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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R. 20-05-003 (Filed May 7, 2020)

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE ADMINISTRATIVE LAW JUDGE'S AND ALTERNATE PROPOSED DECISIONS REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY

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Decisions of the California Public Utilities Commission

Constitutional Provisions

Subject Index

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I. INTRODUCTION

The Independent Energy Producers Association (IEP) hereby responds to both the proposed decision (PD) of the administrative law judge (the "ALJ PD") and the alternate PD of Commissioner Rechtschaffen regarding procurement to address mid-term reliability. IEP's comments do not address aspects of the PD that primarily affect load-serving entities, such as the allocation of procurement obligation or the proposed penalties for non-compliance. Both PDs would require load-serving entities (LSEs) to procure enough capacity to substantially mitigate the risk of future load-shedding events in the mid-term timeframe.

IEP appreciates the acknowledgment in both PDs of the critical role that gas-fired capacity plays in maintaining reliable service. Based on recent efforts to model long-term low-carbon pathways for California's electric sector, the ALJ PD's fossil-fueled capacity targets better match the amount of gas-fired capacity that needs to be repowered or replaced between now and 2045. IEP opposes the restrictions on incremental gas-fired capacity in disadvantaged communities in both PDs, particularly the outright prohibition in the Alternate PD, because these restrictions will yield no material improvement in air quality and will foreclose options to develop incremental capacity in areas of high local value. Finally, IEP urges the Commission to defer requirements for any portion of the authorized fossil-fueled capacity to blend green hydrogen into the fuel supply. The record has not been sufficiently developed, and the Commission and stakeholders would benefit from additional information on the costs and

technical feasibility of various blending requirements. At a minimum, the Commission should revise the PDs allow for use other zero-carbon fuels such as biogas or blue hydrogen and to allow the use of directed fuels delivered by natural gas pipelines.

II. THE COMMISSION SHOULD ADOPT THE 11.5 GW PROCUREMENT TARGET

IEP was among several parties who supported the 7.5 GW of procurement proposed in the ALJ Ruling of February 22, 2021 ("Ruling"). As the PDs explain, the amount proposed in the Ruling was based on a Mid-Need Scenario that resulted from the application of the 15 percent planning reserve margin to the 1-in-2 load forecast, with another 1.5 percent added for operating reserves and 2 gigawatts (GW) of generic capacity that previous analysis indicated may be necessary to cover calibration differences between RESOLVE and SERVM models.[1] The PDs state that the comments of the California Independent System Operator (CAISO) and the California Public Advocates Office ("Cal Advocates") were persuasive in convincing the Commission to support a procurement obligation based on a high-need scenario that assumes a higher load, the retirement of more gas-fired generation, and lower import availability due to accelerating coal plant retirements.[2] Given the amount of additional capacity that will be needed in this decade to meet 2030 climate goals, whether based on the 46 million metric ton (MMT) of CO_2 or the 38 MMT target, IEP concurs with the PDs that requiring LSEs to procure 11,500 MW by 2026 is a prudent measure to ensure reliability.

Regardless of the 2030 GHG target the Commission ultimately sets, IEP shares concerns expressed by other parties about whether the state is on track to build enough transmission to accommodate the additional capacity required to meet both the GHG and reliability needs.[3] The IRP and transmission planning process assume that LSEs will procure large amounts of energy-only resources for GHG purposes, allowing the interconnection of several GW renewable capacity without triggering the need for substantial transmission upgrades. However, LSEs have little interest in energy-only contracts due to the large amounts of qualifying capacity, which must be fully deliverable, they will be obligated to procure over the next several years and the

[1] ALJ PD, p. 6. Alternate PD, p. 6.
[2] ALJ PD, pp. 16-20. Alternate PD, pp. 16-20.
[3] Center for Energy Efficiency and Renewable Technologies, Opening Comments on Ruling, pp. 12-13. American Clean Power - California, Opening Comments on Ruling, p. 4.

increased curtailment risk that energy-only projects are exposed to. Therefore, it is essential that the Commission ensures that transmission projects under its jurisdiction are approved and sited.

III. THE COMMISSION SHOULD DEFER 1,500 MW OF THE 2023 PROCUREMENT OBLIGATION TO 2024 AND CONSIDER ACCELERATING 500 MW OF THE 2026 OBLIGATION TO 2025

Several parties, including IEP, expressed strong concerns about the ability of project developers to construct and interconnect additional capacity by 2023 and the effect this tight deadline could have on offer prices.[4] While IEP agreed that some advanced procurement is reasonable to ensure reliability in 2023 and 2024, we argued in comments on the Ruling that due to the concerns about 2023 project viability, advanced procurement in 2023 should be reduced to 20% of the forecasted 2024 need rather than 40%.[5] We continue to support such an approach.

Additionally, we note that the procurement schedule shown in Table 3 results in a significant capacity deficit in 2025. IEP understands that one reason that the total cumulative capacity requirement is held to 9.5 GW in 2025 is to allow more time for the development of long lead-time (LLT) resources. However, one of the categories of LLT resources, the "firm and/or dispatchable zero-emitting resources," can be readily met by five hours of stand-alone or hybrid storage projects, which do not need long lead times. Because the proposed procurement schedule is quite aggressive with respect to ensuring reliability, IEP speculates that the Commission does not believe that a 1.3 GW shortfall of net qualifying capacity (NQC) in 2025 based on the high-need scenario assumptions is likely to jeopardize reliability. If that is the case, it would be helpful for the Commission to explain its reasoning. If, on the other hand, it is cause for concern, some of the capacity scheduled for 2026 should be accelerated to 2025.

The table below, which draws on Table 3 from the PDs, compares the cumulative capacity need to the proposed capacity requirements and includes an alternative schedule that we propose to address both areas of concern we have identified. Our alternate proposal would defer 1,500 MW of capacity from 2023 to 2024 and accelerate 500 MW of firm/dispatchable capacity from 2026 to 2025.

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[4] IEP Reply Comments on Ruling, p. 5. California Energy Storage Alliance, Opening Comments on Ruling, p. 15. Pacific Gas and Electric Company, Opening Comments on Ruling, p. 19. Public Advocates Office, Opening Comments on Ruling, pp. 14-15. City and County of San Francisco, Opening Comments, p. 5.

[5] IEP, Reply Comments on Ruling, p. 5.

Table 1. Cumulative Capacity Need, Proposed Procurement Requirements, and IEP Proposed Alternative (MW NQC)

Need Determination and Required NQC	2023	2024	2025	2026	Total
Cumulative Resource Adequacy Need	-	7,361	10,816	11,597	11,597
Cumulative Proposed Capacity Requirements	3,000	7,500	9,500	11,500	11,500
Capacity Shortfall	(3,000)	(139)	1,316	97	97
IEP Alternative Procurement Schedule	1,500	7,500	10,000	11,500	11,500
Capacity Shortfall, IEP Alternative	(1,500)	(139)	816	97	97

IV. ELIGIBLE RESOURCES

A. IEP Supports the LLT Target but the Commission Should Combine the "Firm" and "Dispatchable" Categories and Clarify the Definition of "Firm"

In comments on the Ruling, IEP opposed the recommendation that the Commission establish 1 GW carve-outs that were defined only with respect to specific technologies.[6] Whereas the Ruling recommended 1 GW each for long-duration energy storage (LDES) and geothermal, the PDs retain the requirement for 1 GW of LDES but replace the carve-out for geothermal with an attribute-based carve-out, namely that the capacity procured for this bucket must either be "firm zero-emitting" (operating at a capacity factor of at least 85 percent) or "dispatchable zero-emitting" (capable of generating or discharging during five peak hours every day). IEP appreciates the PDs' movement toward a greater level of technological neutrality. While the PDs could define the two LLT categories in even more general terms, IEP supports the proposed LLT procurement obligations.

IEP requests, however, that the Commission clarify the definition of dispatchable zero-emitting resources to make the terms and hours more consistent with the CAISO nomenclature. The PDs state that dispatchable resources must be available "during hours 17 and 22 daily."[7] This definition is ambiguous and does not align with CAISO's current and anticipated availability hours. IEP suggests two changes for clarity. First, CAISO uses "hour ending" (HE) nomenclature to define when transactions are scheduled in its market. In this system, the start and end of a time period includes the hours used to bookend the description of the time period. For example, a trade starting HE 14 and ending HE 16 is trade scheduled for delivery from 1 pm

[6] IEP Opening Comments on Ruling, pp. 4-5.
[7] ALJ PD, p. 35. Alternate PD, p. 35.

through 4 pm. CAISO also uses prevailing time so that HE 14 is 1 pm to 2 pm standard time in the winter and daylight savings time in the summer. The PDs should either consistently use the HE nomenclature or state that dispatchable resources must be capable of delivering from x pm to y pm. In both cases, the Commission should clarify that the times are denoted in prevailing time.

Second, if the "hours" used in the PDs are interpreted as "hours ending," then the PDs would require delivery from 4 pm to 10 pm. The Commission should revise the PDs to align with CAISO's current availability assessment hours, which are from 4 pm to 9 pm (HE 17 to HE 21) or a five-hour period during whatever availability assessment hours are in effect at the time the contracts are executed.

IEP also suggests that the "firm" and "dispatchable" resource categories be combined into one "firm" category. Because a high capacity factor "firm" resource will typically be available during net peak hours on a daily basis, the distinction between "firm" and "dispatchable" is not useful. The attribute that the Commission is seeking is the ability to consistently deliver electricity at the NQC rating during the net peak hours, regardless of whether the resource operates at a high or low capacity factor. IEP suggests that, for the purposes of this decision, the PDs define the term "firm zero-emissions resource" as a resource that emits no on-site GHGs, unless the emissions are from biomass that meets the RPS requirements, and that is capable of generating or discharging continuously at its NQC rating from 4 pm to 9 pm prevailing time on a daily basis. Defining "firm" in this manner in Section 5.2.1 would also be consistent with the PDs use of "firm" in Section 5.2.3, which, as currently written, matches the definition of "dispatchable" in Section 5.2.1.[8] Allowing any zero-emissions resource that is capable of delivering reliably during peak hours will maximize flexibility for LSEs and lower costs to consumers.

B. Regarding Fossil-Fueled Procurement, the Commission Should Adopt the Targets of the ALJ PD, Eliminate Geographic Restrictions, Eliminate Technology-Specific Requirements Based on Project Categories, and Defer Consideration of Hydrogen Blending Requirements

IEP appreciates the frank discussion of the reliability benefits of gas-fired resources and the acknowledgement that reliability problems can both undermine support for the state's

[8] If the Commission determines that maintaining a distinction between "firm" and "dispatchable" is necessary, the PDs should use the terms consistently in Sections 5.2.1 and 5.2.3.

environmental goals and lead to increased use of much more polluting back-up diesel generators.[9] As the PDs explain, fossil-fueled resources may be needed to remain on standby for capacity purposes even though they may not generate much energy. Furthermore, investing in newer, more efficient generation technologies can facilitate the retirement of older, more polluting units.[10]

Recognizing that some investment in incremental gas-fired capacity is necessary to maintain reliability, both PDs require the investor-owned utilities (IOUs) to procure certain amounts of gas-fired capacity on behalf of all LSEs. The ALJ PD requires incremental capacity ranging from 1 GW to 1.5 GW of NQC and imposes certain restrictions on incremental capacity located in disadvantaged communities ("DACs").[11] The Alternate PD requires 500 MW of incremental gas-fired capacity, limits contracts with conventional gas-fired generation to no more than five years duration, prohibits incremental capacity in DACs, and requires all incremental capacity to demonstrate a reduction in the GHG emission rate. Additionally, the Alternate PD allows up to another 300 MW of capacity, but only from units that commit to using 30 percent green hydrogen by 2026 and 50 percent green hydrogen by 2031.[12]

Overall, IEP supports the ALJ PD, albeit with suggested modifications which we discuss below. We noted in our comments on the Ruling that the SB 100 Report found that 25 GW or more gas-fired capacity would be retained until 2045 to maintain reliability at a reasonable cost.[13] The SB 100 Report focuses on incremental resource needs and does not provide the total amount of installed existing and new capacity in 2045. However, in a similar study E3 conducted on long-run resource adequacy, which actually forecast lower GHG emissions than the SB 100 Report,[14] the gas-fired capacity in the base case scenario was also 25 GW and accounted for 8.6 percent of the installed generation and storage capacity.[15] The Alternate PD would only authorize

[9] Alternate PD, pp. 38-42. ALJ PD, pp. 37-41.
[10] Alternate PD, p. 41. ALJ PD, p. 40.
[11] ALJ PD, pp. 43-45.
[12] Alternate PD, pp. 42-45.
[13] IEP Opening Comments on the Ruling, p. 8.
[14] E3. Long-Run Resource Adequacy under Deep Decarbonization Pathways for California. June 2019. This report estimates approximately 10 MMT CO_2 from the electricity sector in 2050 to meet the economy wide 80 percent GHG reduction target. (p. 25) The SB 100 Report estimates 24 MMT CO_2 from the electricity sector in 2045 to meet the SB 100 goal. (p. 99)
[15] E3. Long-Run Resource Adequacy under Deep Decarbonization Pathways for California. June 2019, p. 50.

4.3 to 7 percent of the incremental capacity to come from fossil-fueled resources. Given our concerns about the cost and feasibility of the hydrogen blending requirements, the lower end is the more likely outcome. IEP's support for the ALJ PD is driven both by the larger capacity targets for incremental fossil-fueled generation and the greater flexibility the ALJ PD would grant for siting, operations, and fuel blending requirements. Below, IEP addresses the issues that pertain to both PDs. In subsequent subsections we provide comments specific to each PD.

1. Issues Common to Both the ALJ and Alternate PDs

(a) The Commission Should Not Restrict or Prohibit Fossil-Fueled Projects in DACs

It should be acknowledged that natural gas fueled generators over 50 MW have been permitted by the California Energy Commission (CEC) and those under 50 MW by the local governments responsible for CEQA approval. These resources also meet the stringent air quality standards promulgated by local air quality districts and the California Air Resources Board (CARB). Generators' compliance with these standards is continuously monitored. Many of these facilities are also subject to the cap-and-trade program, which directs at least 25 percent of the proceeds to DACs. IEP expects that any significant improvement, alternation, or change of operations will result in these environmental regulators imposing site-specific restrictions or mitigation requirements. This is appropriate.

The Commission, as an economic regulator, has historically avoided directly weighing in on environmental issues beyond its purview and expertise. This has included approving contracts for a solar plant facing a local land-use dispute[16] and the licensing of a natural gas plant (the Puente project)[17] leaving the environmental decisions to the appropriate environmental regulator. In the Puente case, the Commission explicitly refrained from prejudging the CEC's environmental review and approved the Puente contract, although the CEC subsequently denied the license application.

Experience has shown that virtually all generation projects, regardless of technology, attract opposition. Subjecting contract approval to environmental restrictions will invite further

[16] Resolution E-4962, pp. 2-3.
[17] D.16-05-050, pp. 18-22, 35-37. (See specifically Conclusion of Law 2, which states "The California Energy Commission has jurisdiction to review environmental issues, including issues about flooding and environmental justice in its review of the NRG Puente Project.")

environmental litigation before the Commission on issues (e.g., desert land-use, offshore fisheries, etc.) beyond its purview and expertise. The Commission should continue its prudent avoidance of not limiting approval of contracts for projects that otherwise meet California's environmental laws and regulations.

Limiting incremental gas capacity in DACs may prevent development of units necessary to serve localized reliability needs. IEP notes that nearly the entire San Joaquin Valley is a DAC and in a local reliability area. It is reasonable to plan for significant heat events in the Valley, which will increase use of air conditioning and stress the grid. Localized electricity outages impacting air conditioning will have immediate health impacts on vulnerable populations. The need for localized generation is dynamic and likely to change over time. Therefore, it would be imprudent to limit generation options that are otherwise compliant with California law.

The ALJ and Alternate PDs would respectively restrict or prohibit contracts for incremental gas-fired capacity located in DACs. In our reply comments on the Ruling, IEP provided data from the CARB showing that all sources of electricity generation, including combined heat and power (CHP), account for a range one to three percent of NOx and PM 2.5 emissions statewide or in either of the San Joaquin or South Coast air basins.[18] However, the table in IEP's reply comments includes data on combustion of biomass, coal, and refinery fuels. When limited to natural gas, the values range from only 0.5 percent to 1.4 percent.[19] Because gas-fired generation represents such a small contribution to NOx and PM 2.5 emission at both the statewide and air basin levels, prohibiting incremental gas-fired generation in DACs will have no material impact on the health of DAC residents, particularly given the small amount of incremental capacity either PD would authorize. Moreover, since DAC census tracts are located in the same air basins as non-DAC census tracts, restricting incremental gas-fired capacity to non-DAC census tracts will not necessarily protect DAC residents from the de minimis criteria pollution emissions attributable to the incremental gas-fired generation the PDs would require.

While prohibiting incremental gas-fired capacity in DACs will bestow virtually no benefit to DAC residents, it can prevent the development of high-value projects. Gas-fired facilities in certain DACs may be necessary to provide capacity that meets long-duration local

[18] IEP Reply Comments on Ruling, pp. 7-8.
[19] ARB. 2016 SIP Emission Projection Data: 2020 Estimate Average Annual Emissions. https://www.arb.ca.gov/app/emsinv/2017/emseic1p_query.php

reliability needs in addition to system reliability needs. Facilities in DACs may also be good candidates for investments in hybridization or repowering, both of which can significantly improve the emission rates of existing, older facilities. To the extent the Commission hopes to reduce emissions from gas-fired facilities in DACs, a prohibition on incremental capacity in DACs could be self-defeating. The general point the PDs make by explaining that investment in incremental capacity can facilitate the retirement of older, more polluting units also applies at the DAC level.[20] Rather than restricting or prohibiting the procurement of gas-fired capacity in DACs, IEP recommends that the Commission allow incremental capacity in DACs but impose the more straightforward obligation to demonstrate a reduction in the facilities' GHG emission rates, *if* the Commission feels such plant-level requirements are necessary.

(b) Eliminate the Categories of Fossil-Fueled Plant Modifications

Related to the above recommendation, the PDs should eliminate the categories of modifications that the PDs propose for classifying investments in incremental gas-fired capacity. There are no industry-standard definitions for these terms. They are ambiguous and will likely lead to disputes about the categories that investments fall into. For example, if an operational facility replaces some turbine blades, and that modification increases both efficiency and capacity, the project could theoretically fall into any of categories 1, 2, or 4. Simply put, these categories are not useful.

If, for some reason, the Commission believes a system of project categorization is needed, IEP suggests that the classification be based on less ambiguous project characteristics. For example, the classification could consist of three categories: 1) modification of an existing turbine, 2) installation of a new turbine, and 3) addition of storage to an existing turbine. If the Commission determines that plant-level GHG requirements are needed in addition to the cap-and-trade and LSE-specific GHG targets that gas-fired generation is already subject to, it should simply require that facilities demonstrate that the investment in incremental capacity will lower the GHG emission rate of the facility rather than tailoring different requirements to different types of investments.

[20] ALJ PD, pp. 40-41. Alternate PD, p. 41.

(c) Eliminate or Modify the Green Hydrogen Requirements

IEP is optimistic about the future role of hydrogen as a generation fuel. However, IEP opposes the green hydrogen blending requirement because the requirement is premature and supported by insufficient record evidence on the cost and technical feasibility of blending various levels of hydrogen into the fuel supply used by combustion turbines. The Commission should further develop the record before finalizing hydrogen blending requirements for any portion of the fossil-fueled capacity required or authorized by this decision.

If the Commission does require the blending of zero-emission fuels to reduce GHG emissions in this decision, the Commission should modify the PDs to allow the use of RPS-eligible biogas or blue hydrogen (i.e., hydrogen derived from natural gas for which the CO_2 has been permanently sequestered) and should clarify that the blending requirements are defined on a volumetric rather than a mass or heat content basis.

IEP also recommends that the PDs clarify that "directed" green hydrogen (and/or other zero-carbon fuels) delivered via natural gas pipelines meets the proposed requirements. Allowing green hydrogen developers to site their electrolyzers elsewhere would offer several advantages to requiring them to be collocated. First, because the hydrogen would only be nominally delivered to the gas-fired units, the units would not need potentially expensive retrofits because the units would continue to burn almost entirely natural gas. Second, allowing directed hydrogen avoids the need for expensive onsite storage. Third, electrolysis facilities could be located in areas with higher levels of solar curtailment where they could make use of solar energy that would otherwise be wasted. Fourth, separately located electrolysis facilities can serve multiple end-use customers (possibly in other end-use sectors), enabling the facilities to benefit from greater economies of scale and contracting optionality.

(d) The Commission Should Defer Some of the Diablo Canyon Replacement Capacity to 2025

As discussed above, the PDs use the term "firm" inconsistently. The fact that the definition for "firm" in Section 5.2.3 is the same as "dispatchable" in Section 5.2.1 raises a question about the interaction between LLT and Diablo Canyon procurement obligations, namely whether the procurement of dispatchable zero-emissions resources to meet the Diablo Canyon requirement counts toward meeting the LLT requirement. Presumably that is not the intent because if it were, the Diablo Canyon obligation would render the LLT firm and/or dispatchable

obligation moot. If the point of the Diablo Canyon obligation is to replace Diablo Canyon output, principally during net peak hours, the output could be replaced by either baseload or dispatchable zero-emissions resources. That being the case, IEP recommends combining the "Firm, zero-emissions resources" and "Firm and/or dispatchable zero-emitting resources" rows in Table 6 into one row of firm zero-emissions resources.

IEP also requests one revision to the schedule related to the Diablo Canyon replacement procurement. Because one unit of Diablo Canyon is retiring in 2024 and the other in 2025, the full replacement capacity is not needed in 2024. Deferring some of the firm zero-emissions capacity requirement to 2025 will give project developers more time to bring projects online that meet the availability requirements. Since each PD authorizes different amounts of fossil-fueled capacity, we include specific recommendations below regarding the timing and categories of capacity to be procured for each PD.

2. Issues Specific to the ALJ PD

(a) If the Commission Adopts the ALJ PD, 500 MW of Diablo Canyon Replacement Capacity Should Be Deferred to 2025

Table 2 shows IEP's alternative to the annual capacity obligations based on the ALJ PD. Above, we proposed deferring 1.5 GW of capacity from 2023 to 2024 to improve project feasibility and relieve pressure on offer prices. We also propose deferring 500 MW of firm zero-emitting capacity to 2025 because the entire Diablo Canyon replacement capacity is not needed in 2024. However, the need to bring substantial capacity online by 2024 and the ALJ PD's 2025 fossil procurement obligations do not allow much of the Diablo Canyon-related capacity to be deferred, but every MW that can be deferred will help the market deliver capacity at a lower cost. Note that 500 MW of the firm zero-emitting resource has been accelerated from 2026 to 2025 to reduce the projected 2025 shortfall.

Table 2. IEP Proposed Alternative to ALJ PD's Total Mid-Term Procurement Requirements (MW NQC)

Type of Resource	2023	2024	2025	2026	Total
Firm zero-emitting resource		2,000	1,000	500	3,500
Long-duration energy storage				1,000	1,000
Fossil-fueled resources			1,000 to 1,500		1,000 to 1,500
Any non-fossil fueled resource	1,500	4,000	0 to 500		5,500 to 6,000
Annual total	1,500	6,000	2,500	1,500	-
Cumulative total	1,500	7,500	10,000	11,500	-

3. Issues Specific to the Alternate PD

(a) The Commission Should Eliminate the Prohibition on Repowering at Mothballed Facilities

The Alternate PD prohibits repowering at retired or mothballed plants, whether they are located in DACs or not. The Alternate PD provides no rationale for this prohibition. If the Commission favors the Alternate PD, IEP recommends the Alternate PD be modified to allow incremental capacity at mothballed plants. IEP cannot think of a compelling reason to allow for the installation of a new turbine at a currently operational plant but prohibit installation of the same turbine at a mothballed facility in the same air basin. It is possible that some mothballed facilities are located where the incremental capacity is especially valuable for local capacity and voltage support, and this restriction would foreclose opportunities to reap the benefits of reusing these locations. IEP urges the Commission not to impose rules on procurement of incremental gas-fired capacity that are not justified by a demonstrable benefit.

(b) The Commission Should Defer Consideration of the Green Hydrogen Blending Requirement or Alternatively Reduce the Requirement, Allow Other Zero-Carbon Fuels, and Allow "Directed" Fuel Delivery

In addition to the 500 MW of incremental gas-fired capacity the Alternate PD requires, it also authorizes an additional 300 MW, but any capacity over 500 MW must commit to using a minimum of 30 percent green hydrogen by 2026 and 50 percent green hydrogen by 2031.[21] If the Commission decides to approve the gas capacity targets in the Alternate PD, IEP suggests that no

[21] Alternate PD, p. 41.

green hydrogen condition by placed on the capacity between 500 MW and 800 MW. Instead, the Alternate PD could simply require that all incremental capacity demonstrate that the investments reduce the GHG emission rate of the plant. If the Commission believes that it must prime the market for green hydrogen by imposing a mandate on gas-fired generators, the hydrogen blending requirement should be lowered substantially. Most of the gas turbines installed today cannot handle a hydrogen mix of greater than 20 percent to 30 percent by volume without major upgrades to the fuel delivery and combustion components. [22] If the Alternate PD is adopted, IEP suggests that the green hydrogen requirement be revised to mirror the more feasible and cost-effective requirement in the ALJ PD, i.e., that only 30 percent green hydrogen be required by the fifth year of operation. We also reiterate our support for allowing generators to blend other zero-carbon fuels and use directed fuels delivered by natural gas pipelines.

(c) If the Commission Adopts the Alternate PD, 1,200 MW of Diablo Canyon Replacement Capacity Should Be Deferred to 2025

Because the Alternate PD would require less procurement of fossil-fueled resources in 2025, there is more wiggle room to defer additional Diablo Canyon-related capacity (i.e., the firm zero-emissions category) to 2025. If the Commission adopts fossil-fueled procurement obligations closer to those in the Alternate PD, IEP proposes splitting the Diablo Canyon-related procurement more evenly between 2024 and 2025. Table 3 shows IEP's recommended schedule of procurement obligations based on the Alternate PD.

Table 3. IEP Proposed Alternative to the Alternate PD's Total Mid-Term Procurement Requirements (MW NQC)

Type of Resource	2023	2024	2025	2026	Total
Firm zero-emitting resource		1,300	1,700	500	3,500
Long-duration energy storage				1,000	1,000
Fossil-fueled resources			500 to 800		500 to 800
Any non-fossil fueled resource	1,500	4,700	0 to 300		6,200 to 6,500
Annual total	1,500	6,000	2,500	1,500	-
Cumulative total	1,500	7,500	10,000	11,500	-

[22] Mitsubishi Power. "The hydrogen gas turbine, successfully fired with a 30% fuel mix is a major step towards a carbon-free society." https://power.mhi.com/special/hydrogen/article_1

V. THE COMMISSION SHOULD NOT REQUIRE SUBMISSION OF FULL APPLICATIONS FOR FOSSIL-FUELED OR LONG-DURATION STORAGE PROJECTS

IEP objects to the requirement that fossil-fueled and LDES contracts be subject to a full application process. With respect to fossil-fueled resources, the PDs state that the applications need to address "the GHG, local air emissions, and disadvantaged community impacts of the procurement."[23] However, the GHG emissions are already subject to the state's cap and trade limits and the Commission's LSE-specific GHG targets. If the Commission determines that additional unit- or plant-level GHG emission rate reductions are necessary, the requisite information can be readily provided in a Tier 3 advice letter. As explained above, the criteria pollution emissions from gas-fired generation are minimal. Incremental gas-fired capacity in the range of 500 MW to 1.5 GW will have no discernible impact on air quality. Regardless, gas-fired generation facilities are already subject to the air quality regulations of the state and the regional air quality regulatory authorities.

Regarding LDES, the PDs state that "it is likely that long-duration storage projects will raise other environmental issues… and will likely represent new technologies or configurations that will require additional scrutiny and deliberation." [24] This is not a compelling rationale for requiring LDES projects to incur the additional expense, delay, and prolonged uncertainty associated with the application process. If the LDES project uses pumped storage, then the technology is well-established and any environmental impacts will have undergone extensive review under the FERC licensing process. LDES projects using less commercialized electrochemical or mechanical storage processes will, presumably, contain provisions that require the projects to meet certain performance milestones. If a project fails to meet those milestones, the procuring LSE can terminate the contract and pursue other firm resources that can be developed on shorter timelines.

[23] ALJ PD, p. 64. Alternate PD, p. 65.
[24] ALJ PD, p. 64. Alternate PD, p. 65.

VI. THE COMMISSION SHOULD NOT LIMIT CONTRACTS WITH CONVENTIONAL FOSSIL-FUELED PROJECTS TO FIVE YEARS

The Alternate PD includes a provision not found in the ALJ PD that would limit contracts with conventional fossil-fueled resources to five-year terms.[25] IEP supports the ALJ PD, which would hold all contracts to the same 10-year minimum standard.[26] The ALJ PD states:

> In order to induce developers of resources to make large capital investments and finance their projects, it is likely that at least a 10-year contract is necessary. Shorter-term contracts for new resources will likely just lead to higher annual costs, because the total costs will need to be amortized over a shorter period of time.

Five years is a very short period of time to amortize a major capital investment, particularly the installation of a new combustion turbine. Above, we noted that recent efforts to model long-term low-carbon electric sector scenarios for California have found the need to keep 25 GW or more of gas-fired capacity online through 2045-2050, capacity that is used very little but that is critical for maintaining reliability at a reasonable cost. Signing 10-year contracts in 2025 with a potential maximum 500 MW of gas-fired capacity as stipulated in the Alternate PD is only a small step toward the investments that will be necessary to replace or repower aging gas-fired units over the next 25 years.

VII. CONCLUSIONS

Both PDs take an important step toward ensuring the reliability of California's grid while continuing to make substantial progress to reducing GHG emissions. IEP supports the incremental fossil-fuel capacity required by the ALJ PD, which more closely tracks the share of capacity that long-term modeling indicates will be necessary to support reliability. Whichever PD the Commission ultimately approves, the project categorization for fossil-fueled projects should be eliminated and consideration of hydrogen blending requirements should be deferred to provide for further record development. Fuel blending requirements, if adopted, should lower costs to ratepayers by enabling project developers to use fuels other than green hydrogen and to use directed fuels rather than requiring on-site fuel use. The PDs should also be substantially revised to increase the geographic and technological flexibility afforded to fossil-fueled projects.

[25] Alternate PD, p. 70.
[26] ALJ PD, pp. 69-70.

Respectfully submitted June 10, 2021 at Berkeley, California.

By */s/ Scott Murtishaw*
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APPENDIX 1: Suggested Revisions to the ALJ PD Findings, Conclusions, and Orders

Findings of Fact

7. Requiring ~~2,500 MW~~ *at least 1,250 MW of firm, zero-emissions resources by 2024 and a total of 2,500 MW by 2025* will further ensure that there is no increase in GHG emissions as a result of the closure of Diablo Canyon.

13. Specification of long-duration storage and firm ~~(available between hours 17 and 22 daily)~~ zero-emissions resources *(a resource that emits no on-site GHGs, unless the emissions are from biomass that meets the RPS requirements, and that is capable of generating or discharging continuously at its NQC rating from 4 pm to 9 pm prevailing time, or other five-hour window during availability assessment hours if CAISO revises the availability assessment hours before the contracts are executed, on a daily basis)* as LLT by 226 will help diversify the grid resources and improve reliability and renewables integration.

New finding: *The 2021 SB 100 Joint Agency Report estimated that 25 GW or more of gas-fired capacity would be retained through 2045 to maintain reliability at a reasonable cost.*

New finding: *Electricity generation is a de minimis source of PM 2.5 and NOx emissions in California. All electricity generation in California accounts for 0.9 percent of annual PM 2.5 emissions and 3.1 percent of annual NOx emissions statewide. Gas-fired generation accounts for 0.5 percent of PM 2.5 and 1.3 percent of NOx emissions statewide. The percentages are approximately the same for the South Coast and San Joaquin air basins.*

New finding: *There is very little record in R.20-05-003 on the costs and technical feasibility of blending green hydrogen in gas-fired turbines.*

Conclusions of Law

4. ~~The Commission should adopt the 38 MMT GHG limit for 2030 when considering the aggregated IRPs of all LSEs when we consider the PSP later this year as long as the resource mix results in a reliable system with a 0.1 LOLE or less.~~ [This conclusion should be struck because it is not supported by the record and prejudges a future Commission decision before the Energy Division's PSP report has even been released.]

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

9. The Commission should require the procurement, in aggregate, of at least 1,000 MW of firm ~~(at least 85 percent capacity factor) and/or dispatchable (between hours 17 and 22 daily)~~ *zero-emissions* resources*, as defined in finding of fact 13,* ~~that have zero or de minimis emissions~~ by 2026, with the option of an extension to 2028 for compliance, if good cause and a good faith effort to procure are shown.

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

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

New conclusion: *The Commission should further develop the record on the cost and technical feasibility of blending hydrogen with natural gas in gas-fired turbines before finalizing requirements to blend green hydrogen or other zero-carbon fuels for any portion of the incremental fossil-fueled capacity required by this decision.*

17. To ensure no ambiguity about the emissions profile of replacement capacity for Diablo Canyon, the Commission should require that a minimum of 2,500 MW of incremental NQC be from firm, zero-~~emitting~~*emissions* resources, *as defined in finding of fact 13,* ~~that are available every day between hours 17 and 22, and can deliver 5 MWh of energy during each of those periods for every MW of incremental capacity used~~ to comply with the requirements of this order.

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

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

ORDER

1. Procurement of 11,500 megawatts (MW) of incremental net qualifying capacity shall be conducted over the course of four years, with ~~3,000~~ *1,500* MW online by August 1, 2023, an

additional ~~4,500~~ *6,000* MW online by June 1, 2024, and additional ~~2,000~~ *2,500* MW online by June 1, 2025, and an additional ~~2,000~~ *1,500* MW online by June 1, 2026.

2. Long lead-time resources required by this order shall be defined as at least 1,000 megawatts (MW) of long-duration storage (able to deliver *continuously at net qualifying capacity rating* for ~~a~~ *at* least eight hours) and at least 1,000 MW of firm ~~(at least 85 percent capacity factor) and/or dispatchable (between at least hours 17 and 22 daily)~~ zero-emissions resources*, as defined in finding of fact 13,* by June 1, 2026.

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

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

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

~~(c) If a project is in Category 1 (efficiency improvements), it must include a contractual commitment to use at least 30 percent green hydrogen by the fifth year of operation.~~

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

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

[Given the de minimis impact of gas-fired generation on air quality, there is no reason to impose additional requirements on gas-fired generation based on its location. These requirements should either be struck entirely, or, alternatively, replaced with a more straightforward and consistent requirement to demonstrate a reduction in the GHG emissions rate of the facility.]

6. Collectively, to ensure that the capacity retiring at the Diablo Canyon Power Plant is replaced entirely with firm zero-~~emitting~~*emissions* resources, the load-serving entities shall collectively procure a minimum of 2,500 megawatts (MW) of incremental, firm zero-~~emitting~~*emissions* capacity*, as defined in finding of fact 13,* out of the total 11,500 MW required in this decision. ~~This firm, zero-emitting capacity shall have the following characteristics:~~

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

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

7. Requiring ~~2,500 MW~~ *at least 1,250 MW of firm, zero-emissions resources by 2024 and a total of 2,500 MW by 2025* will further ensure that there is no increase in GHG emissions as a result of the closure of Diablo Canyon.

13. Specification of long-duration storage and firm ~~(available between hours 17 and 22 daily)~~ zero-emissions resources *(a resource that emits no on-site GHGs, unless the emissions are from biomass that meets the RPS requirements, and that is capable of generating or discharging continuously at its NQC rating from 4 pm to 9 pm prevailing time, or other five-hour window during availability assessment hours if CAISO revises the availability assessment hours before the contracts are executed, on a daily basis)* as LLT by 226 will help diversify the grid resources and improve reliability and renewables integration.

New finding: *The 2021 SB 100 Joint Agency Report estimated that 25 GW or more of gas-fired capacity would be retained through 2045 to maintain reliability at a reasonable cost.*

New finding: *Electricity generation is a de minimis source of PM 2.5 and NOx emissions in California. All electricity generation in California accounts for 0.9 percent of annual PM 2.5 emissions and 3.1 percent of annual NOx emissions statewide. Gas-fired generation accounts for 0.5 percent of PM 2.5 and 1.3 percent of NOx emissions statewide. The percentages are approximately the same for the South Coast and San Joaquin air basins.*

New finding: *There is very little record in R.20-05-003 on the costs and technical feasibility of blending green hydrogen in gas-fired turbines.*

~~17. Fossil-fueled electricity generators located in disadvantaged communities contribute to the high pollutant burden in those communities.~~

19. A fossil-fueled resource using at least a 30 percent green hydrogen blend reduces GHG emissions from the facility and will help accelerate conversion of fossil-fueled electricity generation to a GHG free fuel.

Conclusions of Law

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

is not supported by the record and prejudges a future Commission decision before the Energy Division's PSP report has even been released.]

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

9. The Commission should require the procurement, in aggregate, of at least 1,000 MW of firm ~~(at least 85 percent capacity factor) and/or dispatchable (between hours 17 and 22 daily)~~ *zero-emissions* resources*, as defined in finding of fact 13,* ~~that have zero or de minimis emissions~~ by 2026, with the option of an extension to 2028 for compliance, if good cause and a good faith effort to procure are shown.

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

New conclusion: *The Commission should further develop the record on the cost and technical feasibility of blending hydrogen with natural gas in gas-fired turbines before finalizing requirements to blend green hydrogen or other zero-carbon fuels for any portion of the incremental fossil-fueled capacity required by this decision.*

~~15. The Commission should not authorize in this decision procurement from any incremental natural gas generation or green hydrogen/fossil fueled generation that are [sic] located in disadvantaged communities.~~

17. To ensure no ambiguity about the emissions profile of replacement capacity for Diablo Canyon, the Commission should require that a minimum of 2,500 MW of incremental NQC be from firm, zero-~~emitting~~*emissions* resources, *as defined in finding of fact 13,* ~~that are available every day between hours 17 and 22, and can deliver 5 MWh of energy during each of those periods for every MW of incremental capacity used~~ to comply with the requirements of this order.

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

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

ORDER

1. Procurement of 11,500 megawatts (MW) of incremental net qualifying capacity shall be conducted over the course of four years, with ~~3,000~~ *1,500* MW online by August 1, 2023, an additional ~~4,500~~ *6,000* MW online by June 1, 2024, and additional ~~2,000~~ *2,500* MW online by June 1, 2025, and an additional ~~2,000~~ *1,500* MW online by June 1, 2026.

2. Long lead-time resources required by this order shall be defined as at least 1,000 megawatts (MW) of long-duration storage (able to deliver *continuously at net qualifying capacity rating* for ~~a~~ *at* least eight hours) and at least 1,000 MW of firm ~~(at least 85 percent capacity factor) and/or dispatchable (between at least hours 17 and 22 daily)~~ zero-emissions resources*, as defined in finding of fact 13,* by June 1, 2026.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall procure the amounts of natural gas net qualifying capacity given in Table 5 of this decision, ~~500 megawatts (MW)~~ *collectively the range of a minimum 1,000 megawatts (MW) and maximum 1,500 MW*, by no later than 2025, as a portion of their overall procurement required by this decision in Table 7. The natural gas capacity costs shall be allocated to all benefitting customers in each service territory using the cost allocation mechanism established by the Commission for purposes of allocating the costs of resources needed for reliability and renewables integration purposes.

~~(a) The authorized natural gas capacity shall not be located in a disadvantaged community, as defined by being in the top 25 percent of communities with the highest environmental burden, as given in the most recent version of the CalEnviroScreen tool maintained by the Office of Environmental Health Hazard Assessment.~~

~~(b) Contracts for the required natural gas capacity may not exceed five years in length.~~

~~6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company are authorized to procure the amounts of green hydrogen and fossil-fueled net qualifying capacity given in Table 5 of this decision, collectively 300 megawatts, by no later~~

~~than 2025, as a portion of their overall procurement required by this decision in Table 7. If procured, the costs shall be allocated to all benefitting customers in each service territory using the cost allocation mechanism established by the Commission for purposes of allocating the costs of resources needed for reliability and renewables integration purposes.~~

~~(a) The authorized green hydrogen and fossil-fueled capacity shall not be located in a disadvantaged community, as defined by being in the top 25 percent of communities with the highest environmental burden, as given in the most recent version of the CalEnviroScreen tool maintained by the California Office of Environmental Health Hazard Assessment.~~

~~(b) Green hydrogen and fossil-fueled projects must commit to using at least a 30 percent green hydrogen blend as its fuel by 2026, and 50 percent by 2031.~~

~~(c) IOUs may request a one-year extension to the 2025 procurement deadline to 2026.~~

7. Collectively, to ensure that the capacity retiring at the Diablo Canyon Power Plant is replaced entirely with firm zero-~~emitting~~*emissions* resources, the load-serving entities shall collectively procure a minimum of 2,500 megawatts (MW) of incremental, firm zero-~~emitting~~*emissions* capacity*, as defined in finding of fact 13,* out of the total 11,500 MW required in this decision. ~~This firm, zero-emitting capacity shall have the following characteristics:~~

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

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