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

TRACK 4 REPLY BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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On November 25, 2013, parties to this Track 4 proceeding, including the California Independent System Operator Corporation (ISO), filed opening briefs on the issues raised in testimony and in comments. According to the schedule established by ALJ Gamson at the close of the hearing, the ISO herewith submits its reply to assertions and arguments in the opening briefs that pertain to the issues addressed by the ISO.

I. The Need for Additional Resources in the SONGS Study Area has been Clearly Established; Procurement Requested by SCE and SDG&E Should be Authorized Immediately.

In its opening brief, the ISO presented a detailed description of the residual resource needs identified by power flow studies conducted by the ISO, SCE and SDG&E.[1] These residual resource needs range from 2300-2542 MW, depending on the split of resources between the SCE and SDG&E local areas. The City of Redondo Beach also conducted separate power flow studies which, while adopting different assumptions, form the basis for the City's recommendation that a combination of 1000 MW of conventional resources, plus 2000 MW of

[1] ISO brief at p. 32.

preferred resources, be authorized for the LA Basin local area with 1100 MW of conventional resources in the San Diego area.[2] No other party to this proceeding conducted analytical technical studies or, for that matter, any studies, that seriously dispute these conclusions. In addition, no party presented any credible evidence or advanced any logical argument that would lead to any conclusion contradicting the results of the technical studies, which clearly establish these local area needs starting in 2018 unless additional steps are taken and without changes to the compliance dates for the once-through-cooled (OTC) units assumed to be going offline. Furthermore, there seems to be general agreement that, to the extent local capacity needs are being triggered by OTC retirement and the SONGS closure, these needs can be filled by a combination of resources, with particular emphasis on preferred resources.

Many parties have predictably focused on two topics: 1) whether the study assumptions should be modified to include both updated information not considered in the May 21 Revised Scoping Ruling and additional amounts of preferred resources; and 2) whether involuntary load dropping, in blocks of 500 MW, should be adopted as a resource planning tool to address these substantial local needs.[3] Many parties have also urged the Commission to take a "wait and see" approach to additional resource authorization until the ISO has completed the 2013/2014 transmission plan and considered the extent to which transmission mitigation solutions, including reactive support requirements, will offset the need for local resources.

Despite the volumes of discussion and arguments set forth in opening briefs, the immediate path forward outlined by SCE and SDG&E and supported by the ISO is still the best approach: an interim "no regrets" all-source procurement authorization of 500 MW for SCE and

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[2] Redondo Beach brief, p. 3.

[3] *See, e.g.*, opening briefs filed by CEJA, ORA, TURN, Sierra Club, NRDC, among others.

550 MW for SDG&E, with additional resource needs met through a combination of preferred resources, energy storage, transmission solutions and other alternatives to transmission or conventional generation. As discussed extensively in its opening brief, the ISO considers this "no regrets" approach to be the most reasonable outcome of this Track 4 proceeding, with transmission alternatives and other options considered in the upcoming 2014/2015 LTPP.[4]

II. The Commission Should not Stray from the Original Intent of Track 4 by Adjusting the Study Assumptions.

As noted in the ISO's opening brief, several parties argued in comments and testimony that the Commission update the Track 4 study assumptions set forth in the Revised Scoping Memo for the current draft CEC load forecast and recently adopted energy efficiency standards, and also adjust the Track 4 assumptions to increase the amount of preferred resources beyond the levels adopted in D.13-02-015 and D.13-03-029. The ORA, CEJA and NRDC briefs contained extensive arguments along these lines, and these parties raised similar concerns in Track 1 and virtually every other proceeding in which the ISO (and other parties) submit study results. However, there are two fundamental problems with following this approach.

First, reaching back into time to change the load forecast and study assumptions simply flies in the face of the whole purpose of Track 4. It bears repeating that Track 4 was added to this LTPP to test the assumptions adopted in the two prior proceedings in light of the SONGS outage – not to re-litigate and modify D.13-02-015 and D.13-03-029. The Commission asked the ISO to provide information about residual local capacity needs in the combined SONGS

[4] The ISO notes that several parties focused on the ISO's previous recommendation, discussed at the prehearing conference on September 4, 2013, that Track 4 be extended into 2014, which would allow the Commission to reach a holistic decision on all local resource needs. However, as the ISO explained in rebuttal testimony, after further considering the SCE and SDG&E interim authorization requests as well as the Commission's desire to move forward on the established Track 4 procedural schedule, the interim "no regrets" approach is preferable to any other recommendations. ISO brief, p. 3.

study area, and that is exactly what the ISO did. Changing the study assumptions in Track 4 is tantamount to admitting that decisions issued in the first quarter of one year quite possibly will have no validity by the fourth quarter of the same year and are therefore subject to constant modification. This is particularly unsettling for procurement decisions issued in the same biennial long term procurement proceeding where utilities must take steps to solicit and contract for resources. Proposed study assumptions that will be used by the ISO in the upcoming 2014/2015 biennial LTPP have already been presented for stakeholder consideration at an upcoming workshop scheduled for December 18, and updates to the studies conducted in the 2012/2013 LTPP tracks can be considered in that venue. In contrast to wholesale changes to decisions that are already being implemented, the Commission's reason for establishing Track 4 was not only consistent with the work previously accomplished but consistent with the notion specifically identified in D.13-02-015 that SONGS was considered to be online in the Track 1 studies.[5]

The ISO's second fundamental concern with the suggestions that the study assumptions and load be revisited in Track 4 according to the current schedule is that there is no time left for the ISO to revise its studies. However, restudying would be required because, as the Commission acknowledged in both D.13-02-015 and D.13-03-029, simply increasing the level of preferred resources does not equate to a one-for-one reduction in the local area resource needs.[6] The parties advocating simple reductions from the LCR needs identified through comprehensive power system studies did not conduct their own studies and therefore have no valid basis for following this course.

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[5] *See, e.g.,* D.13-02-015 at p. 88, Finding of Fact No. 2.

[6] D.13-02-015 at p. 50; D.13-03-029 at p. 10.

In particular, CEJA recommends that for the purposes of the Track 4 decision the Commission adopt changes to the load forecast, DR, small PV, EE and energy storage assumptions used by the ISO, without in-depth analysis and based on high-level arguments.[7] For the demand forecast and additional achievable EE levels, CEJA basically argues that the Commission should use the latest information available, highlighting the ISO's concerns that following this approach leads to a never-ending cycle of studies without ever reaching conclusions that have any certainty. With respect to the 2013 load forecast, the ISO did recommend in opening testimony that delaying a Track 4 decision to include the results of the ISO's transmission planning process would allow for the updated load forecast to be considered in the decision.[8] However, this recommendation assumed that the ISO would produce revised study results for Commission evaluation, rather than the mathematical exercise that CEJA recommends. Because the Commission intends to issue a Track 4 decision prior to the time that the ISO's studies are finalized, the 2013 load forecast and updated achievable EE levels can be considered in the upcoming 2014/2015 LTPP local and system studies.[9]

With respect to energy storage, CEJA implies that the Commission will be "ignoring the substantial likelihood that that such clean and flexible resources will be available for local reliability purposes" by not assuming that the storage level contemplated in D.13-10-040 will have the necessary local capacity characteristic and used to reduce additional local capacity needs.[10] Once again, this argument oversimplifies the many variables associated with storage

[7] CEJA brief, pp. 10-11.

[8] ISO-1, p. 30.

[9] *See* Proposed Decision opening the 2014/2015 LTPP issued December 9, 2013 at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M082/K835/82835571.PDF

[10] CEJA brief, p. 38.

procurement, such as location, which CEJA acknowledges but sweeps aside by stating that the utilities simply "must procure storage located in areas with demand for peak power, areas where investment in generation, transmission or distribution would occur, or areas with grid reliability issues."[11] As to SCE's concerns with the cost of energy storage, CEJA relies on testimony provided by Sierra Club witness Powers that a four hour battery replacement is "excessive" for local capacity needs, and that there is a substantial difference in the capital costs of two hour battery replacement. This scant level of technical detail is wholly insufficient to make wholesale changes to the energy storage assumptions used in the ISO studies and reduce local capacity needs. Storage options still represent significant costs over and above other options. This was recognized and addressed through reasonable energy storage targets adopted in D.13-10-040 to be incorporated into the IOUs RFOs to fill the residual resource needs identified in the Track 4 decision, as described in the SCE and SDG&E testimony. That decision should not be relitigated in this one.

The ISO addressed CEJA witness May's testimony with respect to the ISO's modeling of "second contingency" DR, noting that the 997 MW available to address post second contingency reliability issues does not have the characteristics needed to respond within the time period needed to adjust the system after the first contingency.[12] The ISO also noted that the Commission, the ISO and other parties are working hard to develop additional DR programs with the necessary characteristics to be available as local capacity resources. Undaunted by the logic of the Revised Scoping Memo's directive, CEJA continues to argue in its brief that the local capacity needs should be reduced by 997 MW simply because the Commission has

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[11] *Id.*, p.37-38.

[12] ISO brief, pp. 12-14.

instituted an OIR to address the need for further DR program development which is "likely to increase the role of DR in the SONGS study area."[13] CEJA also quotes a bit of cross-examination testimony from Mr. Millar about the possibility that some DR programs could be given sufficient advance notice under certain circumstances that response might be needed within a certain time period. Mr. Millar's testimony indicated that the ISO had not been actively exploring additional advance notice of possible times when demand response may be at risk of being called upon. Mr. Millar also clarified that this advance notice hadn't been identified by industry to the ISO during its consultation processes as an issue that was material in helping demand response meet the 30 minute overall requirement for demand response meeting post-first-contingency needs.[14] These very broad concepts should not, under any circumstances, lead the Commission to reduce local capacity needs by an astonishing 997 MW rather than addressing the development of DR programs through the channels that have previously been established.

CEJA's arguments about "second contingency" small PV are equally unpersuasive and provide absolutely no information or guidance as to how the ISO was to model PV "in the most effective locations" beyond the levels that were included in the first contingency assumptions. Needless to say, "the likely implementation of smart inverters and a smarter grid in general" does not provide a valid basis for changing the study assumptions and the ISO's modeling.[15]

Like CEJA, Sierra Club advances the same arguments about adjustments to the modeling assumptions without providing detail or analysis. In addition, Sierra Club requests that an additional 528-1540 MW of DG be deducted from local capacity needs, based on several

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[13] CEJA brief, p. 41.

[14] Tr.1606: 26-1607: 1.

[15] *Id.*, p. 42

programs recently created by legislation and on promising descriptions about the capability of these small scale distributed resources.[16] While such resources will definitely play a role in meeting local needs, the lack of locational information and other technical details should dissuade the Commission from adding to the levels of small DG already included in the study assumptions.

III. Transmission Mitigation Solutions Can Be Considered in the 2014/2015 LTPP.

It is abundantly clear that in the 2013/2014 transmission planning process the ISO is evaluating transmission mitigation solutions that could address some of the local capacity needs in the SONGS area. This includes the Mesa loop-in project proposed by SCE and the projects submitted by SDG&E. However, for the purposes of the Track 4 studies, the ISO modeled transmission projects approved in the 2012/2013 transmission plan, as directed by the Revised Scoping Memo.[17] As noted above, because the Commission intends to issue a decision on the additional SCE and SDG&E procurement authorization requests in this Track 4 decision before the ISO's transmission planning studies are concluded, the ISO recommends that transmission alternatives be reflected in the upcoming LTPP.

Several parties, including ORA, have urged the Commission to defer issuing a Track 4 decision until the ISO's transmission planning results are available. Alternatively, ORA recommends that if the Commission rules on Track 4 local capacity needs without taking these results into account, the decision should nonetheless assume ISO approval of certain transmission mitigation solutions.[18] In its brief, ORA presents a procurement authorization

[16] Sierra Club brief, pp. 14-15.

[17] Revised Scoping Memo, Attachment A, p. 3.

[18] ORA brief, pp. 13-23.

proposal by starting with the ISO's local capacity need determination (including both resource allocations between SDG&E and SCE – one third/two thirds and 20%/80%) and subtracting the procurement authorized in D.13-02-015 and D.13-03-029. Next, ORA subtracts 734 MW, based on SCE's testimony that the Mesa loop-in project would reduce local needs by this amount, and also subtracts 350 MW to reflect the impact of additional reactive resources. ORA acknowledged that the latter adjustment "should be confirmed by comprehensive power flow studies."[19] Finally, ORA assumed that 1100 MW of preferred resources will be available to "fill" part of the local resource needs, leaving 350 MW or 215 MW of residual resource needs depending on the resource allocation split. Adopting the lower allocation, ORA also noted that the SDG&E proposed transmission projects could further reduce the residual need so that there ultimately would be no need for residual all-source resource authorization.[20]

While as with CEJA or Sierra Club's recommendations there might be some appeal to using such an approach, also as with CEJA or Sierra Club's recommendations there is no basis in technical analysis to support it. In addition, these parties advocate using the most optimistic assumptions possible from all sources of mitigation solutions. Simply summing up these assumptions and speculations is neither reasonable nor prudent and it flies in the face of reasonable incremental procurement steps in light of the retirement of SONGS that is envisioned by Track 4. From another perspective, the ISO's transmission planning studies might not support the Mesa loop-in as the most cost effective or efficient mitigation solution, and also might find the need for significantly higher (or lower) amounts of reactive support. Rather than attempting to artificially reduce the level of residual local needs by assuming transmission

[19] *Id.,* p. 17.

[20] *Id.*, p. 22.

alternatives that might not be approved, the Commission should make a decision based on the record evidence in Track 4, which does not include these alternatives. The ISO's studies submitted in the 2014/2015 LTPP will provide updated information about transmission alternatives approved in 2014. In the meantime, all-source procurement authorization for a total of 1050 MW, as requested by SDG&E and SCE, will have the effect of filling needs with preferred resources first, and then transmission and conventional resources, as required by the loading order. Because the ISO has identified substantial local capacity needs in its studies, the 1050 MW likely will be needed regardless of the transmission alternatives approved in the 2014/2015 plan. Thus, the "no regrets" level of procurement authorization will provide essentially that, no regrets. In the unlikely event this level of procurement proves to be too high in light of the ISO's transmission solutions, the Commission can make adjustments in the next proceeding.

IV. The Record Does Not Support a Finding that Service Reliability Should be Reduced as a Means by Which to Address System Reliability. The Need for Additional Local Resources is clear.

There can be no doubt that the central issue in Track 4 became the ISO's well-established transmission planning practice that planning for load-shedding (blackouts) in major urban areas should not be adopted as a mitigation tool in response to Category C contingencies. The ISO agrees with the parties who expressed astonishment that the Commission would even consider accepting a reduced level of service reliability for the eighth largest US city (San Diego) that is not used in other parts of the country and is more typical of third world countries where electric service is more of a scarcity.[21] The load shedding issue was thoroughly addressed in the ISO's

[21] IEP brief, p. 19; Nevada Hydro brief, p. 5.

opening brief and there is no need to repeat these arguments.[22] In addition, no party has successfully argued that the ISO's LCR study methodology is flawed and should not be approved for use in Track 4, just as it was in Track 1 and in A.11-05-023. However, there were specific arguments raised in some briefs that require a response and additional clarification.

For example, CEJA provides some "background" information about planning standards and reserve margins that is off-point and misleading. As was the case in Track 1, CEJA mixes apples and oranges by starting the historical background discussion with the Commission's adoption of a 15-17% reserve margin in D.04-12-048, contrasted with WECC operating reserve margin requirements.[23] This information has nothing to do with the LCR planning criteria discussed in detail in Track 1 and Track 4 evidentiary records, and the ISO carefully explained the differences between planning and operating criteria in its Track 1 testimony and brief.[24]

Similarly, CEJA incorrectly implies that the ISO changed the LCR study methodology adopted in D.06-06-064 by introducing in Track 1 "for the first time" the use of a 1-in-10 load forecast and a "Category C" contingency. Once again, the LCR methodology and how the ISO used it to conduct the OTC studies in Track 1 was thoroughly vetted and CEJA's confusion on these points was discussed in detail in the ISO's briefs.[25] Like POC, CEJA advances the erroneous argument that the ISO is able to "decide" on a policy basis what the most critical contingency should be for a given set of studies (see discussion below). The reality is that the most severe contingency is what it is. The ISO has repeatedly attempted to educate the parties to

[22] ISO brief, pp. 15-26.

[23] CEJA brief, pp. 2-3.

[24] ISO Track 1 opening brief, pp. 19-21.

[25] *See* Section II.A of the ISO Track 1 opening brief, starting at p. 6.

these LTPP and procurement proceedings about the basic concepts of transmission planning – admittedly a complex subject – but it seems that some of this information is being purposely ignored. The ISO is confident that the Commission understands the central planning issue that is being debated in this proceeding, and that is whether blackouts are an appropriate permanent transmission planning solution for densely populated areas. The choice of transmission planning "tools" to address Category C contingencies is a longstanding NERC reliability criteria and has been embedded in the LCR methodology since it was adopted by the Commission for use on an annual basis in the resource adequacy proceedings.[26]

Like CEJA, POC clearly believes that the limiting contingency for the SONGS study area is something that the ISO, and the other parties who conducted power flow studies, can simply choose.[27] This notion was dispelled during POC's cross-examination of Robert Sparks when he explained that according to NERC planning standards the critical contingency for a study area is the *result* of the power flow studies – not a pre-established input.[28] None of the parties to this proceeding has credibly disputed the mathematics and physics underlying the power flow studies conducted by the ISO, SDG&E and SCE, although this seems to be what POC is trying to do.

The difference in local capacity need between the N-1-1 contingency (Category C3) and the N-1/G-1 contingency (Category B) also seems to be creating confusion.[29] This difference is relevant only as a comparison of local capacity needs with and without load shedding for the N-1-1 contingency, but POC seems to believe that the N-1/G-1 standard is the "only" ISO grid

[26] *Id.*

[27] POC brief, p. 3 "…neither SDG&E nor CAISO has made a showing on the record establishing the reasonableness of the key assumption underlying their studies- the use of N-1-1 as the limiting critical contingency."

[28] ISO brief, pp. 19-20.

[29] As noted in ISO-2, pp.6-7., this difference amounts to 150-300 MW.

planning standard that can be used for resource procurement determinations without ISO and Commission approval.[30] These misplaced arguments provide no useful information for the Commission's decision. The ISO's G-1/N-1 grid planning standard does go beyond the current NERC Category B[31] N-1 planning criteria and it is a well-settled requirement used by the IOUs prior to ISO formation. The only aspect of the N-1-1 NERC reliability standard that is not set forth in the ISO's grid planning standards is whether involuntary load shedding should be used as a long-term planned mitigation tool in large urban areas. As discussed in the ISO's testimony and opening brief, the ISO Governing Board is aware of the ISO's position on this issue, and the standing practice will be documented in the grid planning standards through a stakeholder process in early 2014.

POC also provides inaccurate engineering information in a lengthy discussion about the import capability of the Sunrise Powerlink line and the ISO's "elimination of path ratings for major SDG&E import pathways."[32] Specifically, POC argues that there must be a path rating for Sunrise in order for the ISO to determine LCR needs in the San Diego area. According to POC, the WECC Path 44 rating also should be increased from 2500 MW to 3200 MW. These assertions appear to be based on a series of garbled questions posed to Mr. Sparks by Sierra Club about the data in the table set forth on pages 9-10 of his rebuttal testimony.[33] Indeed, this line of questioning became so confusing that at one point Mr. Sparks commented that "we walked into

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[30] "The use of N-1-1 for the San Diego area has not been approved by CAISO's board and is inconsistent with the CAISO's official G-1/N-1 standard." POC brief, p. 5.

[31] NERC recently approved revised planning standards that will effectively reclassify the G-1/N-1 contingency to Category B. These revised planning standards are pending FERC approval.

[32] POC brief, pp. 5-11.

[33] The ISO notes that Sierra Club did not raise this issue in its opening brief.

the room backwards and I can't see what I'm looking at."[34] The take-away from this discussion is that simply subtracting the LCR need from the load does not produce the import capability of the lines serving San Diego when Southwest Powerlink (SWPL) and Sunrise are out, and Mr. Sparks never agreed that the path rating for Path 44 should be 3200 MW. The WECC path rating process – that produced the 2500 MW rating still in place for Path 44 – employs a different methodology than simply subtracting the LCR need from the load to produce the WECC path rating for the lines serving San Diego when SWPL and Sunrise are out. The point of Mr. Sparks' rebuttal testimony was not to debate the rating on Path 44 but to emphasize that the ISO's current analysis of local area needs in San Diego is consistent with the analysis conducted in the Sunrise CPCN proceeding, and that under stressed conditions with SWPL out of service, Sunrise actually produces a higher level of benefits (1100 MW) than the 1000 MW originally contemplated.[35]

Mr. Peffer, the POC witness and author of the POC brief, offered opinions about the need for path ratings in determining local area requirements needs that do not represent established practice and are not based in fact. These opinions therefore should be disregarded in the scope of this proceeding. Similarly, POC's arguments that the ISO erroneously categorized outages at Palomar Energy Center and Otay Mesa as "whole plant" outages are based entirely on the inaccurate testimony put forth by Sierra Club witness Mr. Powers,[36] and the ISO thoroughly addressed these arguments at pages 15 and 16 of its opening brief. Mr. Peffer has provided no

[34] Tr. 1515:10-11.

[35] ISO-2, p. 10 (bottom line of the table). The ISO also notes that the approximately 2000 MW of Sunrise thermal capability, described by Mr. Sparks at Tr. 1510:26-1511:2, does not impact the study conclusions about Sunrise capability under N-1/G-1 and N-1-1 conditions.

[36] POC brief, p. 10

independent engineering analysis, or any other useful information, that would guide the Commission's decision on these topics. Therefore, POC's conclusion – that with the combination of load shedding, "accurate path ratings" and "a G-1 that reflects inherent design capabilities" there would be no local needs – has no factual basis on the record of this proceeding.

As discussed above, Redondo Beach conducted power flow studies based largely on the ISO's assumptions and methodology. At the beginning of its brief the city recommended additional resource procurement authorization consistent with ISO, SCE and SDG&E testimony. Thus, it is quite surprising that much of the rest of the brief was focused on criticizing the ISO's study methodology, disagreeing with the ISO's position on load shedding and generally criticizing Mr. Sparks' rebuttal testimony with statements that ignore the record evidence.[37]

For example, at page 22, Redondo Beach argues that none of the parties presented evidence as to how "different levels" of load shedding could be employed or why sensitive load could not be excluded. These comments ignore the extensive cross examination evidence, summarized in the ISO's brief, that load shedding schemes are "blunt instruments" that do not differentiate between hospitals, schools, fire and police protection and air conditioning load.[38] The city also comments that Mr. Sparks presented "no evidence" of the risk of fire outage on the Sunrise and SWPL lines, which is completely inconsistent with all of the lengthy cross examination about the SDG&E Sunrise path rating study described in his rebuttal testimony.[39]

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[37] Redondo Beach brief, pp. 21-31.

[38] ISO brief, p.24; see also IEP brief, p. 14.

[39] ISO-2, pp. 5-6. The ISO also notes that from 2011-2013, there have been numerous unplanned outages on various SWPL segments due to other causes as well.

Also on page 22, Redondo Beach appears not to understand what Mr. Sparks meant when he described the complexity of system operating conditions in the San Diego area and the grid to widespread outages under the high stress levels that would call for load shedding in the first place. The ISO notes that Redondo Beach did not cross examine Mr. Sparks to seek clarification on any of these points; therefore the city's failure to understand this testimony should not influence the Commission's decision. Furthermore, these topics were not only addressed in detail on the record of this proceeding, but also on the record in A.11-05-023 in Mr. Sparks' rebuttal testimony. In that case, Mr. Sparks explained that the Imperial Valley substation is a major source of imported power for three different utilities: SDG&E, IID, and CFE. With three different balancing areas independently operating and optimizing the operation of the three interconnected systems, the level of exposure to operational coordination issues and failures is potentially higher than it would be for a similar substation not located at a seam between multiple balancing areas and transmission operators.[40] Finally, "stress level" is an industry term describing the level of electric flows on the system. Relying on load shedding to meet the planning standards under increased precontingency electrical flows on an already burdened system increases the risk of cascading outages and widespread blackouts during multiple contingency events.

Redondo Beach argues at page 24 that load shedding can be used as a "stop-gap" measure and the ISO agrees with this concept when unexpected events occur, but only as an interim mitigation until transmission upgrades or additional resources can be placed in service. The ISO explained in detail in testimony and brief, load shedding should not be adopted as a

[40] *See* A.11-05-023, Sparks rebuttal testimony, pp. 8-10. The ISO notes that Jaleh Firooz, the witness for Redondo Beach, also participated in that proceeding on behalf of CEJA.

long term mitigation solutions. The NERC criteria require the analysis of N-1-1 contingencies because the system needs to be designed to withstand these contingencies in order to be a reliable system. Load shedding can be used as a stopgap measure to mitigate for these contingencies – the industry practice is to not rely on load shedding in lieu of transmission or resource additions – in long term planning. At page 25 the city conveniently misinterprets Mr. Sparks' testimony with regard to the risk of increased outages by overlooking his statement that this risk has increased because of SONGS retirement.[41] Like POC, the city also engages in a discussion of the import capability on Path 44 and speculates that simply increasing the path rating would save ratepayers "hundreds of millions of dollars" and possibly should have been taken into account when Sunrise was being evaluated.[42] Once again, this simplistic spreadsheet approach to import capability is misplaced, as discussed above in response to POC. Furthermore, increasing or eliminating the Path 44 rating prior to Sunrise construction and energization would have reduced reliability in San Diego to levels below those in place prior to ISO formation, which contravenes AB 1890. Finally, the city continues to insist that the worst contingency drives local capacity needs in the LA Basin is the N-1-1 outage of the 230 kV Serrano-Lewis #1 line followed by the outage of the Serrano-Villa Park # 2 line,[43] despite the ISO's clear testimony (and the Revised Scoping Memo directive) that the loss of SONGS impacts both San Diego and the LA Basin, so the two areas need to be studied together. The N-1-1 of the two 500 kV lines west of Imperial Valley substation is the worst contingency driving the need for local resources in the San Diego and LA Basin areas. In the 2012-2013 CAISO Transmission Plan, which Redondo Beach

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[41] ISO-2, pp. 13-14,

[42] Redondo Beach brief, p. 28.

[43] *Id.*, p. 31.

witness Firooz consulted as part of her power flow studies, also provided, on page 184, that the critical contingency requiring mitigations in the LA Basin and San Diego LCR areas is the Category C contingency (i.e., N-1-1 of Sunrise, followed by SWPL line out), which causes post-transient voltage instability.

In support of load shedding as a long term planning solution, many parties have argued that an extensive cost –benefit analysis should be undertaken, or they have put forth a very simplistic evaluation of benefits based the avoided costs of generation times the load shedding MWs, times the estimated probability that the outage might occur. TURN in particular devotes a substantial portion of its brief to a "preliminary" cost-benefit analysis[44], despite the ISO's admonition as to the complexity of such an analysis due to the many permutations of outage possibilities when load is dropped involuntarily in an urban area.[45]

Indeed, the fact that there are practical barriers to developing a meaningful quantitative benefit analysis in a complex transmission network, with evolving load patterns and varying generation conditions has been made clear in this proceeding. Such a determination requires a means to both assess the frequency and duration of outages and attribute a financial impact to the consequences of the outages. A meaningful cost-benefit analysis needs to consider not only the risk of the most severe contingency at times of highest system stress, but <u>all</u> other combinations of events that can occur throughout the year that create the possibility of customer outage before a cost of outage can be applied to determine the total benefit of adequately reinforcing the transmission system. While these methods can provide meaningful input to decision-makers under more straightforward circumstances, the data and tools do not support this approach under

[44] TURN brief, pp.8-17.

[45] ISO-7, pp. 10-11.

these circumstances.[46] Furthermore, as discussed below, the cost impacts to consumers and communities must be factored into this analysis, adding to the complications of a meaningful analysis. No party has provided any meaningful input to the contrary in this regard, and in fact parties generally err as the ISO cautioned in Track 1 of this proceeding (TRACK 1 - Millar reply testimony, Page 5, lines 20-28) by focusing too narrowly on only a specific contingency under a specific set of conditions and drawing their own conclusions.

What TURN's analysis – and the other parties advancing similar arguments – also overlook is the true societal costs, consumer costs, and business costs of widespread outages that may last for long periods of time. As discussed in the IEP opening brief, "the analysis of the choice between adding resources and blacking out customers must include all relevant costs, including the full direct and indirect costs that customers, the local economy, and local communities incur and the effect on public health and safety when electric service is cut off unexpectedly.[47] IEP noted that the societal costs of a 500 MW load shed (blackout) lasting only one hour could cost $20 million, and that the costs of a 12 hour outage, such as the one experienced by the residents of San Diego in September 2011, could be as high as a quarter of a billion dollars.[48] It bears repeating that while some parties naively believe that hundreds of thousands of customers might somehow be forewarned that their service will be interrupted and that there will be minimal impact from this disruption, the fact of the matter is that suddenly dropping huge swaths of customers places burdens and costs on communities that have not been addressed on the record of this proceeding and are difficult to estimate. The Commission should

[46] *Id.*; Tr. 1621:13-1624:20.

[47] IEP brief, p. 12.

[48] *Id.*, p. 16.

recognize that the arguments advanced by parties advocating large amounts of load shedding in an urban area as a planning tool are a call to accept an unprecedented lower level of service reliability not adopted most other areas of the country.

The more reasonable approach is to allow load shedding in response to Category C contingencies as interim "or stop-gap" measures and only while permanent mitigation solutions are implemented. The ISO endorses this course, but cautions that judiciously using load shedding as an interim measure in large urban areas requires that there be a permanent solution identified and ongoing. On this point, the ISO strongly disagrees with Sierra Club's conclusion that using load shedding as a "short-term bridge" of up to ten years should lead to a finding that there is no need for additional resource procurement.[49] The needs identified by SCE, SDG&E and the ISO must be addressed in this proceeding with resource procurement or infrastructure development, and not through reduced service reliability.

V. Simply Considering the Most Critical Category C Contingency to be the "Functional Equivalent" of a Category D Contingency is Not Permitted by NERC Reliability Standards and Should not be Considered by the Commission.

In its opening brief, Sierra Club cites Mr. Powers' assertions that, based on WECC criteria, the overlapping outage of SWPL and Sunrise should be considered equivalent to a Category D contingency for which permanent mitigation solutions are not required.[50] This opinion is certainly not based in established process or mandated reliability standards. Based on this testimony, Sierra Club argues that no new resources are needed in the SONGS study area. POC joins in this argument with the incorrect and totally misplaced assertion that "the N-1-1 is a *prima facie* probabilistic Category D" that would succeed in a WECC contingency exception

[49] Sierra Club brief, pp. 25.

[50] *Id.*, p. 24.

process.[51] However, this line of reasoning is built on a faulty premise, for which there is no supporting evidence (certainly no credible evidence included in the record of this proceeding) and upon which the Commission cannot rely.

Sierra Club starts out by mischaracterizing the ISO's position on load shedding for Category C contingencies with the statement that "CAISO will allow load shedding for Category D contingencies but not Category C contingencies."[52] Rather, as discussed repeatedly in the testimony of both Mr. Sparks and Mr. Millar, the ISO's historic practice is much more balanced and load shedding arrangements are utilized in isolated areas throughout the ISO planning area. However, both witnesses made it clear that large amounts of *urban* load shedding are relied upon for local capacity purposes only on an interim basis as a last resort.[53]

Building on that incorrect basis, Sierra Club glosses over the substantial difference in NERC reliability criteria between a Category C and Category D contingency ("only thirty minutes").[54] As Mr. Sparks has explained, the difference in studying an N-1-1 contingency versus an N-2 contingency is that the system can be readjusted between the conditions in the former case, but not the latter, to further harden and prepare the system in anticipation of the next contingency. This difference between outages occurring less than 30 minutes apart, as Mr. Sparks stated "is typically considered a Category D outage if you haven't had time to readjust the system and it's more extreme."[55] Mr. Sparks has been clear that the definition applied by NERC

[51] POC brief, p. 12.

[52] Sierra Club, p. 24.

[53] ISO-2, p. 9; ISO-7; p. 8.

[54] Sierra Club, p. 24.

[55] Tr.1503:16-1504:20; *see also* 1505:5-15.

is very specific and leaves no room for interpretation. The n-1-1 loss of the two circuits (as opposed to the simultaneous loss) is a Category C contingency.[56]

Both Sierra Club and POC make much of the WECC process for exceptions to NERC reliability contingencies, but these parties overlook the critical fact, explained repeatedly throughout the record, that the ISO as the grid planning coordinator must comply with all of the WECC, ISO and NERC standards, and that WECC (and ISO) standards are layered *on top of* the NERC standards. While there are circumstances in the WECC standards that call for the escalation of a contingency from one category to another based on WECC-specific definitions, WECC also provides the probabilistic analysis methodology to reduce a contingency back down to a lower level of requirement. No evidence has been put forth to dispute that NERC standards (including the NERC deterministic test of n-1-1 outages as Category C disturbances) cannot be set aside by a WECC definition for a WECC standard, particularly because the NERC standards have become *mandatory* reliability standards.

Even if the Commission were to ignore the reality that WECC standards cannot be used to set aside the need to comply with a NERC standard, the probabilistic test clearly would not have the impact Sierra Club's witness Mr. Powers has asserted, as demonstrated by the evidence in the proceeding. Sierra Club goes on to refer to TURN-x-ISO-7 as indicating that the range of simultaneous outage probability for the Sunrise route (the alternative route which was ultimately built) was within the same 21 year to 928 year estimate as for the Sunrise preferred route which did not get built. However, Sierra Club has overlooked the WECC Reliability Subcommittee determination of the review of the material, which concluded that the alternative route, which did

[56] Tr. 1508:1-3; 1510:4-7.

get built, trended to the once-in-21 year probability, whereas the preferred route trended to the once-in-928 year probability.[57] On a probabilistic basis, the WECC review concluded that the N-2 simultaneous outage for the Sunrise route – that was ultimately built by SDG&E – would be a Category C contingency. Because, as Mr. Sparks explained in his rebuttal testimony, N-1-1 outages are more likely than N-2 simultaneous outages, clearly the N-1-1 outage would similarly fail the probabilistic test set at less than once every 30 years to 300 years .[58] It should be noted that after the probabilistic analysis had been prepared by SDG&E and considered by the WECC Reliability Subcommittee, the N-2 outage of Sunrise and SWPL was reclassified as a Category D contingency through other and unrelated changes to the WECC definition of Category C contingencies, notwithstanding the outcome of the probability review. This change was addressed in A.11-05-023.

The Sierra Club/POC simplistic and erroneous notion that planning for an N-1-1 Category C contingency can simply be ignored because of a WECC process that they erroneously represented is a distraction and does nothing more than distract from the central issue – whether blackouts in large urban areas is an acceptable level of reliability for California citizens. The ISO submits that it is not.

VI. The Development of Preferred Resources Must be Carefully Tracked and Verified.

When the rhetoric about contingency planning and the ISO's study methodology is cleared away, it seems that there is some general agreement among the parties. In particular, the ISO has been quite clear that substantial portions of the local capacity needs created by the SONGS outage can be filled with preferred resources, a fundamental concept that is endorsed by

[57] ISO-2, p. 6.

[58] TURN-x-CASIO-7, p. 2

parties who recognize that there *are* additional local area needs. However, achieving the important role of preferred resources in meeting reliability needs and furthering California's clean energy goals will require a continued and focused effort by the Commission and others. First, the Commission and parties must be diligent in moving ahead to develop the necessary programs that can participate with other supply-side resources (such as demand response) and that will provide load-shaping demand-side benefits (such as EE and small PV) with the necessary locational data that the ISO can use in its local area capacity studies to offset the need for conventional infrastructure. Much progress is being made on these issues in various venues at the Commission and in collaboration with the CEC and the ISO. Much more progress is needed.

Secondly but equally important, given the long lead times needed to site and build conventional infrastructure resources, the Commission must be diligent and expeditious in tracking the development of preferred resources in order to verify that they are actually materializing in the locations and amounts predicted in the studies and resource procurement efforts that established such forecasts. This truism also has been endorsed by many parties to this proceeding.[59] "Assumptions" about the growth of preferred resources are not sufficient when essentially needed conventional resources are being deferred indefinitely. If deferred to a point beyond which it is infeasible to site and construct resources or grid facilities, and then these resources ultimately become necessary, California may be forced into a regretful decision to sacrifice environmental policy or reliability, or both. The ISO is confident that the correct, "no regrets" balance of preferred and conventional resources, along with transmission infrastructure,

[59] *See, e.g.*, ORA brief, p. 26; recommending annual evaluations to determine the ability of preferred resources to meet local reliability needs; Redondo Beach brief, p. 6.

will be developed in time to meet the OTC resources retirement dates, but there is much work to be done.

Respectfully submitted,

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