structure, in order to ensure fair and unbiased results in the interests of ratepayers.

While there is no perfect approach to conducting this analysis, we will allow the IOUs to propose to own a portion of the resources to be procured. In making any such proposal to the Commission after the conduct of an all-source solicitation, the IOUs shall propose their evaluation and comparison metrics for Commission consideration, as justification for its proposed ownership structure. the IOUs shall also adhere to the existing rules about utility participation in utility-run solicitations.[18]

We agree with LS Power that Appendix A of D.19-06-032, specifically Section 2c, is an appropriate starting point as a basis for metrics, particularly for storage projects.

We also note that since we do not exert authority over ownership structure decisions of the non-IOU LSEs, those entities may conduct procurement in the interests of their own ratepayers and may also propose some ownership of resources. We see no reason to restrict the IOUs from availing themselves of the same options, should the value justification be deemed reasonable by the Commission at the time the results of the solicitations are considered. The overall process for that consideration is discussed further in the next section.

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[18] *See*, at a minimum, D.07-12-052, at 201, 2016, and Ordering Paragraph 30; and D.04-12-048.

10. Approval Process

The June 20, 2019 Ruling suggested that those LSEs that require Commission approval for their contracts be authorized to file Tier 3 Advice Letters seeking that approval. The advice letters would be required to show project development status milestones, including date of site control, date of environmental application "deemed complete" or data adequate, and date of the CAISO interconnection study completed. LSEs who do not need Commission contract approval would be required to provide the same information in their individual IRP filings due in 2020.

10.1. Comments of Parties

Most parties supported the suggestion of a Tier 3 advice letter as the expedient approach to Commission approval for any contracts proposed as a result of the procurement required. Some parties advocated for Tier 2 advice letters for certain types of projects that they advocate should be considered "preferred."

POC opposed the advice letter process entirely, though mainly because they did not support procurement being conducted through this mechanism at all. Cal Advocates also opposed the advice letter process because they argue it fails to provide parties an adequate opportunity to review and comment on the IOUs' proposed procurement.

Most parties did not comment on the process for non-IOU LSEs making their showing about their progress toward achievement of their system capacity requirements.

Cal Advocates did particularly suggest that the Commission require LSEs to update their contractual status, with a special focus on resources under development, at least every year, to better ensure that the Commission has an updated list of baseline resources.

10.2. Discussion

As suggested in the June 20, 2019 Ruling, we will require that IOUs conducting procurement as a result of this decision file a Tier 3 advice letter for approval of any contracts resulting from a solicitation to meet these requirements. The Tier 3 advice letter shall include the project development milestones suggested, including dates for site control, environmental application "deemed complete" or data adequate, and CAISO interconnection study completed.

We note that this is an exception to our normal requirements, where IOUs are usually not required to obtain Commission pre-approval for contracts less than five years in length except under certain circumstances, such as contracts with OTC units; in addition, contracts longer than five years normally require separate applications.[19] In this case, because this procurement is outside of our ordinary processes established prior to now, we will require the IOUs to present Tier 3 advice letters for all contracts that will be used to satisfy the obligations in this decision. Advice letters may be presented at any time, but should be submitted no later than January 1, 2021.

In addition, as discussed in Sections 7 and 9 above, justifications shall be included in the advice letters showing the metrics used to compare all bids, the approach to incrementality for demand-side resources, and the justification for any proposals for utility-owned assets.

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[19] *See* D.14-02-020 for pre-approval requirements.

All LSEs procuring resources as a result of this decision will be required to present an informational progress report by no later than February 15, 2020 summarizing their efforts being undertaken in response to these requirements. This information should be filed formally in the proceeding as a "compliance filing" document type in the Commission's e-filing system and served on all parties to this service list.

Also for all LSEs, further information about progress toward their obligations in this decision, should be included in their 2020 IRP filings, currently due May 1, 2020. In these IRP filings, each non-IOU LSE with an obligation shall include an attestation from a senior executive in its management structure that it will provide the necessary capacity required by this decision, if it has elected to self-provide this capacity in its progress report due February 15, 2020. This attestation shall be accompanied by a detailed list of projects, capacities, and dates by which the projects expect to be providing service to the LSE, as well as a demonstration that the projects are incremental, to meet the 2021, 2022, and 2023 requirements outlined in this decision. LSEs shall also include a description of how their activities have complied with §454.52(a)(1)(H) related to disadvantaged communities.

For all LSEs, since the system reliability situation is dynamic and our data collection processes are evolving, we also are going to move to a regular data collection schedule to ensure that the Commission has access to the most updated procurement information possible. The data request required by D.19-09-040, responses to which were submitted on September 16, 2019, is the first such effort to collect relevant data from all LSEs.

By this decision, we set a schedule for collection of this type of data once a year, on May 1 of every year beginning in 2020, in an individual IRP if one is due that year, or separately if not, to ensure continuous access for the Commission and for stakeholders to relevant system reliability information from all LSEs. Each submittal by each LSE shall be accompanied by an attestation by a senior executive in each company that the information is accurate and represents its obligation under the terms of this decision, and any other decisions by the Commission requiring procurement.

While September 16, 2019 was the first date on which we received the first draft of this information from all LSEs, Commission staff may see a need to refine and update the information requested and/or the format of the data, depending on experience. Thus, Commission staff may, from time to time, and no later than one month prior to the due date for each data showing, provide new instructions and/or templates to LSEs. Commission staff will include all relevant information to LSEs and maintain the format and instructions on the Commission's web site, such that all LSEs are aware of the requirements at least one month in advance of needing to provide the data.

11. Comments on Proposed Decision

The proposed decision of ALJ Fitch in this matter was mailed to the parties on September 12, 2019 in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on or before October 2, 2019 by the following 40 sets of parties: AES Southland, LLC (AES); AReM; AWEA and LSA, jointly; CAC; CalChoice Community Choice Aggregators (CalChoice); CalCCA; Calpine; CalWEA; CCSF; CEERT; CEJA, Sierra Club, and DOW, jointly; CESA; CGNP; Clean Power Alliance of Southern California (CPA); Diamond Generating Corporation (Diamond) and Sentinel Energy Center, LLC (Sentinel), jointly; EDF; GenOn Holdings, Inc. (GenOn); Golden State Clean Energy, LLC

(GSCE); GPI; Hydrostor; IEP; LS Power; Middle River; The Nature Conservancy (TNC); NRDC; CPower, Enel X North America, and Energy Hub (Joint Demand Response parties), jointly; City of Oxnard (Oxnard); Cal Advocates; PG&E; POC; City of Redondo Beach (Redondo Beach); SCE; SDG&E; Sunrun; TURN; UCS; Vote Solar and SEIA, jointly; Wellhead; and WPTF.

Reply comments were filed on or before October 7, 2019 by the following 26 sets of parties: AReM and the UC Regents, jointly; AWEA; CAISO; CalCCA; CLECA; CCSF; Calpine; CEERT; CEJA, Sierra Club, and DOW, jointly; CESA; CGNP; Diamond and Sentinel, LLC, jointly; EDF; GenOn; IEP; Joint Demand Response Parties; LS Power; Middle River; PG&E; POC; Cal Advocates; SCE; SDG&E; TURN; Wellhead; and WPTF.

Below is a summary of the major issues raised by parties in comments on the September 12, 2019 version of the proposed decision, and the changes made in response to them. The changes summarized below have been made in the decision itself.

The first issue raised by many parties was to point out that there was a logical inconsistency in the proposed decision, where a system resource adequacy need was identified, but the procurement obligation to address the system capacity need was placed only on the LSEs in the SCE TAC area. Parties identifying this issue included AReM, SCE, CalChoice, CPA, NRDC, Joint Demand Response Parties, and the City of Redondo Beach.

On a related note, CESA, GSCE, and LS Power, among other parties, pointed out that if the capacity shortfall is at the system level, then the resources to be procured should be able to be located anywhere within the CAISO system, and not just in the SCE TAC area. This clarification has been made in the text of the decision.

Numerous other parties objected to the suggestion that the OTC compliance deadlines be extended, or at least argued that those extensions should be a last resort. This issue was identified in some manner by CPA, TNC, City of Oxnard, City of Redondo Beach, Vote Solar and SEIA, UCS, and EDF. In addition, several parties, including City of Redondo Beach and City of Oxnard, felt that even if some OTC units had compliance deadlines requested to be extended by the Water Board, those units should not include Ormond Beach or Redondo Beach generating units, for reasons either of environmental justice or community opposition, or both.

On October 9, 2019, the City of Redondo Beach also filed a motion for official notice of certain documents related to the City's efforts to purchase property currently used for the Redondo Beach Generating Station, with the intention of developing the land as a park. In this decision, we grant the City of Redondo Beach motion and take official notice of the City actions with respect to redevelopment of the power plant site as a park, and related documents summarizing activities of the Coastal Commission with respect to the AES permit to operate the current power plant. While we take seriously the information contained in the City of Redondo Beach motion, we note that we do not have authority related to siting and permitting decisions, and our responsibility relates to ensuring electric grid reliability. But in consideration of the evidence before us, we have elected to shorten the request for an OTC extension for Redondo Beach to no more than two years, so as not to unduly interfere with the future planned uses of the OTC plant site, after the units are retired.

In deference to the considerable local government and disadvantaged community opposition to the Ormond Beach OTC extension request, we also limit the timeframe for this extension to no more than one year.

Also related to OTC extensions, the CAISO recommended a clarification related to the upgrades currently being installed at Moss Landing, a power plant that also has an OTC compliance deadline of December 31, 2020. CAISO notes that upgrades to comply with OTC requirements are taking place, but that if the upgrades are not certified by the compliance deadline, the plant should still be allowed to operate or be contracted with (with a short-term, temporary OTC compliance deadline extension) until such time as the upgrades have been certified by the Water Board. We agree and have made the technical changes to request that the Water Board allow this bridging strategy to take place, if necessary. This does not result in additional electric capacity, however, only continuing access to capacity that was already planned for.

Taken together, these changes to make the OTC extension requests specific and time limited are intended to balance our obligations to ensure electric reliability with the state's priority on complying with OTC requirements and regulations.

Many parties also argued that the baseline for the required "incremental" capacity procurement was not clear, and that existing resources without contractual commitments beyond the 2021 period should also be allowed to participate in solicitations. We agree that the list baseline resources needs to be explicit, and have made a provision that Commission staff will publish the baseline listing by no later than December 2, 2019 on the Commission's web site, and also email the service list with the link to the final baseline set. Parties may file and serve comments on this staff list by no later than December 9, 2019, and the assigned ALJ will finalize the baseline list via a ruling thereafter.

Several parties also made the point that it could be ineffective to attempt to address a capacity shortfall by signing contracts with new resources, only to see existing resources fall off of their contracts and possibly retire, potentially resulting in no incremental capacity availability at all. Parties making these points in some manner included Calpine, CalWEA, CAC, Wellhead, and WPTF. CAC specifically requests standstill or simple extension contracts for existing combined heat and power facilities. While we agree that it is important to maintain the existing resources while also developing new resources, we are confident that there are existing mechanisms, either through the year-ahead resource adequacy program, the renewables portfolio standard obligations, and/or backstop authority through the CAISO (if necessary), to provide for the retention of needed existing resources. Our focus here is on developing incremental resources to bolster the reliability position of the system.

Several parties were concerned to make sure that the Commission continues to prioritize clean, preferred resources in the solicitations that will be conducted to satisfy the capacity needs identified in this decision. CEJA, Sierra Club, and DOW argued that new fossil-fueled resources should not be allowed to compete at all in the solicitations. GPI, Cal Advocates, the Joint Demand Response Parties, and POC offered alternatives referencing the "loading order" preference for clean new resources, prioritized over fossil-fueled resources.

To address all of the points summarized above in a comprehensive manner, we have made the following changes to the proposed decision. First, we will request that the Water Board consider extensions of up to three years for the Alamitos and Huntington Beach units, with only two years for Redondo Beach and one year for Ormond Beach. We will also ask for a temporary extension for Moss Landing in case the upgrades are not certified by December 31, 2020, as suggested by the CAISO.

Second, we have made the change recommended by CEJA, Sierra Club, and DOW, and will not allow contracts with any new fossil-fuel-only generation at sites not previously used for electricity generation, to be used to meet the capacity needs identified in this decision.

In order to account for the loss of the potential capacity we sought in the proposed decision for OTC compliance extensions of Ormond Beach and Redondo Beach for longer periods of time, and to account for minor changes to the baseline units considered, we have also increased the capacity procurement requirements in this decision to 3,300 MW instead of 2,500 MW.

Finally, because of the increase in procurement needs, as well as the identified needs being at the system level and not local, we have modified the decision to require all LSEs within our purview to conduct procurement to meet the identified capacity need, and not just LSEs within the SCE TAC area. This will result in a more equitable distribution of costs and benefits throughout the CAISO system than would have taken place under the provisions of the proposed decision.

Since this change will result in a much larger number of LSEs being affected by the requirement to procure additional resources, we have also taken the additional step of seeking additional comments from parties on these new provisions of the proposed decision, in order to ensure that the capacity allocation to LSEs is accurate and to ensure that all parties have the opportunity to comment on these modifications.

In addition to the above policy-level changes, there are several other smaller changes included, as suggested by parties and described below.

SCE, IEP, and UCS pointed out the need to clarify whether the extension of the OTC compliance deadlines requested in the proposed decision were intended to count toward the incremental procurement requirements. They were not, and this has been clarified in the text. OTC extensions are necessary insurance, over and above the resource procurement requirements in this decision.

UCS also questioned how imports could count towards the procurement requirement. We have clarified that imports may count toward the requirements, as long as they are incremental to the baseline assumptions, and otherwise meet the requirements outlined in D.19-10-021.

Several parties, including CAISO, IEP, TURN, and CalChoice, in their comments, urged the Commission to be explicit about the enforcement that will take place in the event that the procurement levels required out in this decision are not forthcoming from all LSEs. In modifications to the decision, we have made it explicit that if an LSE does not procure its required share of the capacity requirements in this decision, our recourse will be to require the IOU to procure on behalf of the LSE in its territory, and then have the costs of that procurement allocated to the customers of the LSE that is deficient, through the use of a cost allocation mechanism, potentially as modified in the future to address this scenario. It is also the case that CCAs are in the position to choose whether they wish to self-provide these reliability and renewable integration resources. If they do not self-provide the resources, then we are authorized by statute to require procurement by another LSE, with cost allocation to the CCA customers on a non-bypassable basis.

Several parties also objected to the proposed decision's provisions that required at least three-year contracts for existing resources and ten-year contracts for new resources. Those parties included AReM, CalChoice, and Calpine (for the 10-year requirement). We have not modified these provisions in the decision, because the ten-year requirement for new resource contracts is consistent with the long-term contract provisions in the renewables portfolio standard program, specifically § 399.13(b) requirements, as well as previous procurement requirements for new resources generally. However, we have made one change requested by SCE, which is to make an exception to the ten-year requirement for any energy efficiency contracts, to require them to be at least five years in length.

Cal Advocates and TURN requested, in their comments on the proposed decision, that the decision clarify which NQC values count for purposes of meeting the system resource adequacy requirements. We have clarified that the September NQC values will be used.

CCSF's comments requested that we make the reporting requirements for contractual status be annual and not semi-annual, as suggested in the proposed decision. We agree that annual reporting should be sufficient and have modified the decision to seek this contract status data annually on May 1.

We also note that on September 27, 2019, a motion was filed simultaneously in this proceeding and the resource adequacy rulemaking, seeking a determination from the Commission about the capacity value of hybrid resources. The motion was filed jointly by Enel X, Sunrun, Tesla, CESA, CEERT, and Vote Solar. Numerous parties filed comments in support of the joint motion. We understand parties' desire to have a determination about how such resources will be valued when participating in the solicitations likely to follow from this decision. The Commission intends to take up this motion in the resource adequacy rulemaking (R.17-09-020), where traditionally capacity counting issues have been handled. Therefore, the motion is denied procedurally for purposes of this proceeding, but will be considered in R.17-09-020.

In addition, AReM, in particular, pointed out in comments that basing the LSE allocation on the publicly-available IEPR energy forecasts for 2021 creates a bias for some LSEs based on differential load shapes, since the requirements for incremental procurement in this decision are for system capacity and not energy. AReM makes a reasonable point and we have considered the impact, particularly on ESPs serving, on average, higher load factor customers than other LSEs. To account for this difference, while still using publicly-available load forecasts from the IEPR, we have first allocated the procurement responsibility by LSE class (IOU, CCA, or ESP) on the basis of their peak load contribution as contained in the resource adequacy year ahead requirements for 2020. Then, we have further allocated the procurement responsibility in this decision on the basis of the publicly-available IEPR load forecast for each LSE.

Finally, we appreciate the considerable volume of other comments from parties not summarized here for the sake of space. All comments have been considered. Many offered points similar to those included in their original comments in response to the various rulings. We have considered all of the comments and have elected to make only the changes summarized above to the September 12, 2019 version of the proposed decision.

Consistent with the comments and revisions described above, on October 21, 2019 a revised version of the proposed decision (Revision 1) was mailed to parties. One round of comments from parties was invited, due on October 31, 2019.

The following 36 sets of parties filed comments on the October 21, 2019 version of the proposed decision by October 31, 2019: AES; AReM; AWEA; CAISO; Cal Advocates; CalCCA; Calpine; CCSF; CEERT; CEJA, Sierra Club, and DOW, jointly; CESA; CGNP; CLECA; CPA; Diamond and Sentinel, jointly; EDF; GenOn; GPI; Hydrostor; IEP; Joint Demand Response Parties; LS Power; Middle River; Oxnard; Pattern Energy Group 2 LP (Pattern); PG&E; POC; Range; Redondo Beach; SCE; SDG&E; SWPG; TURN; UCS; Vote Solar and SEIA, jointly; and WPTF.

Below is a summary of the major themes of comments from parties on the revised proposed decision, and the changes made in the decision in response to those comments.

Many parties were concerned that the total incremental capacity procurement of 4,000 MW included in the revised proposed decision was too high and not supported by rigorous enough analysis, thereby not representing the right "least regrets" amount of capacity procurement required. Parties commenting with concerns about the 4,000 MW requirement included PG&E, CalCCA, AReM, CLECA, CPA, Cal Advocates, CCSF, and TURN. Parties suggested different "least regrets" amounts ranging from none at this time (and instead seeking additional analysis), to 3,300 MW, suggested by CalCCA. We have revised this decision to make the incremental capacity procurement requirement 3,300 MW, to account for the changes to the baseline units already detailed in the decision, and to account for the requested ramp-down in OTC capacity that we are requesting from the Water Board. We will also reevaluate the capacity requirements almost immediately in the development of the RSP for this proceeding in the near future, and expect that additional capacity procurement may be determined to be necessary based on that additional analysis.

We also take this opportunity to encourage LSEs to make procurement choices for purposes of the requirements in this decision not only for their capacity benefits, but also for grid resiliency purposes, the importance of which has been emphasized during recent wildfire and power shutoff experiences. The Commission intends to further explore specific requirements related to grid resiliency in the rulemakings related to de-energization and microgrids, at a minimum, but to the extent that LSEs can serve multiple purposes with capacity procurement required by this decision, that is highly encouraged. In addition, we encourage aggressive procurement, even beyond the minimum levels required by this decision, in order to minimize or eliminate the need for OTC deadline extensions included in this decision, as well as to support the orderly planned retirement of Diablo Canyon beginning in 2024.

Many parties also commented on the ramp up of procurement required between 2021 and 2023, including SCE, Vote Solar/SEIA, CLECA, and CalCCA. The original proposed decision required 60 percent of the capacity to be online in 2021, 80 percent by 2022, and 100 percent by 2023. Several parties commented that this requirement, combined with a high capacity procurement requirement, could create a seller's market where there are not enough eligible projects to meet the requirements, thereby potentially driving up costs for customers. To further mitigate against this potential, we have revised the ramp to require 50 percent by 2021, 75 percent by 2022, and 100 percent by 2023, as suggested by SCE.

Numerous parties commented on the need to clarify how incremental imports may count toward the procurement requirements in this decision, including SWPG, AReM, CAISO, Range, UCS, CalCCA, Cal Advocates, Pattern, and AWEA. We agree that imports should be allowed to count but have struggled with how to set a meaningful baseline for this type of product in light of our need for additional capacity identified in this decision. Changes have been made in the body of the decision and the findings to allow for imports to count up to 20 percent of each LSE's total procurement obligation, if the imports are resource-specific and dynamically scheduled or pseudo tied, under a contract for at least three years, and otherwise meet all of the resource adequacy requirements for imported power. Additional work may be needed in the future to address reliance on imports and set meaningful baselines and targets for additional procurement that includes imports. But for purposes of this decision, our desire was not to exclude imports, but simply to limit their applicability so that the incremental capacity procurement requirements actually result in enough new capacity development to keep the system reliable.

A number of parties were also concerned about the prohibition, included in the revised proposed decision, on greenfield development of natural gas facilities. Some parties, including CEJA/Sierra Club/DOW and Vote Solar/SEIA, would like the prohibition to be tighter, not allowing any additional incremental fossil-fueled generation, even at existing sites. On the other hand, several parties including WPTF, CESA, Diamond/Sentinel, Range, and Calpine, would like clarifications to make it clear that modifications at existing sites are eligible. In this instance, we agree with the latter set of parties. Our intention is to prohibit new fossil-fuel-only facilities at new sites which have not previously hosted electricity generation. However, storage facilities co-located with existing fossil-fueled facilities may represent GHG emissions improvements over the status quo and are desirable. Likewise, new projects that may utilize storage combined with some natural gas may be desirable. And finally, some augmentation of capacity, at existing sites and including efficiency improvements or repowering, may also help support system reliability. At existing sites where the facilities were already included in the baseline, only the incremental capacity additions would count toward the incremental requirements in this decision. All of the situations described here are intended to be able to count toward the incremental procurement required by this decision, and the text has been clarified accordingly. However, for clarity, returning mothballed units to service that were already in the baseline are not eligible to be counted toward the incremental procurement requirement in this decision.

A number of parties are also concerned about the allocation of costs and benefits of the procurement required in this decision to benefitting customers of particular LSEs. AReM, CalCCA, and the IOUs all commented seeking particular clarifications to the language about self-provisions of renewable integration capacity and system resource adequacy. In response, we offer a number of clarifications to the language to deal with the various potential ambiguities.

To begin with, we emphasize that while there is a statutory ability of CCAs to elect to self-provide renewable integration capacity, there is no such statutory ability for ESPs. However, for essential fairness, we are allowing for that possibility for both CCAs and ESPs in this decision, for purposes of the procurement required in this decision only. We are also deciding, also for purposes of this decision only, that the IOUs will be the backstop providers of the capacity if the CCA or ESP elects not to self-provide the capacity. Again, this is an interim step and is not intended to prejudge the outcome of the central procurement entity discussions in the resource adequacy proceeding. A better mechanism may well be adopted in the near future.

We also clarify that the capacity procured by the IOUs in response to this decision will be allocated on a non-bypassable basis through a modified CAM mechanism and not PCIA. In other words, we will not reduce the cost allocation amounts to be recovered by the IOUs after load migrates. Thus, we do not make the modifications suggested by SDG&E, in its comments, to account for load migration before or after the CCA or ESP elects whether it will self-provide, or for PCIA vintaging.

We also agree with the comments of SCE that ESPs or CCAs electing not to self-provide capacity at the beginning of this process is fundamentally different from the situation that will arise when an LSE tries but fails to self-provide its capacity. In that instance, the emergency procurement required is likely to be more limited and more costly than if it is procured in an orderly fashion over the time period expected for this decision. We make clear here that either way, if an IOU procures the necessary capacity on behalf of another LSE's customers, we will allow them to recover those full costs. We also agree with SCE that if an LSE elects to provide its own capacity, it should be responsible for the full requirement. Partial self-provision is not something we are contemplating here.

We recognize that these are complex questions that are not completely addressed by current mechanisms. Therefore, we will request that Commission staff initiate a workshop or working group process by mid-January 2020 to begin to develop proposals for the exact mechanisms contemplated here.

The contradictory comments of the City of Redondo Beach and AES indicate an apparent disagreement about the safety of the dewatering system used at the Redondo Beach Generating Facility. The Commission is not in a position to adjudicate this dispute, but trusts that the Water Board will take this issue into consideration when deciding whether to extend the OTC compliance deadline for the Redondo Beach facility.

Finally, Diamond and Sentinel's comments suggest that the final baseline list to be posted by Commission staff be issued via a formal resolution. While we do not adopt that recommendation, we do include a provision for parties to file comments in response to the staff list, now to be issued no later than December 2, 2019. Parties may file comments in response to the staff list no later than December 9, 2019, after which the assigned ALJ will issue a ruling taking those comments into account and finalizing the baseline list.

12. Assignment of Proceeding

Liane M. Randolph is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission has a responsibility to ensure safe and reliable electricity service to customers served by LSEs within its jurisdiction.

2. The Commission is required by Section 454.51(a) to "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."

3. Commission staff analysis of the supply stack of current system resource adequacy resources available to serve load in 2021 suggests that supplies are tight and that reliance on imports will be increased beyond historical levels, creating uncertainty in system capacity supply.

4. Reliability-related production cost modeling conducted in this proceeding to support the development of the PSP adopted in D.19-04-040 did not test for loss of load expectation in any years before 2030.

5. There is a significant possibility of a system resource adequacy shortfall in California by Summer 2021 if the Commission does not act to authorize the procurement of additional electric capacity resources to address system reliability.

6. Additional electric capacity resources are necessary to ensure integration of large volumes of renewable energy being procured by LSEs.

7. Current system resource adequacy requirements are one year ahead, such that a 2021 capacity shortfall would not be detected until Fall 2020, which is too late to secure necessary capacity through procurement actions using resource adequacy mechanisms.

8. The CAISO's CPM and RMR mechanisms are designed as backstop measures, in case LSE procurement fails to provide necessary resources.

9. The resource adequacy rulemaking (R.17-09-020) is currently addressing issues related to development of a central buyer for local resource adequacy capacity, as well as clarification and modification of rules related to the counting of imported capacity for resource adequacy purposes. In addition, R.17-09-020 will address the September 27, 2019 joint motion with respect to counting methodology for NQC for hybrid generation and storage resources.

10. Approximately 3,750 MW of capacity from OTC units is currently scheduled to retire by December 31, 2020 and could be available for a compliance date extension from the Water Board, in order to serve as a bridge to allow new clean resources to come online.

11. All of the OTC units with current retirement dates of December 31, 2020 are within the TAC area of SCE except for Moss Landing Units 1 and 2.

12. The capacity factors of the OTC units with current retirement dates of December 31, 2020 are all under 10 percent for the past several years, which

means that the use of sea water for cooling and emissions are minimal compared to their historic levels.

13. Hydroelectric capacity, especially from the Northwest imported into California, is becoming in higher demand, in part due to the renewable policies of other states in the West. Imported capacity for California may become scarcer in the future.

14. California's system peak is moving later in the day and later in the year, which does not coincide with the value provided by solar resources, though they have been the resource of choice to date for most LSEs to meet their RPS and clean energy needs.

15. Additional renewable integration resources will continue to be needed to support system peak load as it shifts later in the day and later in the year.

16. In addition to extension of OTC capacity, another minimum of 3,300 MW of incremental system resource adequacy and renewable integration resources will be needed by Summer 2021, as a "least regrets" amount necessary to ensure system reliability.

17. The need for system resource adequacy and renewable integration resources begins in 2021 and will extend through at least 2023, and beyond, as more renewable resources are added to meet California's climate goals and as more fossil-fueled and nuclear power plants retire. The need for additional resources is being examined in the 2019-2020 IRP cycle currently underway.

18. The most logical baseline against which to measure incremental resources is the set of baseline resources used to develop the PSP adopted in D.19-04-040, with certain adjustments. The baseline resources should be those included for the year 2022, the year that most closely matches the timeframe associated with this decision.

19. Neither the Commission's PSP adopted in D.19-04-040 nor the RSP adopted in D.18-02-018 identified a need for new fossil-fuel-only resources. Additionally, no LSE proposed procurement of fossil-fuel-only resources in their 2018 individual IRPs.

20. Numerous LSEs are in the process of or have already contracted for capacity incremental to the 2022 baseline resources used to develop the PSP. That capacity procurement, except if specifically required and authorized separately by the Commission, is reasonable to be considered to fill the need beginning in 2021, even if procurement activities began before the adoption of this decision.

21. The Commission has the authority, articulated in Section 454.51(c), to direct the IOUs to procure renewable integration resources on behalf of the electricity system as a whole, and to allocate those costs on a non-bypassable basis to all benefiting customers.

22. The Commission has the authority, as discussed in D.19-04-040, according to Section 454.51(d), to permit procurement of renewable integration resources by CCAs to fulfill their portion of the renewable integration requirements through long-term commitments.

23. Numerous parties, in numerous venues, over many years, have objected to the design and use of the CAM mechanism.

24. The CEC's IEPR load forecast represents the most recent publicly-available source of load forecasts for the year 2021 for LSEs serving load within the CAISO footprint.

25. The resource adequacy capacity allocation for 2020 by LSE type of 66.5% to IOUs, 24.5% to CCAs, and 9.0% to ESPs is a reasonable proxy for allocating the

procurement responsibility in this decision to classes of LSEs, and then further allocating within LSE class by load share.

26. Section 454.52(a)(1)(H) requires LSEs to minimize localized air pollutants and GHG emissions, with early priority on disadvantaged communities.

27. D.19-06-032, Appendix A, Section 2c, includes a useful starting point for demonstrating a comparison between third-party development and utility ownership of storage resources.

28. Tier 3 advice letters represent an appropriate vehicle to balance a need for expedited approval and appropriate due process for parties wishing to weigh in on an LSE's procurement approval requests.

29. Existing bundled procurement rules for IOUs do not require advice letters to be submitted for contracts less than five years in length, unless they are with OTC units, and do require applications for contracts five years or greater.

30. The Commission requires more frequent informational updates from all LSEs in order to evaluate and track progress toward the 2021 system resource adequacy and renewable integration reliability requirements and any subsequent procurement targets.

Conclusions of Law

1. The Commission should act now to forestall a potential system reliability emergency by 2021 and require "least regrets" actions with respect to OTC deadlines and LSE procurement.

2. The issues of development of a central buyer mechanism for resource adequacy capacity and rules related to the counting of imported capacity for resource adequacy purposes, as well as resource adequacy counting rules for hybrid resources, should continue to be addressed in R.17-09-020.

3. The September 27, 2019 Joint Motion related to counting of hybrid resources should be denied without prejudice in this proceeding, for procedural reasons, to be taken up instead in R.17-09-020.

4. The Commission is committed to retirement of OTC units to comply with Water Board regulations, but also has a responsibility to ensure safe and reliable electric service.

5. The Commission should recommend to the SACCWIS and the Water Board that OTC compliance deadline extensions be granted for the following OTC units, as a bridge strategy to allow new capacity to come online: Alamitos Generating Station Units 3-5, for up to three years; Huntington Beach Generating Station Unit 2, for up to three years; Redondo Beach Generating Station Units 5,6, and 8, for up to two years; Ormond Beach Generating Station Units 1 and 2, for up to one year; and Moss Landing for a period until such time as the Water Board certifies its upgrades to be in compliance with OTC policy.

6. The Commission should waive the prohibition in D.12-04-046 against contracting with OTC units beyond their compliance deadlines, even if the deadlines are later extended. Utilities should be allowed to contract with OTC units in anticipation of potential compliance deadline extensions, but those contracts would not go into effect if the Water Board does not grant the compliance deadline extensions.

7. The Commission should address the need for system peak capacity given the shift of the peak to later in the day and later in the year, which makes the contribution of solar resources without storage less valuable and the need for other renewable integration resources more acute.

8. The Commission should rely on the determinations in the resource adequacy proceeding (R.17-09-020) for how to count imports for purposes of resource adequacy.

9. It is reasonable for the Commission to require 3,300 MW of incremental system resource adequacy resources to be procured, with at least 50 percent online by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023.

10. It is reasonable for the Commission to continue to evaluate the need for additional procurement in the cycle of the IRP process underway now.

11. Because incremental system resource adequacy capacity is needed at the system level, it is reasonable for the Commission to allocate responsibility for this procurement to all LSEs on behalf of the customers they serve in all IOU TAC areas.

12. The Commission should require all LSEs serving load within the CAISO to procure system resource adequacy and renewable integration capacity on behalf of the customers they serve, consistent with Section 454.51(d), instead of asking the IOUs to handle the entirety of the procurement and allocating costs to all benefiting customers.

13. If an LSE notifies the Commission by May 1, 2020 that it will not procure the required incremental system resource adequacy and renewable integration capacity in this decision, the Commission should require the relevant IOU to conduct additional system resource adequacy procurement and allocate the costs to the customers of the LSE that has not procured on behalf of its customers. The associated benefits of this backstop procurement by the IOUs will be allocated to the LSEs of the customers paying the costs of the procurement. Commission staff should convene a workshop in January 2020 to work out the details of the cost

allocation, which will be a modified version of the CAM and will not rely on the PCIA.

14. Resources procured by LSEs in response to this decision should be incremental to the set of baseline resources for the year 2022 identified in the analysis that led to the adoption of the PSP in D.19-04-040, with adjustments outlined in this decision. The baseline will be detailed in a list that will be posted by Commission staff to the Commission web site by no later than December 2, 2019, and finalized in an ALJ ruling after considering party comments filed no later than December 9, 2019.

15. For purposes of the 3,300 MW of incremental procurement required in this decision, imported power should be allowed to count toward no more than 20% of the total obligation of each LSE, as long as the import is under a contract of at least three years in length, is associated with an identified specific resource and is dynamically transferred or pseudo tied to the CAISO, and otherwise meets all of the resource adequacy import requirements.

16. Any procurement of resources not included in the 2022 baseline resources used for the development of the PSP, except any capacity specifically required and already approved separately by the Commission, even if the procurement occurred prior to the adoption of this decision, and except any contracts with OTC units whose extensions are requested in this decision, should be counted toward the requirements in this decision.

17. The Commission should waive the requirement from D.12-04-046 that bars utilities from signing power purchase agreements with OTC resources where the term of the agreement goes beyond the OTC deadline for the specific resource, even if the deadline is later extended, for the Alamitos, Huntington Beach,

Redondo Beach, Ormond Beach, and Moss Landing power plants identified as needed for OTC extensions in this decision.

18. The Commission should base the allocation of procurement responsibility for system resource adequacy and renewable integration capacity to LSEs first on the capacity allocation by LSE type (IOU, CCA, or ESP) in the resource adequacy proceeding. Then, the allocation should be further distributed to individual LSEs based on the 2018 IEPR load forecast, adopted by the CEC in February 2019, with the 2021 projected load shares identified in Form 1.1c, "California Energy Demand Update Forecast 2018-2030, Mid Demand Baseline Case, Mid Additional Achievable Energy Efficiency and Additional Achievable Photovoltaics."

19. Compliance with the requirements for capacity procurement outlined in this decision should be based on the NQC values of the resources for the month of September.

20. Load forecast breakdown among individual ESPs is confidential; individual ESPs should be informed of their responsibilities confidentially by Commission staff within 10 business days of the adoption of this decision.

21. The Commission should not distinguish, in its incremental procurement requirement identified herein, between existing and new resources, except with respect to contract length required and prohibiting new fossil-fuel-only resources (without storage) at sites not previously used for electricity generation, for purposes of the procurement required in this decision.

22. The Commission should prefer all-source procurement of resources, including demand-side resources and preferred resources, to the extent possible, as long as resources can be shown to be incremental to the 2022 baseline set of resources. New fossil-fuel-only resources (without storage) at sites not previously used for electricity generation and OTC units are not eligible to meet

the 3,300 MW incremental need identified in this decision. Capacity upgrades to and repowers to add capacity to existing resources, including baseline resources, are eligible based on the incremental capacity addition.

23. The IOUs should be required to conduct an all-source solicitation in a non-discriminatory manner, with resources delivering the same attributes being valued in the same manner. The IOUs should be required to show their bid comparison metrics to the Commission to justify their requested procurement.

24. Any negotiation for the delivery of demand response resources should begin with the DRAM contract as a starting point.

25. Any demand-side resources should be required to show incrementality based on the principles adopted in D.16-12-036, as a starting point.

26. The Commission should not set a specific capacity target for hybrid resources, but should allow them to count toward the procurement requirements in this decision, as determined by counting protocols to be considered in R.17-09-020.

27. The Commission should require that the incremental system resource adequacy and renewable integration resources required to be procured by this decision come online at least 50 percent by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. On an interim basis for the 2021 requirement, the Commission will consider resources that do not yet count for resource adequacy but are online and required to submit bids in the CAISO markets consistent with the resource adequacy must offer obligations to be online for the purposes of this requirement.

28. Contracts entered into LSEs for new resources to deliver for system resource adequacy and renewable integration capacity should be required to be at least ten years in length, except for any energy efficiency contracts, which

must be at least five years in length. Contracts entered into by LSEs for existing resources to deliver system resource adequacy and renewable integration capacity should be required to be at least three years in length, except for OTC units where contracts may be no longer than any extension granted by the Water Board.

29. For purposes of the requirements of this decision, the IOUs should be authorized to consider third-party ownership and utility ownership of resources to be procured to satisfy the requirements of this order, but should be required to show that any utility-owned resources represent least cost to ratepayers, utilizing Appendix A, Section 2c, of D.19-06-032 as a starting point.

30. The IOUs should be required to include its bid evaluation metrics and comparison metrics between third-party and utility-owned resources, in their advice letter(s) submitted for approval of the resources procured in response to this decision.

31. The IOUs should also be required to adhere to all existing rules about utility and affiliate participation in utility-run solicitations.

32. The Commission should create an exception to the existing bundled procurement rules for IOUs and should require each IOU to submit a Tier 3 advice letter, or more than one, no later than January 1, 2021, to propose Commission approval for any procurement conducted to satisfy the requirements of this decision.

33. All LSEs with procurement obligations under this decision should be required to provide an informational progress report on their activities by no later than February 15, 2020. Non-utility LSEs should be required to include in this progress report a declaration for whether they intend to self-provide all or

none of the capacity required in this decision, so that the Commission and IOUs will be able to plan accordingly.

34. All LSEs should be required to include in their individual IRPs currently due May 1, 2020 an attestation from a senior executive that they will or will not fulfill the total obligations of this decision, and detailed information about the projects, capacities, and dates by which the LSEs expect projects to be providing electricity service, demonstration of incrementality to the baseline, and a description of how they have addressed pollutants in disadvantaged communities.

35. All LSEs should also be required to provide electricity resource contract information on May 1 every year beginning in 2020 (and included in the individual IRP filings in years where those are required) in order for the Commission to monitor progress of resource development and reliability and renewable integration challenges.

36. The Commission should grant the October 9, 2019 motion for official notice of the City of Redondo Beach in order to consider its actions and those of the Coastal Commission with respect to the Redondo Beach Generating Station.

O R D E R

IT IS ORDERED that:

1. The Commission recommends that the State Water Resources Control Board extend the once-through-cooling compliance deadlines of the following units with current compliance deadlines of December 31, 2020, for the period specified, in order to allow time for new clean electricity capacity to come online:

    a. Alamitos Generating Station, Units 3-5, for up to three years;

b. Huntington Beach Generating Station, Unit 2, for up to three years;

c. Redondo Beach Generating Station, Units 5, 6, and 8, for up to two years;

d. Ormond Beach Generating Station, Units 1 and 2, for up to one year; and

e. Moss Landing, Units 1 and 2, until such time as the planned upgrades are certified by the State Water Resources Control Board.

2. The provisions of Decision 12-04-046 that bar utilities from signing power purchase agreements with units utilizing once-through cooling technologies where the term of the agreement extends beyond the compliance deadlines, even if the deadlines are later extended, are waived for purposes of the power plants listed in Ordering Paragraph 1 above. Any contracts with plants listed in Ordering Paragraph 1 above shall be for a duration of no more than the time period specified by the State Water Resources Control Board. Any contracts executed by any load-serving entity with plants listed in Ordering Paragraph 1 are in addition to and do not count toward the obligations required by Ordering Paragraph 3 of this decision.

3. The following load-serving entities shall procure at least the amount of capacity in megawatts (MW) qualifying as system resource adequacy and for purposes of renewable integration as defined in Public Utilities Code Section 454.51, with at least 50 percent delivered by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023:

a. Pacific Gas and Electric Company, 716.9 MW;

b. Pacific Gas and Electric Direct Access (aggregated), 114.0 MW;

c. Clean Power San Francisco, 57.0 MW;

d. East Bay Community Energy, 99.6 MW;

e. King City Community Energy, 0.7 MW;

f. Marin Clean Energy, 87.5 MW;

g. Monterey Bay Community Power Authority, 57.4 MW;

h. Peninsula Clean Energy, 55.0 MW;

i. Pioneer Community Energy, 18.5 MW;

j. Redwood Coast Energy Authority, 10.7 MW;

k. San Jose Clean Energy, 77.6 MW;

l. Silicon Valley Clean Energy, 67.2 MW;

m. Sonoma Clean Power, 43.3 MW;

n. Valley Clean Energy Alliance, 12.6 MW;

o. Southern California Edison Company, 1,184.7 MW;

p. Southern California Edison Direct Access (aggregated), 140.3 MW;

q. Apple Valley Choice Energy, 3.8 MW;

r. Clean Power Alliance of Southern California, 196.9 MW;

s. Lancaster Clean Energy, 9.4 MW;

t. Pico Rivera Innovative Municipal Energy, 2.6 MW;

u. Rancho Mirage Energy Authority, 4.8 MW;

v. San Jacinto Power, 2.8 MW;

w. San Diego Gas & Electric Company, 292.9 MW;

x. San Diego Gas & Electric Direct Access (aggregated), 42.7 MW; and

y. City of Solana Beach, 1.1 MW.

4. Commission staff shall provide the disaggregated confidential allocations to each electric service provider covered under in Ordering Paragraph 3 of this decision by no later than 10 business days after the issuance of this decision.

5. The system resource adequacy procurement allocated to community choice aggregators (CCAs) in Ordering Paragraph 3 of this decision shall be

considered their opportunity to self-provide renewable integration resources as described in Section 454.51(d) of the Public Utilities Code. The Commission is also voluntarily making this opportunity available to electric service providers (ESPs). If a CCA or an ESP chooses not to procure the total amount required by Ordering Paragraph 3 of this decision, the CCA or ESP shall elect not to provide the full amount of its obligation and shall notify the Commission in its February 15, 2020 progress report required by Ordering Paragraph 11 below. The Commission will then require the relevant investor-owned utility to procure on behalf of the CCA or ESP and have the costs of any such procurement allocated to the customers of the CCA or ESP on a non-bypassable basis based on the cost allocation mechanism and not the procurement charge indifference amount mechanism. Commission staff shall convene a workshop or working group to discuss the particulars of the cost allocation mechanism in January 2020. The resulting cost allocation mechanism shall address both the instance where CCAs and ESPs elect not to self-provide the capacity at the front end, and the situation where CCAs and ESPs elect to self-provide capacity but fail to meet their obligations.

6. All resources utilized by all load serving entities (LSEs) to satisfy the requirements of Ordering Paragraph 3 of this decision shall be shown to be incremental to the baseline resource assumptions identified for 2022 in the analysis that led to the adoption of the Preferred System Plan adopted by the Commission in Decision (D.) 19-04-040, as adjusted to remove the Sutter Power Plant (which also shall not be considered an import, for purposes of this decision) and Inland Empire Energy Center, add Moss Landing, and detail specific storage resources with projected online dates prior to the end of 2022. Commission staff shall post the baseline list to the Commission's web site no

later than December 2, 2019; parties may file and serve comments on the staff baseline list no later than December 9, 2019, after which the final baseline list will be issued via a ruling from the assigned administrative law judge. Incrementality of demand-side resources shall be demonstrated by using the principles adopted by the Commission in D.16-12-036 as a starting point. All LSEs shall also demonstrate their compliance with Public Utilities Code Section 454.52(a)(1)(H). Imported power may be used to satisfy the Ordering Paragraph 3 requirements up to a maximum of 20 percent of each LSE's requirement, if the imported power is under a contract of at least three years in length, is associated with an identified specific resource and dynamically transferred or pseudo tied, and meets all other resource adequacy requirements for imports.

7. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall conduct all-source solicitations to procure their obligations given in Ordering Paragraph 3 above and shall consider existing as well as new resources, demand-side resources, combined heat and power, and storage, as long as all resources are shown to be incremental to the baseline identified in Ordering Paragraph 6 above. New fossil-fuel-only resources, without storage, at sites not previously used for electricity generation, are not eligible to satisfy the requirements of Ordering Paragraph 3 above, but modifications and augmentations to existing facilities are eligible for the incremental capacity addition, even if the facility is in the baseline identified in Ordering Paragraph 6. The utilities shall utilize the Demand Response Auction Mechanism contract as a starting point for negotiations with any demand response resources that bid into the solicitations.

8. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall be authorized to propose utility ownership of a portion of the resources required by Ordering Paragraph 3 of this decision to be procured, and for that portion, shall abide by any existing procurement rules governing utility-owned resource participation in solicitations.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall present the results of their solicitations required in Ordering Paragraph 7 above in one or more Tier 3 advice letters filed no later than January 1, 2021 and shall include the following information in their advice letters:

a. Metrics used to compare bids received in the solicitation;

b. Metrics used to compare utility-owned resource options, using Appendix A, Section 2c, of Decision 19-06-032 as a guide;

c. Demonstration of incrementality to the baseline given in Ordering Paragraph 5 of this decision.

10. For any procurement of resources that are new after the date of this decision, load serving entities with procurement obligations under Ordering Paragraph 3 of this decision shall enter into contracts of at least ten years in length except for energy efficiency resources, which shall be at least five years in length. For any procurement of existing resources, contracts shall be of at least three years in length.

11. All load-serving entities (LSEs) named in Ordering Paragraph 3 and by Commission staff as discussed in Ordering Paragraph 4 of this decision shall present a progress report summarizing their activities and efforts to date to comply with this decision, along with a declaration as to whether the LSE

intends to self-provide all or none of the capacity required by this decision, as a "compliance filing" filed and served in this proceeding, or its successor, by no later than February 15, 2020.

12. All load-serving entities (LSEs) named in Ordering Paragraph 3 and by Commission staff as discussed in Ordering Paragraph 4 of this decision shall present in their individual integrated resource plans currently due May 1, 2020 an attestation from a senior executive in the company that the necessary capacity required in this decision shall be provided if the LSE is electing to provide the capacity required. This attestation shall be accompanied by a detailed list of projects, capacities, and dates by which the LSE expects the projects to be providing service to the LSE, as well as a demonstration that the projects are incremental, to meet the 2021, 2022, and 2023 requirements of this decision.

13. All load serving entities serving load as of May 1 of every year beginning in 2020 shall provide the Commission staff with a data response detailing contract and resource information, to allow the Commission and stakeholders to monitor progress about system reliability and renewable integration. In years where an individual integrated resource plan (IRP) is required by Decision (D.) 18-02-018 to be filed, the same information shall be included in each LSE's individual IRP. This standing data request may be updated from time to time, at least one month in advance of each due date, by Commission staff. The information is likely to be similar to that requested in the first such data request discussed in D.19-04-040, which was due on September 16, 2019.

14. The September 27, 2019 Joint Motion to Establish a Schedule and Process for Determining the Capacity Value of Hybrid Resources is denied without prejudice in this proceeding, and will be considered in Rulemaking 17-09-020.

15. The October 9, 2019 Motion for Official Notice by the City of Redondo Beach is granted.

This order is effective today.

Dated ____________________________, at San Francisco, California.