SDG&E's Comments on:

- **CAISO's October, 2017 Version of the *Draft Manual, 2019 Local Capacity Area Technical Study*, and**

- **October 31, 2017 Stakeholder Call regarding the *2019 ISO LCR Study Criteria, Methodology, and Assumptions***

<u>The *2019 Local Capacity Area Technical Studies* Should Provide Information to Local Regulatory Authorities (LRAs) to Assist in Determining whether LCR Costs are Being Fairly Apportioned</u>

The CAISO's May 1, 2017 *2018 Local Capacity Technical Analysis, Final Study Report and Study Results* confirms that LA Basin area and the San Diego-Imperial Valley area "are electrically interdependent on each other." (page 55) This final study report describes the "iterative" process by which the "LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area." SDG&E understands that this iterative process minimizes the *combined* LCR for the LA Basin area and the San Diego-Imperial Valley area.

The October, 2017 version of the *Draft Manual, 2019 Local Capacity Area Technical Study* does not describe the iterative process that SDG&E expects will also be used to produce the year 2019 results. Such a description would be a useful addition to the manual.

In any event, SDG&E supports the objective of minimizing the *combined* LCR. However, as in past years, SDG&E remains concerned that Load Serving Entities (LSEs) with obligations to secure dependable capacity to meet the respective LA Basin area and San Diego-Imperial Valley area LCRs, may be bearing too much or too little of the associated cost burden. As the final study report notes, the LCR in one area is "dependent on the amount of resources that are dispatched for the adjacent area and vice versa." Accordingly, it is possible that LSEs in one LCR area are incurring LCR costs that, in fact, materially benefit the LSEs in the other LCR area. Collectively, all LSEs may be better off, but that does not answer the question of whether LSEs in one LCR area, or the other, are bearing a fair share of the overall LCR costs.

To answer this question SDG&E recommends that the October, 2017 version of the manual be augmented with study results showing what the LA Basin area and San Diego-Imperial Valley area LCRs would be assuming the study objective was to minimize the amount of LCR for each area without considering the amount of resources that are dispatched in the other area. These results would provide the CPUC and other stakeholders with an indication of the extent to which dependable generation in one LCR area is supporting a lower LCR in the other area. It might also provide a basis for LRAs to allocate the combined areas' LCR costs among the respective LSEs such that all LSEs bear a fair proportion of the costs.

In the CPUC's Resource Adequacy Order Instituting Rulemaking (OIR), SDG&E submitted comments to the above effect. On 11/9/2017 the CAISO provided reply comments stating:

> "the 2018 CAISO local capacity report…identifies the requirements for San Diego-Imperial Valley area…and the corresponding Los Angeles Basin LCR need….It is unclear exactly what further studies SDG&E is requesting at this time and what information any such additional studies would provide, If SDG&E continues to believe that additional studies are warranted, it should raise that concern in the CAISO's LCR study process."

To illustrate the "further studies" SDG&E has in mind, and to show how the information from these further studies could be used, consider the following strictly hypothetical example. Assume that the CAISO's results for 2019 indicate that to minimize the combined LCR for the LA Basin area and the San Diego-Imperial Valley area, the LA Basin LCR would be 7000 MW and the San Diego-Imperial Valley LCR would be 4000 MW. Assuming an LCR cost of $50/kW-year, LA Basin LSEs would incur $350 million in costs and San Diego-Imperial Valley LSEs would incur $200 million in costs. Combined LCR costs would be $550 million.

Assume that an LCR study minimizing the amount of LCR for each area without considering the amount of resources that are dispatched in the other area, produces an LA Basin LCR of 8000 MW and a San Diego-Imperial Valley LCR of 3500 MW. These results suggest that dispatching an additional 500 MW of resources in the San Diego-Imperial Valley area (4000 – 3500) allows for 1000 MW less to be dispatched in the LA Basin LCR area (7000 – 8000). If these results are used to allocate the $550 million in combined LCR costs, then LA Basin LSEs would be responsible for $383 million in LCR costs {550 x [8000/(8000+3500)]} and San Diego-Imperial Valley LSEs would be responsible for $167 million in LCR costs {550 x [3500/(8000+3500)]}.

<u>The LCR for the Combined LA Basin and Greater Imperial Valley-San Diego Areas Should be Based on Studies Using Coincident Peak Loads</u>

The October, 2017 version of the manual indicates that the CAISO intends to "…perform additional assessments of the reliability impacts when loads continue to remain high as forecasted by the CEC but without the contribution of solar photovoltaic distributed generation at an early evening hour (i.e., 6:00 p.m.)." (page 9)

SDG&E understands that because the Greater Imperial Valley-San Diego area has a higher proportion of rooftop solar PV than LA Basin area, the CEC expects the peak load for the Greater Imperial Valley-San Diego area to occur at a later hour than for the LA Basin area. For purposes of establishing the combined LA Basin and Greater Imperial Valley-San Diego LCR, the studies should use load levels whose timing is coincident between the two areas.

The October, 2017 version of the manual should be augmented to make it clear that studies establishing the combined LA Basin and Greater Imperial Valley-San Diego LCR should use data which is coincident in time between the two LCR areas. Further, a coincident time should be used for both the LA Basin and Imperial Valley-San Diego areas when determining the separate LA Basin LCR. Likewise, a coincident time should be used for both the LA Basin and Imperial Valley-San Diego areas when determining the separate Imperial Valley-San Diego LCR. It is possible, therefore, that three different coincident time periods may need to be evaluated.

Establish a Criteria for Determining the Circumstances Under Which Normal Ratings, Short-Term Emergency Ratings and Long-Term Emergency Ratings will be Used in LCR Studies.

The October, 2017 version of the manual includes a discussion of "Applicable Ratings." The discussion states:

> "short-term emergency ratings, if available, can be used as long as 'system readjustment' is provided in the 'short-time' available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings." (page 13)

For the 2018 LCR studies, the CAISO used "normal ratings" for IID's "S-Line" when determining the maximum level of imports into the San Diego area under contingency conditions. The CAISO indicated that the 30-minute emergency rating for the S-Line was not applicable because the contingency condition could last for longer than 30 minutes and the CAISO had no assurance that "system readjustment" could be made within 30 minutes to reduce "S-Line" flows from the short-term emergency rating down to the normal rating. The CAISO has many tools, including generator curtailment provisions -- via Exceptional Dispatch orders in Participating Generator Agreements (PGAs) -- that should be utilized to readjust the system within 30 minutes. SDG&E notes that the system conditions assumed for purposes of setting LCRs are extreme: a 1 in 10 load condition overlapping with one critical outage, and preparation for a second overlapping critical outage. Given this extreme system condition, the CAISO should rely on all system readjustment tools at its disposal.[1]

The October, 2017 version of the manual needs to be augmented to explain the basis for deciding the duration of contingency conditions, and specifically what assurances the CAISO requires for accepting that "system readjustment" within the emergency rating period will occur.

Has the Impact of Public Appeals Been Fully Accounted For?

SDG&E requests that the CAISO opine on whether public appeals during a one-in-ten heat event are fully accounted for in the LCR studies. For example, would the expected response to public appeals provide the assurance necessary for the CAISO to rely on 30 minute emergency ratings following a contingency?

[1] For example, SDG&E has a contract with a generator which gives SDG&E the right to curtail the output of the generator in real-time. During the 30 minute system readjustment period, the CAISO can work with SDG&E to exercise this contractual right if it helps to minimize LCRs.

It is Reasonable to Assume Flow Control Devices will be Set to Minimize LCRs.

The October, 2017 version of the manual does not specifically address phase shifter settings. It does, however, state that "import capability into the local area shall be maximized, thus minimizing the generation required in the local area to meet reliability requirements." (page 7) Consistent with this study methodology, SDG&E suggests the October, 2017 version of the manual be augmented to make it clear that phase shifters under the operational control of the CAISO will have angles set (within the range of the device) so as to maximize flows into the LCR area for the most severe contingency condition.

Loads and Generation Dispatch in Adjacent Balancing Authorities should be Consistent with the Contingency Condition Being Studied

Load levels and generation dispatch patterns in neighboring balancing authorities can have an effect on LCRs. For example, the relative dispatch of generation between the western and eastern sides of the northern Baja electrical system, can impact LCRs within the San Diego area. It is therefore important that these loads and generation dispatch patterns are consistent with the system condition that establishes the LCRs. This is potentially more critical as the times of the highest load hours changes as a result of differing penetrations of rooftop solar PV in different areas of the southwest.

SDG&E continues to question whether the use of historically-based Maximum Import Capability (MIC) is appropriate considering that the LCR determination is forward-looking and assumes very extreme system conditions (e.g., a one-in-ten peak load level within the LCR area), while the historically-based MIC results from system conditions which may be quite different. SDG&E understands that a historically-based MIC is, by definition, "feasible;" however, forward-looking imports into the CAISO balancing authority using power-flow modeling would likewise be "feasible."

Other than references to the historically-based MIC assumption, the October, 2017 version of the manual has no discussion of how load levels and generation dispatch patterns in adjacent balancing authorities should be set for study purposes. It would be helpful to describe these settings, both pre-contingency and for purposes of system readjustment after an initial contingency. For example if a critical generator within the CAISO balancing authority is lost during an extreme heat event, system adjustments may be needed to bring imports from adjacent balancing authorities down to a level that will not violate thermal line ratings in the event there was a subsequent loss of a major transmission line within the CAISO balancing authority.

SDG&E also recommends that a discussion of forward-looking imports into the CAISO balancing authority using power-flow modeling be added to the October, 2017 version of the manual.

The October, 2017 version of the manual states that:

> "…import capability, relied upon in the RA program, deliverability status shall be maintained for all common mode contingencies (including all single contingencies as well as double circuit tower line and same right-of-way contingencies)….
>
> After a single contingency during the "System Readjustment" all generating units as well as imports can be reduced (up to a limit – see system readjustment) in order to protect for the next most limiting contingency." (page 8)

SDG&E finds this language confusing. On the one hand, this language seems to indicate that LCR modeling should assume power flows from neighboring control areas are at the historically-based MIC level and that these imports are to be "maintained" for single contingencies. At least for the San Diego-Imperial Valley LCR area, maintaining imports at the historically-based MIC level are impossible following the first critical outage; doing so would result in thermal overloads should a second critical contingency occur. In general, historical imports during peak load hours are not limited because the first critical outage has not occurred.

On the other hand, the language suggests "imports can be reduced" for the next most limiting contingency. This seems to be in conflict with the statement that imports are to be "maintained." SDG&E believes the above language in the October, 2017 version of the manual needs to be modified to clearly explain the treatment of imports from neighboring balancing authorities both before, and after, critical contingencies.

<u>Criteria for Dispatching Generators with Similar Technology</u>

The October, 2017 version of the manual describes the process for mitigating a reliability criteria violation as follows:

> "Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating:
>
> a. QF/Nuclear/State/Federal units
> b. Units under known existing long-term contracts with LSEs
> c. Other market units without long-term contracts"

The manual does not describe the logic for this ordering. SDG&E wonders why it makes sense to dispatch units with existing long-term contracts ahead of other market units, especially if the other market units had lower operating costs. SDG&E also believes that, in practice, the CAISO makes exceptions to this ordering. For example, even though there are multiple units with similar technology at one location, not all of the units may be dispatched. This is problematic if generation at the particular location is effective in mitigating a reliability criteria violation.

The October, 2017 version of the manual should be expanded to explain the logic for the CAISO's dispatch ordering. As well, the CAISO should detail any exceptions to this ordering.

What Reliability Standards Apply to Non-Bulk Electric System (non-BES) Facilities?

Table 1 in the October, 2017 version of the manual sets forth the NERC performance standards. The NERC reliability standards apply to the BES, which generally means only those facilities operated above 200 kV. The manual does not specify the reliability standards that will be applied to non-BES facilities (e.g., 138 kV and 69 kV) for purposes of establishing LCRs. The manual needs to be expanded to include reliability standards for non-BES facilities.

There Should be an Interim Release of the Baseline Power Flow Case that the CAISO Intends to Use to Set LCRs

Based on experience with earlier LCR studies, it would be helpful if the CAISO could release in interim version of the baseline power flow case that the CAISO intends to use to set LCRs. This would be helpful in allowing stakeholders to work with the CAISO to identify any errors or modeling anomalies early in the process.