Item A:

Provide a load forecast that incorporates industry accepted methods for estimating load growth and incorporating load reduction programs due to energy efficiency, demand response, and behind-the-meter generation.

Response to Item A:

1.0 Executive Summary

Southern California Edison Company's (SCE) load forecast for the Valley South subtransmission system for the 10-year period covering 2019-2028 is provided in Table 1. This forecast is a subset of the larger SCE system-wide forecast, which was recently filed to support the SCE 2021 General Rate Case proceeding (Application A.19-08-013). SCE uses the system forecast across the entire organization for system planning purposes and applies it to all proceedings regardless of the size of the project or its licensing requirements.

Table 1. SCE 2019-2028 Valley South System Forecast Load (MVA)

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand – 1-in-5 Heat Storm	1,103	1,104	1,116	1,125	1,142	1,153	1,161	1,170	1,179	1,187

The SCE load forecast is derived from SCE's disaggregation of the California Energy Commission (CEC) annual California Energy Demand (CED) Forecast as part of the annual Integrated Energy Policy Report (IEPR) proceeding. The CED Forecast presents statewide projections for the various "load-serving entities" which includes investor-owned utilities, publicly-owned utilities, municipalities, and co-ops. Disaggregation methods are presented to stakeholders via the Distribution Forecasting Working Group (DFWG) that is chartered by the California Public Utility Commission (CPUC) to address disaggregation of the overall CED forecast to the distribution circuit level[1]. As such, the SCE forecast incorporates Distribution Resources Plan stakeholder-vetted methods for incorporation of Distributed Energy Resources (DERs) including energy efficiency, demand response and behind-the-meter generation. Note that this is the second year in which SCE has participated in the DFWG and utilized CED forecasts for system planning.

Based on the CED forecast and SCE's disaggregation of that forecast, SCE projects that the peak demand served by the Valley South System is expected to exceed the maximum capacity of 1,119 MVA by 2022[2], impacting SCE's ability to provide continuous, safe and reliable electrical service to the area served by the Valley South System, which has a population of approximately

[1] CPUC Assigned Commissioner's Ruling R.14-08-013 formally requested that the IOUs form the DFWG.
[2] Based on the SCE 2018-2027 forecast, the Valley South System load is expected to exceed its transformer capacity in 2022 with no further capacity additions possible within the design limits of the substation.

560,000 people and includes nearly 6,000 critical customers[3]. This need is also supported by historical data that show a peak load when adjusted to reflect a 1-in-5 year heat storm of 1,118 MVA in 2018 that represents 99.9% of the Valley South System's ultimate design capacity[4]. Notably, the Valley South System capacity margin is currently limited as evidenced by the fact that it is the only subtransmission system in the SCE service territory with a temporary operating procedure in use to place an installed, spare transformer in service during times of high demand[5]. The system is also the only radial system in SCE's territory directly serving SCE customers that does not have system tie-lines to another system.

To provide a varied approach to evaluating the system need in the area based on forecast peak demand load values, SCE also contracted Quanta Technology[6] to provide independent load forecasting services for the Valley South System. Quanta Technology developed load forecasts using two different independent forecasting methodologies both of which are consistent with industry accepted methods[7] and include incorporation of DERs. These forecasts confirm the 2022 project need date derived from the SCE forecast derived from the disaggregation of the CEC IEPR forecast.

Compound annual growth rates were calculated for each of the three forecasts, showing growth rates of **0.74%** (SCE), **0.88%** (Quanta Spatial Load Forecast), and **1.09%** (Quanta Conventional Forecast). The two Quanta forecasts show slightly higher average annual growth rates than SCE's forecast predicts, making SCE's forecast generally conservative. Though continual 10-year forecasting of the load in the Valley South System show an overall decline in the rate of growth, the growth rate continues to be positive and the electrical load on the Valley South System will exceed capacity in the near future, most likely by the year 2022 as all three forecasts predict.

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[3] Critical customers are those customers that require an exceptional level of reliability, such as hospitals, emergency centers, data centers, etc. These customers typically have 99.999% or more reliability requirements, and may include an on-site source of backup power generation.

[4] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B for additional information on constraints related to the ultimate system capacity.

[5] Normal condition, long-term and short-term load ratings are used by SCE grid operators to ensure that transformer temperature ratings are not exceeded during normal and temporary overload conditions. Based on these ratings, it is not permissible to operate the two Valley South System transformers with a combined total load over 896 MVA because the instantaneous loading that would be placed upon one transformer during an unplanned outage of the other would be beyond the short-term rating, exposing the transformer to potential damage or catastrophic failure. See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item H for discussion of why in-servicing this spare transformer is not a permanent solution to the capacity shortfall.

[6] Quanta Technology is a recognized industry leader in load forecasting and distribution system planning studies. A co-founder of Quanta Technology, who provided oversight for the Quanta Technology forecasts presented here, is the author of the seminal text on load forecasting, the methodologies of which have been the basis for commercial and in-house developed software packages utilized for load forecasting throughout the industry. The load forecasting methodologies developed by Quanta have been used by municipal, co-op, and investor-owned utilities to support distribution planning in regulatory filings throughout the United States.

[7] See the following references for examples:

1. Willis, Lee, *Power Distribution Planning Reference Book*, Second Edition, Raleigh, NC: CRC Press, 2004.
2. EPRI report, "Research Into Load Forecasting and Distribution Planning," Project RP-570, report # EL-1198, 1979.
3. J.E.D Northcote-Green, et al., "Long-Range Distribution Planning – A Unified Approach," 1979 7th IEEE/PES Transmission and Distribution Conference and Exposition, IEEE, April 1979.

2.0 Background

In Decision 18-08-026, the CPUC took no action on the Alberhill System Project (ASP) and directed SCE to supplement the existing record with specific additional analyses. These additional analyses include, in part, a load forecast that incorporates industry accepted methods for **estimating load growth** and **incorporating load reduction** programs due to energy efficiency, demand response, and behind-the-meter generation. The requested load forecast applies to the Valley South System which includes the area that would ultimately be served by the ASP and is documented herein.

Central to the discussion surrounding SCE's load forecast is the methodology by which SCE determines a need for further subtransmission system infrastructure investment. The bottom-up methodology used by SCE has been previously recognized by the CPUC as sound and consistent with industry forecasting methodology[8,9]. Prior to 2018, SCE used its own recorded peak demand data for facilities at the distribution voltage level to forecast load growth, aggregating this growth up through the subtransmission and transmission voltage levels, ultimately reflecting a value for the entire SCE system. For the past two years, however, as required by the CPUC, SCE has used the CED energy forecast (provided at SCE's service territory level) and hourly circuit loading profiles to develop peak demand values. SCE begins by disaggregating the CED energy forecast down to the distribution circuit level. SCE's disaggregation methodology incorporates local-area knowledge to inform the disaggregation process to ensure that capacity studies reflect the local-area needs. Once the process is complete at the distribution system level, the values are aggregated back up through the subtransmission and transmission voltage levels. This bottom-up forecast development methodology (necessary for proper local-area planning in a radial system design) is consistent with SCE's forecast methodology prior to the use of the CED forecast[10].

SCE is providing three forecasts in order to satisfy this data request. SCE's forecast for the 10-year period covering 2019-2028 was previously submitted to support the SCE 2021 General Rate Case proceeding (Application A.19-08-013). SCE's 10-year forecast, derived from the disaggregation of the CEC's IEPR forecast, serves as the conventional basis for SCE system planning. Additionally, two independent forecasts were performed by Quanta Technology to confirm SCE's 10-year forecast and to support the cost benefit analysis of alternatives requested by the CPUC[11]. The intended use of all three of these forecasts is to determine if there is a

[8] See pages 29 and 30 of Decision 18-08-026. The CPUC compared a top-down approach to forecasting substation-level system load (using CAISO transmission system-level coincident peak demand) to SCE's bottom-up approach, which considers local non-coincident peak demand at the circuit level. The Commission noted that SCE's approach is more appropriate for local area system planning.

[9] See footnote 52, page 32 of Decision 18-08-026. SCE notes that the load forecast referenced in this decision utilizes SCE-based inputs, while the 2019-2028 load forecast utilizes inputs from the CEC's IEPR forecast. However, the underlying bottom-up methodology for both forecasts is identical, and was affirmed in the EIR as noted in Decision 18-08-026.

[10] For a detailed explanation of SCE's disaggregation, adjustment, and re-aggregation methodologies, see SCE's 2019 Grid Needs Assessment, dated August 15, 2019, submitted to the CPUC August 23, 2019.

[11] The Quanta Technology forecasts are used to determine the benefits that accrue from various project alternatives in the cost benefit analysis requested by the CPUC. For this purpose, Quanta has extended the forecast period to 30 years, roughly corresponding to the economic life of conventional transmission and distribution assets that make-up

continued need for a project to meet future load growth in the Valley South System, to establish the corresponding project need date[12], and to inform the cost-benefit analysis of a variety of project alternatives.

3.0 Methodology

Three load forecasts were performed in support of this data submittal. This section describes the methodology for each load forecast from SCE and Quanta Technology. The Quanta Technology load forecasts were independently performed using industry standard techniques, historical load data, and publicly available information. The SCE forecast for the Valley South System is derived from the California Energy Demand Forecast, published by the CEC as part of the annual IEPR proceeding. SCE utilizes an approach agreed upon by the DFWG to accomplish the disaggregation.

3.1. Overview of Approach for SCE Forecast

SCE begins its annual forecasting process once the summer peak season has concluded and utilizes the most updated CEC published CED forecast as part of the annual IEPR proceeding. The CED forecast presents statewide projections for the various "load-serving entities" which includes investor-owned utilities, publicly owned utilities, municipalities, and co-ops. For SCE in particular, a forecast is provided for the entire SCE system covering all 50,000 square miles of its service territory. Since the forecast is provided at the SCE system level, it must be disaggregated down to the individual distribution circuit level. From this disaggregation process, peak demand values are derived based on hourly circuit profiles. These peak demand values are then aggregated up to develop the associated subtransmission and transmission system-level peak demands (e.g., the Valley South System). SCE accomplishes this by using methodologies that are presented to and reviewed by the DFWG[13], in which SCE participates as required by the CPUC.

Once the forecast is disaggregated to the distribution circuit level, there may be adjustments based on SCE's specific knowledge of local-area developments that were not represented in the IEPR forecast (e.g., cannabis cultivation). SCE's planning engineers work closely with area developers, using institutional knowledge and experience, to estimate the impact of these local factors. SCE also applies profiles to relevant DERs included in the forecast such as photovoltaic (PV) distributed generation which has a peak output during mid-day (12-1 P.M), which is not coincident with electrical system peak demand timing (typically 4-6 P.M.). SCE must adjust accordingly the

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the ASP and many of the alternatives. The results of the forecast beyond the typical 10-year project planning horizon are reported in the Cost Benefit Analysis and Planning Study Data Submittals (see DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Items G and C, respectively) and are not reported here.

[12] Need date is defined as the date at which the 1-in-5 year heat storm peak system load is expected to exceed the system capacity.

[13] The DFWG is made up of representatives from the IOUs, CEC, CAISO, and other industry groups with an objective to "vet the disaggregation methods and data sources available and operational profiles, ensure that the circuit level forecasts apply the best data sources available and incorporate evaluation feedback in future forecasts." See Distribution Forecasting Working Group Progress Report, Dated July 2, 2018, as part of Rulemaking 14-08-013, Application 15-07-002, Application 15-07-003, Application 15-07-005, Application 15-07-006, Application 15-07-007, Application 15-07-008.

contribution of PV generation to the reduction of system peak demand. Specifically, SCE's analysis of DER integration determines the amount of PV that can be depended on during peak times of the electrical systems in which they are installed. Note that other DERs, such as Energy Efficiency, Electric Vehicles, Energy Storage, and Demand Response, are incorporated into the SCE forecast by disaggregation of the individual DER forecasts provided by the IEPR CED forecast[14]. The historical recorded load data from the most recent peak loading season that is used to inform SCE's forecast is normalized to historical average annual peak temperatures specific to the areas served by each of it radial systems. As peak temperatures vary from year to year and temperature is known to have a very strong correlation to electrical demand, normalizing electrical demand to the average peak temperature is a fundamental element in developing an annual starting point for which a forecast of future expected demand can be anchored. In addition, a forecast is produced to reflect peak demand values expected during heat storm conditions[15], reflecting a reasonably expected maximum demand scenario. The heat storm forecast uses the same peak demand forecast described above and increases the peak demand expected based on the increased temperatures during 1-in-5 year heat storm conditions. The projected peak demand values from the 1-in-5 year heat storm forecast are used to determine the need date of the ASP.

For a more detailed explanation of SCE's load and DER forecast methodology, see the discussion in Appendix A.

3.2. Overview of Approach for Quanta Technology Load Forecasts

Quanta Technology employed two independent methodologies to derive various load forecasts for the Valley South System[16]: a Conventional Forecast and a Spatial Load Forecast (SLF). For each load forecast, Quanta Technology used a well-proven method that is considered industry best-practice known as the "Gompertz curve fit regression with horizon-year load" method. In addition, Quanta Technology developed a tool that applies "Gompertz trending" called INSITE®, which is used by its planning and engineering teams throughout the industry for system planning studies.

The distinction of this method is that it fits Gompertz, or "S-curves" to load histories and a horizon-year expected load value[17] versus using polynomial or linear regression. A standard industry understanding is that load growth invariably does not occur in a straight line trend over the long term. Rather, load growth typically forms an S-curve with a very identifiable period of more intense growth/redevelopment that occurs locally in different small areas at different times as each area "fills up" with growth or redevelopment to a point where it reaches saturation. Load growth

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[14] See SCE's 2019 Grid Needs Assessment, dated August 15, 2019, submitted to the CPUC August 23, 2019.
[15] Heat storm conditions and the adjustments used vary depending on the portion of the electrical system being planned for. 1-in-10 year values are used for the distribution system (33 kV and below), 1-in-5 year values are used for the subtransmission level (above 33 kV and below 200 kV), and 1-in-2 year values are used at the transmission level (200 kV and above).
[16] The Quanta Technology forecasts also covered the Valley North System in order to support elements of the cost benefit analysis that related to its capacity. These results are not discussed here but are covered in Quanta Technology Report *Load Forecasting for Alberhill System Project*, attached as Appendix B.
[17] The horizon year (i.e., 2048) was chosen as a typical 30-year long-term horizon. A 30-year horizon allows for analysis over several alternatives with varying asset lifetimes and is typical for utility assessments of capital equipment depreciation.

within an area continues because those brief "spurts" of growth eventually "move on" to other neighborhoods and other areas of a locality. Added to this, already developed areas are also expected to continue to grow, albeit at a slower pace. There are definite statistical properties and behaviors that have been shown to occur among the S-curves of growth in power systems – interrelationships and correlations that can be used to improve load forecasts. Statistical analysis of area size, load characteristics, and other factors can be used to determine characteristics of the expected S-curve's steepest ramp rate and period in a way that provides more forecasting accuracy than polynomial or linear regression models will provide.

The major distinction between the two methods of load forecasting employed by Quanta Technologies is in the size of the area that is considered when forecasting future load growth. The Conventional Forecast considers load growth at the distribution substation level, treating each substation and its service area as a single unit that experiences a local rate of growth based solely on historical trends. The SLF considers much smaller, discrete areas within the entire region, and utilizes local area planning and zoning data to inform the rate of load growth in each discrete area. Note that both methods utilize S-curves to forecast load growth.

3.2.1. Conventional Forecast

The Conventional Forecast performed by Quanta Technology forecasts the load at individual distribution substations and then aggregates those to the higher system level (i.e., the radial transmission system serving those distribution substations). In order to fit historical data to an S-curve, the horizon year load, or the load for the year where the S-curve flattens out, must be estimated. Horizon year load was estimated using a combination of curve-fitting techniques, incorporation of expected load for non-traditional developments (e.g., cannabis cultivation), and estimation of expected incremental changes in residential load densities. Following the estimation of the horizon year load for each substation, the Gompertz curve fitting technique was applied to estimate forecasted load for all intermediate years between the historical data (up through 2018) and the 2048 horizon year estimate.

For the Conventional Forecast, DER, energy efficiency (EE), and demand-side management (DSM) are considered implicitly based on an assumed continuation of their adoption trend reflected in recent historical load data. Importantly, increased rates of PV adoption due to the California Net Zero Energy mandate for new residential homes beginning in 2020, or increased load due to future plug-in electric vehicles (PEV) adoption, are not explicitly captured in this forecast. Like DER, EE, and DSM, the historical trends of PV and PEV adoption are assumed to continue into the future. As with SCE's forecast, the historical load from year to year is normalized to a common peak temperature base. The full forecast is then adjusted to represent equivalent load during heat storm conditions.

Ranges of potential outcomes are introduced in the Conventional Forecast by varying the temperature used for adjustment of the load, incorporating varying levels of non-traditional load developments, and incorporating varying levels of incremental changes in residential load densities. These potential outcomes were characterized by Quanta as:

- **Current Trend**: represents growth during a period of economic activity similar to what has been observed in recent years.
- **Reduced Trend**: represents growth under a scenario of conditions in between Current Trend Forecast and Low Forecast.
- **Low Forecast**: represents growth under a scenario of substantially less growth, as would occur under a severe recession or other significant slowdown in the economy.

In comparison to the Current Trend, the Low Forecast considers substantially reduced economic and housing development growth rates than would otherwise be suggested by existing trends, and completely discounts proposed cannabis cultivation. The Reduced Trend considers some cannabis cultivation load and includes some economic and housing growth. Of the three forecasts, the Current Trend Forecast, which reflects the current period of economic growth and includes all proposed cannabis cultivation load, is considered by Quanta in their report to be the most appropriate, of the three variations of the Conventional Forecast, for projecting the project need date.

3.2.2. Spatial Load Forecast (SLF)

In the SLF, the INSITE® model was applied to small, discrete areas, 150 acres in size within the areas served by the Valley North and South Systems. For existing developed areas, geo-referenced peak load individual customer meter data (peak load) and local land use information was used to determine load density values for each of the areas and customer load mix (i.e., a combination of residential, commercial/industrial, agricultural, etc.). Having established the load densities of already fully-developed areas, load densities were then applied to yet-to-be-developed areas based on their planned land use as described by zoning designation and county and city master and specific development plans. The yet-to-be-developed areas therefore represented an expected total load based upon their anticipated eventual build out. The summation of the load assigned to the discrete areas (both developed and undeveloped) then represents the total load that the entire larger study area would reasonably be expected to have over time.

The SLF method is similar to the Conventional Forecast in that historical load is normalized to a common peak temperature, and forecasted load is adjusted to reflect appropriate heat storm conditions. It differs, however, in that the ultimate build out capacity of an area over time is incorporated by considering population, demographic, and land-use constraints, and the geographic study area is split up into smaller, more granular areas. Additionally, DER growth forecasts are directly incorporated into the system load forecast using forecast data provided by the IEPR CED forecast. Energy Efficiency, Solar Photovoltaic, Electric Vehicles, Energy Storage, and Demand Response are all incorporated individually, using the IEPR-derived forecast growth in each DER category.

3.3. Valley South Historical Load

The 2004-2018 Valley South System historical load is shown in Table 2. Peak recorded demand increased at a compound annual growth rate of approximately 3%. Table 2 also shows peak demand on a normalized weather basis, as well as peak demand adjusted for a 1-in-5 heat storm. Note that the heat storm peak adjusted load of 1,118 MVA in 2018 represents 99.9% of the Valley South System's ultimate design capacity.

Table 2. SCE 2004-2018 Valley South System Historical Load (MVA)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Demand, Recorded*	658	753	853	909	787	829	894	924	928	897	925	881	943	947	995
Peak Demand, Adjusted - Normal Weather	703	777	874	944	817	867	921	934	923	960	951	940	995	1,006	1,039
Peak Demand, Adjusted - 1-in-5 Heat Storm	748	827	930	1,004	869	922	980	994	982	1,033	1,023	1,011	1,071	1,083	1,118

4.0 Results of Load Forecasts

4.1. Summary

The SCE forecast and the Quanta forecasts yield similar results with each showing that the Valley South System peak load, adjusted for a 1-in-5 year heat storm (which is the basis for system planning[18]), will exceed the design capacity in 2022.

4.2. Load Forecast Results

The SCE 10-year forecast (2019-2028) is summarized in Table 3. The forecast shows that the peak load is expected to exceed system capacity of 1,119 MVA in 2022 and grows at a compound annual growth rate of ***0.74%*** over the 10-year forecast period.

Table 3. SCE 2019-2028 Valley South System Forecast Load (MVA)

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Demand – 1-in-5 Heat Storm	1,103	1,104	1,116	1,125	1,142	1,153	1,161	1,170	1,179	1,187

Table 4 contains the results of the Quanta Conventional Forecast based on the Current Trend outcome. The results of all three of the Quanta Technology-produced Conventional Forecasts are detailed in Quanta Technology Report *Load Forecasting for Alberhill System Project* (Appendix B). Note that the Current Trend Conventional Forecast does project a slightly lower near-term growth rate than the SLF. Quanta's Conventional Forecast, showing a compound annual growth rate of **1.09%** over the ten-year forecast period, corroborates SCE's 10-year forecast and confirms the 2022 need date for a solution. The Reduced Trend and Low Forecast shown in Appendix B also demonstrate that a project will ultimately be needed.

[18] As previously provided in SCE's comments to the Proposed Decision (page 8) submitted to the CPUC on April 24, 2018, SCE described its methodology for adjusting raw, unadjusted peak load values to reflect expected peak load values for appropriate use in annual planning activities to ensure adequate capacity. See Southern California Edison Company's (U 338-E) Comments to the Proposed Decision, Application A.07-01-031, Application A.07-04-028, Application A.09-09-022, Dated April 24, 2018.

Table 4. Quanta Technology 2019-2028 Valley South System Conventional Forecast Load (MVA)

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Current Trend – 1-in-5 Heat Storm	1,081	1,093	1,108	1,122	1,137	1,150	1,163	1,177	1,191	1,204

Table 5 contains the results of the Quanta SLF. The results of the Quanta Technology-produced SLF are detailed in Quanta Technology Report *Load Forecasting for Alberhill System Project* (Appendix B). The Quanta SLF shows a compound annual growth rate of **0.88%** over the ten year forecast period, corroborates SCE's 10-year forecast, and confirms the 2022 need date for a solution.

Table 5. Quanta Technology 2019-2028 Valley South System Spatial Load Forecast Load (MVA)

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Spatial – 1-in-5 Heat Storm	1,083	1,099	1,118	1,132	1,146	1,152	1,159	1,166	1,174	1,183

Figure 1 shows all three load forecasts along with historical load in a single figure. The key takeaways from this figure and the work that supports it are:

- All three forecasts demonstrate a need for system capacity additions well within SCE's 10-year planning horizon, and all three forecasts reflect a need date of 2022.
- 2028 peak load projections result in capacity need in the range of 1,183 MVA to 1,204 MVA over the 10-year planning horizon.
- The two Quanta forecasts show slightly higher average annual growth rates than SCE's forecast predicts, making SCE's forecast the most conservative.

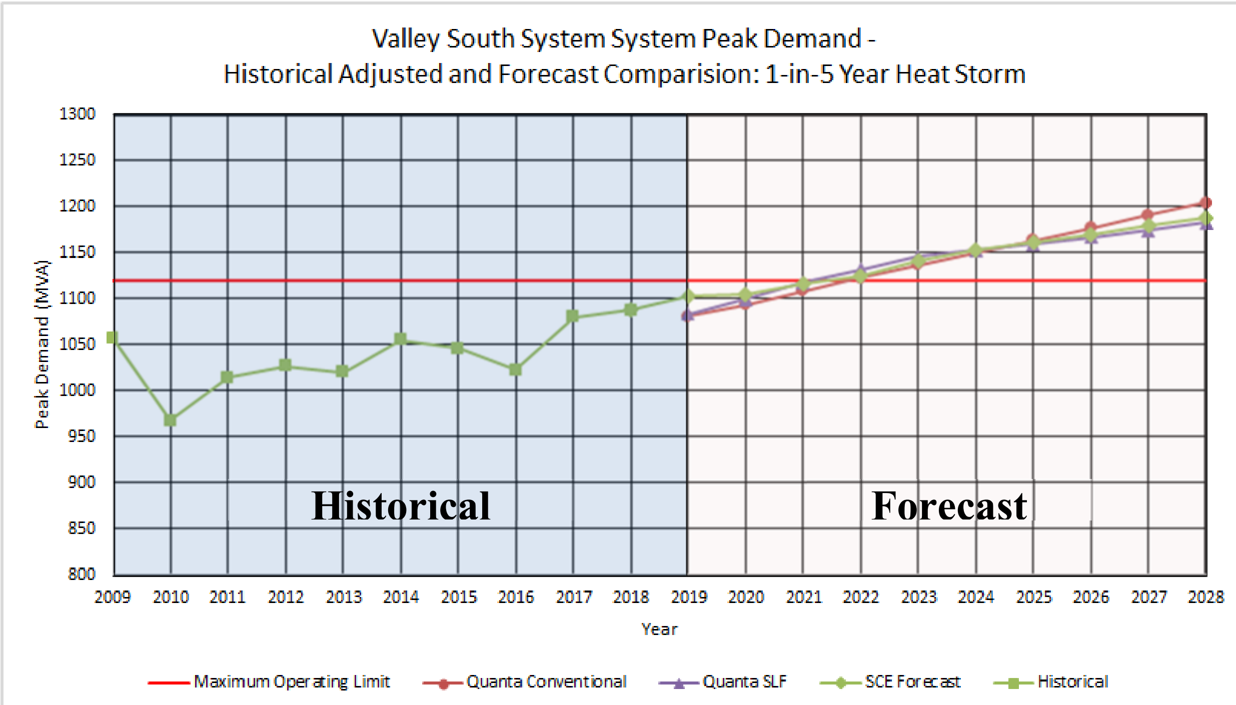

Figure 1. Valley South System Peak Demand, Historical and Forecast

A Appendix: Development of Load and DER Forecasts

A.1 Approach

The first step in SCE's distribution and subtransmission planning process is to develop peak load and DER forecasts for all distribution circuits, distribution substations, subtransmission lines, and load-serving transmission substations. These forecasts span 10 years and include expected customer load and DER growth.

Traditionally, SCE annually evaluates peak load conditions to determine the impacts to SCE's distribution and subtransmission systems over a 10-year horizon. With increasing DER penetration on the distribution system, the traditional peak load studies that do not account for variable generation and timing of DERs are not able to capture criteria violations due to the DERs that could arise outside of the peak hours. As such, SCE now also evaluates high DER output conditions and the mitigations necessary to address criteria violations. The planning process for peak load and high DER output conditions are described in more detail throughout this section.

A.2 Development of Load Growth Forecast

For both peak load and high DER output scenarios, SCE begins by developing a 10-year load growth forecast at the distribution circuit level. Pursuant to CPUC guidance in the Distribution Resources Plan (DRP), this load growth forecast is established through the disaggregation of the CEC annual CED forecast as part of the annual IEPR proceeding[19]. The CEC provides this forecast to SCE, at the system-wide level, and not with the granularity necessary to account for localized electrical needs on the distribution and subtransmission systems. SCE and other stakeholders participate in the Distribution Forecasting Working Group (DFWG) to discuss and develop load and DER methodologies to disaggregate system-wide forecasts to the distribution circuit level. "SCE also incorporates additional load growth that may not have been fully reflected in the CEC forecast (e.g., cultivation load growth was not included in the 2016 IEPR),"[20] which SCE considers to be incremental[21] to the IEPR forecast.

SCE's disaggregation methodology of the CEC forecast encompasses specific local-area knowledge from the system planning engineers about new development projects, as well as econometric data relative to each planning area. Local-area knowledge is derived from SCE's system planning engineers working closely with developers of agricultural, commercial, industrial, and residential projects to understand their electrical needs, timing of projects, and the projected increases in demand that would be placed on SCE's distribution facilities. These process results in an SCE forecast consistent with the CEC's IEPR energy forecast but which reflects incremental growth where appropriate. SCE then uses hourly circuit profile data to develop peak demand forecasts.

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[19] The process by which SCE develops this forecast is detailed in SCE's 2019 Grid Needs Assessment (GNA) filed in Rulemaking (R.)14-08-013 on August 15, 2019. Due to the close proximity of filing dates for the GNA and the 2021 GRC, SCE provided the relevant sections of the GNA as a supplemental work paper to this testimony. Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 364 - 365 – SCE's Grid Needs Assessment Narrative.
[20] R.14-08-013, Appendix A, p. 97.
[21] SCE considers Cultivation, Light Electric Vehicle (LEV) Superchargers, Mega Tract Homes, and Agricultural Pump Loads as incremental to the CEC IEPR forecast.

A.3 Incorporation of DERs That Produce and Consume Energy

Along with the development of a load growth forecast, SCE incorporates forecasts that account for other load-modifying inputs such as DERs, including energy efficiency (EE), energy storage (ES), demand response (DR), Plug-in Electric Vehicles (PEVs), and distributed generation (DG), such as solar photovoltaic (PV) systems. SCE utilizes the CEC-developed IEPR forecasts for these load-modifying inputs and disaggregates them to the distribution circuit level. In some cases, these inputs can reduce aggregate load (although not necessarily peak demands on certain circuits), while in other cases, they may increase aggregate load.

For PV included in the 10-year forecast (2019-2028), SCE has incorporated an updated methodology[22] for representing the impacts (i.e., reductions) to peak load demand. This change in methodology represents SCE's adoption of an increase in the amount of solar PV output that is considered "dependable" and can be relied upon for planning purposes, also known as "solar PV dependability." The updated dependable output values are based on (1) a cross-sectional analysis of historical PV outputs for each hour of the day within discrete operating regions of SCE's service territory and (2) the regional output percentage for each hour empirically derived from the 10th percentile of each cross-section's data set.

Previous analysis, studied at a system-wide level filed with SCE's 2018 GRC, calculated that 19% of the installed nameplate value of solar PV could be considered "dependable" for planning purposes at *solar peak* or approximately 12:00 PM. The dependable output at 5:00 PM (when the SCE *system peak* typically occurs and when PV production is a small fraction of its solar peak maximum production, would result in approximately 2% of the total of installed solar PV considered as dependable and could be used to "offset" load for planning purposes.

Since the time of peak for each of SCE's distribution circuits and substations varies, SCE has continued to evaluate and refine its methodology for determining the expected maximum dependable solar PV output. As an example of the updated methodology, 45% of the installed nameplate of solar PV can be considered dependable at 12:00 PM for the San Jacinto region and 11.6% at 5:00 PM. Using data collected from customer generation and Advanced Metering Infrastructure (AMI) sources, SCE developed multiple regional-specific PV dependability curves in order to represent factors such as local climate conditions in the forecasted PV performance output. SCE's updated methodology applied to the 10-year forecast results in a greater amount of solar PV output considered dependable for planning purposes, an increase in the load-modifying impacts, and a corresponding decrease in net load growth.

Once the DER forecast is developed and applied, the result is a forecast of peak load and DER conditions developed for the planning activities initially associated with distribution circuits and distribution substations, which then serves as the input necessary to perform the planning activities associated with subtransmission lines and load-serving transmission substations. This forecasting methodology is the basis of SCE's Distribution Substation Plan, Subtransmission Lines Plan, and Transmission Substation Plan (including the A-bank Plan and Subtransmission VAR Plan).

[22] Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 4 – 13 – SCE's Dependable Photovoltaic Generation Methodology.

B Appendix: Quanta Load Forecast

The Quanta Technology *Load Forecasting for Alberhill System Project* is attached as Appendix B to this data submittal.