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)

PREPARED DIRECT TESTIMONY OF DAVID PEFFER ON BEHALF OF THE PROTECT OUR COMMUNITIES FOUNDATION

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Pursuant to Rule 13.8 of the Commission's Rules of Practice and Procedure, the Protect Our Communities Foundation ("POC") respectfully submits the following Testimony of David Peffer on Behalf of the Protect Our Communities Foundation for Track 4 of the Commission's Long Term Procurement Plan ("LTPP") proceeding, R.12-03-014.

SDG&E does not have a Local Capacity Requirement ("LCR") need for the foreseeable future. In the instant proceeding and in related proceedings (Track 2 of R.12-03-014, A.13-06-015, and A.11-05-023), SDG&E and CAISO have attempted replace this concrete reality with a "paper reality" of their own creation, one in which an illusory 500 MW LCR need must be met with costly (for ratepayers) and profitable (for SDG&E) new generation projects. SDG&E and CAISO have attempted to substitute this "paper reality" for objective fact in three ways:

1. SDG&E and CAISO have attempted to impose an arbitrary and unreasonable Category D event, the N-1-1 loss of the Sunrise Powerlink and the Southwest Powerlink, as the limiting contingency reliability criterion. This largely erases the reliability contributions of the Sunrise Powerlink transmission line and artificially adds 400 MW of LCR need.
2. This unwarranted redefinition of the limiting contingency by SDG&E and CAISO has selectively restricted the San Diego local area cutplane to unreasonably exclude 1,080 MW in generation assets connected to SDG&E's Imperial Valley substation.
3. SDG&E has assumed that the State Water Resources Control Board's Once-Through Cooling ("OTC") Guidelines require the retirement of the Encina Generating Station, while simultaneously using its significant negotiating power to force Encina to retire by making Encina's compliance with OTC guidelines economically infeasible.

I. SDG&E and CAISO's N-1-1 Criterion is Arbitrary and Unreasonable

A. <u>Background on Reliability Criteria and N-1-1</u>

Reliability standards and reliability criteria are rules designed to ensure that a local area has sufficient generation and transmission capacity to meet the designated limiting contingency. Reliability standards are established by the North American Electric Reliability Corporation ("NERC"). Federal law requires that utilities comply with the reliability standards set by NERC. The official NERC reliability standard is "N-1." Under an "N-1" standard, utilities must procure sufficient generation to cover for an N-1 contingency – the loss of a local area's single largest transmission line.[1]

Reliability criteria are additional reliability guidelines set by transmission planning entities, such as CAISO. Shortly after CAISO's inception in the late 1990s, CAISO's board of directors voluntarily opted to impose a planning criterion that was significantly more stringent than the mandatory NERC standard.[2] While NERC's N-1 standard requires that utilities procure enough generation to cover for the loss of an area's single largest transmission line, CAISO's "G-1, N-1" criterion requires utilities to procure enough generation to cover for a G-1, N-1 contingency – the simultaneous loss of both an area's largest power plant ("G"), and the area's largest transmission line ("N").

G-1, N-1 remains CAISO's official planning criterion to this date, and was reaffirmed by CAISO in its most recent 2011 update to the planning standard.[3]

In 2012 CAISO introduced a new limiting contingency, N-1-1, for the San Diego local area. Applied to San Diego, N-1-1 is substantially more stringent than CAISO's stated G-1, N-1 criterion. It is in fact an NERC Category D event. Category D events are of such low probability that utilities are not expected to plan for them. As SCE states, "Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and

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[1] NERC, *Standard TPL-002-0b — System Performance Following Los s of a Single BES Element*, October 24, 2011http://www.nerc.com/files/tpl-002-0b.pdf, attached hereto as **Exhibit 1**.
[2] K. Edson, CAISO, *CAISO Response to Powers Engineering*, November 7, 2012, attached hereto as **Exhibit 2**.
[3] CAISO, *California ISO Planning Standards*(http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf), June 23, 2011, p. 4, attached hereto as **Exhibit 3**. "2. Combined Line and Generator Outage Standard: A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002)." p. 10: "The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G -1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO."

consequences."[4] San Diego's G-1, N-1 contingency is the concurrent outage of the 604 MW Otay generation plant and the ~2,000 MW Southwest Powerlink transmission line. San Diego's N-1-1 contingency is the concurrent outage of the ~1,000 MW Sunrise Powerlink transmission line and the 2,000 MW Southwest Powerlink. Thus, to meet an N-1-1 criterion (by procuring sufficient generation capacity to cover for an N-1-1 contingency) SDG&E would be required to procure 400 MW more than it would to meet a G-1, N-1 contingency. In effect, the N-1-1 standard imposes a net "loss" of 400 MW of otherwise available local capacity under the G-1, N-1 limiting contingency. In addition, N-1-1 keeps SDG&E's Imperial Valley Substation out of the LCR, removing 1,080 MW of combined cycle capacity connected to the Imperial Valley Substation from the LCR.[5]

According to the planning standard stakeholder webpage, the most recent update to the CAISO standards was the result of a stakeholder process: "*The ISO is revising its reliability planning standards, which will be consistently applied by all participating transmission owners within the ISO grid, to reflect current NERC and WECC standards and industry practices*."[6] CAISO's switch to a Category D N-1-1 limiting contingency for the San Diego area was not the result of a stakeholder process.

Adopting an N-1-1 criterion would force SDG&E ratepayers to cover the cost of this additional 400 MW of generation capacity. The cost of this capacity is likely to significantly exceed $1.6 billion dollars (the cost of the SDG&E's proposed PPA with the 305 MW Pio Pico plant currently being considered in A.13-06-015).[7]

[4] SCE testimony, p. 22, lines 4-6.
[5] CAISO. "2011-2013 Local Capacity Technical Analysis Report and Study Results," December 29, 2008, p. 92. See: http://www.caiso.com/20ad/20ad77d04d70.pdf.
[6] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/TransmissionPlanningStandards.aspx
[7] SDG&E Bill Insert, "Notice of Application 13-06-XXX To Fill the Local Capacity Requirement Need Identified in CPUC Decision 13-03-029," attached hereto as **Exhibit 4**.

B. <u>The Commission has not considered the reasonableness of N-1-1</u>

The Commission has not, in any proceeding, directly considered the reasonableness of CAISO's N-1-1 criterion for the San Diego area. The Commission has not, in any decision, reached a finding of fact or law regarding the reasonableness of the N-1-1 criterion. In no Commission proceeding have the parties presented valid arguments in support of N-1-1 or developed a sufficient evidentiary record upon which the Commission could reach a substantial evidence-based determination of the reasonableness of the N-1-1 criterion.

The N-1-1 standard was first introduced by CAISO in a related CPUC proceeding – A.11-05-023, which involved an application by SDG&E to enter into three Power Purchase Agreements. In their initial testimony in A.11-05-023, neither SDG&E nor CAISO asserted an N-1-1 standard. Instead, both advocated for the use of CAISO's Once Through Cooling ("OTC") Study, which used CAISO's official G-1, N-1 standard. Subsequently, CAISO witness Robert Sparks submitted Supplemental Testimony amending CAISO's initial position and introducing the N-1-1 standard. Sparks stated:

> "…after my initial testimony was served, SDG&E told the ISO that the newly revised WECC criterion for common corridor circuit outages would result in a reclassification of the Sunrise/IV Miguel double outage as a category D contingency because the towers on the two lines are spaced less than '250 apart for less than 3 miles (which is the new WECC criteria). This re-categorization of the common corridor circuit outage as a Category D contingency required the ISO to re-assess its local studies."[8]

[8] Supplemental Testimony of Robert Sparks, A.11-05-023, at p. 1, attached as **Exhibit**

Significantly, nowhere in CAISO's testimony nor its briefs did CAISO quote or cite to the WECC criterion in question. Nor did CAISO quote, cite to, or seek judicial notice of the WECC proceeding wherein changes to the relevant criterion were being considered, WECC-0071, or documents from that proceeding's detailed and publically available record.[9] Rather, CAISO proposed the imposition of a new reliability standard – a major policy shift with multi-billion dollar implications – based solely on hearsay (what "SDG&E told the ISO").

CAISO's brief, unsupported, hearsay claim that a change in WECC criteria requires N-1-1 is the only justification for the switch to an N-1-1 reliability criterion presented by SDG&E or CAISO in any CPUC proceeding (including this proceeding and related proceedings A.13-06-015 and A.11-05-023).

C. N-1-1 is a NERC Category D contingency and as such can not be a reasonable reliability criterion

The mandatory reliability standards adopted by NERC and enforced by NERC and WECC are based on four contingency categories. "Category A" refers to normal system conditions with no contingencies and all facilities in service. "Category B" refers to an event resulting in the loss of a single element. "Category C" refers to an event resulting in the loss of two or more (multiple elements). "Category D" refers to an "extreme event resulting in two or more elements removed or cascading out of service." Directly relevant to this analysis are Category C and Category D described in the following NERC charts:[10]

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[9] The Docket for WECC-0071 is available at: https://www.wecc.biz/standards/development/wecc-0071/default.aspx

[10] NERC Standard [illegible]2b, at [illegible] pp. 5, attached hereto as **Exhibit 6**

C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

NERC standards require that utilities have sufficient generation and transmission resources available to mitigate Category B contingencies without load shedding. The NERC Category B standard, TPL-002-2b, Requirement R1, states:

> The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I.[11]

Utilities are also required to have sufficient resources available to mitigate Category C contingencies. However, in meeting Category C contingencies utilities are allowed to load shed. NERC Category C standard, TPL-003-2b, Requirement R1 states:

> The Planning Authority and Transmission Planner shall each demonstrate through

[11] Exhibit 1, NERC Standard TPL-002-2b, at p. 1.

a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.[12]

In contrast, Category D contingencies are events so rare and extreme that NERC does not require utilities to mitigate for them. Instead, the standard governing Category D contingencies, NERC Standard TPL-004-2a, Requirement R1, merely requires that the planning authority (CAISO) and transmission planner (SDG&E) "demonstrate through a valid assessment that its portion of the interconnected transmission system is *evaluated* for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I."[13] (*emphasis added*). In its Opening Testimony, SCE reiterates this definition of Category D contingencies, stating that "Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences."[14]

Thus, the reasonableness of CAISO and SDG&E's proposed N-1-1 standard and procurement based on N-1-1 hinges on whether N-1-1 is a NERC Category C contingency that must be mitigated, or a NERC Category D contingency that, by definition, is so rare and extreme that it is only required to be evaluated.

In the instant proceeding, both SDG&E and CAISO claim that N-1-1 is a Category C contingency. In SDG&E's Opening Testimony, Jointry succinctly asserts that "N-1-1 is a NERC Category C contingency."[15] Similarly, CAISO's Track 4 Opening Testimony states:

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[12] NERC Standard TPL-003-2b, at p. 1, attached as Exhibit P6
[13] NERC Standard TPL-004-2a, at p. 1, attached as Exhibit P7
[14] SCE Opening Testimony at p. 22
[15] At p. 7

> The Revised Scoping Ruling recommended a total of 189 MW of DR to be used for the SONGS Study Area under post first contingency, in preparation for the second contingency condition. This condition is sometimes referred to as an overlapping N-1-1 contingency condition, and is considered a Category C (C.3) contingency by both NERC and WECC reliability standards.[16]

Both the SDG&E and CAISO testimony specifically identify the outage of Southwest Powerlink and Sunrise Powerlink in their common corridor as their N-1-1 contingency. SDG&E's Jointry testimony states "The system condition that determined the generation need is the overlapping outage (N-1-1) of the ECO-Miguel section of the Southwest Powerlink 500 kV line and the Ocotillo Express-Suncrest section of the Sunrise Powerlink 500 kV line."[17] Similarly, CAISO's Opening Testimony repeatedly refers to: "an N-1-1 contingency of the Sunrise Powerlink, system readjusted, followed by the Southwest Powerlink line outage."[18]

Contrary to SDG&E and CAISO's claims, N-1-1 outage of Sunrise Powerlink and Southwest Powerlink is clearly and uncontestably a NERC Category D contingency under both NERC standards and WECC guidelines. The NERC/WECC planning standards *specifically* state that "the loss of all transmission lines on a common right-of-way" is a Category D contingency.[19] Similarly, WECC criterion TPL-001-WECC-RBP-2.1 specifically excludes "Adjacent Transmission Circuits that share a common right-of-way for a total of three miles or less, including – but not limited to – substation entrances, pinch points, and river crossings" from Category C (thus making them Category D).[20]

CAISO has previously *admitted* that N-1-1 is a Category D contingency. CAISO's justification for first introducing N-1-1 in A.11-05-023 was that:

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[16] At p. 6

[17] At p. 3

[18] At p. 6

[19] Exhibit 7 at p. 5

[20] WECC Criterion TPL-001-WECC-RBP-2.1, at p. 3, attached as Exhibit 8

> SDG&E told ISO that the newly revised WECC criterion for common corridor circuit outages would result in a reclassification of the Sunrise/IV Miguel double outage as a Category D contingency because the towers on the two lines are spaced less than 250' apart for less than 3 miles (which is the new WECC criteria). *This re-categorization of the common corridor circuit outage as a Category D contingency required the ISO to reassess its local studies*.[21]

Because N-1-1 is a Category D contingency, an event so unlikely and extreme that NERC does not require utilities to plan for it, SDG&E and CAISO's attempt to apply an N-1-1 criterion to the San Diego area and justify generation procurement based on N-1-1 is unreasonable.

D. <u>N-1-1 is not a credible contingency and adopting N-1-1 would not provide a clear, cost-effective reliability benefit to ratepayers</u>

The reasonableness of N-1-1 is not an abstract question. The N-1-1 contingency refers to a real-world event – the concurrent outage of Sunrise Powerlink and Southwest Powerlink.[22] N-1-1 and related procurement are unreasonable because: (1) N-1-1 is not a credible contingency with a significant likelihood of occurring; (2) adopting an N-1-1 contingency and authorizing related procurement will not result in a substantial reliability benefit to ratepayers; and (3) any benefit to ratepayers is not significant enough to justify the multi-billion dollar cost of acquiring an additional 500 MW of generation capacity.

N-1-1 is not a credible contingency upon which a reliability criterion can reasonably be based. WECC has assessed the outage frequency associated with each NERC performance category (on an outage/year basis).[23] Category B contingencies have an outage frequency of 0.33 per year or greater. Roughly speaking, this means Category B events occur at intervals of

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[21] Exhibit 6 at p. 1 (*emphasis added*)
[22] *See* SDG&E Opening Testimony (Jointry) at p. 7, CAISO Opening Testimony at p. 6.
[23] Exhibit 8 at p. 8.

three years or less. Category C contingencies have an outage frequency from 0.033 per year to 0.33 per year. Category D contingencies are highly unlikely, having an outage frequency of less than 0.033 per year, or fewer than one Category D event every 30 years.

The WECC specifically amended its guidelines regarding common corridor outages (such as San Diego's N-1-1 Sunrise Powerlink / Southwest Powerlink common outage) because of the extremely low likelihood of simultaneous outages of two separate transmission lines sharing a common corridor and separated by 250 feet or more centerline-to-centerline.[24]

The most likely scenario that could cause an N-1-1 event involving Southwest Powerlink and Sunrise Powerlink is a wildfire. WECC stated that the likelihood of a fire leading to a simultaneous outage of two transmission lines in the same corridor (such as Sunrise Powerlink and Southwest Powerlink) was too low to justify treating a simultaneous outage as a Category C contingency:

> The primary reason for the previous distance was to mitigate outages caused by fire. The time between common outages as a result of fire varies, depending upon the rate the fire advances. Often Transmission Operators have time to reduce transfers, even though the fire is moving at a rapid rate, because they are notified of the fire in the area. The time delay between outages caused by fire, and the advance preparation that is likely for fires, reduces the severity of the multiple circuit outages when there are separate towers. The Drafting Team believes that requiring increased performance equivalent to a double-circuit outage on a common tower for this condition is not warranted.[25]

It is uncertain that applying the stricter N-1-1 reliability standard and procuring additional resources based on N-1-1 would result in any actual reliability benefit to ratepayers. The SDG&E load pocket has experienced two major blackouts in the last three years. Both blackouts occurred under single contingency conditions. The first blackout was caused by the CAISO when it erroneously scheduled a generator that was in forced outage. This blackout was caused by a G-

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[24] See WECC-0071 TPL-001-WECC-CRT-2 Posting 3 Clean, at p. 7, attached hereto as **Exhibit 19**.
[25] *Id.* at p. 6

1 condition that was not addressed in a timely manner. FERC ordered CAISO to pay a $200,000 fine for this error.[26]

The second blackout occurred on September 8, 2011 and resulted from the loss of a single 500 kV transmission line.[27] Inadequate grid management procedures were cited as the cause, not lack of generation or transmission resources. Planning to adjust to the loss of a single transmission line with little or no load shedding is the NERC planning standard. CAISO's more stringent transmission standard has not in practice avoided blackouts that resulted from single contingency events. The benefit of maintaining high levels of capacity reserves, if any, has not been critically evaluated by the CPUC. The number of blackouts in SDG&E territory has risen concurrently with the cost of maintaining high levels of capacity reserves.

Given the low likelihood of an "extreme" N-1-1 event, and the uncertainty that mitigating for a N-1-1 contingency will result in any actual reliability improvement, the multi-billion dollar cost to ratepayers of N-1-1 and related procurement is unreasonable.

E. Adopting N-1-1 will substantially harm ratepayers by reducing the value of their investment in Sunrise Powerlink

CAISO's switch to N-1-1 nullifies a significant portion of the reliability benefit to ratepayers used to justify SDG&E's $2 billion Sunrise Powerlink project.

Sunrise Powerlink was presented to the public and justified to the Commission as a project that would significantly increase San Diego's long-term reliability. The Commission

[26] FERC, Order Approving Stipulation and Consent Agreement, Docket No. IN13-4-000, Issued December 14, 2012, at p. 2, attached hereto as **Exhibit 10**.
[27] FERC, *Arizona – Southern California Outages on September 8, 2011: Causes and Recommendations*, April 27, 2012, attached hereto as **Exhibit 11**. See: http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

approved Sunrise Powerlink on the grounds that it would add 1,000 MW of Local Reliability under the G-1, N-1 standard. In the Commission's decision approving Sunrise Powerlink, the Commission noted:

> SDG&E's Local Capacity Requirement – both now and in the future – is a critical factor in determining whether Sunrise or other generation or transmission resources are needed to meet reliability criteria. Pursuant to reliably 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 its 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.[28]

The Decision's Finding of Fact 14 places a specific cash value on the Sunrise Powerlink's reliability benefit to ratepayers:

> 14. Modeling performed by the CAISO, updated for our baseline assumptions, demonstrates total projected reliability benefits of [Sunrise Powerlink built along] the Environmentally Superior Southern Route to be $214 million per year.[29]

The CPUC must not allow CAISO and SDG&E to pull a "bait and switch" on SDG&E ratepayers – justifying a $2 billion dollar transmission line based on claimed reliability benefits

[28] D.06-08-010 at p. 28
[29] D.06-08-010 at p. 285

under the G-1, N-1 standard, then changing the standard to obviate the Sunrise Powerlink's reliability benefits to justify even more reliability procurement. Switching from G-1, N-1 to N-1-1 would effectively reduce the reliability benefit of Sunrise Powerlink by 40% (the 1000 MW reliability loss under the N-1-1 standard is partially offset by the 604 MW Otay Plant, which is not assumed out as it would be under N-1, G-1), and exclude existing combined cycle RA capacity connected to the Imperial Valley Substation. Ratepayers have invested $2 billion in Sunrise Powerlink. A 40% reduction of the value of this investment amounts to an $800 million loss to ratepayers. Assuming that the Commission's Finding of Fact 14 is correct, a loss of 40% of the reliability value of Sunrise Powerlink will harm ratepayers at the rate of $85 million per year.

II. CAISO and SDG&E have manipulated the definition of the San Diego Local Area to exclude generation assets

The San Diego Local Area definition used by SDG&E and CAISO in the instant proceeding differs significantly from the Local Area Definition previously established by SDG&E, CAISO, and the Commission. This inconsistency has resulted in the wrongful exclusion of generation assets from the San Diego Local Area and the overestimation of LCR need.

On December 14, 2012 the Federal Energy Regulatory Commission ("FERC") issued an order resolving the agency's investigation into the blackouts that occurred in the San Diego area between March 31 and April 1, 2010. The Order reveals that SDG&E and CAISO had counted the approximately 500-MW La Rosita II power plant toward meeting the LCR for April 1, 2010. FERC stated:

> On March 31, 2010, CAISO, in conjunction with SDG&E, established its Day-Ahead schedule for April 1, 2010. CAISO scheduled the Central La Rosita II Generating Unit (La Rosita II) to provide a substantial portion of the Internal Generation needed to meet the 25 percent Requirement during the first several hours of April 1, 2010.[30]

SDG&E, CAISO, and the Commission regularly included the combined generation capabilities of the La Rosita II power plant and another Mexico-area plant operated by SDG&E's parent company, the approximately 600-MW Sempra TDM plant as LCR. For instance, in Attachment 1 to SDG&E's LTPP Scoping Memo (R.10-05-006), the Commission lists SDG&E's total combined cycle and simple cycle turbine local capacity as 2,978 MW in the 2010 LTPP.[31] In its 2008 Local Capacity Report, CAISO states that completion of the Sunrise Powerlink will make available 1,084 MW of additional local capacity from the La Rosita II and Sempra TDM combined cycle export projects (with generator ties to the Imperial Valley Substation).[32] The only difference in the 1,894-MW quantification of existing local capacity in SDG&E's 2010 LTPP Local Need Worksheet[33] (at pp. 1-2) and the 2,978 MW calculation made by the Commission in Attachment 1 to SDG&E's LTPP Scoping Memo is the 1,084 MW of Mexicali export capacity represented by the La Rosita II and Sempra TDM plants.

Despite CAISO's prior practice of dispatching the Mexicali plants connected to SDG&E's Imperial Valley Substation as internal SDG&E generation to meet local capacity needs, CAISO excluded these assets from the definition of the San Diego Local Area it used in its 2011/2012 OTC Study. This significant break from prior "real world" practice resulted in the

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[30] Exhibit 10 at p. 2.

[31] Attachment 1 (Standardized Planning Assumptions (Part 1) for System Resource Plans) to SDG&E's December 3, 2010, Long-Term Procurement Plan Scoping Memorandum in Commission Rulemaking 10-05-006, at p. 19, attached hereto as **Exhibit 12**.

[32] CAISO's December 29, 2008, 2011-2013 Local Capacity Technical Analysis Report and Study Results, at p. 92, attached hereto as **Exhibit 13**.

[33] SDG&E's Local Need Workpaper in its 2010 LTPP proceeding, Commission Rulemaking 10-05-006, at p. 1-2, attached hereto as **Exhibit 14**.

artificial exclusion of 1,084 MW of local generating capacity from the La Rosita II and Sempra TDM plants.

In light of available evidence, the Commission must reject SDG&E and CAISO's unreasonable attempt to redefine the San Diego Local Area to exclude generation capacity. Any need determination or procurement authorization must be based on a San Diego Local Area definition that includes the La Rosita II plant, the Sempra TDM plant, and all other generation assets connected to the Imperial Valley substation. The 1,084 MW of energy represented by these facilities obviates any local capacity need identified by SDG&E.

III. Retirement of the Encina OTC plant should not be assumed

It is unreasonable to assume the retirement of the Encina OTC ("Once-Through-Cooling") plant.

Both SDG&E and CAISO assume that Encina will be retired. SDG&E states:

> SDG&E assumed all 964 MW of dependable capacity at the Encina power plant would be retired, including the 14 MW combustion turbine at the site that does not use OTC.[34]

Similarly, CAISO states:

> For San Diego sub-area, the ISO identified the need for repowering or replacement of 520 MW of OTC generation in the northwest area, adding 100 MW of resources in the southwest area, and constructing 300 MW of new generation in the southeastern San Diego area. These locations are based on known resource development in the San Diego area.[35]

The State Water Resources Control Board's OTC policy does not require retirement of the Encina OTC plant. Rather, it merely requires that OTC plants either reduce intake flow and

[34] Anderson Opening Testimony at p. 8
[35] CAISO Opening Testimony at p. 20

velocity (Track 1 compliance) or reduce impacts to aquatic life comparably by other means (Track 2 compliance).[36]

SDG&E has used its significant negotiating power to force Encina into retirement. The company that operates Encina 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 a Power Purchase Agreement:

> Cabrillo no longer intends to pursue Track 2 compliance for Units 4 and 5. Instead, Cabrillo anticipates operating Units 4 and 5 in their current configuration until the OTC policy compliance date of December 31, 2017, and then retiring the units. Since the filing of the IP [the March 2011 Implementation Plan], Cabrillo has conducted further analysis of potential Track 2 compliance options to meet the Impingement Mortality and Entrainment reduction requirements in the OTC Policy. Cabrillo has determined that the implementation of technological and/or operational controls to achieve the requisite reductions at Units 4 and 5, while technologically and logistically feasible, may not be economical without a multi-year PPA that accounts for the capital expenditure and potential reduction in plant efficiency.[37]

Cabrillo has been unable to secure a PPA with SDG&E because SDG&E has used its significant negotiating advantage to impose contract conditions that make OTC compliance economically impractical. Under SDG&E's 2009 RFO[38] (and subsequent one-year RA contracts with Encina),[39] Cabrillo may not include the cost of upgrading or retrofitting Encina to comply with the OTC policy in its offer:

> In consideration of California State Once through Cooling (OTC) goals and pending Water Board rules, any Offer for supply from a unit utilizing OTC will be offered a contract with SDG&E that consists of a 2 year transaction with the possibility to extend for eight – 1 year options. OTC offers shall not include proposals for upgrades or retrofits of OTC facilities. The decision to exercise the option will be based upon future rules governing OTC or SDG&E's sole discretion given its portfolio need.

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[36] http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/
[37] 2013 NRG Information Update to SWRCB, at p. 5, attached hereto as **Exhibit 15**.
[38] SDG&E 2009 RFO, at p. 3 (document p. 88), attached hereto as **Exhibit 16**
[39] SDG&E Advice Letter 2390-E, attached hereto as **Exhibit 17**

It is highly unusual for a utility to refuse to allow the inclusion of legally-mandated compliance costs in offers. SDG&E has admitted that: "Most, if not all, generators include costs related to compliance with government mandates in the pricing for their generation resources. Hence, it is reasonable to assume that all offers include some government-mandated compliance costs."[40]

SDG&E has explained its decision to exclude OTC offers that include costs associated with upgrading or retrofitting OTC facilities on the grounds that "There was substantial concern for costs ratepayer (sic) may bear regarding plants subject to OTC regulations."[41] This is not a valid justification, as any offers including compliance costs would still be subject to the competitive RFO process. If including compliance costs actually rendered Encina too costly, then the Encina offer would be out-competed by other generators.

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."[42] 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."[43]

By refusing to allow Encina to include compliance upgrade costs in its contracts, SDG&E is denying ratepayers the benefit of an "apples to apples" comparison of most cost-effective generation options. It may be that, even with OTC compliance costs factored in, Encina generation is significantly more cost-effective than other existing and proposed resources. It would be unreasonable for the Commission to allow any generation procurement based on

[40] SDG&E Response to POC DR-1, Question 5(e), attached hereto as **Exhibit 18.**
[41] SDG&E Response to POC DR-1, Question 5(c)
[42] CAISO testimony at p. 17
[43] A.11-05-023, SDG&E Anderson Testimony, at p. 3, attached hereto as **Exhibit 19**.

projections that assume the retirement of potentially competitive generation that has been effectively forced into retirement.

IV. Scoping Memo assumptions must be updated

Pursuant to ALJ Gamson's request at the September 5, 2013 Prehearing Conference, POC requests that the following assumptions from the May 21, 2013 Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge, Attachment A, be updated to correct errors of fact and law contained therein.

A. N-1-1

To the extent that any of the Attachment A assumptions integrate, rely upon, or reference the N-1-1 reliability criterion proposed by SDG&E and CAISO, these assumptions are in error for reasons specified in Section I, above, and must be corrected or removed.

B. OTC Retirement

For the reasons specified in Section III, above, the Scoping Memo Attachment A assumption that the Encina OTC plant will be retired is in error and must be amended.

Respectfully Submitted,

Dated: September 30, 2013

/S/

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