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OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Data Request Responses from Southern California Edison Company

San Francisco, California
November 1, 2016

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-003

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 09/12/2016

Question 1A.:

On page 10 of SCE's Phase 2 testimony, SCE refers to a projected load of 285 MW for 2018 in the Santa Barbara/Goleta area based on SCE's 2016 Transmission Substation Plan load forecast.

A. Please provide the SCE's 2016 Transmission Substation Plan and workpapers for the Santa Barbara/Goleta area load forecast, including SCE's underlying assumptions.

Response to Question 1A.:

The attached is the basis for SCE's 2016 Transmission Substation Plan and shows the ten year peak load forecast for the Goleta 220/66 kilovolt System, which serves the Santa Barbara/Goleta area. All numbers are given in mega volt amperes (MVA). A power factor of 1.0 was assumed for this purpose making these numbers equivalent in terms of megawatts (MW). A cogeneration facility within the area is assumed to serve its own facility load, therefore their load is factored out of the 2018 projected load to arrive at 285 MW.

SOUTHERN CALIFORNIA EDISON
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ABank Projected Load

Goleta 220/66 System
(MVA)

Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Goleta 220/66 System	**261.4**	**273.3**	**280.6**	**285.1**	**287.3**	**288.4**	**289.2**	**291.5**	**292.3**	**293.2**	**294.1**

Southern California Edison
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DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-003

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Question 1B.:

On page 10 of SCE’s Phase 2 testimony, SCE refers to a projected load of 285 MW for 2018 in the Santa Barbara/Goleta area based on SCE’s 2016 Transmission Substation Plan load forecast

B. Please identify the proceeding or process in which the CPUC or CAISO is reviewing this Plan.

Response to Question 1B.:

SCE’s overall 2016 Transmission Substation Plan (TSP) is not distributed externally or reviewed by the CPUC or CAISO in any proceeding or process. Individual projects resulting from SCE’s TSP and associated costs are reviewed by the CPUC in separate licensing proceedings or through SCE’s General Rate Case (GRC) filing. SCE has previously provided to ORA the attached excerpt from SCE's 2018 GRC testimony (SCE-02 Vol. 3) that provides an overview of SCE's internal Distribution & Subtransmission Planning Process.

Phase II studies with the CAISO under the CAISO's FERC jurisdictional tariff[56] and NERC Reliability Standards, and identifies upgrade projects specific to each generator to enable them to interconnect and not adversely affect system reliability.[57]

3. Policy-Driven Transmission Projects

Policy-driven transmission additions and upgrades are those needed to enable the grid infrastructure to support state and federal directives. This includes the state's RPS to source 33 percent of energy sales from renewable resources by 2020 and 50 percent by 2030. Achieving this objective requires the development and interconnection of renewable generating resources, and building new infrastructure to deliver their output to customers. The CAISO and CPUC have a memorandum of understanding under which the CPUC provides a renewable resource portfolio for CAISO to analyze in its annual TPP.[58] Policy-driven transmission upgrade projects are identified to enable the state in meeting RPS goals.

B. Distribution & Subtransmission Planning Process

The Distribution & Subtransmission Planning Process is comprised of various plans and programs that address the entire grid below the bulk power transmission system. Our Distribution Substation Plan (DSP) covers the planning process for the distribution system, identifying new distribution circuits, substation expansion projects, and new substations. Our subtransmission system is covered in our annual Transmission Substation Plans (TSP) that includes our substations (A-bank Plan), our subtransmission lines (Subtransmission Lines Plan), and our large reactive power requirements (Subtransmission VAR Plan) that identifies the reactive power needs to ensure the overall system. In addition, there are System Improvement programs that cover additional needs for the distribution system such as the reactive power requirements in our Distribution VAR program, Substation Monitoring and

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Continued from the previous page

Operator Corporation, 2015-2016 Transmission Plan (available at http://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx).

[56] California Independent System Operator Corporation, FERC order 1000 compliance phase 1 - tariff (available at http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrder1000Compliance.aspx).[56] California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 25 (available at: https://www.caiso.com/Documents/ConformedTariff_asof_Jul06_2016.pdf). *See* also, CAISO Generator Interconnection Procedures, Appendix Y, available at: https://www.caiso.com/Documents/AppendixY_GIPForInterconnectionRequests_Dec19_2014.pdf

[57] Refer to WP SCE-02 T&D-Vol. 3, Book C, pp. 18 – 20 (Transmission & Interconnection Planning Processes).

[58] 2015-2016 ISO Transmission Plan, Chapter 4 Policy-Driven Need Assessment (available at http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf).

Substation Equipment Replacement programs. Lastly, we have Programs intended to provide additional distribution plant betterment to meet local needs that are not covered by load growth programs, and 4 kV elimination for needed conversions of our aging 4 kV system. The capital request for this section is described in Section IV.B, Distribution & Subtransmission Planning Programs and Projects.

The objective of the planning process is to provide adequate substation and distribution circuit capacity to serve forecast peak loads under the maximum expected temperature over a 10-year period. Our annual planning process focuses on identifying future system needs based on forecast growth of customer demand. Often referred to as a "bottom-up" forecast, our distribution and subtransmission system needs are based on demand forecasts[59] that best represent new customer additions at specific geographical locations throughout our system.

In our DSP, we annually evaluate the ability of each transformer in the distribution substation, referred to as B-Bank transformers, and each distribution circuit to operate within its established loading limits under normal conditions with all facilities in service over a 10-year period. In our DSP we forecast the load at each substation and circuit, propose operational reconfigurations or transfers to balance loads, and propose upgrades to meet capacity requirements outlined in our Distribution Criteria and Guidelines. Typical projects identified in the planning process include:

- installation of new distribution substation transformers at existing substations;
- replacement of existing distribution substation transformers with ones having higher capacity ratings; and
- construction of new distribution circuits and substations.

When an upgrade or new project is identified, it is evaluated considering all connection points between distribution circuits across the system, and the reserves of adjacent substations and circuits. In this way, multiple issues (*e.g.*, projected circuit overloads), can be addressed holistically with a single, potentially larger capacity addition rather than multiple smaller additions, reducing cost and customer impact.

1. <u>Development of Peak Load Forecasts</u>

The first step in SCE's subtransmission and distribution planning process is to develop peak load forecasts for all distribution circuits, substations, and subtransmission lines. SCE's forecasts

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[59] Our aggregated distribution substation (B-substation) load forecast for the 2016-2025 period is 1.23 percent per year, although there are differences station to station due to different types of customer demand.

span 10 years and include customer load growth and DERs that impact the peak demand, including energy efficiency, PEVs, and distributed generation.

a) Base Load Growth and Known Developments

SCE begins with a 10-year base load growth forecast of demand increases by considering historical growth rates, development plans, and local economic conditions. We analyze historical substation load profiles and historical customer load growth in a geographic region to forecast how demand may change due to the customer base. In addition, SCE works with available agricultural, commercial, industrial, and residential development plans to understand projected increases in demand on existing distribution equipment. This projected increase is based on information provided by the developer and historical load profiles of the distribution equipment planned to serve the development. Historical growth rates and known development plans are compared to past and present economic conditions to determine if forecast growth should be adjusted to represent existing conditions.

b) Incorporation of DERs That Produce and Consume Energy

SCE adjusts the base load forecast by incorporating DER forecasts that predictably impact the peak demand at a substation level. These forecasts include the effects of energy efficiency codes and standards, SCE's energy efficiency programs, increased electrical demand associated with Plug-in Electric Vehicles (PEV), and distributed generation. This information is gathered from a variety of sources and synthesized to adjust the forecast for each distribution circuit, distribution substation, and subtransmission substation in our system.

The peak load forecast incorporates two energy efficiency forecasts. The first is the CEC Codes and Standards forecast, which displays the potential savings due to California codes and standards, which are approved and funded.[60] The second is the SCE IOU program savings based on the CPUC's current EE Potential Study.[61] We combine the two forecasts to include energy savings up to the code or standard and the forecast energy savings above the code or standard. After combining the two forecasts, these results apply to the base forecast to reduce future load growth.

SCE also expects a growing number of PEVs on the system, which could ultimately increase the load on our system.[62] The PEV forecast used in this filing is documented by Ms. Sheng in the Sales Forecast testimony of Exhibit SCE-09, Results of Operations-Vol. 1. Forecasts of

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[60] CEC (IEPR) 2013 Final Forecast, revised April 2014.
[61] The current CPUC EE Potential Study is dated 2013.
[62] Refer to SCE-09 Results of Operations-Vol. 1 Sales Forecast.

PEVs are allocated down to each substation as another input to the peak demand over the 10-year period.

SCE also incorporates the effects of distributed generation in our load forecast in compliance with the Vote Solar Settlement, as discussed in Section II.B. In 2015, SCE re-evaluated how much photovoltaic distributed generation can be reasonably relied on to offset peak load conditions, accounting for intermittency and variability. SCE's study determined that the amount of photovoltaic generation that can be considered dependable varies with the time of day.[63] Our study showed that at noon approximately nineteen percent of nameplate capacity could be dependable, while approximately two percent of nameplate capacity could be dependable at 5:00 PM. We use this information to adjust further peak loads. In making this adjustment, we consider the time of day when the peak occurs and the dependable photovoltaic generation.

The result is a forecast of peak loads through all distribution circuits, B-substations, and A-substations. The variables described above are input at the distribution circuit level, aggregated up to the distribution substations, and then aggregated up to the subtransmission substations. SCE compares the bottom-up forecast to the top-down Sales Forecast.[64] Differences between the two forecasts are analyzed and reconciled, which can cause adjustments. This forecast is the basis of our DSP.

2. Proposed Solution Identification

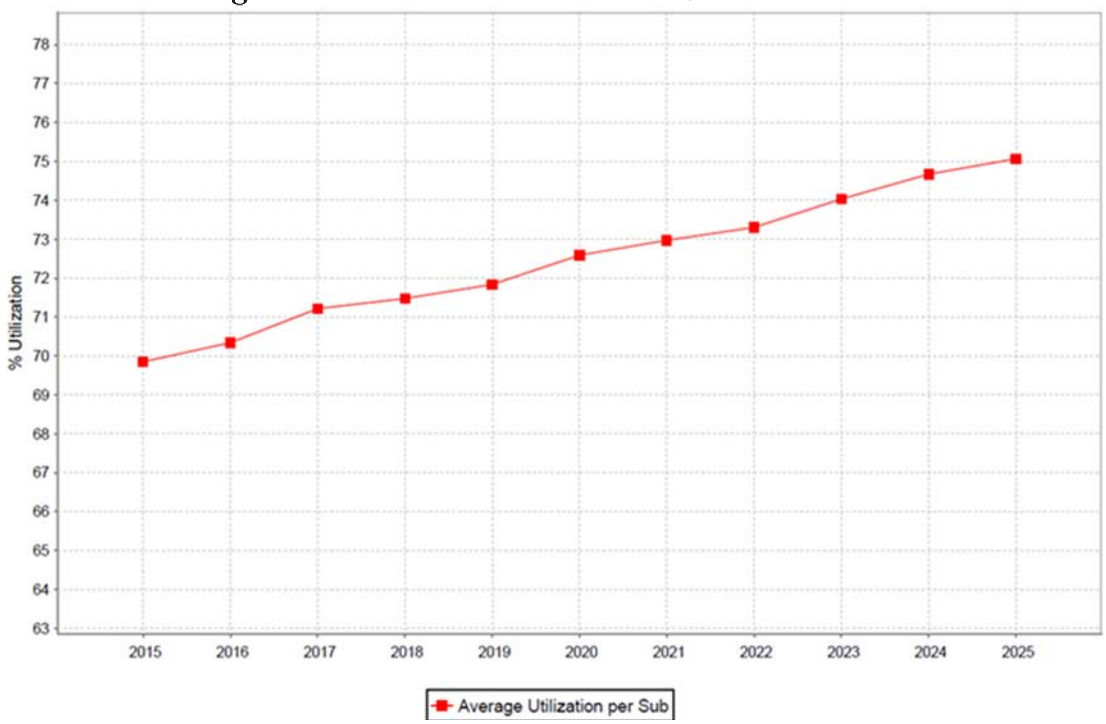
Once the load forecast is developed, the next step is technical studies that determine whether the projected load can be accommodated using existing transmission, subtransmission, and distribution facilities. We use longstanding planning criteria as the basis for designing a reliable system. The planning criteria is based on equipment loading limits, known as planned loading limits, that consider the effect of loading on thermal, voltage, and protection limits under normal and emergency conditions. The analysis includes comparing the expected forecast demand under the maximum temperature conditions over a 10-year period to these established limits.

When our studies show that load will exceed planning limits, we identify potential solutions. These solutions are needed to mitigate the risk of overloading equipment, which increases the probability of failures, *e.g.*, transformer fires, and service interruptions that might affect many customers over widespread geographic areas. As part of identifying solution alternatives, SCE will first maximize

63 Refer to WP SCE-02 T&D-Vol. 3, Book C, pp. 21 – 27 (SCE Dependable PV Generation Study).
64 Refer to SCE-09 Results of Operations-Vol. 1 Sales Forecast.

the utilization of distribution assets before developing projects that require capital expense. Figure III-10 illustrates how the forecast average distribution substation utilization percentages for the 2016 – 2025 DSP increase over the life of the plan.

Figure III-10
Average Distribution Substation Utilization 2015 – 2025



As shown on the graph, the steady increase in forecast utilization indicates how capacity reserves are efficiently spread across the substations throughout our service territory. We maximize planned utilization across our distribution system by designing enough operating flexibility to allow us to reconfigure distribution circuits and balance loading across distribution circuits and substations.

During the distribution planning process, SCE performs analyses to maximize asset utilization and achieve the least-cost implementation. This progression begins with evaluating the lowest cost alternatives first and involves the following:[65]

a) Existing equipment utilization through phase balancing or switching;

b) Distribution plant betterment

[65] While DER growth is included in the planning forecast, the evaluation of DERs as an alternative to distribution upgrades is not currently part of the established process. SCE recognizes the value DERs can contribute and proposes pilots in Section III.E to advance our understanding with the objective of making DER evaluation an alternative part of the process.

c) Distribution circuit upgrades;

d) New distribution circuits; and

e) Substation expansion projects.

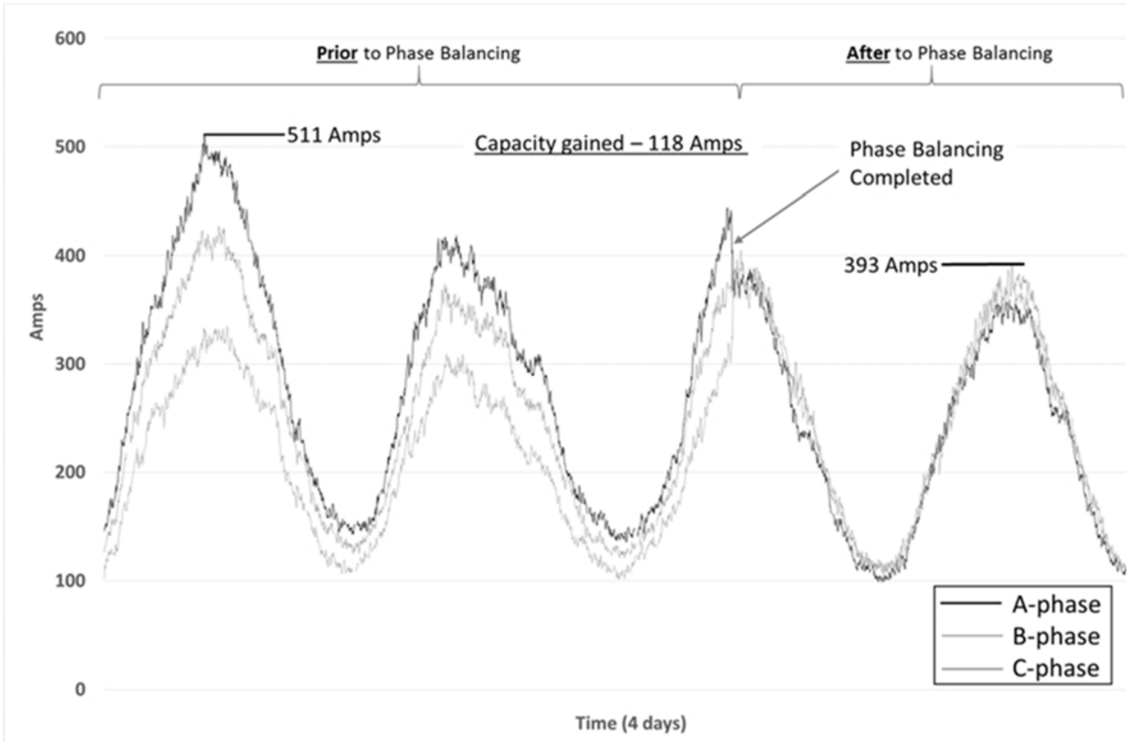
Throughout the progression, SCE develops a set of potential projects that can address the forecast distribution needs. The technical feasibility of each proposed alternative is reviewed with various internal stakeholders responsible for design, construction, operation, and maintenance. SCE uses this stakeholder input, with reliability, operational flexibility, and cost effectiveness factors, to determine which projects are not technically feasible and eliminates these projects leaving the most appropriate project. The project lists provided in the Distribution Planning Programs and Projects Section IV.B have been evaluated in this manner giving confidence that the proposed projects best fit the needs of the system.

a) <u>Maximize Equipment Utilization</u>

When we forecast that load will exceed planning limits on a distribution circuit or substation, our first step is to analyze solutions that require minor or operational mitigation solutions that do not require additional infrastructure. Potential solutions include balancing load between phases on distribution circuits or utilizing existing infrastructure to transfer load through switching to balance between circuits and substations.

Each distribution circuit provides three-phase power capable of serving a variety of customer needs. Many loads on the system today require three phases, such as large motors in commercial and industrial facilities. Other loads on the system are single phase like in a residential home, meaning they can utilize only one of the three phases on the distribution circuit. This provides the opportunity to physically move load from one phase to another, referred to as phase balancing. It is important to balance power across the three-phases because the loading of the highest loaded phase determines the peak loading of the circuit for planning. By balancing phases where available, the peak loading on the circuit can be reduced as an alternative to upgrading the infrastructure. Figure III-11 below shows an example of how the peak loading on a circuit can be reduced by phase balancing. The figure shows two days of loading before balancing, one day during the balancing process, and one day after the balancing has occurred. While phase balancing is often a cost-effective solution, this may not always be the case depending on the particular system characteristics, the load profiles of individual customers and DERs, and how they are connected.

Figure III-11
Circuit Load Balancing



If phase balancing is not an available option, SCE analyzes potential solutions that transfer load through switching. If neighboring facilities have capacity reserves, and infrastructure exists that tie circuits and/or substations together, SCE performs load transfers through those facilities to reduce loading at the location with the forecast violation. SCE maximizes the use of installed capacity and existing infrastructure where possible. These types of solutions typically incur minimal to no capital expense and often solve identified overloads by increasing the utilization of installed assets.

If existing infrastructure configurations cannot accommodate the transfer of load through switching or phase balancing, the next option is to consider upgrades to facilitate the transfer of load between distribution circuitry and substations. This option is covered in the following section on distribution circuit upgrades.

b) <u>Distribution Plant Betterment</u>

Besides improvements and projects covered by our DSP, other upgrades arise because of isolated local reasons. These may be caused by new developments that require a single-phase circuit voltage where none exists, individual changes in load profiles that drive local low voltage problems, where new protection devices and switches are needed for safety and reliability, or new street or freeway improvements.

An example of a plant betterment addition is the modification of a distribution circuit, such as the provisioning of a single-phase voltage. Single-phase[66] circuit voltage is often needed when a sizeable new housing development is being constructed in a location served by multi-phase only distribution circuits. Circuits with single-phase voltage (phase to ground) are less costly to build because single-phase transformers only require one underground cable versus two. However, in these situations, a new neutral conductor (fourth wire) on the primary distribution circuit must be furnished to establish single-phase power where no neutral conductor exists.

Another reason for increasing the capability of the distribution system is to resolve local low voltage problems. Low voltage situations may arise relatively quickly due to customer and system changes, sometimes requiring installing voltage regulators or increasing the size of existing overhead conductors or underground cables to improve voltage. SCE must serve customers sufficient voltage to meet equipment standards. Solutions to improve customer voltage where needed that require modifications described above are covered under Section IV.B.1, Plant Betterment.

Third, distribution circuit modifications may be needed for either reliability, or safety and protection reasons. Over time, some distribution circuits will not be equipped with adequate switches or protective devices as the system needs change with varying customer loads or reconfiguration. To minimize the interruption to customers to perform routine maintenance, or to adequately protect the system after reconfiguration where deficiencies exist, switches and automatic reclosers are required in strategic locations. Sometimes, on longer distribution circuits, the location of automatic reclosers are insufficient if circuits must be reconfigured, requiring an additional recloser to be installed to provide adequate protection. In other cases, customer loads have exceeded our standards to adequately isolate and minimize disruption to our customers when performing routine maintenance or restoration of power under emergencies, requiring the installation of new or upgraded switches.

Finally, sometimes new street improvements or freeway crossings provide SCE the opportunity to inexpensively install conduits for future use. By leveraging construction in progress, SCE avoids the need to install conduits that would otherwise be costly when trenching new streets, adding conduit cells in freeway overpasses, or across bridges would be required. Developers often work

[66] Single-phase voltage referenced here is phase-to-ground connected.

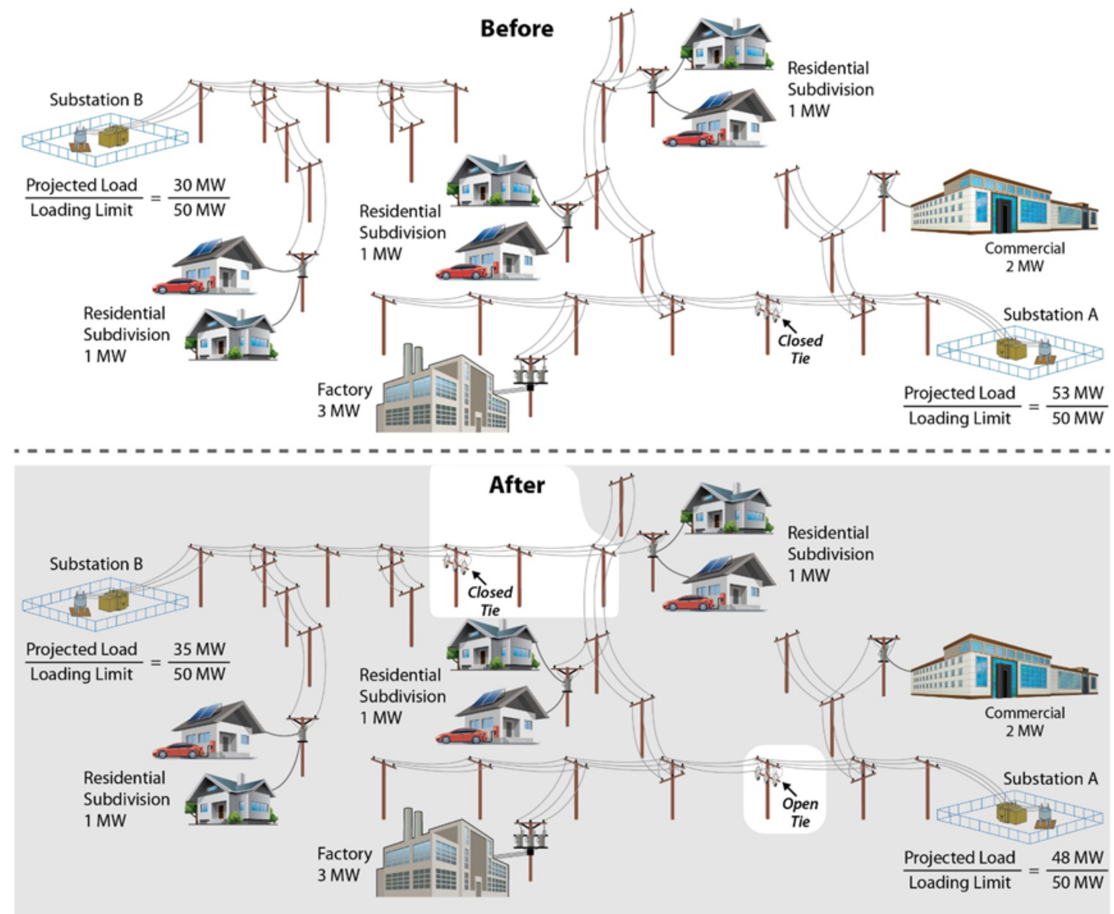
with SCE in these situations, covered by Plant Betterment, to avoid costly improvements needed at a later time.

c) Distribution Circuit Upgrades

Within the distribution planning process, if we forecast any portion of our distribution system to be overloaded and if existing distribution equipment cannot meet the needs of the system, we consider distribution circuit upgrades. Distribution circuit upgrades should support the DSP and involve work required on distribution circuits not including work on substation equipment. Typical work under this category includes installing new switches, upgrading cable or conductor, or installing new conductor to create circuit ties to facilitate load transfers between substations and circuits. The expenditure forecast is shown in the Distribution Circuit Upgrade Section IV.B.1.

If Substation A is forecast to exceed capacity, geographically neighboring Substation B has capacity reserves, and no infrastructure ties exist, a Distribution Circuit upgrade may be required to create circuit ties to facilitate load transfers from Substation A to Substation B to keep Substation A below its capacity limit. This scenario is depicted in Figure III-12.

Figure III-12
Distribution Circuit Upgrade Relieving Substation Capacity Limitation



In this figure, Substation A in the before case is overloaded by 3 MW and substation B has 20 MW of reserve. By adding a circuit tie between Substation A and B, the circuits can be reconfigured to balance loads between them.

Some distribution circuit upgrades are required due to the collective overloads of multiple distribution circuits in our underground distribution system. Work in this category includes rearranging duct bank getaways[67] at substations to reduce underground cable temperature and installing or replacing equipment to increase the capacity of a distribution circuit. Duct banks are concrete

[67] Duct bank getaways are underground conduit systems used to route multiple distribution circuits that exit out of the substation.

enclosures that house conduits for underground cables. A typical duct bank can contain four to eight or more conduits. During high load conditions, the temperature of the cables within these ducts experience mutual heating, leading to overloads that can cause cable melting when the demand on circuits exceed planned limits. By rearranging duct banks, the number of circuits within them can be reduced, reducing the overall number and resolving the high temperature condition.

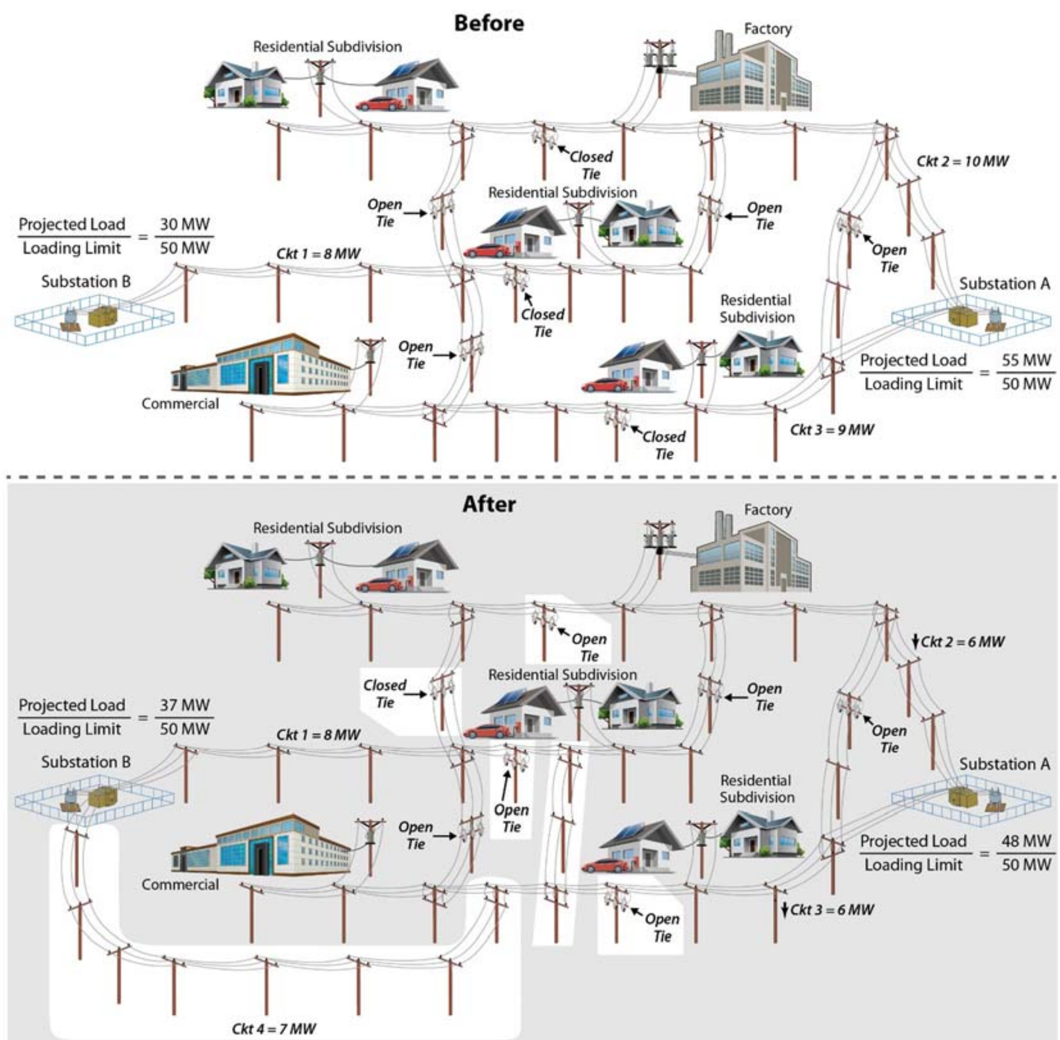
Another way to increase capacity on circuits is upgrading the cable or conductor, or installing a new conductor. Depending on the physical characteristics of the distribution circuit and projected overload, each option is considered as an alternative to provide enough capacity and stay within the circuit's thermal capacity limits. In addition, because in a one-way power flow system, the power flowing decreases with distance, some circuits may have smaller cable or conductor further away from the distribution substation. The size of cable or conductor at these circuit segments may need to be increased to accommodate the increasing demand on these facilities or support operational flexibility in these parts of the SCE system.

d) <u>New Distribution Circuits</u>

If Distribution Circuit Upgrade projects cannot meet the need of a forecast violation, or the Distribution Circuit Upgrade solution is economically unfeasible and does not meet the long term needs of the area, SCE will consider new distribution circuit solutions in the DSP. SCE builds new distribution circuits as part of three types of projects: (1) new substation projects, (2) substation capacity increase projects, and (3) as standalone projects. When multiple existing distribution circuits in a general geographic area are forecast to reach or exceed capacity limits, or if the average circuit loading exceeds our distribution planning criteria and guidelines, a new distribution circuit is identified after considering lower cost solutions such as reconfiguration. This scenario requires a new DSP circuit to provide additional distribution capacity outside the substation fence enabling existing circuits exceeding capacity to be relieved. SCE anticipates new DSP circuits to be required to accommodate forecast load growth, generation of DERs, and 4 kV substation eliminations. New DSP circuits will be needed in areas where DER generation forecast exceeds capacity of existing circuits.

New DSP circuits are also considered for offloading neighboring substations. If, for example, there is one substation that is forecast to exceed its capacity limit, we determine there is another adjacent substation that can provide relief by balancing loads between them. When there is not sufficient circuitry to accomplish moving loads from one substation to another, it may be economical to build a new DSP circuit to provide this transferability. Figure III-13 represents a graphical depiction of the example.

Figure III-13
DSP New Circuit Used to Offload Substation



In the before solution, Substation A is overloaded by 5 MW, and Substation B has 20 MW of reserve capacity. However, the loading on the circuits that potentially connect the substations are highly loaded. In the after example, a new circuit 4 is constructed and through reconfiguration via a series of switching actions, load is moved from Substation A to Substation B. The net result is reducing the load at Substation A below the loading limit, and increasing the load at Substation B. By adding this circuit, additional operating flexibility is also provided to all of the circuits, reducing their loading and increasing their transfer capability, especially important during outages and performing restoration. This solution is usually not economical if there are long distances between substations, or where the cost to construct a new feeder will exceed other alternatives such as substation level upgrades. The option of a new DSP circuit as a solution to offload a neighboring substation is compared to the cost and overall effectiveness of a substation expansion project to determine which one is the better alternative to meet the long term needs of the area.

e) Substation Expansion Projects

If a distribution substation is expected to exceed its planning limits and cannot transfer load to a neighboring substation, a substation expansion project may be the most cost effective solution when compared against others, such as adding a new distribution circuit. These types of projects are identified in our DSP to increase capacity at existing substations by installing new transformers, replace limiting components to maximize substation capacity, or build new substations. A substation expansion project is compared to other alternatives to help ensure the most economical project or combination of projects is selected to reliably meet the long term needs of the area. It may be more economical to add capacity at a distribution substation in combination with a new DSP circuit to offload a neighboring substation instead of building a new substation.

Distribution substation expansion projects come in three categories: (1) Install new or upgrade existing substation equipment within the existing fenced in substation footprint; (2) Install new or upgrade existing equipment at a substation that requires additional substation property and/or expansion of its existing footprint to accommodate the capacity increase; and (3) New substations. Typically, the preferred economical solution is to upgrade an existing substation to serve local area load and generation if located in close proximity to the load growth. Sometimes, upgrading substations may be limited by the available space, requiring the expansion of the substation property. If multiple distribution substations in the same geographic region are built to maximum capacity and are expected to continue experiencing load growth, or if a new development is being constructed in a geographically isolated region where there is little to no electric infrastructure, a new substation may solve the long term needs of the area.

f) Subtransmission Lines Plan

Networks of subtransmission lines operating at 66 kV or 115 kV deliver electricity from the low-voltage side of our transmission substations to our distribution substations. In the Subtransmission Lines Plan, SCE annually reviews the requirements for these 66 kV and 115 kV system over a 10-year planning horizon to be in conformance with our subtransmission planning criteria.

Without a comprehensive plan, SCE risks loading its 66 kV and 115 kV subtransmission lines beyond their capabilities as the demand for electricity continues to increase in our service territory. This could ultimately result in failures of our overhead and/or underground subtransmission lines and service interruptions to tens of thousands of customers over fairly limited geographic areas.

The objective of the Subtransmission Lines Plan is to provide adequate 66 kV or 115 kV line capacity to serve forecast peak loads at our B-substations. The ability of each subtransmission line is evaluated to determine if it can operate within its established loading limits under normal conditions with all facilities in service ("Base Case"), and under contingency conditions when critical equipment is out of service ("Likely Contingency"). Studies are performed to evaluate whether adequate voltage can be maintained under contingency conditions. When we forecast that a subtransmission line will become overloaded or that it cannot maintain adequate voltage, operational solutions are first considered, similar to the distribution planning process. This includes determining if existing infrastructure can transfer electric power from a highly loaded subtransmission line to a less loaded one. If infeasible, a capital project is initiated to expand, upgrade, or reinforce the system. Typical projects include replacing existing subtransmission lines and/or circuit breakers with higher capacity ones, constructing new lines, and installing 66 kV or 115 kV capacitor banks at B-substations.

SCE's Subtransmission Planning Criteria also defines how many lines must feed each of our distribution substations depending on how much load is being served. Over time, as load increases in an area, an additional subtransmission line must be brought into a distribution substation to help ensure sufficient capacity under normal and contingency conditions. When this is identified, SCE will review various available alternatives to accomplish in the most cost effective way that maintains reliability.

g) <u>A-Bank Plan</u>

SCE's substations that reduce our system voltage from the transmission level (220 kV or 500 kV) to the subtransmission level (66 kV or 115 kV) are A-substations that serve the distribution substations. The transformer banks that step down the voltage within these substations are A-banks. SCE identifies needed upgrades within these transmission level substations in the A-bank Plan, where we annually review requirements for our 500/115 kV, 220/115 kV, and 220/66 kV A-banks over a ten-year planning horizon to avoid the risk of loading beyond their capabilities per SCE's planning criteria. The consequences of overloading these transformers are in-service failures that would cause service interruptions to hundreds of thousands of customers over widespread geographic areas.

The objective of the A-bank plan is providing adequate capacity at each transmission substation to serve forecast peak loads under normal, or base case conditions. These forecast loads represent the maximum demand for the highest expected temperature within a five-year period, referred to as a one-in-five year heat storm condition. SCE's planning criteria requires a thorough review of SCE's facilities and the impact of peak demands under both normal conditions with all facilities in service, and emergency conditions, referred to as likely contingency conditions, when critical equipment is out of service. When we forecast that an A-bank transformer will become overloaded within the ten-year planning horizon, we evaluate whether we can utilize existing infrastructure to balance electric power between highly loaded substations and substations with additional reserve margins. If this cannot be achieved, a project to expand, upgrade, or reinforce our system is initiated. Typical projects include installing new A-bank transformers at existing substations, replacing existing transformers with higher capacity units, replacing other existing equipment such as switchracks and circuit breakers, and installing new-A-substations.

h) Subtransmission VAR Plan

The objective of the Subtransmission VAR Plan is to fully supply the reactive power needs of each of our 66 kV and 115 kV subtransmission networks (including A-banks) under heat storm conditions. In practical terms, this means having enough reactive support to avoid reactive power deficiencies that impact the transmission grid. This is accomplished by comparing reactive power supplies (primarily 66 kV and 115 kV capacitor banks) against the projected reactive power needs of our A-bank transformers, subtransmission lines, and any large customers we serve directly at the subtransmission voltage level. When we forecast a VAR deficiency within our ten-year planning horizon, we design a capital project to install a 66 kV or 115 kV substation capacitor bank. These capacitor banks are typically installed at the low voltage side of our A-substations.[68]

3. Implementation of Solutions

To proceed with the needed capital improvements, the proposed solutions include internal stakeholder review at various stages. Part of this review includes the coordination of work activities to avoid any duplicate or redundant work with other programs, such as aging infrastructure replacement.

[68] If there are physical space constraints that prohibit us from installing a needed capacitor bank at an A-substation, we will instead consider installing the capacitor bank at the high voltage side of one of the downstream B-substations served by the A-substation.

If we have identified a substation transformer replacement to a larger size, but that same transformer is scheduled for replacement, processes exist to avoid unnecessary and overlapping work, which is part of our overall internal stakeholder prioritization process. Similar work processes occur throughout the grid and is reflected in this GRC request. The 10-year plan is refreshed annually, so this review occurs annually.

As discussed in Section I.B.1 above, SCE believes it is important that, as more work is identified throughout the T&D system, we execute work plans in a systematic and holistic way. Incorporating the right technologies, capabilities, and needed upgrades across various programs is an increasingly important way to manage expenditures.

C. System Improvement Planning Process

The System Improvement Programs include three categories: the Substation Equipment Replacement Program (SERP), the Distribution VAR (reactive power) plan, and the Substation Monitoring Programs. These programs include upgrades to the distribution system that involve protection, reactive power support, and monitoring substation loading and duct bank temperatures, all of which are vital to serve customers safely and reliably. Descriptions of these categories are included in the following sections. The capital forecast for this section is described in Section IV.C, System Improvement Programs.

1. Substation Equipment Replacement Program (SERP)

The Substation Equipment Replacement Program (SERP) evaluates the adequacy of substation terminal equipment and system protection equipment, and proposes upgrades when deficiencies are identified. The SERP identifies substations where available fault current, or short-circuit duty, exceeds safe equipment ratings essential to the provision of safe, reliable service.

SCE's electrical distribution system is designed to safely detect and isolate faults. Distribution system faults can be caused by natural events, equipment failures, or accidents caused by human error. When a fault occurs, dangerous levels of current flow from all electrical sources (generators) to the location of the fault. Due to the magnitude of fault current, a fault condition must be isolated quickly to restore safe operating conditions of the electrical system. Prolonged fault current will cause major damage to distribution equipment, can ignite brush fires, and can seriously jeopardize public and employee safety. Substation circuit breakers are the most common devices used to isolate faults and are relied upon to interrupt the highest fault currents experienced on the distribution system. Substation circuit breakers incapable of interrupting expected fault currents are likely to fail when those

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-003 Supplemental

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 10/10/2016

Question 01a:

On page 10 of SCE's Phase 2 testimony, SCE refers to a projected load of 285 MW for 2018 in the Santa Barbara/Goleta area based on SCE's 2016 Transmission Substation Plan load forecast.

A. Please provide the SCE's 2016 Transmission Substation Plan and workpapers for the Santa Barbara/Goleta area load forecast, including SCE's underlying assumptions.

Response to Question 01a:

There are no workpapers for this data as these are outputs of an in-house software tool that is not transmittable.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 09/20/2016

Question 01:

Ellwood Refurbishment Project

On page 10 of SCE's Phase 2 testimony, SCE refers to a projected load of 285 MW for 2018 in the Santa Barbara/Goleta area based on SCE's 2016 Transmission Substation Plan load forecast. Please explain how this load forecast differs from the CEC IEPR load forecast and the CAISO local capacity requirements technical study.

a. Please explain any differences in assumptions for Energy Efficiency and Distributed Energy Resources penetration and the impact on the different forecasts.

b. Please explain any differences in assumptions regarding the availability of resources to meet demand. Are there resources that the CAISO counts that SCE's forecast doesn't count? If so, please identify those resources and their capacity.

Response to Question 01:

The CEC develops the IEPR load forecast that is utilized for the CAISO local capacity requirements technical study, thus, the CEC is best-suited to provide the assumptions they used for Energy Efficiency and Distributed Energy Resources penetration and incorporation of those assumptions into its forecast. As such, SCE is not in a position to explain any differences between the CEC's assumptions and those used by SCE in its internal Transmission Substation Plan (TSP) load forecast.

Please see SCE's response to ORA's Data Request No. 003 Question 1 for a general description of how SCE incorporates Energy Efficiency and Distributed Energy Resources penetration in its TSP peak load forecasts.

On page 94 of CAISO's Final 2017 Local Capacity Technical Report, the following existing generation units in the Goleta area are identified along with the available net qualifying capacity (NQC) of each facility.

Resources (net qualifying capacity in MW)	
GOLETA_2_QF	0.08
GOLETA_6_ELLWOD	54
GOLETA_6_EXGEN	0.79
GOLETA_6_GAVOTA	0.68

GOLETA_6_TAJIGS	2.9

In SCE’s TSP forecast, zero availability of these resources is modeled to meet its forecasted peak demand in the Goleta area.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Gene Lee
Title: Contract Manager
Dated: 09/20/2016

Question 02:

Ellwood Refurbishment Project

What quantitative and/or qualitative factors are considered by SCE when determining that a GFG facility needs refurbishment?

a.Did SCE review information on similar facilities to determine the likely need for refurbishment of Ellwood? If so, please provide identify those other facilities and information on their refurbishment.

Response to Question 02:

SCE does not itself determine whether a non-SCE facility needs refurbishment. SCE evaluates offers bid into its solicitations using a least-cost, best-fit methodology. NRG submitted an offer to refurbish Ellwood through the LCR RFO and it was selected. Given the advanced age of the Ellwood facility it is reasonable to assume that a refurbishment will be required in order to keep the facility operational for many more years. Per the contract, the refurbishment will result in a 30 year design life of the resource.

a. SCE did not review information on similar facilities in determining the likely need for refurbishment of Ellwood.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Gene Lee
Title: Contract Manager
Dated: 09/20/2016

Question 03:

Ellwood Refurbishment Project

Please explain why the Ellwood plant is currently considered “not reliable”

a. Please explain how the refurbishment would change the reliability of the plant.

b. Would the heat rate of the plant change with refurbishment?

Response to Question 03:

See attached confidential Exhibit Sierra Club-01C (Response to Question 05a and Attachment 1 to Question 05a).

a. Once the refurbishment is complete, the facility will be required to provide a certification from an independent, non-Affiliate California registered professional mechanical engineer that Ellwood has been designed and refurbished to have a thirty (30) year design life. Once the delivery term starts and for the duration of the 10 year agreement, within operational constraints SCE will have the right to dispatch the facility, and if the facility is unavailable then capacity payment reductions would apply. In addition, the contract requires the facility to be maintained in accordance with industry standards, and if the facility falls below a certain threshold of performance, the Seller must repair the facility.

b. The refurbishment will not change the heat rate of Ellwood.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Gene Lee
Title: Contract Manager
Dated: 09/20/2016

Question 04:

Process

SCE chose to solicit offers through the LCR RFO rather than through a bilateral transaction or an all source RFO. It stated that it did so because it preferred a competitive process because in an all source RFO the contract term would have been limited to 59 months or less under that option. SCE stated under the LCR RFO NRG can refurbish Ellwood which would provide for an extended operating life and therefore a longer contract duration over which to amortize the project cost which provides savings for customers. Does SCE believe that NRG would not choose to refurbish Ellwood under a 59 month contract? How would SCE expect the price to change for a shorter term contract?

Response to Question 04:

To clarify, in D.13-02-015, the Commission ordered SCE to procure between 215 and 290 MW of electrical capacity in the Moorpark sub-area to meet long-term local capacity requirements by 2021. To meet this need, SCE issued the LCR RFO.

SCE cannot speak to what NRG would or would not do under a 59 month contract. SCE selected the option that was available, which was a cost competitive offer to refurbish the Ellwood resource through the LCR RFO. SCE would expect a higher contract price if the contract term were shorter as costs for the capital improvements would need to be collected over a shorter period of time.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 09/20/2016

Question 05:

Process

On page 13 of SCE's Phase 2 testimony, SCE states that additional upgrades to its subtransmission system are potential solutions that SCE plans to evaluate against DER procurement to determine the lease-cost and best-fit options for the area.

a. What additional capacity could these upgrades provide to the area? Please provide an estimate of the MW increments.

b. Please provide an estimate cost for such projects.

c. Please explain why SCE hasn't compared the Ellwood contract to such solutions to determine the least-cost and best-fit option.

Response to Question 05:

a. SCE has so far identified a reconductoring project of an existing 66 kV subtransmission line to help address a portion of the resiliency target. This is in addition to the Santa Barbara Reliability Project currently being licensed, and would provide approximately up to 15 MW of additional capacity.

b. Preliminary estimates for the 66 kV reconductoring project indicate an estimated cost approximately $50 million. This estimate is purely indicative for planning purposes only and is subject to change once further engineering, design, and potential licensing is completed.

c. SCE has compared the Ellwood contract to the 66 kV reconductoring project and believes Ellwood provides greater benefits in terms of short circuit duty (SCD), system capacity, and less cost.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Jonathan Yuen
Title: Power System Planner
Dated: 09/20/2016

Question 06:

Process

On page 10, SCE states that following the loss of the two 230 kV lines, a major source of Short Circuit Duty (SCD) is removed and overall SCD is reduced. And on page 12 SCE states that its "mitigation strategy is expected to provide sufficient SCD."

a. Please identify any CPUC requirement or standard for the appropriate level of SCD. If none is available, please provide the standard that SCE would use to determine "sufficient SCD."

b. Please identify any non-CPUC requirement or standard for the appropriate level of SCD. If none is available, please provide the standard that SCE would use to determine "sufficient SCD."

c. Please explain the current level of SCD and how the planned upgrade to the 66kW subtransmission ties impact the level of SCD.

Response to Question 06:

a-b. SCE is not aware of any CPUC or non-CPUC requirement or standard for appropriate levels of SCD. As a minimum design guideline, SCE uses a fault current/minimum trip current ratio of 2.3 for minimum three-phase fault conditions, 2.0 for minimum phase-to-phase fault conditions, and 3.0 for minimum single line to ground fault conditions. Although these are minimal guidelines, in practice SCE prefers ratios on the order of 4.0 to 5.0 for single line to ground fault conditions.

c. Post loss of the 220 kV lines, the current level of SCD includes Ellwood online and is sufficient. The planned upgrade to the 66 kV subtransmission ties known as the Santa Barbara County Reliability Project (SBCRP) would further improve the level of SCD.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Gene Lee
Title: Contract Manager
Dated: 09/20/2016

Question 07:

Process

Please identify other proceedings or RFOs where SCE plans to procure resources that could be located in the Goleta area.

Response to Question 07:

SCE is currently planning on launching its 2016 Energy Storage RFO later this year, which would specifically ask for energy storage offers in the Goleta area, among a few other specific locations. Additionally, many of SCE's Renewable procurement activities (such as the annual RPS solicitation or Re-MAT, etc.) are open to resources across SCE's service territory, including the Goleta area. However, just because solicitations are open to a large geographic area doesn't necessarily mean that SCE will receive competitive offers in areas of need. SCE is also planning to launch a distributed energy resources RFO for resources in the Goleta area in the near future.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-004

To: ORA
Prepared by: Gene Lee
Title: Contract Manager
Dated: 09/20/2016

Question 08:

.5 MW Storage

Has SCE inquired into why NRG has bundled the storage contract with the Ellwood refurbishment contract? If no, what does SCE believe to be the reason for bundling the two together?

Response to Question 08:

In the LCR RFO, SCE allowed all counterparties to submit offer sets whereby two or more of the offers must be taken together as an inclusive set. Many of the LCR RFO counterparties incorporated this packaging of offers in their submittal, and other than generic communications to ensure that SCE understood the intent of the submitted offer structures (e.g., offer A must be taken with offer B or C), SCE did not inquire as to the reasoning behind the bundling of offers.

In order to satisfy the requirement of providing incremental LCR capacity in the LCR RFO, NRG bundled the energy storage and Ellwood refurbishment projects together since the inclusion of the energy storage contract allowed the combined offering to meet this obligation.

The combined proposal resulted in (a) Incremental capacity from the energy storage project that assisted in meeting LCR need, (b) energy storage MW to assist in meeting California's statewide storage procurement targets, and (c) 54 MW of gas fired capacity made more reliable via the refurbishment project, at a fraction of the cost of 54 MW of brand new gas fired capacity.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-005

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 10/14/2016

Question 01:

1. Please provide an estimate of how often the two Goleta-Santa Clara 230 kV transmission lines are likely to fail simultaneously. For example, is the probability of a simultaneous outage of the two lines once in ten years, twenty years, etc.?

a. Please identify any assumptions used in developing this estimate that were adopted in the LTPP proceeding.

b. Please identify any assumptions used in developing this estimate that were not adopted in the LTPP proceeding.

Response to Question 01:

SCE has estimated the frequency of a simultaneous outage of the two lines as approximately on the order of a one in eight year event based upon the observed historical frequency of event drivers including landslide and fire.

These assumptions were not adopted in the LTPP proceeding as the above frequency analysis for this area differs from LTPP stochastic modeling practices and methodology which are primarily utilized for consideration of the performance of generation resources and not transmission system infrastructure.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-005

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 10/14/2016

Question 02:

2. Please provide any analysis SCE or CAISO has done to determine the loss of load probability for the Goleta area under the current LTPP standards.

Response to Question 02:

SCE has not performed such analysis and is not aware of any analyses performed by CAISO to determine the loss of load probability for the Goleta area under the current LTPP standards.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-ORA-SCE-005

To: ORA
Prepared by: Jonathan Yuen
Title: Power Systems Planner
Dated: 10/14/2016

Question 03:

3. SCE states that with the completion of the Santa Barbara County Reliability Project in 2018, 180 MW could be rerouted to the Goleta area through the 66 kV subtransmission system. How many hours of the year was load in the Goleta area greater than 180 MW for each of the following years:

a. 2011
b. 2012
c. 2013
d. 2014
e. 2015
f. Please provide an estimate of the number of hours in 2018 that load in the Goleta area would be greater than 180 MW.

Response to Question 03:

a - e. The following table provides the number of hours in the requested years that load in the Goleta area was greater than 180 MW.

2011	2012	2013	2014	2015
2769	2560	3697	2437	2185

f. SCE only forecasts the peak load in 2018 and does not have an estimate of the number of hours in 2018 that load in the Goleta area would be greater than a given threshold.

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016-LCR RFO-ORA-SCE-006

To: ORA
Prepared by: Aimee Wong
Title: Project Manager
Dated: 10/17/2016

Question 01:

How much demand response is currently available in the Moorpark sub-area (please include all utility DR programs and third-party DR RA contracts)? Please break this down to DR that has

a. Less than or equal to 20 minute response time
b. Great than 20 minute response time.
c. How much of this DR is currently counted towards meeting SCE's 2016 LCR RA requirements? If there is a difference between what is currently available in Moorpark and what is currently counted towards local capacity RA requirements, please explain why.

Response to Question 01:

<u>Response to 1.a. and 1.b.:</u>
The Moorpark sub-area includes SCE's Moorpark, Santa Clara, and Goleta substations. SCE estimates the DR megawatts (MW) for its DR programs for the Moorpark sub-area and by response time as follows:

	≤20 Minute Response Time (SCE DR Programs: SDP, AP-I, & BIP-15)	>20 Minute Response Time (SCE DR Programs: BIP-30, AMP, CBP-DO, CBP-DA, DBP, CPP, & PTR)
Moorpark Sub-Area 2016 Ex Ante DR MW Based Upon CAISO 1-in-10 for August Peak	15.44 MW	44.89 MW

The DR MW provided above uses the ex ante estimates for 2016 from the PY2015 load impact reports. SCE DR programs that respond in less than or equal to 20 minutes include Base Interruptible Program 15-minute notification (BIP-15), Summer Discount Plan Program (SDP), and the Agricultural Pumping Interruptible Program (API). SCE DR programs that respond in greater than 20 minutes, including day-ahead programs, include BIP-30, Aggregator Managed Portfolio (AMP) Program, Capacity Bidding Program Day-Of (CBP-DO), Capacity Bidding Program Day-Ahead (CBP-DA), Demand Bidding Program (DBP), Critical Peak Pricing (CPP), and Peak Time Rebate (PTR) also known as Save Power Day (SPD).

<u>Response to 1.c.:</u>
SCE does not have data for the DR RA allocations specifically for the Moorpark sub-area. SCE only has the 2016 DR RA MW allocations for the Big Creek-Ventura area.

DATA REQUEST SET A.14-11-016-LCR RFO-ORA-SCE-006

To: ORA
Prepared by: Aimee Wong
Title: Project Manager
Dated: 10/17/2016

Question 02:

Please provide an estimate of the amount of demand response that would be available in the Moorpark sub-area in 2021. Please provide an explanation of any assumptions used in this forecast and break this down to DR that has

a. Less than or equal to 20 minute response time.
b. Great than 20 minute response time.

Response to Question 02:

SCE does not have an estimate on the amount of demand response that would be available for the Moorpark sub-area in 2021. SCE does not estimate DR program enrollment forecasts at this granular level (e.g., SCE does not forecast DR enrollment by substation).

Exhibit Number	:	ORA 8
Proceeding No:	:	A.14-11-016
Commissioner	:	Michel P. Florio
Admin. Law Judge	:	Regina DeAngelis
	:	

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Data Request Responses from The California Independent System Operator

San Francisco, California
November 1, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area.	**Application 14-11-016**

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO THE FIRST SET OF DATA REQUESTS OF THE OFFICE OF RATEPAYER ADVOCATES

Below are the California Independent System Operator (CAISO) responses to the First Set of Data Requests served by the Office of Ratepayer Advocates (ORA).

Request No. 1.

In Attachment 1 of the ISO's testimony, "Available resources in the Moorpark area to meet 2021 LCR," Demand Response (DR) is listed with an 18.1 MW August NQC and available capacity.

1(a) Please explain how the ISO developed this number. What types of DR is included or excluded from this number?

CAISO RESPONSE TO No. 1(a).

The 18.1 MW is the amount of DR with less than or equal to 20-minute response time that SCE modeled for the Moorpark area in the 2021 LCR base case.

1(b) On October 3, 2016 there was a joint ISO-CPUC workshop on Slow Response Local Capacity Resource; the attached slides are from Nebiyu Yimer's presentation on Southern California Area results. Slide 58 shows 37.5 MW of existing slow DR in the Moorpark area. How do the assumptions for this amount differ from the assumptions used to develop the 18.1 MW value?

CAISO RESPONSE TO No. 1(b)

The 37.5 MW is the amount of DR in the Moorpark area with greater than 20 minute response time.

1(c) If the ISO were to count all available DR in the Moorpark area, with less than and greater than 20 minutes response time, what would be the MW capacity? Please break this down to DR that has

i. Less than or equal to 20 minute response time
ii. Greater than 20 minute response time

CAISO RESPONSE TO No. 1(c)

DR resources in the Moorpark sub-area total 55.6 MW. 37.5 MW are resources with a response time greater than 20 minutes. 18.1 MW are resources with a response time less than or equal to 20 minutes.

DR resources with response times greater than 20 minutes cannot be dispatched to allow the CAISO reposition the system within 30 minutes of a contingency event, as required by the CAISO tariff and NERC mandatory reliability standards. Notwithstanding this limitation, the CAISO conducted further analysis with all 55.6 MW of DR resources modeled and found that the resources were insufficient to prevent voltage collapse in the Moorpark sub-area. Table 1, below, indicates that voltage collapse occurs when area load exceeds 1660 MW which is below the forecast 2021 area peak load with AAEE of 1676 MW. This means that the Moorpark sub-area would be deficient by 16 MW even if all slow-responding DR resources are assumed to count toward LCR needs. In comparison, Table 2, below, indicates voltage collapse does not occur when the area load is at peak if Ellwood (54 MW) is available instead of the 55.6 MW of DR.

The main reason for the difference in effectiveness between Ellwood and the DR is that, unlike the DR, Ellwood has the capability to provide dynamic reactive power support in addition to active power which helps to reduce LCR in a voltage stability limited area such as Moorpark.

(see next page for Tables 1 and 2)

TABLE 1

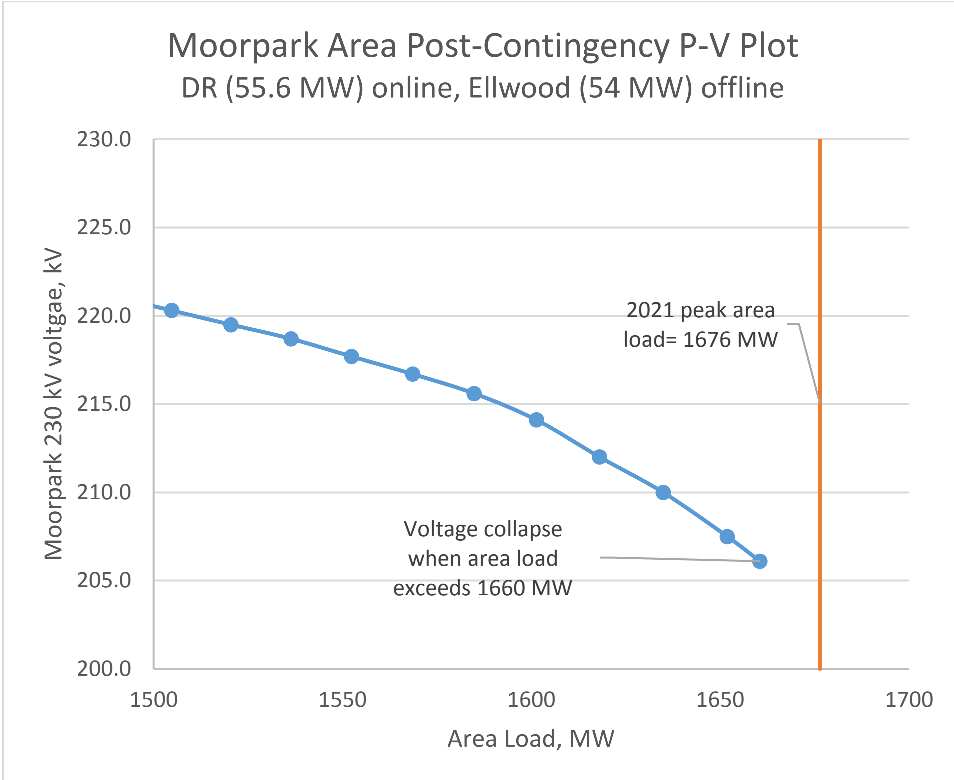


TABLE 2

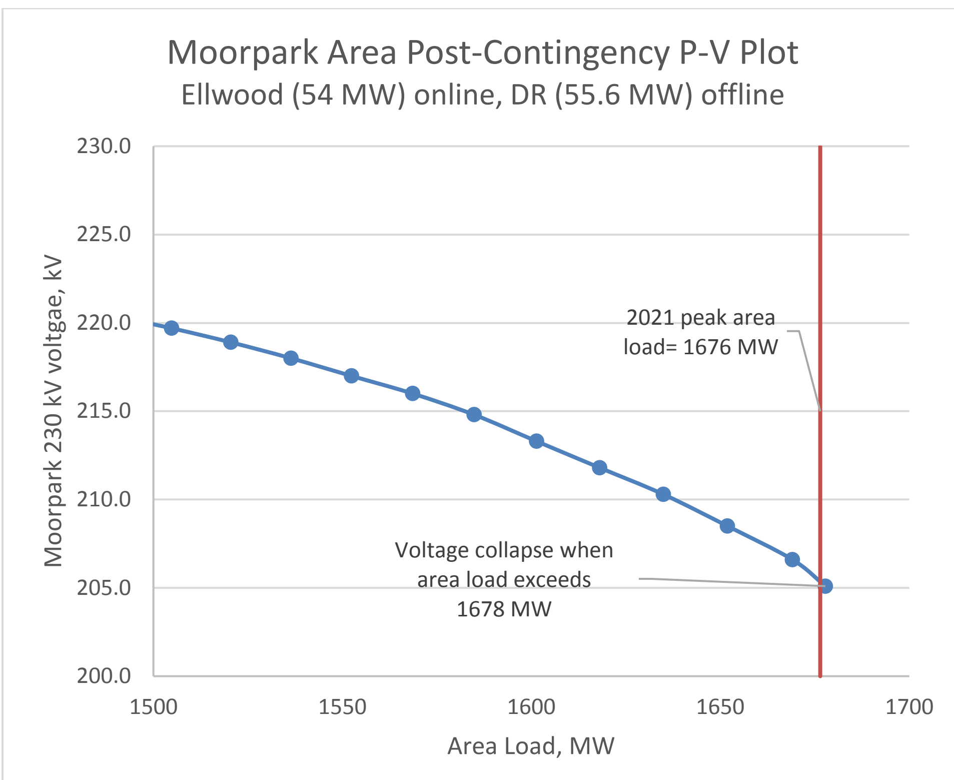


Exhibit Number	:	ORA 9
Proceeding No:	:	A.14-11-016
Commissioner	:	Michel P. Florio
Admin. Law Judge	:	Regina DeAngelis
	:	

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Data Request Responses from NRG California South LP

San Francisco, California
November 1, 2016

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October 31, 2016

BY ELECTRONIC MAIL

Candace Choe, Analyst, cc2@cpuc.ca.gov
Cindy Li, Analyst, xl2@cpuc.ca.gov
Christopher Clay, Counsel, cec@cpuc.ca.gov
Office of Ratepayer Advocates ("ORA")

Re: ORA Data Request No. NRG Data Request 001

Dear Ms. Choe, Ms. Li, and Mr. Clay:

NRG California South LP ("NRG California South") provides this response to ORA Data Request No. NRG Data Request 001 ("Data Request"), submitted in connection with Phase 2 of Application 14-11-016 before the California Public Utilities Commission ("Commission").

GENERAL OBJECTIONS

NRG California South hereby interposes the following general objections ("General Objections") into its responses to the Data Request as if the General Objections were set forth in full in each such response. The assertion of the same or additional objections in any particular response does not waive the other General Objections set forth below that are not specifically repeated in the individual responses.

1. NRG California South objects to the Data Request to the extent that the Data Request seeks to impose obligations and burdens on NRG California South beyond those imposed by the Commission's Rules of Practice and Procedure and applicable law. NRG California South is not a public utility regulated by the Commission. Public Utilities Code Sections 309.5 and 314 do not authorize ORA to compel NRG California South's responses to the Data Request.

2. NRG California South objects to the Data Request to the extent that the Data Request seeks information and/or documentation protected by the attorney-client privilege, the attorney work product doctrine, joint interest privilege, or any other applicable privilege, rule or duty of confidentiality that precludes or limits the production of such information and/or documentation.

3. NRG California South objects to the Data Request to the extent that the Data Request seeks information and/or documentation requiring the disclosure of proprietary, trade secret, or competitively sensitive information of NRG California South.

4. NRG California South objects to the Data Request to the extent that the Data Request seeks information and/or documentation that is not relevant to the subject matter of

Phase 2 of Application 14-11-016, and not reasonably calculated to lead to the discovery of admissible evidence.

5. NRG California South objects to the Data Request to the extent that the Data Request seeks information that is already in the possession of or easily accessible to ORA through means other than the Data Request.

6. NRG California South objects to each and every request included in the Data Request as overly broad to the extent that it purports to require the furnishing of information that is not in NRG California South's possession or control or otherwise available to NRG California South.

7. NRG California South objects to the Data Request to the extent that the Data Request is otherwise improper, overly broad as to time or content, vague and/or ambiguous, insufficiently precise to permit a response, unduly burdensome or oppressive, or unreasonably cumulative or duplicative.

Subject to, in accordance with, and without limiting or waiving the foregoing General Objections, NRG California South further responds to the Data Request as set forth below. NRG California South provides these responses without any waiver of NRG California South's rights, and with all rights expressly reserved.

RESPONSES

ORA Data Request No. NRG Data Request 001:

1. In Resolution E-4781, the Commission approved SCE's contract with NRG Energy, Inc. for the Ellwood Peaker for the term of August 1, 2016 to May 31, 2018. Currently, SCE is seeking Commission approval of a contract term which begins in June 2018. This contract also includes refurbishment of the Ellwood facility.

a. When does NRG expect to perform this refurbishment?

b. What kind of schedule does NRG anticipate for the Ellwood facility while it is performing the refurbishment?

c. Please provide a description of the work that NRG plans to do in refurbishing Ellwood.

Responses to Data Request No. NRG Data Request 001:

NRG California South incorporates by reference each of its General Objections as if set forth in full herein. Subject to and without waiving the foregoing General Objections, NRG California South responds as follows.

a. The 2013 LCR Power Purchase Tolling Agreement between Southern California Edison Company ("SCE") and NRG California South dated November 3, 2014 ("Tolling Agreement") specifies the requirements for when refurbishment of the

Project (as defined in the Tolling Agreement) must be complete. NRG California South expects to perform all necessary refurbishment work in accordance with those requirements. The work will be conducted after the Commission's approval of the Tolling Agreement becomes final. Assuming timely Commission approval, the work likely will be conducted during a planned maintenance outage in 2017 or 2018, before the Delivery Period under the Tolling Agreement commences. Work will be conducted during a planned maintenance outage in accordance with the resource adequacy agreement that is currently in effect.

b. As stated in SCE's testimony in this proceeding, refurbishment of the Project "will result in a resource that can be relied on for the next 30 years." (Exhibit SCE-1 at page 57, lines 11-15.) NRG California South will perform all work required by an independent professional engineer in order to confirm that the 30-year standard is satisfied. The independent engineer will determine the scope of the required work, and that scope will determine how long the work will take to complete. As explained in part (a) above, the work will be conducted during a planned maintenance outage before the Delivery Period under the Tolling Agreement commences.

c. As explained in part (b) above, the refurbishment must satisfy the specifications of an independent engineer. Work likely will involve inspections of components of the Project, which will then be repaired and replaced as needed in order for the independent engineer to certify a 30-year remaining design life. The Ellwood Generating Station experienced a forced outage in 2016, and it became necessary to conduct major maintenance work during 2016 that was not expected. It is possible that the unexpected completion of this major maintenance work could affect the scope of the work required for the refurbishment. As stated above, the independent engineer will make that determination.

Please do not hesitate to contact the undersigned should you have questions concerning this response.

Sincerely,

Lisa A. Cottle
Winston & Strawn LLP
101 California Street, 35th Floor
San Francisco, CA 94111-5802
Phone: (415) 591-1579
Email: lcottle@winston.com

Exhibit Number	:	ORA 10
Proceeding No:	:	A.14-11-016
Commissioner	:	Michel P. Florio
Admin. Law Judge	:	Regina DeAngelis
	:	

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

California Independent System Operator 2017 Final LCR Study Results Big Creek/ Ventura Local Area

San Francisco, California
November 1, 2016

2017 Final LCR Study Results Big Creek/Ventura Local Area

Nebiyu Yimer

Regional Transmission Engineer Lead

Stakeholder Call

April 14, 2016

Big Creek/Ventura Area Loads & Resources

Load

Year	Load (MW)	AEEE (MW)	Pump Load (MW)	Transmission Losses (MW)	Total (MW)
2017	4377	-78	369	51	4719

Available Generation

Year	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
2017	171	372	4920	5463

Critical Area Contingencies

Rector Sub-area – Category B

Contingency: Vestal-Rector #1 or #2 230 kV line with Eastwood out of service

Limiting component: Remaining Vestal-Rector 230 kV line

2017 LCR need: 513 MW (include 1 MW of QF generation)

Rector Sub-area – Category C

Same as above.

Critical Area Contingencies

Vestal Sub-area – Category B

Contingency: Magunden-Vestal #1 or #2 230 kV line with Eastwood out of service

Limiting component: Remaining Magunden-Vestal 230 kV line

2017 LCR need: 715 MW (includes 46 MW of QF generation)

Vestal Sub-area – Category C

Same as above.

Critical Area Contingencies

Santa Clara Sub-area – Category C

Contingency: Pardee-S. Clara 230 kV line followed by DCTL
Moorpark-S. Clara #1 and #2 230 kV lines

Limiting component: Voltage collapse

2017 LCR need: 227 MW (includes 90 MW of QF generation)

2021 LCR need: 253 MW (includes 90 MW of QF generation)

Santa Clara Sub-area – Category B

No requirement.

Critical Area Contingencies

Moorpark Sub-area – Category C

Contingency: Pardee-Moorpark #3 230 kV line followed by DCTL

Pardee-Moorpark #1 and #2 230 kV lines

Limiting component: Voltage collapse

2017 LCR need: 511 MW (includes 119 MW of QF generation)

2021 LCR need: 492 MW (includes 119 MW of QF generation)

Moorpark Sub-area – Category B

No requirement.

Critical Area Contingencies

Big Creek/Ventura Overall – Category B

Contingency: Sylmar-Pardee #1 or #2 230 kV line with Ormond #2 out of service

Limiting component: Remaining Sylmar-Pardee 230 kV line

2017 LCR need: 1,841 MW (includes 543 MW of QF and Muni)

Big Creek/Ventura Overall – Category C

Contingency: Sylmar-Pardee #1 or #2 230 kV line followed by Lugo-Victorville 500 kV or vice versa

Limiting component: Remaining Sylmar-Pardee 230 kV line

2017 LCR need: 2,057 MW (includes 543 MW of QF and Muni)

Changes

Since last year:

1) 2017 load forecast is down by 87 MW vs. 2016.
2) Overall LCR is down by 341 MW.

Since last stakeholder meeting:

1) Updated NQC
2) Updated 2017 LCR results for Santa Clara and Moorpark due to long-term shutdown of the Las Flores Canyon Cogeneration Facility (http://www.sbcountyplanning.org/energy/projects/exxon.asp)
3) Added preliminary 2021 LCR results for Santa Clara and Moorpark areas due to ongoing procurement activity

Your comments and questions are welcome.

For written comments, please send to: RegionalTransmission@caiso.com

Exhibit Number	:	ORA 11
Proceeding No:	:	A.14-11-016
Commissioner	:	Michel P. Florio
Admin. Law Judge	:	Regina DeAngelis
	:	

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

California Independent System Operator 2020 Local Capacity Technical Analysis Final Report and Study Results

San Francisco, California
November 1, 2016

California ISO

California Independent
System Operator

2020
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2015

24312	B CRK3-2	3	44
24312	B CRK3-2	4	44
24313	B CRK3-3	5	44
24317	MAMOTH1G	1	44
24318	MAMOTH2G	2	44
24314	B CRK 4	41	42
24314	B CRK 4	42	42

Santa Clara Sub-area:

The most critical contingency is the loss of the Pardee - Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 293 MW (includes 80 MW QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Moorpark Sub-area:

The most critical contingency is the loss of the Moorpark - Pardee 230 kV #3 line followed by the loss of the Moorpark - Pardee 230 kV #1 and #2 lines, which will cause voltage collapse. This limiting contingency establishes a local capacity need of 547 MW (includes 109 MW QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar - Pardee #1 (or # 2) line with Ormond #2 unit out of service, which would thermally overload the remaining Sylmar - Pardee 230 kV line. This limiting contingency establishes a local capacity need of 2598 MW