BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long -Term Procurement Plans	Rulemaking 12-03-014 (Filed March 22, 2012)

PETITION FOR MODIFICATION OF DECISION 14-03-004

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Pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure, the Protect Our Communities Foundation ("POC") hereby submits the following Petition For Modification of Decision 14-03-004.

Concurrently with this Petition for Modification, POC has filed a Motion to set the issuance date for D.14-03-004 as April 24, 2014. POC is prepared to withdraw this Petition for Modification if POC's Motion is granted and the Commission considers the Application for Rehearing attached to POC's Motion as timely filed.

I. LEGAL STANDARD

A party may file a PFM to request changes to an issued Commission decision. Under Rule 16.4(b), PFMs shall "concisely state the justification for the requested relief." Rule 16.4(d) requires an explanation of timing for any PFM filed more than one year after the effective date of the Commission's decision. In the following sections POC explains the need for the requested relief. A PFM "must propose specific wording to carry out all requested modifications to the decision." Rule 16.4(b). POC proposes changes to the findings of fact, conclusions of law, and ordering paragraphs in D.14-03-004 as set forth in below.

II. THE DECISION DISCOUNTS UNCOMMITTED ENERGY EFFICIENCY BASED ON AN ERROR OF FACT

In calculating the LCR for the SONGS area, the Decision fails to to account for 576 MW of "naturally occurring" Energy Efficiency savings identified by the Natural Resources Defense Counsel and the Sierra Club. The Decision declines to count this resource, in part, based on the claim that the naturally occurring EE identified by NRDC and the Sierra Club was "based on a CEC staff draft forecast of uncommitted energy efficiency that came out in September 2013." Based, in part, on this conclusion, the Decision reached Finding of Fact 49, which states, in part: "Potential amounts of… energy efficiency… cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."

The Decision's claim that this 576 MW of naturally occurring EE was based on a draft report is a factual error. The 576 MW of 'naturally occurring' savings do not, as the PD suggests, come from the September 2013 CEC draft forecast. Rather, they come from the CEC's Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022, a final report issued in September of 2012.

To correct this factual error, the Commission should modify Finding of Fact 49 to read as follows:

49. 576 MW of naturally occurring Energy Efficiency is very likely or to be in place and available to meet the SONGS area LCR by 2022.

III. THE DECISION'S ISSUANCE DATE SHOULD BE ESTABLISHED AS APRIL 24, 2014

POC is a small public interest organization based in San Diego, California.[1] Because of the significant cost and burden of traveling to the Commission in San Francisco, POC practices before the Commission by electronic means as much as possible, and is not often physically present at the Commission.[2] POC instead relies on the Commission's service of its Decisions for notification as to when a Decision has been issued.[3]

[1] Attachment A (Peffer Declaration) at p. 1, Para 1
[2] Id. at p. 1, Para. 1
[3] Id. at p. 2, Para. 4

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POC has been an active party in Track 4 of R.12-03-014, and has participated in all aspects of the proceeding, including submitting comments on the Proposed Decision.[4] Although the Final Decision in Track 4 (D.14-03-004) is date-stamped March 14, 2014, POC was not provided with any form of notification of the Decision after the decision was voted on.[5] POC did not become aware of the Decision until April 22, 2014.[6] POC did not receive any form of notification of the Decision from the Commission until April 24, 2014.[7]

Public Utilities Code Section 1731(b)(2) requires that the Commission notify the parties to a proceeding when a Decision in that proceeding is issued. This section further requires that the Commission provide this notice in one of three ways:

> (A) By mailing the order or decision to the parties to the action or proceeding;
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> (B) By emailing an electronic copy of the official version of the order or decision to the party;
>
> (C) Or by emailing a link to an Internet Web site where the official version of the order or decision is readily available to the party.

POC did not receive notice of the Decision as required by Section 1731(b)(2) until April 24, 2014.[8] Prior to that date, POC had not received notice of the decision in the form of a hard copy of the Decision sent by mail as provided by Section 1731(b)(2)(A).[9] POC also did not receive notice of the Decision by email containing a full electronic copy of the Decision as provided by Section 1731(b)(2)(B);[10] nor did POC receive notice of the Decision by an email containing a link to the Decision as provided by Section 1731(b)(2)(C).[11] POC has also not received non-statutory notification of the decision from the Commission in the form of a "Notice of Availability" mailing.[12]

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[4] Id. at p. 1, Para. 2

[5] Id. at p. 2, Para. 6

[6] Id. at p. 3, Para. 10

[7] Id. at p. 2, Para. 6

[8] Id. at p. 2, Para. 6

[9] Id. [illegible] Para. 6

[10] Id. at p. 2, Para. 7

[11] Id. at p. 2, Para. 8

[12] Id. at p. 3, Para. 9

POC believes that the Commission inadvertently failed to provide official service of the Decision to the parties. POC discovered by happenstance on April 22nd that Decision had been voted on at the Commission's March 13, 2014 meeting and that the Decision had been date-stamped as issued on March 14, 2014. On April 23rd POC sent an email to the Legal Support Supervisor for the ALJ Division (Star Unit) who had previously served D.14-02-040 to the service list for R.12-03-014, informing her that POC had not received official e-mail service of D.14-03-004 and asking when POC should expect service.[13] On April 24th POC received an email from the Commission containing a link to D.14-03-004 with no other information as to whether service had been effected.[14] This email link was the first, and only, service of the Decision that POC has received from the Commission.

On April 25, 2014, in response to POC's repeated requests for a copy of any official service email for D.14-03-004, POC received an email from an ALJ Star Division Supervisor stating that she "did not have any luck" in finding the email providing notice of D.14-03-004 to the service list.[15] POC has subsequently confirmed that at least four other parties to R.12-03-014 – Sierra Club, California Environmental Justice Alliance, TURN, and the Office of Ratepayer Advocates –were unable to locate any record of having received an email providing official service of D.14-03-004.[16]

Public Utilities Code Section 1731(b)(3) defines "date of issuance" as follows: "For the purposes of this article, "date of issuance" means *the mailing or electronic transmission date* that is stamped on the official version of the order or decision." (*Emphasis added*). The use of the phrase "for the purposes of this article" makes clear that Section 1731(b)(3) is intended to be read in the context of the other provisions of the article. Read in the context of the Section 1731(b)(2) requirement that official notice be provided to the parties in the form of mailing pursuant to Section 1731(b)(2)(A), or electronic transmission pursuant to Sections 1731(b)(2)(B) and 1731(b)(2)(C), it is clear that Section the "mailing or electronic date" referenced in Section 1731(b)(3) refers to the date that the Decision is mailed or electronically transmitted to the parties in conformity with Section 1731(b)(2). To interpret it otherwise would defeat the clear intent and the language of the service and date of issuance statutes, when read in harmony. It is

[13] at p. 3, Para. 11
[14] at p. 3, Para. 12
[15] at p. 3, Para. 13
[16] at p. 3-4, Para. 15

in the public interest and consistent with the intent and language of Section 1731 to modify the decision set the issuance date of D.14-03-004 as April 24th, the date that POC was served with notice of the Final Decision by the Commission.

If POC had received service of D.14-03-004 on March 14, 2014, POC would have filed an Application for Rehearing that would have tracked the bases for modification set forth in Sections IV - IX, as follows.

IV. THE DECISION ERRS IN USING AN UNSUPPORTED AND ARBITRARY APPROACH TO DISCOUNT PREFERRED RESOURCES IN DETERMINING LCR NEED AND AS SUCH MUST BE MODIFIED

A. More Than Sufficient Non-Fossil Fuel Resources Are Available to Meet the Identified Need, But The Decision Largely Discounts These Resources Based on Arbitrary and Unsupported Methodologies.

California statutes and Commission policy prioritize the use of clean, non-fossil fuel "preferred resources" to meet new electricity demand. As the Decision recognizes:

> The Commission . . . has a statutory mandate to implement procurement-related policies to protect the environment. Section 454.5(b)(9)(C)[17] states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Consistent with this code section, the Commission has held that all utility procurement must be consistent with the Commission's established Loading Order, or prioritization.[18]
>
> Preferred Resources are defined in the State's Energy Action Plan II, at 2, as follows: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation . . . in this decision, we also include Energy Storage in the category of Preferred Resources for ease of use unless otherwise noted.[19]

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[17] Unless otherwise noted, all further statutory references in this Application for Rehearing are to the Public Utilities Code.

[18] Decision, pp. 13-14.

[19] Decision, p. 6, fn. 3 and Conclusion of Law 3, p. 135: "The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, and presented in the Energy Action Plan II adopted by this Commission and the CEC in October 2005, established that the State, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."

> Once procurement targets are achieved for preferred resources, the IOUs [Investor Owned Utilities] are not relieved of their duty to follow the Loading Order. In D.07-12-052 at 12, the Commission stated that once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing.[20]

In this proceeding, parties identified several non-fossil fuel resources that were not included in CAISO's modeling of LCR resources. These resources are listed in Table 1:[21]

Table 1. Resources Not Included in CAISO Modeling

	Impact On Need
Temporary Load-Shedding	- 588 MW
Mesa-Loop in Transmission Project	- 734 MW
Uncommitted Energy Efficiency (EE)	- 733 MW
Energy Storage	- 745 MW
Second contingency Solar PV	- 800 MW
Second contingency Demand Response (DR)	- 997 MW

If fully accounted for, these non-fossil fuel resources would provide a total of 4,597 MW, which is far more capacity than the 2,390 MW need identified by CAISO's modeling and accepted by the Decision.[22]

The parties offered credible and substantial evidence that these preferred resources will be in place at or near the quantities identified in Table 1 by 2022. However, the Decision largely discounts these resources, finding that they are not "very likely" to be available by 2022, and thus cannot be counted toward meeting LCR need, based on arbitrary conditions that have no basis in the law or the record and no effect on these resources' ability to meet the LCR need on a megawatt-to-megawatt basis. For example, the Decision requires that, to be counted, DR must be dispatchable within 30 minutes, and the exact location(s) of solar PV PV within the LCR area must be identifiable. Applying these arbitrary requirements with no basis in the evidentiary record and, in the case of energy storage, based simply on an ill-defined unease with the technology in general, the Decision assures that the preferred resources largely fail the "very likely" test.[23] Using this approach, the Decision qualitatively distinguishes between those

[20] Decision, p. 14.
[21] Decision, Table 2, at p. 73
[22] Decision, p. 76.
[23] D.14-03-014, Finding of Fact 62, at p. 130. The highest reasonable LCR need level must take into account those resources which are very likely to be procured in thetime frame between now and 2022.

resources that are "reasonably possible" to be in place, and those that are "very likely." Only those resources which the Commission deems "very likely" to be in place by 2022 are counted. The Decision applies this methodology to each preferred resource, and without record support finds that each preferred resource in the quantities listed in Table 1 fails to meet the "very likely" threshold.

In an alternative methodology, the Decision acknowledges that collectively *some* of these preferred resources may be in place by 2022. To account for this possibility, the Decision adds together all of the resources in Table 1, rounds the total up from 4,597 MW to 4,600 MW, and discounts this total by assuming *only one* of the resources listed in Table 1 will be developed. Using this approach, only 13 to 22 percent of the 4,600 MW in Table 1 is counted in the Decision toward meeting the LCR need.[24] Paradoxically, the Decision assumes *any one* of the preferred resources will be available megawatt-for-megawatt to reduce LCR need (i.e., be 100 percent available), but then only counts one of the resources, either DR or EE or solar PV or energy storage, ignoring the rest.

Both of the Decision's methodologies are deeply flawed. The Decision provides no support for its adoption and application of the "very likely" test. The test has no basis in statute, and the Decision provides no legal citations supporting the test. The Decision does not support this test by citation to any prior Commission decision, and POC is unaware of any prior Commission Decision where this test was adopted or applied. The test was not used in resolving the Track 1 authorization of the instant proceeding, which addressed the same resources: solar PV, demand response, EE, and energy storage.[25]

The Decision's alternative methodology collectively discounting the resources in Table 1 is equally unreasonable, arbitrary, and lacking evidentiary support in the record of this proceeding. Findings of Fact 66-73 in the Decision[26] are proffered to support the position of the Decision that, despite controlling statutes[27] prioritizing preferred resources over all other resource types, preferred resources are largely unavailable to meet the identified LCR need. The net effect of these findings of fact, none of which has an evidentiary basis in the record, is to moderately trim the procurement authorizations recommended by CAISO, instead of discarding

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[24] Decision, Finding of Fact 67, p. 131.
[25] D.13-02-015켐□η
[26] Decision, p. 131.
[27] Public Utilities Code Section 454.5(b)(9)(C), 2827(c)(4)(B), 2836(a), and 2837

them altogether by validating the uncontested record evidence that available preferred resources can entirely meet the identified LCR need.[28]

The Decision presents its case for largely discounting the role of preferred resources to meet the LCR need based on no substantial evidence and unsupported qualitative judgments. The discounting methodologies applied in the Decision lack any basis in law and are not supported by the evidentiary record. By discounting thousands of MW of preferred resources and by authorizing utility procurement based on an LCR determination driven, in part, by adoption of arbitrary methodologies without any basis in law, the evidentiary record, or prior Commission practice, the Commission has failed to prioritize preferred resources, energy efficiency, and demand response over gas-powered procurement in violation of Section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. Further, the Commission has failed to ensure just and reasonable rates in violation of Sections 451 and 454, instead ensuring that ratepayers will now pay a second time for duplicate resources that will already be in place to meet the LCR need. As such, the Commission has failed to proceed as required by law, made findings unsupported by substantial evidence in the record, and abused its discretion, all in violation of section 1757(a). 펨□η

B. The Decision Improperly Fails to Count 997 MW of Available Demand Response.

The Decision makes the following finding of fact concerning the availability of demand response (DR) resources:

> "Potential amounts of demand response. . . cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[29]

This finding is not supported by substantial evidence in the record and is contrary to law.

The Decision's treatment of DR resources in SCE's LA Basin and SDG&E territory is driven by an arbitrary distinction between "first contingency" DR, defined as DR that can be

[28] The Decision, in Finding of Fact 49, states that the energy storage targets adopted in D.13 -10-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis, and that potential amounts of demand response, energy efficiency or solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis. Finding of Fact 49 is unsupported in the evidentiary record of this proceeding. The record contradicts this finding of fact for each of the preferred resources listed: demand response, energy efficiency, solar PV resources, and energy storage, as explained in the following sections. Thus, Finding of Fact 49 violates Sect. 1757.펨□η

[29] Decision, Finding of Fact 49, at p. 129.

called upon within 30 minutes, and "second contingency" resources. With no substantial evidence to make such a distinction in the definition of available resources, the Decision excludes 997 MW of DR. The Decision simply accepts CAISO's characterization of LCR capacity. Neither the Commission nor CAISO has ever defined LCR requirements for DR, much less defined them in such restrictive terms.[30] The distinction between first contingency and second contingency DR is arbitrary, given a primary purpose of DR is to reduce peak demand and it is reasonable to assume that SCE and SDG&E would be scheduling dispatch of all available DR to reduce peak load on a forecast 1-in-10 year weather event day. CAISO witness Millar testified that a slow-firing gas generation plant (such as a coastal OTC boiler plant) is considered a first-contingency resource despite requiring more than 30 minutes to call up, noting that in high load periods (such as the 1-in-10-year peak weather event modeled in this proceeding) CAISO would be able to commit the plant in advance. He admitted that the same could be true of DR programs.[31] Thus, whether a DR resource is a "first contingency" resource or a "second contingency" resource is an arbitrary distinction from the standpoint of the DR being available to reduce LCR need under an N-1-1 contingency.

EnerNOC introduced evidence that no other Independent System Operator (ISO) or Regional Transmission Operator (RTO) requires demand response resources to be dispatched within 30 minutes in order to qualify as a local capacity resource. Instead, to qualify, these DR resources simply need to be located in the local area and dispatched as instructed by the ISO or RTO.[32] These EnerNOC statements were not contested. EnerNOC also questioned CAISO on the basis for discounting DR, for which the CAISO witness had no answer:[33]

> Q Has the CAISO or the Commission adopted a definition for DR resources qualifying as a local capacity resource, eligibility criteria, if you will?
> A We are -- well, one of the things I left out in my description of the ISO, current ISO planning process and the status of it which is a glaring omission is that we were also working on identifying the necessary characteristics of preferred resources such as demand response such that it can meet local needs.
> Q And that hasn't happened yet; is that correct?
> A It's in the process.

[30] The Track 1 Decision (D.13-02-015) left the definition of local capacity resource attributes to SCE and the CAISO to develop. Today, there is no adopted definition of the requirements DR resources would need to meet in order to satisfy the LCR. EnerNOC, Inc. Prepared Testimony of Mona Tierney-Lloyd at p. 11.
[31] RT at 1692 (CAISO, Millar).
[32] EnerNOC Opening Brief, p. 16.
[33] Sparks hearing transcript, p. 1553: (response to EnerNOC on failure to define DR resources)

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. By failing to account for 997 MW of DR based on an arbitrary distinction, and by authorizing utility procurement based on an LCR determination inflated, in part, by this failure, the Commission has failed to prioritize demand response over gas-powered procurement in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to proceed in the manner required by law in violation of section 1757(a)(2). Further, by adopting an arbitrary distinction for DR despite the strong evidence against it, including CAISO's own admissions, and the lack of evidence establishing that the distinction is valid or reasonable, the Decision has failed to support its findings with substantial evidence in violation of section 1757(a)(4) and abused its discretion in violation of section 1757(a)(5).

C. The Decision Improperly Fails to Count 773 MW of Highly Likely Energy Efficiency Savings.

The Decision makes the following finding of fact concerning the availability of energy efficiency resources:

> "Potential amounts of . . . energy efficiency . . . resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[34]

This finding is not supported by substantial evidence in the record and is contrary to law.

In calculating the LCR for the SONGS area, the Decision fails to include 733 MW of highly likely energy efficiency savings that were omitted from CAISO assumptions.[35] The 733 MW of energy efficiency (EE) at issue falls into two groups: (1) 576 MW of "naturally occurring" EE savings, i.e., EE savings that are expected to occur regardless of any program or policy,[36] and (2) 157 MW of EE savings from California Energy Commission (CEC) building efficiency standards set to take effect in 2017 and 2020, as well as other State and Federal EE codes and standards that will produce savings beginning in 2015.[37]

[34] Decision, Finding of Fact 49, at p. 129.
[35] CEJA Opening Brief, at p. 22; NRDC Opening Brief, at p. 5.
[36] Ex. NRDC-1 (Martinez Opening Testimony), at p. 10.
[37] CEJA Opening Brief, at pp. 23-24; NRDC Opening Brief, at pp. 5-7.

The Decision rejects the 576 MW of "naturally occurring" EE savings on two grounds, both relating to the feasibility and availability of these EE resources. First, the Decision claims that uncommitted EE values were based on a "draft" CEC staff forecast that was "not final."[38] This is a factual error, as "the 576 MW of 'naturally occurring' savings do not, as the Decision states, come from the September 2013 CEC draft forecast. Rather, they come from the CEC's *Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022*, a final report issued in September of 2012."[39]

Second, the Decision claims the LCR impact of uncommitted EE is too uncertain because "there is nothing in the record to show how or whether any such updates might impact LCR needs."[40] This is also in error. The Natural Resources Defense Council (NRDC) provided testimony indicating that the naturally occurring savings detailed in the report "yields 576 MW of additional local impacts from energy efficiency in the SONGS study area (LA Basin and SDG&E territory)."[41] NRDC's witness, Sierra Martinez, testified that NRDC did not merely assume a megawatt-for-megawatt impact on LCR need. Rather, NRDC calculated LCR reduction by utilizing the same methodology used in the Revised Scoping Memo and the busbar allocation methodology of the Energy Commission.[42] This testimony was uncontradicted. Thus, the evidence in the record shows that 576 MW of naturally occurring energy efficiency is very likely to reduce LCR need in the SONGS study area and should therefore be count to reduce overall procurement. The Commission erred in failing to take this available energy efficiency resource into account when it determined need.

The Decision similarly erred in failing to count the 157 MW of EE from new State and Federal Codes. First, while the calculation of EE based on new but already passed legislation was, unlike the "naturally occurring" calculation, based on a draft forecast, the Commission has not been hesitant to use such forecasts in the past.[43] The Commission cannot ignore its own past practice and evidence in the record regarding known efficiency codes and standards with an

[38] Decision, p. 35-36
[39] Ex. NRDC-1 (Martinez Opening Testimony), at p. 10
[40] Decision at p. 36
[41] *Ibid.* , at p. 11
[42] RT 2191-92 (Martinez, NRDC).
[43] D.07-12-052 (2006 LTPP), the Commission approved the use of a draft demand forecast even though it had previously ordered the use of an older one in its Scoping Memo. See also D.13-02-015, at p. 49. ("We find that amounts of uncommitted energy efficiency in programs and standards already approved by this Commission and other agencies, but not yet in the demand forecast used by the ISO, should result in adjustments to demand forecasts for the purpose of authorizing LCR procurement levels.")

identifiable local impact. Second, regarding the claim that "there is nothing in the record to show how or whether any such updates might impact LCR needs," the 157 MW identified by CEJA and NRDC is adjusted for LCR impact.[44]

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. Neither the Commission nor any party raised challenges to the cost effectiveness or reliability of either of the uncommitted EE resources at issue in this proceeding. In light of the clear evidence establishing these EE resources are "very likely" to be available to meet LCR, and the lack of any questions regarding the cost effectiveness and reliability of EE, the Decision's failure to count the full 733 MW of EE is incompatible with section 454.5(b)(9)(C), which requires that an electrical corporation "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." By dismissing 733 MW of EE, the Commission has adopted a position contrary to this requirement, as well as the State's Energy Action Plan and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454, As such, the Commission has failed to proceed as required by law in violation of section 1757(a)(2). Further, by discounting 733 MW of EE despite the uncontradicted evidence in the record establishing the availability of this preferred resource to reduce need, the Commission has made findings that are unsupported by substantial evidence in the record and abused its discretion in violation of section 1757(a)(4) and (5).

D. The Decision Fails to Count At Least 770MW of Solar PV That Will Be Available to Meet LCR Need

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The Decision makes the following findings of fact concerning the availability hundreds of MW of local solar resources:

쩸□η "Potential amounts of . . . solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[45]

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쩸□η "Consistent with the revised Scoping Memo, the ISO correctly designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built."[46]

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[44] CEJA Opening Brief, at p. 23; Ex. NRDC-1 (Martinez Opening Testimony), at p. 5, Table 1.쩸□η

[45] Decision, Finding of Fact 49, at p. 129.

[46] Decision, Finding of Fact 54, at p. 129.

> "It is likely that Commission programs and the marketplace will increase the amount of solar PV in the future. However, there is no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs."[47]

These findings are not supported by substantial evidence in the record and are contrary to law.

1. Location of Solar PV in the LCR Area Does Not Affect LCR Benefit

The location of solar PV matters only to the extent that the solar PV is located either in the LA Basin or SDG&E territory. The Commission recognizes that all solar PV resources will be "on" at the LCR peak condition at the capacity factor of 0.45 or 0.46.[48] The Decision's use of these factors is already a substantial discount relative to the 0.55 capacity factor assumption specified in Track 2 of this proceeding.[49] There is no uncertainty about the output of solar PV at times of peak demand. Nonetheless, the decision ignores these solar resources on the grounds that it is not possible to identify in advance what will be the exact location(s) of solar PV within the LCR area.[50]

Statements in the Decision that the imprecise future location of solar PV within the LCR area is a basis for discounting its LCR value, and that the output at peak demand of this solar PV is uncertain, are unsupported by the record.[51] No record evidence exists in this proceeding upon which the Commission can support its determination that solar PV does not reduce LCR need. No factual support is provided in the Decision for ignoring the 278 MW of additional solar PV (by 2022) that the Commission admits will occur, simply because its location is not precisely known within the LCR area.

By failing to account for 278 MW of solar PV that the Decision admits is likely to be available by 2022, and by authorizing procurement based on an LCR determination inflated, in part, by this failure, the Commission has failed to prioritize solar energy over gas-powered procurement in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to

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[47] Decision, Finding of Fact 55, at p. 129.
[48] Revised Scoping Memo, Attachment A, p. 9.
[49] D.12-12-010, pdf p. 76. IV. Other Assumptions Common To All Scenarios, 0.55 = incremental small PV conversion factor for installed capacity to peak production MW (decimal).
[50] Decision, Finding of Fact 54, at p. 129.
[51] Decision, pp. 63-64.

proceed in the manner required by law in violation of section 1757(a)(2). Further, by ignoring record evidence of the likely availability of 278 MW of solar PV based on the irrelevant fact that it is unknown precisely where in the LCR area these resources will be located, the Decision has failed to support its findings with substantial evidence in violation of section 1757(a)(4) and abused its discretion in violation of section 1757(a)(5).

2. AB 327, Codified as Public Utilities Code Section 2827, Has Greatly Increased the Amount of Solar PV that Will Be Added By 2018 but the Decision Improperly Ignores This Additional Solar Resource.

The Commission assumes that California's investor-owned utilities (IOUs) are in the process of meeting the California Solar Initiative (CSI) solar PV targets.[52] The IOUs are to have 1,940 MW online by December 2016.[53] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as "net-metered" solar.

The IOUs' net-metered solar targets increased dramatically with AB 327[54] in October 2013, which enacted Public Utilities Code Section 2827(c)(4)(B) and, established minimum statutory net-metering rooftop solar targets to be met by the IOUs by mid-2017. AB 327 established a statutory mandate to add up to 5,256 MW of solar energy resources in California. This is a 3,316 MW increase over the 1,940 MW target established for the IOUs by the Commission in D.06-12-033. The IOUs are required by Section 2827(c)(4)(C) to report on a monthly basis their progress in meeting the new minimum solar PV targets by mid-2017. Therefore, at a minimum, the IOUs by law will add 3,316 MW of additional net-metered solar by mid-2017.

In this proceeding, the Commission assumed that only 1,011 MW of additional solar PV would be added by 2018 and 1,300 MW by 2022 in the entire CAISO control area, which includes PG&E, SCE and SDG&E.[55] The Commission's 2018 additional solar PV assumption is only one-third of the additional solar PV that is required by section 2827(c)(4)(B), and therefore only one-third of the solar capacity that is very likely or certain to be added by mid-2017. The

[52] Revised Scoping Memo, Attachment A, p. 8.
[53] Decision 06-12-033, *Opinion Modifying Decision 06-01-024 and Decision 06-08-028 In Response to Senate Bill 1*, December 14, 2006, p. 36. Finding of Fact 15: The Commission's ("The Commission" is equivalent to "the IOUs" in this context) 65% share of the 3,000 MW statewide goal is 1,940 MW, and 1,750 MW for the mainstream solar incentive program.
[54] Assembly Bill No. 327 (Cal. 2013)켑□η
[55] *Ibid.*, Attachment A, p. 9.

Commission's 2022 assumption is only about 40 percent of the solar PV that is required by statute and thus is very likely or certain to be added by mid-2017.

At a minimum, as a result of current statutory requirements, 2,305 MW of additional solar PV capacity will be added by California's IOUs by mid-2017 beyond the 1,011 MW that the Commission counts as available.[56] Of this 2,305 MW of additional solar PV capacity, 866 MW will be located in SCE's LA Basin and 221 MW will be located in SDG&E territory.[57] Of this amount, about 492 MW will be available on peak to meet LCR need in addition to the 278 MW of peak solar PV in 2022 assumed in the Decision.[58] All of this required 770 MW of peak solar PV capacity, that will be meeting LCR need, is ignored by the Decision.

Findings of Fact 49, 54, and 55 are not supported by substantial evidence and are arbitrary and capricious. By ignoring all additional solar PV capacity when assessing LCR need, the Decision has failed to proceed as required by Section 454.5(b)(9)(C), mandating that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Solar PV is a renewable energy resource that reduces demand at the source, consistent with Section 454.5(b)(9)(C).

The Decision has also failed to proceed as required by Section 2827(c)(4)(B), which establishes explicit capacity targets for solar PV in IOU service territories. The solar PV targets are established by state law. The Commission cannot presume that the law will not be followed and that the solar PV resource will play no role in reducing LCR need. The Decision erroneously relies on such an assumption in contravention of the intent of AB 327 and the Commission failed to proceed as required by Section 2827(c)(4)(B).

In addition, by failing to account for the solar PV contribution to reducing LCR need, the Commission has authorized duplicative procurement to address a need that will already be met by solar PV resources, thereby failing to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to proceed as required by law in contravention

[56] 3,316 MW – 1,011 MW = 2,305 MW.

[57] Revised Scoping Memo, Attachment A, p. 9. Fraction of additional solar PV in LA Basin in 2018 compared to ISO as a whole = 380 MW/1011 MW = 0.376. Fraction of additional solar PV in SDG&E territory in 2018 compared to ISO as a whole = 97 MW/1011 MW = 0.096.

[58] The Decision assumes the solar capacity factors at peak demand in the LA Basin and SDG&E territory are 0.45 and 0.46, respectively. Therefore, total additional solar PV available at peak is: (866 MW x 0.45) + (221 MW x 0.46) = 492 MW. This is additional solar PV beyond the 278 MW of peak solar PV in 2022 assumed in the Decision.

of section 1757(a)(2). Likewise, the Commission has failed to support its findings with substantial evidence and abused its discretion in violation of section 1757(a)(4) and.(5).

E. The Decision Fails to Count 745 MW of Highly Likely Energy Storage Resources as Required by AB 2514

The Decision makes the following finding of fact concerning the availability of energy storage resources:

> "The energy storage targets adopted in D.13-10-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[59]

This finding is not supported by substantial evidence in the record and is contrary to law.

AB 2514, as codified at Pub. Util. Code Section 2835 et. seq., mandates that utilities comply with energy storage targets adopted by the Commission.[60] The Commission set mandatory energy storage targets for the utilities in Decision D.13-10-040. Decision D.13-10-040 requires that utilities purchase energy storage projects equal to 1 percent of their 2020 annual peak load by 2020,[61] for a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024.[62] Decision D. 13-10-040 orders SDG&E to purchase 165 MW of energy storage by 2020, and orders SCE to purchase 580 MW of energy storage by 2020, a total of 745 MW.[63]

The Decision in the instant proceeding fails to count 745 MW of energy storage resources that will be added in SCE and SDG&E territories pursuant to AB 2514 and Decision D.13-10-040. The Decision justifies this failure by claiming that these resources are too "uncertain" to count towards LCR. By failing to count these energy storage resources, the Decision ignores the fact that under Pub. Util. Code Section 2835 et. seq. the energy storage targets adopted by the Commission are *mandatory*.[64]

Public Utilities Code Section 2836(a)(1) directs the Commission to "determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective

[59] Decision, Finding of Fact 49, at p. 129.
[60] Pub. Util. Code Sections 2836(a) and 2837
[61] D.13-10-040, Conclusion of Law 29, at p. 74
[62] D.13-10-040, Conclusion of Law 41, at p. 76
[63] D.13-10-040, Ordering Paragraph 1, at p. 76; Appendix A at p. 2.
[64] D.13-10-040, Conclusion of Law 41, p. 76. It is reasonable to require the utilities to contract for their storage targets by no later than 2020, with installation and operation of a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024.

energy storage systems to be achieved by December 31, 2015, and December 31, 2020." Section 2836(a)(2) mandates that the Commission adopt procurement targets, if determined to be appropriate, by October 1, 2013.

AB 2514 further provides that, once adopted by the Commission, energy storage targets are mandatory and *must* be met by the utilities. Public Utilities Code Section 2837 provides that once energy storage targets are adopted, "[e]ach electrical corporation's renewable energy procurement plan [as required by Public Utilities Code Section 399.11 et. seq.] shall require the utility to procure new energy storage systems that are appropriate to allow the electrical corporation to comply with the energy storage system procurement targets and policies adopted pursuant to Section 2836." The purposes of this mandatory utility energy storage procurement include:[65]

- Reducing the need for new fossil-fuel powered peaking generation;
- Reducing purchases of electricity generation sources with higher emissions of greenhouse gasses;
- Reducing the demand for electricity during peak periods;
- Avoiding or delaying investments in transmission system upgrades;
- And using energy storage systems to provide the ancillary services otherwise provided by fossil-fuel generating facilities.

By ignoring 745 MW of energy storage resources required by law to be available, the Decision subverts each of these purposes.

Further, the Commission errs in justifying its failure to account for the energy storage targets by claiming that energy storage is "uncertain."[66] Under AB 2514, the location and effectiveness of energy storage resources are in no way "uncertain." The Commission's authority extends to both the placement of energy storage facilities built by utilities, and the selection of third party energy storage facilities. The statutory mandates are clear. Thus, the Commission must exercise its authority to ensure that energy storage resources are certain.

In meeting the mandatory energy storage requirements adopted by the Commission in D.13-10-040, utilities must comply with Section 2836, which provides that the purposes of energy storage procurement include reducing the need for fossil-fuel powered peaking

[65] Pub. Util. Code § 2837.켐□η
[66] Decision at, p. 61.

generation, reducing the need to purchase electricity generation sources with higher greenhouse gas emissions, and using energy storage to provide the ancillary services normally provided by fossil fuel generation.

In order to satisfy these purposes, the Commission and the Utilities must site and select projects that maximize contributions to meeting LCR. Energy storage that does not contribute to local capacity would need to be backed up by redundant locally sited generation, and as such would not meet the clear purposes stated in section 2836.

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. By failing to count this mandatory 745 MW of energy storage, and by authorizing procurement based on an LCR determination driven, in part, by this failure, the Commission has adopted a position directly contradictory to the requirements of AB 2514 and sections 2835, et seq., and has failed to ensure just and reasonable rates in violation of sections 451 and 454. The Commission thus has failed to proceed as required by law in violation of section 1757(a)(2). Further, by discounting energy storage despite the clear requirements of AB 2514, sections 3835 et seq., and the uncontradicted record evidence of the availability of 745 MW of this resource, the Commission has failed to base its decision on findings supported by substantial evidence and abused its discretion in violation of section 1757(a)(4) and (5)

F. The Discounting of Preferred Resources and Emphasis on Gas-Fired Generation Is Counter to Law and Commission Policy

The Decision approves levels of natural gas-fired procurement that are far higher than current evidence shows is necessary as documented in the CAISO *2014 Summer Loads & Resources Assessment.* [67] The Decision authorizes 60 to 79 percent of the SCE procurement range of 1,900 to 2,500 MW to be natural-gas fired, depending on how much of this approved procurement range SCE chooses to construct.[68] The Decision authorizes 60 to 75 percent of the

[67] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 13 (attached to Attachment B, Declaration of David Peffer in Support of POC's Petition for Modification).

[68] The Decision (p. 141) directs SCE to procure at least 1,000 MW, but no more than 1,500 MW, of this SCE local capacity from conventional gas-fired resources. Assuming SCE opts for the higher 1,500 MW conventional gas-fired procurement limit, the gas-fired percentage of total SCE procurement authorized in the Final Decision ranges from 60 percent [(1,500 MW ÷ 2,500 MW) x 100] to 79 percent [(1,500 MW ÷ 1,900 MW) x 100].

SDG&E approved procurement range of 500 MW to 800 MW to be natural-gas fired generation.[69]

The Decision acknowledges that significant electric power supplies have come online in recent years.[70] The Commission requires the utilities to maintain a planning reserve margin of 15 percent.[71] The planning reserve margin projected by CAISO for the combined peak load of SCE and SDG&E in the summer of 2014 is 35.9 percent. A contributing factor to the high reserve margin is the fact that there has been no net increase in peak load in either SCE or SDG&E service territories over the last eight summers (2006 – 2013).[72]

In the twelve months from SONG's permanent shutdown in June 2013 until the end of May 2014, 3,328 MW of total new capacity has been added in SCE and SDG&E territories.[73] Of this total, 2,257 MW counts as reliable capacity available at peak demand.[74] SONGS had a reliable capacity of 2,246 MW.[75] Thus, the capacity lost by the SONGS closure has already been addressed with new capacity. There is no evidentiary basis for permitting additional procurement based on the closure of SONGS.

Much of the new capacity contributing to the current high planning reserve margin is renewable energy.[76] About 2,752 MW of the 3,328 MW of new SCE and SDG&E capacity is renewable energy, primarily solar energy.[77] The remaining 576 MW is natural gas-fired

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[69] The Decision (p. 143) directs SDG&E to procure at least 500 MW to 800 MW of new local capacity, of which at least 200 MW must be from resources other than conventional gas -fired generation. Therefore, the gas-fired percentage of total SDG&E procurement authorized in the Decision ranges from 60 percent [(300 MW ÷ 500 MW) x 100] to 75 percent [(600 MW ÷ 800 MW) x 100].

[70] Decision, p. 23.

[71] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 4 (attached to Attachment B, Declaration of David Peffer in Support of POC's Petition for Modification).

[72] Opening Comments of Sierra Club California On ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, Figures 1 and 2, pp. 12-13.

[73] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 13 (attached to Attachment B, Declaration of David Peffer in Support of POC's Petition for Modification).

[74] Only a portion of total solar and wind capacity is assumed to be available to meet peak demand. The solar capacity factor assumed by CAISO in the *2014 Summer Loads and Resources Assessment* is 0.68 (Table 5, p. 14). The wind capacity factor assumed by CAISO at peak is 0.19. This is the reason for the difference between installed capacity and capacity available at peak demand.

[75] *Ibid.*, p. 9.

[76] CAISO, *Summer Loads and Resources Assessment*, May 9, 2014, Table 1, p. 6. Total SP26 (SCE + SDG&E) summer 2014 supplies = 36,699 MW. CAISO forecast summer 2014 1-in-2 SP26 peak demand = 26,994 MW. Supply need to maintain 17 percent reserve margin = 26,994 MW × 1.17 = 31,583 MW. Summer 2014 supplies available to SCE and SDG&E beyond Commission 15 – 17 percent planning reserve margin requirement = 36,699 MW – 31,583 MW = 5,116 MW.

[77] *Ibid.*, p. 13. Natural gas-fired generation added between June 1, 2013 and May 31, 2014 in Southern California includes the El Segundo combined cycle plant in SCE territory (526.7 MW) and the Escondido combustion turbine in SDG&E territory (49.5 MW).

generation. As a result, natural gas-fired generation is only 17 percent of total SCE and SDG&E generation capacity that came online in the past year. Natural gas-fired generation is about 25 percent of the 2,257 MW of this new capacity that is available at times of peak demand. The current procurement pattern of SCE and SDG&E is much more consistent than the Decision with D.07-12-052 at 12, where the Commission stated:[78]

> Once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing.

More than 75 percent of the new supply capacity purchased by SCE and SDG&E in 2013-2014 is renewable energy. As a result of the Decision, this procurement trend will reverse in the future, with up to 75 percent or more of the new supply being natural gas-fired generation. This is contrary to California law, including but not only section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's Loading Order, which mandate prioritizing non-gas-fired energy sources. Accordingly, the Commission has failed to proceed as required by law, in violation of section 1757(a) (2). Because the Decision is at odds with current trends minimizing gas-fired generation in California, the Decision also is not supported by substantial evidence and constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

V. IN DETERMINING NEED, THE DECISION IMPROPERLY FAILS TO COUNT VERY LIKELY NON-GAS FIRED GENERATION GRID SUPPORT PROJECTS AND CONTINUED OPERATION OF EXISTING GAS-FIRED GENERATION

A. 550 MVAR of New Static VAR Compensators at San Onofre Is Very Likely to Be Available

SCE has proposed adding another 550 MVAR of Static VAR Compensators at San Onofre.[79] CAISO modeled a 550 MVAR Static Compensator at San Onofre in connection with the 2012-13 Transmission Plan and determined that it would reduce LCR need in the LA Basin by 300 MW.[80] Despite this evidence, the Decision finds, in Finding of Fact 20, that the record lacks sufficient evidence to determine the LCR impact of additional reactive power resources.

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[78] Decision, p. 23.

[79] Decision, p. 33: "SCE has proposed adding another 550 MVAR [Static VAR Compensators] at San Onofre. CEJA shows that the ISO estimates that this addition will reduce need in the LA Basin by 300 MW. This reactive support was not included in the 2022 results of the ISO's Track 4 Opening Testimony."

[80] Ex. CEJA-2 (May Supporting Documents), at p. 56.

The evidence directly contradicts this finding. Finding of Fact 20 is inconsistent with SCE's stated intent to install 550 MVAR at San Onofre. At a minimum, the evidence supports a reduction in LCR need of at least 300 MW, as CAISO determined. By failing to account for this 300 MW of capacity very likely to be available based on SCE's plans, the Decision permits unnecessary and duplicative procurement, in contravention of sections 451 and 454, requiring that rates be just and reasonable. As such, the Commission has not proceeded in the manner required by law, in violation of section 1757(a)(2). For the same reason, the Decision is not based on findings supported by substantial evidence and thus constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

B. Huntington Beach 280 MVAR Synchronous Condensers Already Exist and Must Be Counted.

The Decision fails to count the 280 MVAR Huntington Beach synchronous condensers, despite the fact that these resources are already in place and operational, and are currently providing 280 MVAR of reactive power at a key location, thereby reducing LCR need. CAISO's 2012-2013 Transmission Plan states: "The ISO assumed that the Huntington Beach synchronous condensers will be available for the intermediate (i.e., 2018) time frame and will assume their continued use or equivalent support. This was identified as part of the need for the SONGS absence scenario for summer 2013."[81] CAISO repeated this position in its July 15, 2013 Workshop on SONGS mitigation efforts.[82] Yet CAISO failed to model the Huntington Beach synchronous condensers for 2022 based on the speculative assumption that repowering would occur on that site.[83] The Decision admits that these resources are in place, yet declines to count them on the grounds that "while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions."[84] In so doing, the Decision violates section 1705, which requires the Commission to consider "all issues material to the order or decision." In this regard,

[81] Exhibit CEJA 2, at p. 26.
[82] Exhibit CEJA 2, at p. 39-40.
[83] Decision, p. 32: "The Huntington Beach synchronous condensers are also completed. However, while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions."
[84] CEJA Opening Comments, p. 9.

every issue that must be resolved to reach a Decision's ultimate finding is "material."[85] The Commission is required to "consider sua sponte every element of public interest affected by . . . [utility proposals] which it is called upon to approve," even if not prompted by a party, and the Commission's failure to do so is a ground for its decision's annulment.[86]

The failure to include the impact of the existing Huntington Beach synchronous condensers on LCR need is contradicted by the evidence in the record. These units exist now and will either continue to operate or "equivalent support" will replace them. By failing to account for this 280 MVAR of reactive power, the Decision permits unnecessary and duplicative procurement, in contravention of sections 451 and 454, requiring that rates be just and reasonable. As such, the Commission has not proceeded in the manner required by law, in violation of section 1757(a)(2). For the same reason, the Decision is not based on findings supported by substantial evidence and thus constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

C. The Decision Fails to Even Acknowledge the Imperial Valley Flow Controller Project Which Will Reduce LCR Need by 500 MW In SDG&E Territory

SDG&E has submitted a proposal to CAISO to install a flow control device, referred to as the Imperial Valley flow controller.[87] The purpose of this flow controller is to prevent the tripping of a special protection scheme on the Comisión Federal de Electricidad (CFE) line, a scheme that was triggered by the N-1-1 contingency modeled by CAISO. SDG&E witness Jontry testified that the proposal was submitted with a requested in-service date in either 2015 or 2017.[88] No party submitted testimony or evidence that this flow controller will not be in place by 2017. CEJA testified that the resulting reduction of LCR need in the San Diego region would be at least 500 MW.[89] This testimony was not contradicted. This project is not mentioned in the Decision. This project is very likely to occur. There is no evidence in the record to contradict this. The project addresses a major aspect of the contingency modeled by CAISO in this

[85] *Pacific Tel. & Tel. Co. v. Public Utilities Commission* (1965) 62 Cal.2d 634, 648
[86] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380
[87] CEJA Opening Comments, p. 6.
[88] RT at 1750 (SDG&E, Jontry).
[89] Ex. CEJA-1 (May Opening Testimony), at p. 31.

proceeding and eliminates the need for 500 MW of new resources in SDG&E territory. As a result, SDG&E's procurement authorization should be reduced by 500 MW.

By failing to address the Imperial Valley flow controller project, the Decision violates section 1705, requiring that the Commission make findings of fact and conclusions of law on every material issue, as well as the Commission's duty to "consider sua sponte every element of public interest affected by . . . (utility proposals) which it is called upon to approve."[90] By not reaching any findings regarding this key issue the Commission has failed to support its Decision with findings in violation of Section 1757(a)(3), failed to assure just and reasonable rates in violation of Sections 451 and 454, failed to proceed in the manner required by law in violation of Section 1757(a)(2), and abused its discretion in violation of Section 1757(a)(5).

D. The Decision's Presumption of Complete Early Retirement of OTC Power Plants Is Unsupported by the Record

Historically coastal California power plants have used seawater in once-through cooling (OTC) to meet cooling requirements. California regulations require these plants to either substantially reduce seawater usage in coming years by at least 93 percent through process modifications or reduced operation, or retire.[91] As the only large base-load power plant on the Southern California coast, SONGS was responsible for about 90 percent of Southern California OTC power plant seawater withdrawals when it was operational.[92]In effect, SONGS met its December 2022 OTC compliance date[93] almost ten years in advance when it permanently shut down in June 2013.[94]

The early retirement of SONGS has almost completely met the state's OTC phase-out objectives in Southern California a decade ahead of schedule. However, the Decision presumes as a certainty that all remaining OTC plants, which provide cost-competitive reserve capacity to assure grid reliability in Southern California, will retire over the next several years and create a need for new power supplies in the LA Basin and SDG&E territory that otherwise would not exist.

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[90] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380

[91] State Water Resources Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, as amended June 18, 2013, p. 4. See: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml .

[92] Prepared Opening Testimony of Bill Powers on Behalf of Sierra Club California, September 30, 2013, p. 22.

[93] *Ibid.*, p. 22.

[94] *Ibid.*, p. 22.

The 2018 need identified in the Decision is created by assuming the retirement of once-through cooling ("OTC") power plants and non-OTC power plants such as the 640 MW Etiwanda plant in SCE territory and the 188 MW Cabrillo II combustion turbines in SDG&E territory.[95] The Decision is clear on this point:

> Such long-term LCRs are expected to result from the retirement of approximately 5,900 Megawatts (MW) from current once-through cooling generators in the Los Angeles (LA) Basin, and approximately 900 MW in the San Diego local area, to comply with State Water Quality Control Board regulations. [96]

If these retirements do not occur by 2018, the need identified in the Decision will not materialize. The refusal of the utilities to allow OTC power plant owners to recover the cost of coming into compliance with the OTC regulation in their power supply bids is the reason these OTC plants may retire by 2018.[97] One readily-available alternative to the Commission is to postpone OTC retirements, such as Encina in SDG&E territory, and non-OTC retirements such as Cabrillo II, for a limited time to bridge any projected gap until sufficient preferred resources are added to the system.[98] The Commission failed to consider this material issue that would result in less need and thus less cost for the ratepayers.

The State Water Resources Control Board's OTC policy does not require retirement of the OTC plants in SCE and SDG&E territories. Rather, it merely requires that OTC plants either reduce intake flow and velocity (Track 1 compliance) or reduce impacts to aquatic life comparably by other means (Track 2 compliance).[99]

However, the OTC plants must be able to recover the costs they incur to comply with the OTC policy in the competitive bids these plants submit to utilities. For example, the owner of 964 MW Encina Power Plant in SDG&E territory (Cabrillo, owned by NRG), has stated that it has compliance plans in place for Encina Units 4 and 5, and that the only barrier to implementing these plans is the lack of an adequate Power Purchase Agreement.[100]

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[95] Opening Comments of Sierra Club California on ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, R.12-03-014, September 30, 3013, Figure 2, pp. 11-12.
[96] Decision, p. 6.
[97] POC Opening Testimony, pp. 18-21.
[98] Opening Comments of Sierra Club California On ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, Figures 1 and 2, p. 12, p. 12.
[99] State Water Resources Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, as amended June 18, 2013, p. 4.
[100] POC Opening Testimony, Exhibit 15.

SDG&E and CAISO have admitted that their goal is to push for the retirement of Encina. CAISO describes the objectives of its Track 4 study as including: "minimizing the OTC generation repowering or replacement need."[101] Similarly, in A.11-05-023, SDG&E submitted testimony stating that the PPTA's proposed in that proceeding "will help to… facilitate the retirement of aging and Once Through Cooling ("OTC") generation resources."[102] It may be that Encina generation is significantly more cost-effective than other existing and proposed resources. It is unreasonable and unlawful for the Commission to allow any generation procurement based on projections that assume the retirement of potentially competitive generation that has been effectively forced into retirement.

Using the test of likelihood introduced for the first time by the Commission in Track 4 to determine whether to count a resource toward the LCR, "very likely" or "reasonably possible," the record does not support a factual determination that all OTC plants will retire en mass by their respective compliance dates. There are no findings in that record that support the assumption in the Decision that all OTC plants will retire by their compliance dates, a violation of section 1757(a)(4). As a result the Commission has approved over-procurement, failed to assure just and reasonable rates, in violation of sections 451 and 454, failed to proceed as required by law, in violation of section 1757(a)(2), and abused its discretion in violation of section 1757(a)(5).

VI. THE DECISION ERRS IN ALLOWING THE USE OF N-1-1 AS THE CRITICAL CONTINGENCY
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A. In Allowing N-1-1 the Decision Failed to Consider a Material Issue of Public Interest on the Merits

The need determination reached in D.14-03-004 is based on the results of CAISO's modeling.[103] The results of CAISO's modeling, in turn, were driven in significant part by the decision to use the Sunrise Powerlink/Southwest Powerlink (Sunrise/SWPL) N-1-1 event as the limiting critical contingency for the San Diego local area. "N-1-1" means the sequential loss of these two transmission lines with time for system readjustment (generally assumed to be up to 30

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101 CAISO Opening Testimony, p. 17
102 POC Opening Testimony, Exhibit 19.퀩□ŋ
103 D.14-03-004 at p. 28

minutes) between the first and second outage.[104] In the instant proceeding, several parties, including POC, submitted evidence and presented arguments challenging the use of the Sunrise Powerlink/SWPL N-1-1 event as the limiting critical contingency for the San Diego local area.

The Decision dismisses these challenges to N-1-1 on three grounds: (1) changing the limiting critical contingency used in CAISO's modeling would directly change the CAISO modeling input; (2) the determination of whether N-1-1 is a Western Electricity Coordinating Council ("WECC")[105] Category C contingency, for which contingency planning is required, or a WECC Category D contingency, for which no needs assessment is necessary, is more within the expertise of CAISO than the Commission; and (3) CAISO has referenced a probability range for the N-1-1 event that indicates it is a credible contingency that must be mitigated. [106] Each of these grounds is legally erroneous, not supported by the Commission's findings or the evidentiary record, and, thus, an abuse of the Commission's discretion.

1. *By rejecting challenges to N-1-1 as impermissible challenges to modeling inputs, the Commission has failed to proceed as required by law, violated the parties due process rights, and abused its discretion.*

The Decision rejects the challenges to the use of N-1-1 as the limiting critical contingency for the San Diego area, in part, on the claim that such challenges to the modeling inputs adopted in the Scoping Memo are impermissible, and that only the output results of the model can be adjusted up or down based on differences between the Commission's assumptions on the quantity of available resources to meet the LCR need and the resource assumptions used by CAISO when it ran the model. [107] The Decision treats the CAISO decision to use the Sunrise/SWPL N-1-1 as the critical contingency as inviolate based on CAISO's presumed greater level of expertise in identifying the critical contingency. [108] By treating the modeling assumptions as unchallengeable, and as such rejecting the challenges to N-1-1 on the grounds

[104] Sierra Club Reply Testimony, Exhibit 1, p. 7.
[105] WECC is a regional entity of the North American Electric Reliability Corporation ("NERC"). Pursuant to 16, U.S.C. Section 824o, the Federal Energy Regulatory Commission has named NERC as the entity responsible for developing mandatory and enforceable electricity reliability standards.
[106] Decision, Findings of Fact 24, 31, and 32, p. 126.
[107] Decision at p. 49; Decision, Finding of Fact 30, p. 126.
[108] Decision, Finding of Fact 32, p. 126.

that doing so would change the model input, the Commission has failed to proceed as required by law, violated the parties' due process rights, and abused its discretion.

Section 1705 requires the Commission to consider "all issues material to the order or decision." Every issue that must be resolved to reach a Decision's ultimate finding is "material."[109] The Commission has a proactive duty to identify and fully adjudicate issues of public interest. Failure to fulfill this duty is grounds for a Decision's annulment:

> [t]he Commission may and should consider sua sponte every element of public interest affected by . . . [utility proposals] which it is called upon to approve. It should not be necessary for any private party to rouse the Commission to perform its duty. . . Thus, we conclude that the Commission failed to give adequate consideration to the . . . issues . . . and that its decision must be annulled.[110]

By treating modeling assumptions adopted in the Scoping Memo as unchallengeable, and by dismissing challenges to these assumptions raised by the parties, the Commission has failed to adjudicate, consider, and resolve the reasonableness of these assumptions as required by these provisions. Furthermore, the Commission has denied parties the opportunity for a full and fair hearing on these issues and as such has violated the parties' due process rights. This further constitutes a failure by the Commission to proceed in the manner required by law and an abuse of the Commission's discretion under sections 1757(a)(2) and (a)(5)

2. *The Decision's use of N-1-1 is not supported by substantial evidence in light of the whole record*

NERC standards require modeling of a range of contingencies, from (Category A) to extreme events (Category D).[111] The two intermediate categories of contingencies, Category B, events resulting in the loss of a single element and Category C, event(s) resulting in the loss of two or more elements constitute the majority of contingencies examined in SCE's studies. An example of a Category B contingency is the fault and loss of one transformer bank. An example of a Category C contingency is the fault and simultaneous loss of two transmission lines that

[109] *Pacific Tel. & Tel. Co. v. Public Utilities Commission* (1965) 62 Cal.2d 634, 648
[110] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380
[111] SCE Opening Testimony, p. 21.

share a common tower, [112] or the sequential loss of two transmission lines within 30 minutes of each other. Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences. If the Sunrise/SWPL N-1-1 contingency is a Category D contingency, NERC reliability standards do not require mitigation.[113]

The Decision bases its use of N-1-1, in significant part, on the finding that "[t]here is no credible basis upon which to find that the ISO's analysis, that the limiting contingency for the SONGS study area is the N-1-1 Category C SWPL/Sunrise overlapping outage assumed and modeled by the ISO, is flawed."[114] This finding is based on the Decision's failure to consider key evidence and as such is in error.

CAISO and other parties contended that the Sunrise/SWPL N-1-1 was a WECC Category C contingency. They further contended that because the Sunrise/SWPL N-1-1 was the most severe Category C contingency for the San Diego local area, they were required to use it as the limiting critical contingency for the area in order to comply with mandatory WECC planning guidelines regardless of the probability, consequence and cost associated with the Sunrise/SWPL N-1-1.[115]

In response, several parties, including POC, argued that WECC has an official process in place that would allow SDG&E to have the Sunrise/SWPL N-1-1 re-categorized from a Category C contingency, which must be planned for and mitigated, to a Category D contingency, which is considered so unlikely to occur that utilities are not required to plan for it. The evidence regarding the applicability of this process, known as the Probabilistic Based Criteria Review ("PBRC") process, is discussed briefly in the Decision:

> On cross examination, witness Powers claimed the overlapping outage of SWPL and Sunrise is a "functional" Category D because SDG&E could "convert it from a Category C to a Category D" using the WECC process followed by SDG&E in evaluating the performance criteria of the Sunrise route alternatives. However, SDG&E witness Jontry testified that the WECC re-classification process is not available for an N-1-1 contingency. ISO witness Sparks also noted that he had never seen the process applied to a Category C3 contingency, and that WECC is moving to eliminating the process altogether.[116]

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[112] *Ibid,* p. 21.
[113] SCE Reply Testimony, p. 17.
[114] Finding of Fact 33 at p. 127
[115] Jontry Reply Testimony, p. 3.
[116] Decision, p. 47.

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In cross examination, both SDG&E witness Jontry and CAISO witness Sparks admitted that the PBRC process exists, and that the process allows for probabilistic exceptions to NERC categorizations.[117,118]

In describing CAISO witness Sparks testimony, the Decision selectively omits the fact that Sparks conceded that the Sunrise/SWPN N-1-1 qualifies for the PBRC process:

> THE WITNESS [Mr. Sparks]: As I described, it [the PBRC process] applies to – I've seen it in examples applied to single contingencies being reclassified as Category C and sometimes it can reclassify double contingency to Category B. I've never seen it [the PBRC process] applied to Category C3, but I suppose it could be.[119]

In relying on Sparks' claim that "WECC is moving to eliminating the process altogether" the Decision ignores the fact that, when questioned, Sparks was unable to substantiate this claim with any specific information beyond the vague claim that "the general population of WECC is moving to eliminate this process."[120]

When POC asked whether there was a specific proposal or proceeding at WECC to eliminate the PBRC process, CAISO objected based on relevance, and ALJ Gamson instructed POC's counsel to continue down a different line of questioning.[121]

In relying on SDG&E witness Jontry's claim that the PBRC process does not apply to the Sunrise/SWPL N-1-1, the Decision adopts a highly contradictory position. One of the key findings that the Decision uses to justify the use of N-1-1 is that ISO has a special "expertise" in "issues regarding whether an ISO-determined Category C contingency should be functionally a Category D contingency under WECC reliability standards."[122] Given this special expertise, the testimony of CAISO's transmission expert admitting that the N-1-1 contingency qualifies for the PBRC process should trump SDG&E's testimony claiming otherwise.

In any event, the Commission's failure to consider the availability of the WECC PBRC process to eliminate the Sunrise/SWPL N-1-1 as a viable contingency, amounts to a violation of section 1705, which requires the Commission to consider all material issues, particularly those

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[117] Tr. Vol.12, p. 1772, lines 23-28.
[118] Tr. Vol.11, p. 1560, lines 1-19.
[119] Tr. Vol. 11, p. 1562, lines 15-21.
[120] Tr. Vol. 11, p. 1563, lines 8-10
[121] Tr. Vol 11, p. 1563, line 15 through p. 1564, line 22
[122] Finding of Fact 32 at p. 126

impacting the public interests. Because it results in unnecessary procurement, the Decision also violates the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision also constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, because the Decision selectively ignores key evidence, the Decision's acceptance of N-1-1 as the limiting critical contingency for the San Diego area is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

3. *The Decision relies on CAISO's erroneous interpretation of the probability of a Sunrise Powerlink/SWPL N-1-1 to assert the N-1-1 is a credible event*

The Decision's failure to independently evaluate the probability of Sunrise/SWPL N-1-1 contingency exposes ratepayers to billions in unnecessary infrastructure costs to address a LCR need created in substantial part by application of the Sunrise/SWPL N-1-1 contingency. The Decision's Finding of Fact 24 references probabilities of occurrence for this N-1-1 event that were used by SDG&E to establish the simultaneous loss of Sunrise/SWPL (N-2) as a very low probability Category D event that does not require mitigation. As a result, the Decision is using probability data that would identify the Sunrise/SWPL N-1-1 contingency as a probabilistic Category D event that does not require mitigation. This contravenes its own Finding of Fact 24.

SDG&E witness Jontry insisted that all N-1-1 events must be mitigated regardless of probability, consequence and cost.[123] However, CAISO witness Sparks proffered a probability range for the Sunrise/SWPL N-1-1, referencing the 21 years to 928 years probability of occurrence from the December 2007 SDG&E probabilistic study that was used by SDG&E to reclassify the original Sunrise/SWPL route N-2 from Category C to Category D.[124] The 21 years to 928 years probability of occurrence was incorporated into Finding of Fact 24 as the factual basis for establishing that the Sunrise/SWPL N-1-1 is a probabilistic Category C event. However, the study CAISO referenced for this probability range is the December 19, 2007 probabilistic analysis conducted by SDG&E as a component of an application by SDG&E to

[123] SDG&E Jontry Reply Testimony, p. 3.
[124] CAISO Sparks Reply Testimony, pp. 5-6.

WECC to modify the simultaneous outage of Sunrise Powerlink and SWPL (N-2) from Category C to Category D.[125] This application was successful.

In effect, the Decision uses a probability range developed by SDG&E to demonstrate that the Sunrise/SWPL N-2 is a probabilistic Category D contingency to claim that the Sunrise/SWPL N-1-1 is a probabilistic Category C contingency.[126] Independent of the 2007 SDG&E probabilistic study, WECC determined in 2012 that the Sunrise/SWPL N-2, due to the physical separation between the two lines, fit newly developed WECC requirements for reclassification as a Category D contingency.[127] In contrast to the factually erroneous Finding of Fact 24, POC is aware of no evidence in the record that the N-1-1 event is probabilistically more likely than the N-2 event.[128]

Why did SDG&E go through the effort in 2007 to demonstrate through probability analysis that the Sunrise/SWPL N-2 should be a classified as a Category D event that does not require mitigation? According to the Dec. 18, 2008 Sunrise Powerlink Final Decision:

> SDG&E was concerned that WECC would rate any line parallel to the Southwest Powerlink past that milepost (Milepost 36) as a Category C line, and SDG&E wanted the Proposed Project to obtain a Category D rating, which because it represents a higher measure of reliability, might provide further justification for the line.[129]

There is no mention of a Sunrise/SWPL N-1-1 contingency in the Sunrise Powerlink Final Decision. The use of a Sunrise/SWPL N-1-1 in the Decision is incompatible with the reliability basis for the Commission's approval of the Sunrise Powerlink. Because it results in unnecessary procurement, it also violates the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2) Further, because the Decision misconstrues key evidence, the Decision's acceptance of N-1-1 as the limiting critical contingency for the San Diego area is not supported by substantial evidence in light of the entire

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[125] Exhibit POC-X-CAISO-3.

[126] Ibid, p.3. Regarding the 1-in-21 year low-end probability, SDG&E stated "The lower end of the range, 21 years, would not qualify for Category D status, but SDG&E feels that after review of the Robust Line Design criteria for SWPL, the MTBF would tend towards the higher end of the range. This estimate was based on historical outage statistics for other parallel 500 kV lines with the statistics modified to consider mitigating factors that do not apply to the lines in this report."

[127] POC Opening Testimony, Exhibit 5, p. 1

[128] TURN Opening Brief, p. 12, footnote 37. "While it may be theoretically conceivable that an N1-1 outage would have a higher probability than an N-2 outage, TURN is not aware of any evidence in the record to support basing the Commission's decision on such a theoretical possibility."

[129] Sunrise Powerlink Decision, D. 08-12-058, p. 213.

record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

4. *The Decision's acceptance of N-1-1 based on deference to CAISO constitutes an unlawful delegation of the Commission's regulatory authority*

In deferring to CAISO regarding the reasonableness of N-1-1, rather than exercising its independent judgment on the issue, the Commission has abdicated the statutory responsibilities assigned to it by the Legislature and unlawfully delegated its power to an interested party in these proceedings. Public Utilities Code Section 451 provides that for a new rate to be valid, *the Commission* must make a finding that the new rate is justified. Similarly, Public Utilities Code Section 1705 requires that *the Commission* consider all material issues, and particularly the public interest. The Legislature has not assigned these duties to CAISO. Indeed, CAISO's statutory purpose is to "ensure efficient use and reliable operation of the transmission grid."[130] Unlike the Commission, CAISO has no statutory mandate to protect the public interest by ensuring the reasonableness of utility rates. CAISO is merely a private corporation, with a state corporate charter to operate. But no governmental authority or responsibility attaches to this private corporation and it is not subject to the procedural or conflict of interest safeguards that apply to all other state government entities. Protecting the public interest and ensuring the reasonableness of utility rates is solely the responsibility of the Commission. The Legislature has not authorized the Commission to delegate this responsibility to CAISO.

By failing to exercise its own informed judgment based on the evidentiary record, and instead wholly deferring to CAISO, on the critical issue of the reasonableness of N-1-1, the Commission, thus, has acted outside of its authority, failed to proceed as required law, and substantially prejudiced the rights of the other parties, including POC, not to mention the rights of the ratepayers. *See, e.g., Assiniboine and Sioux Tribes of Fort Peck Indian Reservation v. Board of Oil and Gas Conservation of Montana*, 792 F.2d 782, 794-796 (9th Cir. 1986) (Bureau of Land Management unlawfully delegates its authority concerning applications for placement of oil and gas wells on tribal lands if it approves such applications based on the judgment of another entity without meaningful independent review); *Save our Wetlands v. Sands*, 711 F.2d 634, 641–

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130 Pub. Util. Code Section 345펌□ŋ

43 (5th Cir.1983) (construing the requirements imposed upon agencies under the National Environmental Policy Act to consider environmental consequences of their actions and holding that an agency does not satisfy those requirements if it "reflexively rubber-stamps" reports prepared by others); *Memorial Hosp. of Roxborough v. N.L.R.B.*, 545 F.2d 351, 360-361 (3d Cir. 1976) (National Labor Relations Board unlawfully abdicated its duty under the National Labor Relations Act to determine appropriateness of a bargaining unit by accepting Pennsylvania Labor Relations Board determination without exercising the NLRB's own mandated discretion); *Sierra Club v. Lynn*, 502 F.2d 43, 59 (5th Cir.1974), *cert. denied*, 421 U.S. 994 (1975) (public or private entities may participate in preparation of environmental impact reports, as long as federal agency does not abdicate responsibilities and rubberstamp their work product); *Friends of Endangered Species, Inc. v. Jantzen*, 589 F.Supp. 113, 118–19 (N.D.Cal.1984), *aff'd*, 760 F.2d 976 (9th Cir.1985) (federal agency's delegation of environmental research to a third party is impermissible if agency fails to adequately review the work).

B. Use of Standard CAISO G-1/N-1 Planning Contingency, Correct G-1 In SDG&E Territory, and Consistent Capacity for Path 44 Would Reduce SDG&E LCR Need By About 1,400 MW

1. G-1/N-1 Planning Standard Should Have Been Used in Modeling to Add 1,000 MW of Reliable Transmission Import Capacity on the Sunrise Powerlink

A substantial Commission basis for approving the Sunrise Powerlink was that it would provide at least 1,000 MW of reliability under a standard G-1, N-1 contingency.[131,132] California ratepayers are paying $2 billion for the Sunrise Powerlink.[133]

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[131] Sunrise Powerlink Decision, D.08-12-058, p. 28. "Pursuant to reliability criteria established by the North American Electric Reliability Corporation (NERC), SDG&E must have enough local generation resources to reliably serve all load in its Local Reliability Area after the loss of the largest generating unit in its service area followed by the loss of its most critical transmission line (the "G-1/N-1" criteria). The G-1/N-1 criteria determine SDG&E's "Local Capacity Requirement" since the Local Capacity Requirement is the amount of local generation that SDG&E must have to continue operating reliably after a G-1/N-1 event."

[132] Sunrise Powerlink Decision, D.08-12-058, pp. 110-111. "In estimating Sunrise's impact on SDG&E's Local Capacity Requirement, CAISO assumes that Sunrise will cause SDG&E's "All Lines in Service" Simultaneous Import Limit to increase from 2,850 MW to 4,200 MW and its Non-Simultaneous (G-1/N-1) Import Limit to increase by 1,000 MW, from 2,500 MW to 3,500 MW.331 These increased import limits result in a potential reduction in SDG&E's Local Capacity Requirement, and thus a reduction in the amount of new in-area generating capacity and Must Run contracts needed by SDG&E to meet those requirements."

[133] SC-1, p. 5.

Treating the Sunrise/SWPL N-1-1 as a credible contingency means that the construction of the $2 billion Sunrise Powerlink has actually decreased Southern California grid reliability. This is in direct contrast to the claims made to the Commission by SDG&E and CAISO during the Sunrise Powerlink proceeding that the Sunrise Powerlink would reduce LCR need in SDG&E territory by 1,000 MW.

The reason for the reduced grid reliability is that, with Sunrise Powerlink in operation, much more power can be imported over SDG&E's two 500 kV lines, Sunrise Powerlink and SWPL, than could be imported over SWPL alone. The loss of both of these lines in an N-1-1 event, if this event is credible, means that there is a larger hole to fill with local capacity than there was prior to the existence of the Sunrise Powerlink.

In effect, SDG&E's $2 billion Sunrise Powerlink energized in June 2012 was presented to the Commission by SDG&E and CAISO as a substantial grid reliability benefit under a G-1/N-1 standard planning contingency. However, under the Sunrise/SWPL N-1-1 contingency used in the Decision, the $2 billion Sunrise Powerlink is a grid reliability problem that precipitates a multi-billion procurement authorization of 1,500 to 1,900 MW in SCE's LA Basin and 500 to 800 MW in SDG&E territory.

By allowing the Utilities and CAISO to perpetrate this "bait and switch" tactic on the public and accepting the reasonableness of the Sunrise/SWPL N-1-1 contingency, the Commission undercounts the LCR need contribution of existing SDG&E transmission and generation infrastructure, and as a result authorizes unnecessary procurement for an LCR need that is already being met. This is a violation of the Commission's duty to ensure just and reasonable rates under sections 451 and 454. It also is a failure of the Commission to proceed as required by law and an abuse of the Commission's discretion under section 1757(a)(2) and (a)(5).

2. *Use of Coastal Path 44 Actual Thermal Rating of 3,200 MW Adds 700 MW of Reliable SDG&E Import Capacity Under G-1/N-1Contingency*

The only major transmission pathway in SDG&E territory that remains available to import power under the Sunrise/SWPL N-1-1 consists of the five 230 kV lines in the same right-of-way corridor that parallel Interstate 5 along the San Diego County coastline, collectively known as "Path 44". CAISO identifies the thermal capability of Path 44 as approximately 3,200

MW in the modeling it conducted of the N-1-1 contingency.[134] However, the historic path rating for Path 44 assumed by SDG&E and CAISO and used in modeling of the G-1/N-1 scenario, was 2,500 MW.[135] Mr. Sparks confirmed the 3,200 MW thermal capability of Path 44 under cross-examination.[136]

Use by CAISO of 3,200 MW of import flow on Path 44 in its modeling of the N-1-1 contingency, and use 2,500 MW of import flow on the same Path 44 in its modeling of a G-1/N-1 contingency, is a modeling inconsistency that omits 700 MW of additional reliable import power under the G-1/N-1 contingency. Use of the actual Path 44 thermal rating of about 3,200 MW when modeling the G-1/N-1 case would reduce LCR need by 700 MW under the G-1/N-1 standard contingency.

CAISO explains that before Sunrise Powerlink was built, it applied a now obsolete Path 44 rating based on "N-1 thermal limit historically employed for Path 44 for pre-Sunrise system."[137] CAISO now applies, after the construction of Sunrise Powerlink, a Path 44 power flow based on "voltage collapse criteria."[138] The result of this change by CAISO is that Path 44 carries approximately 700 MW more for N-1-1 contingency modeling purposes, with no physical change to Path 44, than it does when CAISO models the G-1/N-1 contingency. The "voltage collapse criteria" now in use by CAISO must also be applied to Path 44 when modeling the G-1/N-1 contingency with Sunrise Powerlink operational, which CAISO has not done.

The Decision's failure to properly account for the actual power flow capability of Path 44 under the G-1/N-1 contingency results in an over-assessment of need and unnecessary authorization of procurement, thus violating the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, the failure to properly account for the thermal capability of Path 44 is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

[134] SC-1, Exhibit 2, Tables 1 and 2, p. 4 and p. 6.
[135] SC-1, Exhibit 2, Table 1, p. 4.
[136] Tr. Volume 10, p. 1514, lines 25-28, p. 1515, lines 1-5.
[137] POC Opening Testimony, Exhibit 2, p. 6.켐□η
[138] Ibid.켐□η

3. *Proper Categorization of G-1 in SDG&E Territory Would Result in Loss of Only 260 MW Steam Generator at Otay Mesa Combined Cycle Plant, Not Entire 604 MW Plant as the Decision Assumes*

In addition, CAISO's erroneous categorization of outages at Palomar Energy and Otay Mesa combined cycle plants, the two combined cycle plants in SDG&E service territory, as presumptive "whole plant" outages for LCR planning purposes conflicts with the clear statement of the Federal Electricity Regulatory Commission (FERC) on the capabilities of these two combined cycle plants.[139] This matters when the CAISO board-approved G-1/N-1 planning standard is applied. CAISO acknowledgement of the design capabilities of the two combine cycle plants, which allow the plants to continue operating as simple-cycle units with the steam turbine-generator in forced outage, would increase the LCR capacity in the SDG&E load pocket by approximately 344 MW under the CAISO-approved standard G-1/N-1 planning contingency in SDG&E territory.[140] Because the Decision overvalues the loss that would be caused by outages at Palomar and Otay Mesa, the Decision over-assesses LCR need and authorizes unnecessary procurement, thus violating the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, the Decision's overvaluation of the losses caused by Palomar and Otay Mesa outages is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

4. *The Commission Failed to Include a Finding That No Outage "Ripple Effect" Occurs from SDG&E to SCE Territory if G-1/N-1 Is the Contingency Standard*

The Commission adopted a power flow model critical contingency in the Decision (N-1-1) that conflicts with the critical contingency (G-1/N-1) used as a basis for its decision to approve the Sunrise Powerlink and undermines the basis for the prior approval. The Sunrise Powerlink-Southwest Powerlink N-1-1 "ripple effect" felt as an N-1 in SCE territory,[141] the basis

[139] SC-1, Exhibit 1

[140] SC-1(Opening Testimony of Bill Powers [illegible]

[141] Tr. Volume 13, p. 1934, lines 5-11.

for joint SCE-SDG&E power flow modeling in Track 4, would disappear under a G-1/N-1 contingency, as power would continue to flow over the Sunrise Powerlink under contingency conditions and not be rerouted through the SCE transmission system.[142] As SCE explains:[143]

> A Category C contingency, where two 500 kV transmission lines that feed SDG&E are lost, will reroute power to the remaining lines that feed SDG&E (see No. 1 in Figure III-3). The rerouted power flows through lines in the LA Basin and produce thermal overloads and voltage deviation violations (see No. 2).

Under a standard G-1, N-1 planning contingency in SDG&E territory, a Path 44 path rating that accurately reflects the thermal capability of the two lines, and an accurate G-1 capacity for the San Diego area combined cycle units, SDG&E territory would have more than 1,400 MW of LCR capacity that is not counted when the Sunrise Powerlink/SWPL N-1-1 contingency is assumed. There would be no determination of need in either SDG&E territory or SCE territory if a standard G-1, N-1 planning contingency is assumed, an accurate path rating is applied to Path 44, and the designated G-1 unit reflects the inherent design capability of the two San Diego combined cycle plants. The Commission fails to ensure just and reasonable rates by undercounting the LCR need contribution of existing SDG&E transmission and generation infrastructure in CAISO model, and as a result authorizes unnecessary procurement for an LCR need that is already being met. This is a violation of the Commission's duty to ensure just and reasonable rates under Sections 451 and 454. It also is a failure of the Commission to proceed as required by law and an abuse of the Commission's discretion under section 1757(a)(2) and (a)(5).

VII. THE DECISION ERRONEOUSLY AUTHORIZES PROCUREMENT THROUGH BILATERAL CONTRACTS

The Decision authorizes the utilities to procure resources through bilateral contracts,[144] reasoning that SCE was allowed to procure resources with bilateral contracts in Track 1.[145] However, there are major differences between the Track 1 and Track 4 authorization.

[142] SCE Opening Testimony, Figure 3, p. 25.
[143] Ibid, p. 24.
[144] Ex. CESA-1 (Lin Opening Testimony).
[145] Decision, p. 92.

Track 1 authorized a specified minimum amount of natural gas resources, whereas the Track 4 Decision importantly finds that all of the need could be met with preferred and energy storage resources.[146] Bilateral contracts are not an appropriate way to meet the Track 4 need because they will not allow all available preferred and energy storage resources to be considered. Rather, bilateral contracts will target only one entity and likely one type of resource. Bilateral contracts will also not facilitate compliance with the Loading Order and Section454.5 of the Code, which requires that energy efficiency; demand response and renewable resources are procured before fossil fuel resources.

The Decision also importantly requires that all applications must demonstrate "[c]onsistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting LCR need."[147]

Allowing bilateral contracts will effectively negate the language in the Decision requiring compliance with the Loading Order and finding that preferred resources could fill the unmet need. Track 1 also limited bilateral procurement to the narrow situations that meet the requirements of Section 454.6 of the Public Utilities Code,[148] whereas the language of the Decision does not explicitly limit bilateral contracts to that situation. Rather, the Decision states that: [SCE] and [SDG&E] are authorized to procure bilateral cost-of-service contracts to meet authorized local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code Section 454.6.79. [149]

Generally, allowing bilateral contracts will likely result in contracts that do not represent the best deal for ratepayers or the environment. Such contracts will not prioritize preferred resources, energy efficiency, and demand response over gas-powered procurement, in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. Nor will they ensure just and reasonable rates, violating the Commission's duty to ratepayers under sections 451 and 454. As such, by authorizing bilateral contracts the Commission has failed to proceed as required by law and abused its discretion in violation of section 1757(a)(2) and (a)(5).

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[146] Comparison of Decision Ordering Paragraph 3, p. 144, with Track 1 Authorization, D.13-02-015.
[147] Decision Ordering Paragraph 8, p. 145.켐□ŋ
[148] D.13-02-015, Ordering Paragraph 9.
[149] Decision Ordering Paragraph 3, p. 144.

VIII. THE DECISION ERRS IN REJECTING POC'S MOTION FOR OFFICIAL NOTICE AND STRIKING POC'S OPENING AND REPLY BRIEFS

A. Denial of POC's Request for Official Notice Was a Legal Error and Abuse of Discretion.

On November 4, 2013, POC submitted a Motion seeking Official Notice of three official WECC policy Documents setting forth WECC's official PBRC process.[150] These documents were identified as POC-4, POC-5, and POC-6.

ALJ Gamson rejected POC's Motion in a one-sentence, corrected email ruling dated November 15, 2013, stating in full:

> The November 4, 2013 Motion of the Protect Our Communities Foundation for Official Notice of Exhibits, identified as Exhibits POC-4, POC-5, and POC-6, is hereby denied. These items will not be admitted into evidence in this proceeding. [151]

This ruling provided no explanation as to why POC's Motion was denied.

The Decision affirms ALJ Gamson's ruling, citing to two arguments from the Utilities' November 6, 2013 Response to POC's Motion: that "the documents did not qualify for Judicial Notice;" and that "the documents were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand."[152] Both of these justifications are in error and an abuse of the Commission's discretion.

As POC explained in its Motion, POC-4, POC-5, and POC-6 are officially noticeable. Rule 13.9 of the Commission's Rules of Practice and Procedure provides that "Official notice may be taken of such matters as may be judicially noticed by the courts of the State of California pursuant to Evidence Code section 450 et seq." California Evidence Code section 452 states that Judicial notice may be taken of "Regulations and legislative enactments issued by or under the authority of the United States or any public entity in the United States."

The documents submitted by POC were regulations or enactments issued under the authority of the United States and by a public entity in the United States. WECC's transmission

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[150] These documents were titled: Reliability Performance Evaluation Work Group– Phase I Probabilistic Based Reliability Criteria Implementation Procedure, dated June 14, 2001 (Previously markedfor therecord as POC-4); Seven Step Process for Performance Category Upgrade Request, dated October 2004(Previously marked for the record ads POC-5); WECC Board of Directors Request Regarding Performance Category Upgrade Request, dated February 20, 2013 (Previously marked for the record as POC-6).

[151] ALJ Gamson's original email ruling, dated November 15, 2013, erroneously referred to exhibits "POC-3, POC-4, and POC-5."

[152] D.14-03-004 at p. 20

planning rules and policies are part of a comprehensive transmission planning regulatory scheme implemented by the FERC, NERC, and WECC. FERC is the Federal agency responsible for regulating the national electric grid.[153] Pursuant to the Federal Power Act,[154] FERC has delegated its regulatory authority regarding reliability standards to NERC, which in turn has delegated this regulatory authority to WECC. FERC explains the relationship between FERC, NERC, and WECC as follows:

> The Energy Policy Act of 2005 (EP Act 2005) Established section 215 of the Federal Power Act, which authorized the Federal Energy Regulatory commission (Commission or FERC) to certify an Electric Reliability Organization (ERO) for the purpose of proposing reliability standards for the bulk-power system in the continental United States subject to the Commission's approval. After they are approved by the Commission, the standards are mandatory for the users, owners, and operators of the bulk power system and are enforced by the ERO under the Commission's oversight. The statute also authorized the ERO to delegate enforcement authority to a Regional Entity, subject to Commission approval. In July 2006, the Commission certified the North American Electric Reliability Corporation (NERC) as the ERO. And on June 5, 2007, the Commission accepted executed agreements between NERC and eight Regional Entities, including the Western Electricity Coordinating Council (WECC), in regard to the delegation of NERC's ERO standards development and enforcement authorities to such entities.[155]

Thus, for utilities within WECC's jurisdiction, WECC's rules, guidelines, regulations, and policies relating to compliance with NERC standards are regulations or enactments issued under the delegated authority of FERC, a public regulatory entity in the United States, by WECC, a public entity in the United States.

The documents submitted as POC-4 and POC-5 set forth WECC's official, board-approved PBRC policy, which allows for probabilistic exceptions to contingency categorization based on NERC's official categories. POC-6 is an official WECC report that applies POC-4 and POC-5 and identifies the documents as official WECC policies approved by WECC's Board.

The Decision errs in affirming ALJ Gamson's denial of the Motion based on the Utilities' argument that the documents in question do not qualify for judicial notice. WECC does not maintain a formal code of regulations. Instead, official WECC regulatory policies, including those enacted pursuant to delegated federal authority, are set forth in policy documents such as

[153] 16 U.S.C. Section 824 et. seq
[154] 16 U.S.C. Section 791(a) et. seq.
[155] Exhibit SC-01 (Powers Opening Testimony), Exhibit 1, pp. 1-2

POC-4, POC-5, and POC-6. These official policy documents are publically available on WECC's website.[156] Documents setting forth such policies are noticeable.

The Decision further errs in affirming the denial of the Motion based on the Utilities argument that "the documents were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand." Neither the Decision nor the Utilities' Motion provides any explanation as to why WECC's adoption of the PBRC process prior to the adoption of the most recent revision to NERC's standards would make the PBRC process inapplicable to the current standards. This claim is directly contradicted in the evidentiary record, which shows that SDG&E sought a PBRC recategorization of the proposed Sunrise Powerlink and Southwest Powerlink in 2008, three years after the NERC standards relied upon by the Utilities were implemented.[157] The Utilities' claim that the PBRC process set forth in POC-5 doesn't apply to the N-1-1 contingency at issue in this proceeding is unsupported by citation to any WECC policy or any other authority, and is contradicted by CAISO's admission that the PBRC process does apply.[158]

B. Striking Of POC's Opening and Reply Briefs Was a Legal Error, Abuse of Discretion, and Violation of POC's Due Process Rights

On December 4, 2013, SCE and SDG&E (the "Joint Utilities") filed a Motion to Strike several sections of POC's Opening Brief on the grounds that these sections relied on materials excluded from the Evidentiary record by ALJ Gamson's November 14, 2013 ruling denying POC's November 4, 2013 motion for Official Notice.[159]

The Joint Utilities' Motion to strike was overly broad, as only two of the six sections of POC's Opening Brief that the Utilities sought to strike cited to documents not contained in the evidentiary record, specifically, exhibits POC-4, POC-5, and POC-6. The remaining four sections cited to and relied upon exhibit POC-3, which is part of the evidentiary record. In seeking to strike these sections citing exhibit POC-3, the Joint Utilities erroneously relied on ALJ Gamson's November 14 ruling, which erroneously referred to exhibits "POC-3, POC-4, and

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[156] https://www.wecc.biz/library/default.aspx
[157] The Utilities rely on NERC reliability standard TPL-003, which was first effective April 1, 2005쩸□ŋ
[158] Tr. Vol. 11, p. 1562, lines 15-21.
[159] Email Ruling of ALJ Gamson,, Dated Novemer 14, 2013

POC-5" rather than his corrected November 15 ruling, which referred to exhibits "POC-4, POC-5, and POC-6."

The remaining two sections of POC's Opening Brief properly cited to official WECC policies as authority, not evidence. Evidence is "testimony, writings, material objects, or other things presented to the senses that are offered to prove the existence or nonexistence of a fact."[160] POC's Brief, in contrast, cites to the WECC documents setting forth WECC's PBRC process, an official regulatory policy, as *authority*.[161]

As explained above, WECC's transmission planning rules and policies are part of a comprehensive transmission planning regulatory scheme implemented by the FERC, NERC, and WECC. FERC is the Federal agency responsible for regulating the national electric grid. Pursuant to the Federal Power Act, FERC has delegated its regulatory authority regarding reliability standards to NERC, which in turn has delegated this regulatory authority to WECC. Under this scheme, WECC's rules and policies are mandatory and have the force of law. Thus, for utilities within WECC's jurisdiction, WECC exercises federal regulatory authority regarding the establishment, implementation, and enforcement of reliability standards and related policies.

The fact that the PBRC process exists and is an official WECC policy that allows for individual exceptions to mandatory NERC/WECC reliability standards is not contested by any party to this proceeding. In cross examination, both CAISO witness Sparks[162] and SDG&E witness Jontry[163] admitted that the PBRC process exists and is an official WECC policy that allows for such individual exceptions. The evidentiary record in this proceeding includes a PBRC application that SDG&E filed with WECC, seeking an exception to the categorization of the N-2 outage of Southwest Powerlink and the proposed Sunrise Powerlink transmission lines as a NERC/WECC Category C event.[164]

As an official WECC policy that allows utilities to apply for individual exceptions to mandatory NERC/WECC reliably standards, the PBRC process is an essential part of the FERC/NERC/WECC regulatory scheme regarding system reliability. As such, the official WECC documents setting forth the PBRC process are properly viewed as regulatory authority,

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[160] Cal. Evid. Code § 140.

[161] As POC explained in its Response to the Joint Motion, "Although these documents set forth an official WECC regulatory policy, and as such notice and/or inclusion in the evidentiary record is not necessary, POC made the decision to seek official notice of these documents out of an abundance of caution." At p. 3젤□η

[162] Transcript, p. 1559, line 14 to p. 1560, line 22

[163] Transcript, p. 1773, line 25 to p. 1774, line 2

[164] Ex. POC X CAISO 3

which may be directly cited to.   The Commission acted contrary to law, abused its discretion, and violated POC's due process rights by striking POC's opening and Reply briefs.

IX. IMPLICATION IN DECISION THAT LACK OF SUFFICIENT LOCAL CAPACITY MAY HAVE PLAYED A ROLE IN ACTUAL BLACKOUTS IS ERRONEOUS

The Decision references the September 2011 blackout in SDG&E territory to justify requiring new resources as a backdrop to its discussion of the advantages/disadvantages of maintaining sufficient local supply with no load shedding or to consider load shedding as one response to address the Sunrise/SWPL N-1-1 contingency.[165] The implication in Decision that lack of sufficient local capacity may have played a role in actual September 2011 blackout in SDG&E territory is erroneous.

SDG&E territory has experienced two major blackouts in the last four years.[166] Both blackouts occurred under single contingency conditions with large amounts of unused local capacity available. The first blackout was caused by the CAISO when it erroneously scheduled a generator that had already notified CAISO that it was unavailable.[167] This blackout occurred under low demand conditions just after midnight on April 1, 2010. FERC ordered CAISO to pay a $200,000 fine for this avoidable error.[168] The second blackout occurred on September 8, 2011 and was precipitated by the loss of a single 500 kV transmission line, SDG&E's Southwest Powerlink.[169]Inadequate grid management procedures were cited as the cause of this blackout by FERC, not lack of generation or transmission resources.[170] On this hot, high demand day, SDG&E was relying on less than 50 percent of the local capacity available to it in its service territory, only 1,543 MW out of 3,350 MW available.[171] SDG&E demand at the time of the blackout was 4,293 MW.[172] Most of this demand was being met by 2,750 MW of imported power when the blackout occurred. A larger quantity of unused local capacity would have made

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[165] Decision, p. 42.
[166] POC Opening Testimony, Exhibits 10 and 11.
[167] POC Opening Testimony, p. 3, Exhibit 10
[168] POC Opening Testimony, Exhibit 10
[169] POC Opening Testimony, p. 14.
[170] POC Opening Testimony, pp. 13-14.
[171] POC Opening Testimony, Exhibit 11, p. 20, p. 24, and p. 60. SDG&E load at time of blackout = 4,293 MW. Import power level at time of blackout = 2,750 MW along SDG&E Southwest Powerlink. Amount of local generation in use at time of blackout = 4,293 MW – 2,750 MW = 1,543 MW.
[172] *Ibid,* p. 60.

no difference in preventing either blackout. Thus, the Decision's entire justification for the additional procurement it authorizes is not supported by the substantial evidence in the record.

X. CONCLUSION

The Commission should correct the above identified errors in D.14-03-004.

Respectfully Submitted,

Dated: May 22, 2014

/S/

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