Alberhill Webinar Question & Answer Responses - February 20, 2020

Question 1: Why hasn't SCE constructed "system ties" between the Valley North system and the Valley South system, particularly since SCE's planning standards required that they should have been constructed when the Valley System was first split?

Answer 1: The split of the Valley System was required to meet the immediate load growth needs of the area served by Valley Substation. Prior to the split of the Valley System, SCE recognized that a long-term, comprehensive solution was needed to provide sufficient capacity and reliable electric service to the region. Noting that following the split the Valley North System would retain the existing system tie-lines (leaving the Valley South System with none) and that additional capacity would again be needed in the Valley South System, a comprehensive solution, which ultimately became the Alberhill System Project, was proposed to address both issues.

While a separate independent project could have been initiated to create system tie-lines from the Valley South System to some adjacent system, it would have been duplicative of efforts being undertaken at the time to evaluate and design a comprehensive solution. Additionally, construction of effective new system tie-lines as an independent project would almost certainly require CPUC approval through the licensing and permitting process (similar to Alberhill System Project). Because the planned comprehensive solution would already add capacity and create system tie-lines (thereby satisfying the system tie-line need), consideration of a separate independent project just to create system tie-lines would be an inefficient use of resources.

In addition, a Valley South to Valley North load transfer alternative was considered in SCE's Planning Study. The alternative was based on the minimum expected scope required to satisfy the transformer capacity needs over the 10-year planning horizon and create system tie-lines. This alternative ranked very poorly in the benefits assessment specifically in reliability and resiliency due to several factors including lack of power source diversification, advancement of a solution to address the Valley North System loading issues (resulting from shifting the loading issue from the Valley South System to the Valley North System), and relatively ineffective system tie-lines as compared to other alternatives. Variations of this alternative (Valley South to Valley North transfer) to produce more effective system tie-lines would also increase costs and other impacts and it is still unlikely to be produce benefits that would substantially alter the performance and ranking of this alternative in the cost-benefit analysis.

Question 2: Interesting history slides. Isn't there a fifth transformer as a spare now?

Answer 2: Yes, at Valley Substation there is a fifth transformer installed. It was installed in 2011 after the fourth transformer was placed in service to serve load in 2005. The installation of this transformer, since it exceeded the ultimate plan design capacity of the substation required a reconfiguration and modification of the facilities inside the Valley substation. The fifth transformer, the spare, is considered a shared spare between the Valley North and Valley South Systems. **Note that the response to this question provided verbally on the webinar has been edited here for clarity and completeness.**

Question 3: Regarding SCE's forecast: Which IEPR is SCE's forecast based on? 2016? 2018? SCE goes into detail to explain that peak load growth does not occur "in a straight-line trend" and instead it "typically forms an S-curve" (pages 5-6). Can you explain why neither SCE's forecast of peak load growth nor Quanta's forecasts of peak load growth are in the shape of an "S-Curve"? Section A.3 of SCE's forecast analysis describes two different methodologies for determining the amount of dependable PV generation available at 5 PM: one relies on a fixed 2% value that was developed based on a "cross sectional analysis of historic PV outputs" and the other relies on "regional-specific PV dependability curves"; which of these were used to develop SCE's Valley South forecast that shows transformer overloads occurring on the Valley South system by 2022? What percent of installed PV capacity was assumed to be "dependable" in SCE's forecast?

Answer 3: The forecast presented in SCE's data request response to the CPUC incorporated the 2018 IEPR.

Load growth for area electric power systems, whether considered at the substation level (as in the conventional forecast) or a more granular level (as in the spatial load forecast), is modeled assuming an S-curve shape over many decades of development. At any given time, each individual area's peak load may be at a different point on the S-curve. The aggregate of these individual peak loads yields the system peak load, which may or may not appear to be linear over the span of 10 years. The 30-year extended forecast shows the trends predicted by the load forecast are not linear and more closely resemble the portion of the S-curve that flattens out. The S curve typically becomes more evident for lower hierarchical levels, in this case for individual substations or for small areas. When the smaller elements or areas are aggregated to represent larger areas or the Valley regions, the S curves start to look more linear.

Section A.3 does not describe two different methodologies for determining the amount of dependable PV generation at 5PM. Section A.3 describes the history and evolution of how SCE determines the amount of rooftop PV that is dependable during system peak hours. As stated in section A.3, 11.6% is used as the amount of dependable PV that can relied upon as a load modifier during system peak hours.

As stated in A.09-09-022 ED-Alberhill-SCE-JWS-4 Item A (Load Forecast), Appendix A, section A.3, 11.6% of installed PV in the San Jacinto region is assumed to be dependable during system peak loading hours, approximately 5:00 PM.

Question 4: Regarding the Alberhill & Valley Ivy Glen Projects through Lake Elsinore, has SCE considered the undergrounding of the 115-kV line routes as an alternative to the overhead structures?

Answer 4: Yes, along the proposed routes of the 115-kV lines in the Valley-Ivyglen and Alberhill System Projects, there were locations where SCE considered placing segments of the 115-kV lines underground. In general, for these projects and others, SCE assesses several factors including economics, environmental impacts, and technical considerations when evaluating a proposal to place 115-kV lines underground. **Note that the response to this question provided verbally on the webinar has been reviewed and edited here for clarity and completeness where applicable.**

Question 5: Why did you configure the SDGE alternative with only connections to Pechanga? FRONTLINES' analysis shows that configuring this alternative with connections to Pechanga and Moraga will secure all load flows even during peak N-2 events on the 115-kV system. Why would you propose such an under-designed configuration for this alternative?

Answer 5: The alternatives contained in SCE‘s supplemental analysis were designed to meet the minimum requirements to address the stated project objective; to satisfy the electrical needs of the Valley South System for the 10-year planning horizon. There was no intent to propose that the scope of any of the alternatives should address more than the minimum system needs identified within the 10-year planning horizon. Rather, the purpose was to ensure that an incremental approach to meeting the capacity and reliability needs of the region could be assessed and then contrasted with the Alberhill System Project. This approach was necessary in performing a proper cost-benefit analysis across both near-term and long-term horizons. Specifically, for the long-term cost-benefit analysis, incremental scope additions over time for each of the alternatives were included to keep pace with the load forecast.

Within this context, SCE designed the SDG&E alternative to connect to Pechanga Substation which then connected to Pauba Substation, initially transferring both substations to the new system sourced by the SDG&E transmission system. This same approach was consistently applied throughout SCE’s alternatives analysis and allowed for the creation of alternatives that minimized initial scope, schedule, cost, and environmental impacts.

This is in contrast to what would be necessary in constructing an alternative that would include sufficient capacity and reliability to address the hypothetical system conditions posed in the question. Should a proposed solution be considered that could address all the peak demand served in the Valley South System, it is important to note that this would propose transferring load that would increase the SDG&E entire system load by approximately 25%. [1] This would almost certainly require additional transmission line capacity and generation dispatch among many other considerations not contemplated here. A proposed solution with those capabilities (if even feasible) would necessarily include greater scope, schedule, cost, and environmental impacts as compared to the SDG&E alternative SCE presented.

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[1] 1,187 / 4,594 = 25.8%. This assumes a value of 1,187 MVA for the Valley South System at peak conditions in 2028 (from the SCE 2019-2028 forecast) and a projected peak demand for the SDG&E System of 4,594 MVA (from the California Energy Demand 2019-2030 Managed Forecast - Mid Demand / Mid AAEE Case (https://efiling.energy.ca.gov/GetDocument.aspx?tn=232306&DocumentContentId=64306)).

Question 6: Isn't it true that, if Alberhill is built, and an extraordinary event takes out the Valley South system, all the load at the southern substations like Pechanga, Moraga, Auld, Pauba, and Triton will be dropped and remain dropped until Valley South is restored because Alberhill is in the north and it can only "pick up" 175 MVA? So, isn't it true that the only way to serve these southern substations in event of a Valley South loss is to connect them to power coming from the South?

Answer 6: SCE's radially-configured systems are not designed with the level of redundancy (both in transformer and system tie-line capacity) that would be required to allow for the entire electrical demand of an adjacent system (at peak levels) to be served, in addition to the native load of that system. Such a design would be impractical, very costly, have significant environmental impacts, and would be underutilized a majority of the time.

However, a system design that has the ability to transfer some of the electrical demand away from an adjacent system experiencing an outage is providing a greater benefit than would occur in a system with no options. Additionally, upon the creation of a new system (such as the Alberhill System), there is an initial transfer of electrical demand that occurs. Then, any subsequent transfers during emergency conditions are on top of that initial transfer. This is a more appropriate way to measure the total impact of creating a new system to address both normal condition capacity needs and the emergency or extreme conditions system needs such as posed in the question.

It is true that construction of the Alberhill System Project as proposed (initial construction) would not be able to serve all of the Valley South System peak electrical demand (in addition to its own native load) should an event occur which would cause an outage to the entire Valley South System. There is no other SCE system that has this level of redundancy and as stated above, nor would not be cost effective to create it. However, it is not true under the extreme condition posed in this question that if the Alberhill System Project were constructed, the only way to provide power to the unserved substations (i.e., Pechanga, Moraga, Auld, Pauba, and Triton) would be a solution that included a connection to the south. In fact, if the Alberhill System Project were constructed and should it be either A) necessary to provide more capacity relief to the Valley South System over time as load continued to grow, or B) desired to significantly increase the ability to improve resiliency, there are additional projects that could be constructed which would afford further utilization of the capacity and flexibility of the newly created Alberhill System. Examples include transformer additions and additional 115-kV line construction. If the Alberhill System Project were constructed, a new project providing a connection to the south would not be required, nor would it be the preferred method to address the extreme conditions considered in this question.

Question 7: Why did you configure the SCE Orange County alternative with only a single line to Stadler and a single line to Tenaja? That is a ridiculous proposal; a competent system design would use double circuits to Stadler and Tenaja.

Answer 7: The Orange County alternative proposes to construct single circuits from the new proposed substation to each of Stadler and Tenaja substations respectively. The design also incorporates using the existing line that connects Stadler to Tenaja to ensure that each of the substations would retain two sources of power to maintain reliability. **This question was responded to verbally during the webinar, and included here for reference.**

Question 8: Why did you configure the Menifee alternative with only a two-line connection to Sun City that is T'd to Newcomb? That alternative should include lines to Ivyglen and Skylark at a minimum, and it is easily done with less than a mile of new circuits since Skylark and Ivyglen connect nearby at Valley. Why is this alternative so woefully under designed?

Answer 8: The Menifee alternative, similar to each alternative that SCE provided, was designed to meet at a minimum, the 10-year planning horizon system needs for the Valley South System. As it is consistent with that approach, this alternative not an under designed. The Menifee alternative proposes to transfer both Newcomb and Sun City Substations. This approach looks to provide sufficient transformer capacity relief and the operational flexibility to improve reliability and resiliency, while minimizing cost and environmental impacts. These inputs along with power flow analysis and operational considerations all factor into developing a reasonable range of system solutions as alternatives.

In satisfying the basic project objectives through addressing transformer capacity and providing system tie-lines, the Menifee alternative was deemed to, at a minimum, meet these objectives. The design and scope of the Menifee alternative includes the minimum scope expected to be required (i.e., which substations were transferred, the number of connections to the substations, and which lines used to perform the transfers) while conforming to appropriate planning criteria and standards.

Question 9: Does SCE know whether the various alternatives pose additional benefits to CAISO TPP that have not been captured by SCE's quantitative and qualitative cost-benefit analysis?

Answer 9: As is consistent with most of SCE's radial substation projects, the Alberhill System Project and its alternatives address a local area capacity need and therefore there is no direct impact to the CAISO-controlled transmission system that is studied under the annual CAISO TPP planning process.

SCE recognizes that some of the alternatives proposed provide local generation sources through the use of distributed energy resources (DERs) and that they might be considered to "pose additional benefits to the CAISO TPP that have not been captured by SCE's quantitative and qualitative cost-benefit analysis." The amount of DERs considered were sized to keep pace with the growing load and maintain it to a level below the transformer capacity of the existing Valley South System. As such, the CAISO-controlled Bulk Electric System (BES) would see no reduction in the burden on the BES facilities due to installed DERs that were sized and maintained only to keep pace with the load growth of the region. **The response provided verbally in the webinar was edited for clarity and completeness.**

Question 10: Quanta's "Spatial Load" forecast is based on the 2018 IEPR, but the 2018 IEPR does not account for the state mandate that all new buildings be equipped with solar, therefore all the load growth that is predicted by Quanta will not actually result in increased power flows through the Valley South Transformers. Why doesn't the Quanta report address this, and why doesn't it acknowledge that the solar building mandate ensures that load growth in Valley South will not increase power transfers via the Valley South Transformers?

Answer 10: The 2018 IEPR does account for the state mandate that all new buildings be equipped with solar. The 2018 California Energy Demand Forecast (CED) in the 2018 IEPR builds on the 2017 CED, which was the first forecast to incorporate the SB350 2019 Title 24 building standards that require all new homes to include the installation of solar panels (see pg. 240 of CEC-100-2018-001-V2) beginning in

2020. As the Spatial Load Forecast developed by Quanta includes the appropriate Additional Achievable Photovoltaic (AAPV) forecast to model future growth in PV, the Spatial Load Forecast does incorporate the aforementioned 2019 Title 24 building standards.

Question 11: What is the source of Quanta's "load density" values for the "Spatial Load" forecast prepared for the Valley South system? Were they developed particularly for the Valley South area and thus specifically reflect Valley South conditions, or are they based on some sort of national aggregate?

Answer 11: As described in A.09-09-022 ED-Alberhill-SCE-JWS-4 Item A (Load Forecast), Appendix B, section 4.2: within each 150-acre grid square, Quanta first uses geospatial data to identify the relative percentage of area comprised by each of 14 types of land-use categories, then uses actual Valley South System customer meter data to distribute load among the types of land-use categories accordingly. Load densities are then calculated for Valley South using current load for each land use.

Question 12: Regarding Quanta's Trend-based forecast, Quanta states that the Gombertz curve trending has been used for 40 years and is the most accurate load trending forecast methodology at the distribution level. However, it has not been used to forecast distribution systems in which future load growth is statutorily mandated to be served by local generation and even community solar projects. More importantly, these local generation and community solar projects will actually reduce load on the Valley South transformers, so by how much will Quanta's "Trend Forecast" be reduced when these actual energy trends in California are considered?

Answer 12: SCE recognizes that the “Current Trend Forecast” reflects an extension of recent historical rates of DER adoption and thus may underestimate the impact of recent mandates under SB350. The amount of load reduction that could be expected to result from consideration of this mandate could be estimated from incorporation of the rates of change in DER adoption in the IEPR forecast. The 2018 IEPR CED updated forecast incorporates the SB350 mandates. Refer to page 240 of CEC-100-2018-001-V2.

This impact is reflected in the difference between the “Spatial Base Forecast” and the “Spatial Effective PV Forecast” in the planning study and is 30 MVA, 46 MVA and 59 MVA in years 2022, 2025 and 2028 respectively.

Note that accounting for additional PV mandated under SB350 only impacts new load growth associated with new developments. It is also important to note that any PV installation does not result in a decrease in peak demand equal to the amount of total nameplate rating of the PV installation. Rather, it is only a fraction of the nameplate total installed because the timing of the solar peak (approximately 12:00 PM) is not coincident with the timing of the electrical system peak (commonly 4:00-6:00 PM depending on location).

As an example, if a new residential home would contribute 6 kW to the peak demand in an area at 5 PM prior to the SB350 Title 24 mandates, the same home compliant with the mandates may contribute to the peak demand in an area something closer to 4-5 kW (depending on many factors including the size of the PV installation and geographic location). Title 24 mandates that new residential homes are to be “net zero energy” on an annual basis. This means the solar PV installations are generally going to be sized to ensure the net energy consumption for the year is zero. This does not equate to net zero peak demand contribution. In areas with system peaks later in the evening, solar PV output concurrent with that time is significantly less that at solar peak, thus there is only a marginal reduction in the peak demand contribution of the home even though it is Title 24 compliant.

Question 13: Quanta's "Spatial load" forecast methodology assumes full build out of adopted county and local land use plans by 2048, but there is no basis to make such an assumption and there is no reason to think that full build out would occur, Yet, Quanta makes this assumption anyway; how much will Quanta's "Spatial Load" forecast be reduced when a more realistic build out scenario is assumed?.

Answer 13: SCE considers the build out scenarios used by Quanta to be reasonable for the purpose of the planning study.

Full build out of land use plans by year 2048 is assumed as a reference for horizon year load estimation. The basis for this assumption is the county and city general plans, with some compensation for uncertain level of development.

Available county and city plans are defined for a variety of time frames, all of them are sooner than 2048. For example, the planning horizon used for the City of San Jacinto is for year 2032, and that for the City of Lake Elsinore is for year 2030. There is no certainty the plans will be ever fully build out, but by assuming all plans build out will extend up to year 2048 we are including margin that should compensate for some of the undefined level of development.

It is worth noting that the intention of the load forecast is not to predict the exact amount of load, but to provide a reasonable reference for planning. Additionally, the cost benefit analysis results are not highly sensitive to the load forecast in the later years of the study period due to the discounting of BESS additions and associated benefits that occurs over the 30-year analysis period. So, the specific year when the build out currently envisioned by the communities is reached is not a critical factor in the analysis.

Question 14: Why is the LMDR assumed to be 0 in Table 4-7 of the Quanta forecast report?

Answer 14: The load modifying demand response (LMDR) values in Table 4-7 of the Quanta Load Forecast report are values for each year of the load forecast and represents the incremental modification of that year to the forecast of electrical load. An entry of 0 in the table does not indicate an assumption that the LMDR contribution to total electrical load for that year is zero, rather it reflects that the forecast LMDR has not changed year over year.

Question 15: Why does Quanta's "Spatial Load" forecast state that it is consistent with the IEPR, when in reality the DER assumptions set forth in Table 4-7 contradict the IEPR because they actually drop over time, whereas the IEPR assumes these contributions increase over time?

Answer 15: Table 4-7 and the IEPR forecast are consistent in showing increases in DER adoption through the study period. The DER forecasts presented in the 2018 updated IEPR are total load modifying contributions across the entire state of California. The values shown in Table 4-7 of the Quanta Load Forecast Report represent incremental load modifying factors for each year of the forecast for the Valley South and Valley North Systems. Both show increasing DERs throughout the period but changing rates of adoption over time. A reduction in the load modifying factor from one year to the next does not represent a decrease in the total contribution of DERs to the system, rather, it represents a reduction in the adoption rate of DERs.

The CED forecast provided by the IEPR is a high-level forecast for relatively large planning areas (Investor Owned Utilities ("IOUs") and municipalities for example). The IOUs then disaggregate these forecasts, again using industry and stakeholder reviewed methodologies developed in the Distribution Forecasting Working Group, to develop lower-level forecasts. Based on many factors including economics, geography, existing adoption rates, saturation levels, etc., the higher-level system trends shown in the CED forecast presented in the IEPR will not necessarily match that of local-area system trends. However, when all local area trends are aggregated back up to the higher system levels, the resulting trends will match.

Question 16: Page 30 of the Quanta forecast report states that "Spatial Load" forecasts must be "carefully reviewed to make sure they correspond to realistic expectations". What sort of "realistic expectation" corrections are contemplated here, how are they quantified, what were they quantified to be?

Answer 16: Realistic expectations refer to horizon-year loads being commensurate to land-use changes expected in the future. For example, expected increases in residential load density within a small area should be reflected as load increases, no expected change in land-use should produce no changes in load, and expected re-definition to less dense land-uses should result in corresponding load reductions.

A general review of preliminary INSITE outputs was conducted, to ensure the load profile is consistent with the expected land use.

Question 17: Regarding SCE's response to CPUC, SCE says "The minimum level of resiliency that SCE is seeking to achieve would be to add system tie-lines with sufficient transfer capacity to appreciably reduce the amount of load at risk of being unserved during abnormal system conditions". How much is "appreciably reduce"? does it mean reduce the risk of peak load by 10%? 25%? 59%? 75%?

Answer 17: SCE does not have an explicit standard or planning criteria that dictates an exact value of how much transfer capacity a radial system must have. Rather, SCE assesses the reliability and resiliency of each radial system by performing N-1 contingency analysis at peak system loading values to determine system response to reasonably expected contingencies. The goal is to ensure that sufficient system capacity is available to serve all electrical demand at peak conditions under all reasonable N-1 contingency events.

SCE may also evaluate more extreme contingency events (N-2 or greater) to further define the resiliency of the system under those more extreme circumstances to be informative in assessing risks or evaluating and differentiating among proposed project alternatives. For SCE's radial systems (those not part of the CAISO-controlled Bulk Electric System), and specifically related to extreme contingency events (which as SCE has stated, are events beyond those required to be met to be in compliance with its planning criteria), SCE does not have a defined value to be equated with the statement "appreciably reduce." In summary, extreme contingency events are not used to drive the initiation of projects or define alternatives; however, they can be very useful in differentiating among various alternatives which otherwise address basic reliability requirements (i.e., base case and N-1 planning criteria).

The use of the electrical facilities and system tie-line connections to adjacent systems are modeled to evaluate and then identify if any electrical demand would be at risk of being unserved under reasonably expected N-1 contingencies. If use of the available capacity of adjacent systems is sufficient to serve all electrical demand, no further action is required. However, if load remains at risk of being unserved after employing the capacities of adjacent systems, then a project is proposed to address the deficiency.

The amount of transfer capacity in a system is dependent on several factors including: the capacity determined by the rating of the actual electric facilities themselves (e.g., transformers, conductors, and associated equipment) and the incremental additional capacity these facilities can accommodate from an adjacent system in addition to the demand they serve normally ("native load"). Thus, the transfer capacity of a system is the difference between the ratings of the electric facilities and the amount of native load being served during the time of the needed transfer (generally considered during peak system load conditions).

Question 18: If FERC approves the Nevada Hydro Company's LEAPS project at Lake Elsinore, and the CPUC approves Alberhill, is there a possibility the LEAPS lines would connect to the Valley/Serrano lines at Alberhill instead of at Lee Lake?

Answer 18: If the LEAPS Project were to be approved, the Alberhill substation is the currently proposed interconnection facility and a separate project at Lee Lake would not be required. Should the ASP project not be approved, SCE would be obligated to provide other acceptable interconnection facilities for LEAPS upon its approval.

Question 19: Why hasn't SCE constructed "system ties" between the Valley North system and the Valley South system

Answer 19: Duplicate of question Number 1.

Question 20: Is BESS planned for the Alberhill System?

Answer 20: The proposed Alberhill System Project does not include a BESS. A BESS relieves capacity needs of a system by serving load locally (commonly at distribution substations), which reduces the amount of power that is sourced via the subtransmission and transmission systems, including the transformers that interface with the transmission system. In a radial system design (including nearly all of SCE's electrical systems), the capacity ratings of these interfacing transformers are the limiting component in determining the amount of power that can be sourced from the transmission system. As proposed (using SCE standard sized 500/115-kV transformers), the substation transformers of the Alberhill System Project would be able to accommodate enough power to serve load through at least 2048. As such, a BESS would not be required to meet the project objectives.

SCE evaluated alternatives to the Alberhill System Project that do include a BESS. These alternatives are described in Section 6.1.4 of SCE's response to Item C, which can be accessed using the link below.

Question 21: When would today's presentation be made available at the SCE's Alberhill website?

Answer 21: The presentation (audio and PowerPoint deck) was posted on the Alberhill website on February 25, 2020.