# Alberhill Webinar Questions & Responses – April 30, 2021

Question 1: *How and when was the error discovered?*

Response to Question 1:

Immediately below is SCE's response during the webinar. [1]

> We actually have a formal response to that question in a prior data request. You can read the formal response there, but we discovered the error in reviewing a response to another data request in August of 2020. We were working with Quanta Technologies, the consultant that prepared the cost benefit analysis, to review some of the information they provided in response to a data request. We noticed the numbers didn't look right, so we did a more in-depth review of the numbers and identified the inconsistency in the way the probabilities were applied in their spreadsheet. So, it was in reviewing a data request response in August of 2020 when the error was identified.

Additional related information is provided below.

> SCE discovered the first error (that is errors in calculated probabilities of coincidental power line outages and specific electrical system loading conditions that would result in unserved load) ) while preparing and reviewing the response to a data request in the second half of August 2020. Specifically, consultants from MPR Associates noted that the original Quanta analysis did not use correct statistical methods to reflect that three events must occur coincidentally to result in loss of service to customers under the Flex-1 scenario. MPR notified SCE, and upon conferring with Quanta to confirm the error, SCE and Quanta both mobilized independent personnel who had not previously participated in the work. These personnel reviewed the updated Quanta statistical analysis and all other aspects of the Cost/Benefit Analysis, Planning Study, and the remaining analyses contained in SCE's May 2020 Motion to Supplement the Record ("Motion").
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> SCE discovered the second error (error in the application of SCE's Value of Service Study in assigning a monetary value to unserved customer load) in September 2020 while conducting the broader review described above.
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> - MPR identified a mathematical error in combining the Small/Medium Business and Commercial/Industrial monetization rates in the Quanta spreadsheet
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> - MPR, in discussions with the SCE team, identified the need to apply the fraction of <u>energy consumption</u> by each customer class instead of the fraction of <u>customer count</u> in each customer class to correctly monetize EENS

[1] Responses to questions provided verbally during the webinar may have been edited for clarity and completeness.

- An independent Quanta reviewer identified that it is common industry practice to roll outages to minimize the duration of outage impact on a single group of customers when practical and asked SCE to confirm that it is also SCE's practice, which they did confirm. Quanta independent reviewers also identified that the VoS study validity was limited to outages less than 24 hours in duration, and that outages greater than 24 hours have more pronounced financial and overall socioeconomic impacts than outages lasting a day or less. SCE and Quanta researched industry data on costs of long-duration outages, finding a consensus that long duration outages are more costly, but there was a lack of specific data for quantifying these higher costs. SCE and Quanta then mutually agreed to use the average of 1-hour and 24-hour VoS study outage costs to reflect that widespread, multi-day outages have high costs not reflected the VoS study survey.

The third "error" (that is modifying the Flex 2-1 and Flex 2-2 metrics that address the impact of a "high-impact low-probability (HILP) event") was not actually an error in the analysis because the assumption was explicit and identified in the analysis. However, also during September 2020, an SCE independent reviewer expressed concern that Flex-2 outage timing had only considered times of year with the highest load and this assumption was inconsistent with how other metrics treated event timing. The reviewer recommended that the timing constraint be modified to provide a common basis in combining the individual monetized metrics for the cost/benefit analysis. SCE then directed Quanta to relax the timing assumption which had overstated the Flex-2 value relative to other metrics.

Question 2: *How do you define reliability?*

Response to Question 2:

Immediately below is the SCE's response during the webinar.

In general, it is important to understand reliability as it relates to the distribution level of the system versus other levels (e.g., subtransmission, transmission) of the system, in order to provide proper context. In terms of this project, as it relates to the subtransmission level part of the system, SCE defines reliability as being able to provide adequate power to meet the needs of the customers as required by the CPUC, at all times, including normal conditions (e.g., when all facilities are in-service) and during certain abnormal conditions (N-1 conditions when any one single component is out-of-service). This is consistent with most utility practices in planning their system. SCE's reliability studies look to ensure that the system can accommodate all customer load throughout the year. Specifically, we study the problems that manifest themselves during summer peak load conditions, but we may also study any time throughout the year. We evaluate the system with all facilities in service (N-0) and then we sequentially take out one facility at a time (and then return it to service) to ensure that our system is designed adequately to handle all of the customer load that is present.

Additional and related information from the Planning Study is provided below.

> ***Reliability*** refers to a utility's ability to meet service requirements under normal and N-1 contingency conditions,[2] both on a short-term and long-term basis. Reliability is focused on the impacts to the electric grid and the associated effects on the day-to-day customer experience as it relates to power outages and durations thereof. It is conventionally quantified by metrics (such as those defined by IEEE-1366) that demonstrate how well a utility limits the frequency and duration of localized outages from factors such as equipment failure, animal intrusion, damage introduced by third parties, and the number of affected customers during these outages.

Question 3: *What was the 2020 reliability performance, including SAIDI, and SAIFI, of the Valley South System? How is the 2020 Valley South System reliability performance compares with SCE's system average performance?*

Response to Question 3:

The 2020 reliability performance metrics for the Valley South System and the SCE System are provided below.

| | 2020 | | | |
|---|---|---|---|---|
| | SAIDI | SAIFI | MAIFI | CAIDI |
| Valley South System | 3.57 | 0.03 | 0.03 | 120.07 |
| SCE System | 5.75 | 0.03 | 0.04 | 190.47 |

SAIDI and SAIFI data are representative of distribution system reliability performance, so they are not directly relevant to the project being proposed by SCE. To date, most of the historical outages in the Valley South System have been caused by localized, distribution system issues and are reflected in the metrics above. These metrics do not reflect the need for additional transformer capacity and system tie-lines in the Valley South System as these needs are at the *subtransmission* level. Distribution system performance as measured by metrics such as SAIDI and SAIFI reflect reliability issues that have already occurred. SCE relies on these metrics to be informative about existing distribution system performance issues (based on past performance) and then addresses these issues with projects to improve distribution system performance. On the other hand, planning studies (capacity studies and power flow studies) *proactively* inform SCE about future expected system issues so that projects can be proposed and constructed before problems arise. This distinction is important because distribution system metrics would not reflect these future needs. It is also important to note that issues identified at the higher levels (i.e., higher voltage facilities) of the system have the potential to

[2] An N-1 contingency is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element.

impact very large numbers of customers in contrast to distribution system level issues which are constrained to a relatively small number of customers.

Question 4: *For the year 2020, how many customer outages in terms of number of events and number of customers affected that would have been avoided if there are tie-lines to the Valley South System?*

Response to Question 4:

While no subtransmission level events occurred in the Valley South System in 2020 for which tie-lines to an adjacent system would have been used to restore service, this does not imply that having system tie-lines is unimportant. The effectiveness and usefulness of system tie-lines may not demonstrate itself in any given year; however, the design of radially served electrical systems is such that they require system tie-lines to meet basic reliability requirements (e.g., N-1 contingency events) in accordance with SCE planning standards.

As discussed in the response to Webinar Question 3, system power flow analysis is performed to assess expected *future* system performance violations. Identified violations would be mitigated operationally to the extent possible (which can include the use of system tie-lines) or new projects would be proposed. Not planning for reasonably probable events that could result in lost electrical service, just because they did not occur in a given year, would not reflect utility industry practices required to provide the level of service that SCE, its customers, and the CPUC expect. It is also important to note that simply having system tie-lines would not prevent customer outages for any or all line contingencies. System tie-lines are not designed specifically to address all possible N-1 contingencies, but system tie-lines do provide the ability the limit the duration and number of affected outages for some line contingencies and provide operators with the flexibility to restore electrical service during unplanned outages until the system can be returned to its normal operating configuration.

Question 5: *Will this slide deck be available after the presentation? Is it available now?*

Response to Question 5:

Yes. The presentation used during the webinar, as well as an audio recording of the webinar, can be found at the following link:

https://www.sce.com/about-us/reliability/upgrading-transmission/alberhill

Question 6: *Is EENS N-1 what you defined as reliability concerns?*

Response to Question 6:

Immediately below is SCE's response during the webinar.

> Reliability can manifest itself in a number of ways. It really relates to loss of service to customers under typical operating conditions, so reliability is reflected in the Electrical Energy Not Served (“EENS”) N-0 and N-1 metrics. Conditions beyond N-1, such as the N-2 line outages, as well as major substation outages, are more typically characterized as “resiliency” type concerns. But “reliability” is reflected in both the EENS N-0 and EENS N-1 metrics.

Question 7: *Is EENS N-0 the capacity concerns?*

Response to Question 7:

As discussed in Webinar Question 6, reliability and capacity are not distinct, independent elements in system planning. However, it would be correct to say that the EENS (N-0) metric is reflective of both future transformation capacity adequacy and subtransmission line capacity adequacy. Similarly, the EENS (N-1) metric is influenced by system line capacity margin, as overall system loading conditions impact the ability of system operators to leverage temporary overload line ratings during N-1 conditions to minimize loss of service to customers. In radial electrical systems such as the Valley South System, when there is currently inadequate transformation capacity even during N-0 conditions, the situation is exacerbated during N-1 conditions. Adequate line capacity during N-0 conditions does not ensure adequate line capacity during N-1 conditions in a radial system since line outages (i.e., an N-1 condition) impact the magnitude of power flowing on the lines.

Question 8: When you talked about resiliency, do you mean your Flex-1, Flex-2-1, and Flex 2-2 metrics?

Response to Question 8:

Because Flex-1, Flex-2-1, and Flex 2-2 metrics are generally associated with contingency events beyond N-1 (i.e., they result from coincident failures of more than one system element), they are characterized as system resiliency metrics. The Flex-1 metric can be related to reliability as well when one considers that N-2 outages can result from the failure of a single subtransmission line element (such as a pole line supporting multiple subtransmission lines).

Question 9: *on p.14, why the error was discovered so many months after SCE's original filing in May 2020?*

Response to Question 9:

See the response to Webinar Question 1.

Question 10: *On p.14, you mentioned this is first of a kind analysis. Have you reviewed prior analyses conducted in California by other utilities such as SDG&E and PG&E? We understand they may have done similar cost-effectiveness analyses in the past.*

Response to Question 10:

SCE is not aware of either SDG&E or PG&E having conducted cost-benefit analyses for reliability projects. SCE and the other California utilities routinely perform cost-benefit analyses to justify system upgrades to facilitate improvements in power markets that benefit customers. However, this type of cost-benefit analysis does not require development and assignment of costs to forward-looking reliability metrics. Quantifying and assigning value to reliability benefits drives the complexity of the analyses performed by SCE in the Alberhill System Project proceeding. Similarly, "cost-effectiveness analyses" (as specifically addressed in this question) is performed as a high-level screening and prioritization tool in the Distribution Investment Deferral Framework (DIDF) proceeding to identify, among several projects identified in the then current planning cycle, those that have the highest chance of success in utilizing distributed energy resources (DERs) to defer traditional planned investments. This context is substantially different than the cost-benefit analysis performed in the Alberhill System Project proceeding. Among many other differences, cost-effectiveness analyses do not quantify and assign value to reliability benefits.

Question 11: *On p. 15, with Flex-1 and EENS (N-1) significantly reduced, do you still have a reliability problem or concern for the Valley South System in 2021 and for the next 10 to 20 years?*

Response to Question 11:

Yes, the reliability and resiliency concerns associated with EENS (N-1) and Flex-1 metrics continue to be a concern despite the relatively low monetary value of the metrics. The ability to continue to serve load under N-1 conditions is a foundational element of electric system planning, even though the monetary value of relatively short-term customer service interruptions may be low. Similarly, prudent system planning activities for radial subtransmission systems include provisions for operational flexibility to proactively or reactively mitigate N-1-1 and N-2 outages using system tie-lines. The non-monetized Load at Risk (LAR) associated with the Flex-1 metric is indicative of the relative flexibility offered by the alternatives. While the relatively low probability of coincident line outages substantially reduces the monetary value of the Flex-1 metric, such events, when they do occur, can affect tens of thousands of customers for a substantial duration.

Question 12: *On p. 15, by using an area wide statistical base for line outage probabilities, would be erred in overstated outages on some lines and understated outages on other lines?*

Response to Question 12:

Line outage frequencies in the analysis were based on historical line outage data for the Valley South and Valley North Systems from 2005-2018. A system or area-wide statistical basis was used in lieu of independent line outages because there was no clear correlation between outage frequency rates and each line and because the configuration of the Valley South System has not been static. The primary causes of outages within the data did not impact one type of circuit more than any other because SCE's subtransmission lines are of similar construction and are generally susceptible to the same outage causes.

Additionally, as the Valley South System has had many subtransmission line additions and reconfigurations over the past 20 years, an area-wide statistical basis of outage frequency per 100 mile-years was considered to be most appropriate in ensuring a consistent and relative application across the alternatives for line outage probabilities. This would not be the case if individual line outages were used because there would be no historical basis for the new or reconfigured lines.

Question 13: *on p. 16, why SCE did not conduct a VOS specifically for the Valley South System and specifically for a 2-week duration outage?*

Response to Question 13:

The original SCE Value of Service Study (VOS) was developed specifically to support SCE's 2021 General Rate Case filing, not as an input for the Alberhill System Project cost benefit analysis. However, the survey data that were the basis for the SCE VOS, and used for the monetization of customer service interruptions, were explicitly limited to outages fewer than 24 hours. SCE did not conduct a VOS for a 2-week duration outage because there is currently no available industry data or consistently agreed-upon approach to quantify costs associated with outages lasting longer than 24 hours. There is, however, a recognition of the need to develop these data because widespread long-duration outages result in economic disruption that is much greater than outages that last less than a day.

An industry workshop was recently conducted to discuss the need and various approaches to collect the data (see https://emp.lbl.gov/publications/frontiers-economics-widespread-long). As discussed in the workshop, the higher costs of long-duration outages result from customer impacts that include such things as: temporary hotel lodging or relocation; food spoilage; purchase of generators; closing of offices and other business; health impacts due to loss of air conditioning; and other more general limitations in economic activity. The workshop concluded that conducting a customer survey is unlikely to be the best approach for developing these costs. Developing and implementing a cost model to address these disparate impacts would have been a significant effort beyond the scope of this work. It would also have been unnecessary, as the primary objective of the cost-benefit analysis was to assess and compare the *relative* cost-benefit performance of multiple alternatives (using a common set of assumptions), and not to justify a project based on the resultant *absolute* cost-benefit ratio.

Question 14: *On. p.16, is it practical to roll outages to customers one hour at a time? How would SCE do the one-hour at a time outage?*

Response to Question 16:

Immediately below is SCE's response during the webinar.

> Yes, it is practical. SCE's practice to roll outages involving one-hour increments has been in place for at least 20 years. It is consistent with direction provided by the CPUC that if there is a need to reduce load due to a loading problem, rolling the outages between multiple customers for one-hour periods is preferred over longer durations of fewer customers. In response to how SCE would do that, SCE has automated most of its distribution system and has predefined load blocks that can be shed to help remediate a system issue, depending on the nature of the event. If the system issue lasts longer than an hour, SCE's general practice is to restore power after an hour to the first block of customers that were dropped and then drop another block of customers and so on. This practice occurred in August of 2020 when the greater transmission grid had power procurement issues which necessitated the CAISO to direct the utilities to reduce a specified amount of load. SCE was able to respond by using these automated load-shedding schemes throughout its service territory to ensure that it could meet the load-shedding amount required by the CAISO. SCE has the same ability to shed these predefined load blocks if there are local system issues to meet that particular system need. Examples include a N-1 outage of a transformer or of a subtransmission line. In summary, it is practical, SCE has done it for many years under various contingencies, and it is consistent with how many utilities do it.

Question 15: *On p.17, why SCE assumes the Flex-2-1 event as a 1-in-100-year event? Since SCE has 100s of substations like Valley Substation, historically was there such Flex-2-1 outages occurring somewhere in the SCE system once a year?*

Response to Question 15:

The three catastrophic transmission substation fire events in the past twenty years reported in the Planning Study (Vincent, Mira Loma, and El Dorado) support that the 1-in-100 year event probability is reasonable. There are only 11 *transmission* substations (e.g., those with 500 kV voltage) in SCE's system (not hundreds as indicated in the question). The three events correspond to an approximate 1-in-70 year event frequency for single substations (3 events divided by 20 years multiplied by 11 substations). As stated in other responses to these webinar questions, it is important to consider that the context of the cost-benefit analysis is to address the *relative* cost-effectiveness between all alternatives. The frequency rate of the event only needs to be reasonable to develop a relative analysis across alternatives, as the same frequency rate is applied consistently across all alternatives when monetizing the performance metric.

Question 16*: Would it be correct to say that this new analysis demonstrates that the greatest value added from this project is to plan for a very rare 1 in 100-year event, and also, the added transformation capacity benefit?*

Immediately below is SCE's response during the webinar.

> I don't think I would characterize it like that. The greatest benefit of this project as we see it is providing for a sufficient and adequate supply of power to ensure that we can serve our customers' needs on an ongoing basis. The need is imminent, as well as what we are seeing going forward in the future. And then secondly, the ability to improve the reliability and to be consistent with our planning criteria and all of our other radial systems within the SCE grid, while considering the size and magnitude of the number of customers and the load served in this area. It's very important for us to be able to improve that reliability and to be able to supply an adequate amount of power to meet their needs. As it relates to the 1-in-100 event occurrence, what we did was produce a series of alternatives to meet the basic project objectives, adequate capacity, and reliability. It's important in any development of alternatives that meet the basic project objectives and to have an awareness of the performance of these alternatives outside of those basic objectives being met. This is because not all of them would be held equally in how they perform after you meet the basic objectives. This is especially true when there are varying costs and environmental impacts, etc. that are associated with the various alternatives. It's important to understand what the performance of each alternative looks like just outside and beyond the 10-year planning horizon. Those findings would not necessarily be a direct impact on how you plan for these alternatives, rather by the inherent nature of what you did propose to meet the basic objectives, some of them perform better. We evaluated the performance of a resiliency event so that we could better capture the second level of performance which through a cost benefit analysis allowed us to determine which alternatives provided the biggest bang for your buck. So, I wouldn't characterize it as the development of alternatives to meet 1-in-100 year events but rather identify those that perform better under such events should they occur.
>
> To elaborate further, system tie-lines are used much more commonly than once in 100 years. There are lots of events that occur on a regular basis where system tie-lines are used to improve operational flexibility, reliability to individual customers, etc. We discuss the impacts of line outages as well that trigger the system tie-lines benefit in the Planning Study.

Additional related information provided below.

> The primary benefit of the project is to address the urgent capacity need but also to provide system tie-lines that address a wide range of scenarios that challenge the operational flexibility, reliability, and resiliency of the Valley South System. The Alberhill System Project, as well as several of the other alternatives, also provide a diversely located source of power to SCE's system, which aids in mitigating the wide variety of Valley Substation outage scenarios considered in the assumed 1-in-100-year Flex 2-1 scenarios. The Flex 2-1 metric does provide substantial monetary value in the cost-benefit analysis and, while the scenarios that threaten Valley Substation are infrequent, they would have tremendous economic and other more general public impacts due to the resulting widespread and long-duration power outages These impacts would be much greater than the probability-discounted monetized value calculated in this analysis. Recent industry experience certainly suggests there is benefit in considering potential incremental resiliency benefits among alternatives that are developed to address basic planning criteria such as satisfying capacity needs and providing operational flexibility associated with system tie-lines.

Question 17: *On. p. 19, would the EENS (N-0) benefits be reduced to zero if SCE continues to utilize the spare 500/115 kV transformer at Valley Substation to serve demand during high demand hours?*

Response to Question 17:

Continued use of the spare transformer as mitigation under high-loading conditions could provide sufficient capacity to serve all load under N-0 conditions for SCE's current 10-year planning horizon. However, considering this as an acceptable solution to address N-0 transformer capacity needs assumes the spare transformer would always be available (i.e., not already being used as a spare transformer functioning to replace an out-of-service transformer). Using the spare transformer to serve peak load under N-0 conditions is not an appropriate long-term solution for the Valley South System and this solution does not address reliability and resiliency concerns during other operating conditions.

Question 18: *On. p.21, how many alternatives that do not fully met SCE's objectives were included in SCE's cost-effectiveness evaluation?*

Response to Question 18:

Seven alternatives considered in the analysis do not fully satisfy SCE's project objectives. These are:

- the five (5) alternatives with Valley South to Valley North system tie-lines
    - *Valley South to Valley North*
    - *Valley South to Valley North to Vista*

- *Valley South to Valley North plus centralized BESS in both Valley South and Valley North*
- *Valley South to Valley North plus distributed BESS in Valley South*
- *Valley South to Valley North to Vista plus centralized BESS in Valley South*

These alternatives were analyzed by SCE in response to Energy Division and other stakeholder interest in alternatives that create Valley South to Valley North system tie-lines. These system tie-lines are ineffective because their location in the system does not allow the bi-directional transfer of load between the systems. In contrast, locating system tie-lines at the outer edges of the system boundaries generally allows for bi-directional transfer of substations between the two systems to address needs in either system.

- *Centralized BESS alternative* that includes no system tie-lines.

This alternative was analyzed to represent the "evaluation of energy storage, distributed energy resources, demand response or smart-grid solutions" as directed by Decision 18-08-026. .[3]

- *Menifee alternative*

This alternative was analyzed in response to public input suggesting a limited scope alternative with the addition of a fifth load-serving transformer at Valley Substation and Valley South to Valley North system tie-lines. As addressed in the original and Amended Proponent's Environmental Assessment, the addition of fifth load-serving transformer at Valley Substation is not feasible and providing additional transformer capacity at the adjacent Menifee site and transferring the same substations that would otherwise be transferred to Valley North in the *Valley South to Valley North* alternatives most effectively simulates the alternative of interest to stakeholders while also being feasible to implement.

Question 19: *On. p.22, what is SCE's course of action when capacity shortfall is imminent?*

Response to Question 19:

SCE plans to continue mitigating high-loading conditions (over 896 MVA) in the Valley South System by connecting the spare 500/115 kV transformer to the Valley South System until a project is completed. This mitigation plan is not risk-free as it assumes that the spare transformer is available when needed and not already in-service replacing one of the four load-serving transformers at Valley Substation. Should the spare transformer not be available, SCE expects that load shedding would occur to keep the transformers within acceptable operating limits. This mitigation procedure is not considered sustainable as load in the area continues to

[3] See D.18-08-026 at 43

increase SCE will need to rely on this mitigation procedure with increasing frequency and duration.

Question 20: *Can Edison elaborate on why several of the top candidates from the CBA results had "ineffective system tie lines"? Wouldn't there be a way to mitigate that. Please explain in more detail.*

Response to Question 20:

SCE was directed in CPUC Decision 18-08-026 to study and report on a number of system alternatives which would, among other things, incorporate scope components that included DERs. The scope of the alternatives that produced "ineffective system tie-lines" was a by-product of creating solutions to meet the project capacity objectives on a shorter-term basis by minimizing scope to potentially achieve lower-cost solutions while providing opportunity for incorporating DERs. Because of the location of these limited-scope alternatives (i.e., located near the existing Valley Substation), the number and location of substations transferred is limited and the system-tie-lines created in these lower-cost alternatives do not have the ability to provide loading relief to both electrical systems (e.g., Valley South and Valley North). This is in contrast to the bi-directional transfer of load both into and out of Valley South as a requirement in order to be effective. In some cases, these minimal scope alternatives were highly-ranked in the cost-benefit analysis because of the lower costs (though the actual system benefits were low as well). Mitigation of the ineffectiveness of these tie-lines in these lower-cost and lower-performing alternatives was not deemed by SCE to be practical because their additional scope and cost would be similar to or greater than better-performing alternatives that were already represented in the analysis.

Question 21: *Please clarify how resiliency needs were captured and quantified in the metrics in comparison to how operational flexibility and reliability needs were captured?*

Response to Question 21:

Operational flexibility enables power systems to be both reliable and resilient. System operators need the ability to reconfigure the power system to adapt to system conditions resulting from equipment being out-of-service due to maintenance, new construction, or equipment failures. Specific to radially-designed power systems, operational flexibility is improved by implementing a project with scope elements that both increase capacity margin <u>and</u> increase the number and effectiveness of system tie-lines. Consequently, both reliability and resiliency are improved. As discussed in Webinar Questions 6, 7, and 8, reliability improvements are reflected in the EENS (N-0), EENS (N-1), and Flex-1 metrics, whereas resiliency improvements are reflected in the Flex-1, Flex 2-1, and Flex 2-2 metrics.

Question 22: *How many of the 13 alternatives are included in the Final EIR? Does the EIR need to be supplemented with any or all of the 13 alternatives presented?*

Response to Question 22:

The 13 alternatives identified in SCE's February 1, 2021 Amended Motion to Supplement the Record were not included in the Final Environmental Impact Report (FEIR). Decision 18-08-026 which directed SCE to evaluate alternatives which may satisfy the needs of the Valley South System specifically excluded the evaluation of alternatives previously studied in the FEIR. The information contained in the February 1, 2021 Amended Motion to Supplement the Record provides the Commission with information to support the Commission's ongoing analysis of SCE's proposed Alberhill System Project. Of the thirteen alternatives described, ten do not meet the project objectives. Three alternatives were put forth in the Amended PEA, contained in SCE's Amended Application and Proponents Environmental Assessment and Motion to Supplement the Record on May 11, 2020.

Question 23: *For the 8760 power flow analysis: what are the three forwarded looking forecasts?*

Response to Question 23:

All forecasts extend the 2019-2028 SCE 10-year forecast to 2048. Beyond 2028, the three forecasts used varying assumptions for increases in DERs and rates of electrification:

1. **Effective PV:** A mid-range forecast that extends the current forecast, considering SCE's expected dependability and peak load time-of-day performance of installed behind-the-meter solar power systems
2. **Spatial PV Watts:** A lower load forecast reflecting the higher adoption/effectiveness of on-peak PV
3. **Spatial Base:** A higher forecast that assumes continuation of current trends in PV and other DER adoption and thus is reflective of a future scenario where increased electrification effectively offsets increasing DER adoption

See Section 5.4 of the Planning Study for additional details.[4]

Question 24: *Please clarify which alternatives offer system tie-lines and whether any of them include battery energy storage system (BESS) options.*

Response to Question 24:

All alternatives include system tie-lines with the exception of the *Centralized BESS in Valley South* alternative. The five Valley South to Valley North based alternatives (*Valley South to Valley North*, *Valley South to Valley North to Vista*, *Valley South to Valley North and*

[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M363/K790/363790936.PDF

*Distributed BESS in Valley South*, *Valley South to Valley North and Centralized BESS in Valley South and Valley North*, and *Valley South to Valley North to Vista and Centralized BESS in Valley South*), plus the Menifee alternatives were concluded to have ineffective system-tie lines.

The following alternatives include BESS:

- Valley South to Valley North and Distributed BESS in Valley South
- Valley South to Valley North and Centralized BESS in Valley South and Valley North,
- Valley South to Valley North to Vista and Centralized BESS in Valley South
- Centralized BESS in Valley South
- Mira Loma and Centralized BESS in Valley South
- SDG&E and Centralized BESS in Valley South

Question 25: *Please clarify why the "1 in 100" year assumption was selected for the Flex 2-1 metric.*

Response to Question 25:

SCE deemed the 1-in-100 year assumption to be a reasonable representation of the frequency of a “high-impact low-probability” event affecting all of Valley Substation. As discussed in Webinar Question 15 above, it is supported by the history of catastrophic failures in SCE transmission substations (three in about twenty years).

Question 26: *What was the date of SCE's 2020 peak load? Was this related to any of the 2020 heat storms? If so, why does SCE adjust load data for heat storms if the peak load already occurs during a heat storm?*

Response to Question 26:

The peak day in 2020 for the SCE System was on August 19, during a heat storm period that much of California experienced. SCE notes, however, that its service territory covers 50,000 square miles of varying terrains and microclimates, so it is not uncommon that individual radially-served electrical systems (e.g., Valley South System) may peak on different days than the overall system peak. If a radially-served electrical system peaked on a date that was not coincident with the overall SCE System, then its peak load would be understated if the date of the SCE System peak was used for planning activities.

Weather normalization of peak demand is integral to ensure that year-over-year loading values are not overstated or understated based on temperature variability. A common starting point (i.e., the expected electrical demand at the average annual peak temperature) for year zero (i.e., the most recent historical year) of each annually produced 10-year forecast must be temperature normalized (to a normal weather year) to ensure a reasonable year-over-year comparison of loading can be reviewed. From this commonly derived starting point, future load growth can be projected to develop a 10-year forecast of normal-weather peak loading values as well as expected 1-in-5 year heat storm values.

Below are two examples of why this a critical practice. For both, assume that for a given 10-year period, load growth is forecast to increase at 10 MW per year and recognize that SCE's criteria require planning for 1-in-5 year heat storm. During an unusually hot year, if the peak demand occurred during a *1-in-10* year heat storm period, and if the recorded load value was not temperature adjusted to normal weather, the forecast load growth would then be applied to recorded value. This would result in all future forecast load values being based on a *1-in-10* year heat storm. This would greatly (and inaccurately) *overstate* the loading in the system and any resulting system needs (over that which would result from planning to a *1-in-5* year heat storm). Conversely, should there be an unusually cooler year, the recorded peak demand would then be used as the starting point for the 10-year forecast and future values would be based on a cooler than normal year. This would greatly (and inaccurately) *understate* the loading in the system and any mask any resulting electrical system needs (when planning to a 1-in-5 year heat storm).