Alberhill System Project

ENERGY DIVISION STAFF REPORT

September 15, 2023

Final

The purpose of this Energy Division Staff Report is to detail the review and analyses the California Public Utilities Commission Energy Division has conducted to date related to Southern California Edison's supplemental information filed in response to CPUC Decision 18-08-026.

California Public
Utilities Commission

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Acronyms & Abbreviations

AMI	Advanced metering infrastructure
ASR	Alternative Screening Report
BCA	benefit-cost analysis
BESS	battery energy storage systems
BTM	behind-the-meter
C&I	commercial and industrial
CBESS	centralized battery energy storage system(s)
CEQA	California Environmental Quality Act
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DER	distributed energy resources
Draft Staff Report	Alberhill System Project Draft Staff Report
EENS	Expected Energy Not Served
EIR	Environmental Impact Report
Kevala	Kevala, Inc.
kV	kilovolt
LAR	Load at Risk
LCCA	life cycle cost analysis
LOLE	Loss of Load Expectation
MW	megawatt
MWh	megawatt hours
NERC	North American Electric Reliability Corporation
O&M	operations and maintenance
PEA	Proponent's Environmental Assessment
PG&E	Pacific Gas and Electric

Proposed Alberhill Project	Alberhill System Project
PSLF	positive sequence load flow
PV	photovoltaic
PVRR	Present Value Revenue Requirement
ROW	right-of-way
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SPS	special protection scheme
STATCOM	STATic synchronous COMpensator
VOLL	value of loss load
VOS	value of service
WECC	Western Electricity Coordinating Council
WSP	WSP USA Inc.

Executive Summary

California Public Utilities Commission Energy Division Conclusion

The California Public Utilities Commission (CPUC) Energy Division Staff (Energy Division) conducted a series of engineering and economic analyses on Southern California Edison (SCE)-provided data responses and materials. The initial analyses indicated the potential that installation of two smaller-scaled system improvements, an alternative that uses distributed battery energy storage systems (BESS) and a fewer number of tie-lines, might provide a reliable short-term energy solution and be more cost-effective. After considering the additional supplemental analysis performed through a series of technical forums with SCE to evaluate the Valley South to Valley North with Centralized BESS (both with and without a static synchronous compensator [STATCOM]), the Energy Division has determined that the potential alternative does not adequately address the effect on system performance of a high impact, low probability contingency event such as a total loss of the Valley Substation.

Data since the Draft Energy Division Staff Report

The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with SCE in the spring and summer of 2022. The main findings, decisions, and actions in 2022 are highlighted and then described in more detail in the sections below.

Overall, while some of SCE's analyses focused on metrics that incorporate data lacking consensus (i.e., the probability weighting for Expected Energy Not Served [EENS]), many of the SCE supplemental analysis conclusions remain qualitatively sound. Significantly, the Energy Division finds that though unlikely to occur, the high-impact total loss of the Valley Substation contingency considered by SCE in its planning criteria is compelling when weighing the resiliency needs for the proposed Alberhill System Project. Determining the probability of such a high impact but unlikely event to monetize EENS is a challenging endeavor because there is little SCE and industry operational data. Commission Decision D.18-08-026 did not prescribe the method of compliance, and Commission permitting processes typically use least-cost best-fit analysis, not cost-benefit analyses for Certificate of Public Convenience and Necessity (CPCN) projects.

Energy Division has evaded the challenge by exploring the Load At Risk (LAR) of normal conditions and contingency events separately. Energy Division elected to compare the LAR predicted for project alternatives under normal conditions with all facilities in service, likely contingencies, and unlikely contingencies. SCE has convincingly shown that many of the reliability and resiliency challenges potentially faced by the Valley South System may not be fully addressed by addition of BESS and limited tie-lines to the Valley North System, particularly when evaluating mitigations for high-impact contingency events.

However, by instructing SCE to analyze the 13 project alternatives in comparison to basic planning criteria for normal conditions with all facilities in service and likely contingency conditions upon single loss of transformer, Energy Division learned during the technical forums and from data request responses that the five lowest cost alternatives based on SCE Present Value Revenue Requirement (PVRR) costs, and at least two of the substation project alternatives, do not meet basic planning criteria. The Menifee Alternative does not meet basic planning criteria under loss of single transformer (N-1) in 2031 because Menifee experiences LAR. The Mira Loma Alternative does not meet basic planning criteria for normal conditions with all facilities in service (N-0) nor likely contingency conditions for loss of single transformer (N-1) for 2031.[1]

Consequently, at this time, Energy Division does not conclude that two smaller-scaled systems or a different project alternative involving distributed battery energy storage would provide a reliable, short-term energy solution that is more cost-effective than other project alternatives, saving millions of dollars in upfront costs. The Energy Division Staff concludes that the additional supplemental analysis performed through the technical forums to evaluate Valley South to Valley North with Centralized BESS with and without STATCOM accomplished the expected analysis of the potential alternative suggested by Kevala that uses distributed BESS and a fewer number of tie-lines. The analysis did not support the hypothesis that a different project alternative would provide a short-term energy solution that would save millions of dollars in upfront costs, which Energy Division Staff posited in its draft staff report.

Purpose

As directed in the September 30, 2020, Assigned Commissioner's Ruling Amending Scoping Memo, the Energy Division, with support from WSP USA Inc., formerly Ecology and Environment, Inc. (WSP), and Kevala, undertook a review of SCE's amended Proponent's Environmental Assessment (PEA) and other relevant matters pursuant to the California Environmental Quality Act as the procedural next step in the proceeding. The Energy Division analyzed data provided by SCE in the supplemental information filed in the amended application and PEA, subsequent revisions, and in response to data requests made in 2020 and 2021. As part of the Energy Division assessment process, a series of engineering and economic analyses was conducted on SCE-provided data responses and materials.

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Each of the parties to the proceeding, including the applicant, were invited to give a presentation at the workshop on their review of the Draft Energy Division Staff Report and the alternatives and justifications in SCE's modified application at the workshop. Following the workshop, the CPUC invited the parties to the proceeding, including the applicant, to submit written comments by January 27, 2022.

[1] SCE Response to Energy Division Data Request No. 11, question DG-MISC-80.

Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with SCE in the spring and summer 2022 to gain additional understanding and potential alignment around several topics. The CPUC also issued a series of data requests to support and document the technical forum findings.

The 2022 technical forums also explored additional context regarding SCE's operation of the radial subtransmission Valley South System. As stated in SCE's Comments to the Draft Energy Division Staff Report for the proposed Alberhill Project, the Valley Substation is the sole source of 115 kV power for both the Valley South and Valley North Systems. The radial Valley South System is isolated, both physically and electrically, and does not have system tie-lines to serve as electrical connections to other SCE systems. SCE explained the importance of having system tie-lines to provide the ability to transfer load between adjacent systems bidirectionally. System tie-lines would enable system operators to use the available capacity of an adjacent system to provide load relief in the event of an unplanned outage of a subtransmission line or a subtransmission transformer. The SCE Planning Study and the service reliability performance of the proposed Alberhill Project, provide additional information about the Valley South System (SCE 2021, Items C and F).

Engineering Analyses

Since the Draft Staff Report, Kevala has learned that the 115kV portion of SCE's system included in the proposed Alberhill Project is not required to be planned to meet North American Electric Reliability Corporation (NERC) reliability standards. As discussed further in Section 2.3, while SCE's planning criteria align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which are analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios," (SCE 2023a, 6), including Flex-1, Flex-2-1, and Flex-2-2. It is reasonable to expect SCE to craft specific system performance metrics that are rooted in transmission system planning event analysis.

In the absence of the CPUC ordering a specific standardized evaluation approach, the Energy Division finds it reasonable for SCE to define performance metrics and scenarios to use in evaluating unlikely contingencies that may result in loss of load. This form of reliability/resilience assessment is nascent in the electric utility industry and Energy Division has seen examples of this form of assessment under development by Department of Energy National Laboratories, other utilities examining investment plans for extreme events, in white papers or journal articles from the Institute of Electrical and Electronics Engineers, and others. The Federal Energy Regulatory Commission, NERC, and Western Electricity Coordinating Council (WECC) have opened proceedings or opined in annual reports on the need for alternative planning based on high-impact, low-frequency events.

Although SCE is not mandated to follow NERC standards, SCE has provided an evaluation method that is rooted in transmission system planning event analysis. In NERC regulation, the regulatory agency expects the transmission operator to exercise its engineering judgment and operating experience to choose relevant events to study and to provide rationale justifying the events studied. NERC does not specify the duration of study periods in its regulation. Similarly, the CPUC expects SCE to use its engineering judgment and operating experience to evaluate unlikely contingencies at the subtransmission/distribution level even if CPUC has not dictated a standardized evaluation approach by regulation, rule, or order.

Energy Division finds that it is reasonable for SCE to use these evaluation methods involving novel reliability/resilience metrics and modeling as an additional screening method for resilience because high-impact, low-frequency events impacts to this subtransmission system could severely affect a significant number of customers.

SCE presented further background on how and why they chose certain performance metrics. They considered LAR, EENS, and metrics commonly used in resource adequacy studies, such as loss of load expectation. SCE wanted a metric that could compare cost effectiveness of solutions and that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration. These criteria led to SCE's selected use of LAR and EENS.

In response to an Energy Division recommendation in the Draft Staff Report, SCE provided additional analysis on the feasibility of developing distributed BESS in the Valley South system and the capability of the recommended tie-lines to transfer load. SCE expressed concerns that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a centralized battery energy storage system (CBESS) was a more realistic consideration. SCE prepared and presented additional analysis that looked at an alternative (with needed system sizing) that included CBESS paired with a STATCOM.

The Energy Division and its consultants extensively discussed the probabilities SCE used for an extreme event that results in loss of service at the Valley Substation, which was incorporated in calculations of the EENS metric. Due to lack of industry standard and lack of consensus on the appropriate probabilities for such contingency events, the additional analysis of Valley South to Valley North with a CBESS and a STATCOM were shown with LAR values calculated but not EENS values to avoid use of probabilities in comparative metrics.

As shown by the calculated LAR values, BESS cannot defer the proposed Alberhill Project's need alone to meet the Flex-2-1 planning case because the Valley System is a radially operated subtransmission system that would need to be operated as an islanded microgrid (i.e., a stand-alone electrical system disconnected from the main grid). The facilities and approach for operating Valley System like an islanded microgrid has not been tested nor operated at scale for a system this size. The Valley System would remain vulnerable to loss of its source of supply under a high impact, low probability event—which is undesirable for a high-density urban load area subject to extreme heat events.

Economic Analysis

WSP conducted a series of economic analyses finding that SCE's proposed Alberhill Project's Benefit-Cost Analysis (BCA) of alternatives does not display an equitable comparison of alternatives or calculation of each benefit-cost ratio since the benefits and costs for each alternative were not correctly timed in terms of when they would realistically occur. SCE's BCA accrues project benefits before the proposed Alberhill Project has been constructed or placed in service (instead, it is based on a project need date). It is also unclear how operation and maintenance costs were incorporated into the timeline or analysis, as they are not linked with the analysis, and the calculation of costs is not traceable.

Through technical forums with CPUC and SCE in May 2022, the Energy Division concluded that SCE conducted a life cycle cost analysis (LCCA) while preparing their economic analysis, instead of a BCA. An LCCA is a subset of a BCA. In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Although the SCE economic analysis appears to adhere to the criteria for comparing alternatives within an LCCA (determining the most cost-effective option among alternatives with identical in-service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA (Kneifel and Webb 2020; OMB n.d.; USDOT 2002, 2012, 2022).

WSP, on behalf of the Energy Division, conducted economic analysis to re-time the benefits to align with BCA methodologies. Based on the retiming of benefits beginning to accrue on the appropriate project in-service date, the most purely economically attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by San Diego Gas and Electric (seventh place) and Mira Loma (eighth place). Importantly, these rankings necessarily retain the probability weighting SCE used in its original EENS calculations for the contingency events and is agnostic as to whether the alternatives analyzed may be potentially infeasible or undesirable for noneconomic reasons, such as those discussed in the engineering analyses.

Project History

SCE filed an application (A.09-09-022) for a CPCN with the CPUC on September 30, 2009, to construct the proposed Alberhill Project. On August 31, 2018, CPUC Decision 18-08-026 granted SCE's petition to modify the permit to construct the Valley–Ivyglen 115-kV Subtransmission Line Project, deconsolidated Application 09-09-022 from Applications 07-01-031 and 07-04-028, and held Application 09-09-022 open to further review SCE's application for a CPCN for the proposed Alberhill Project. Ordering Paragraph 4 of Decision 18-08-026 directed SCE to supplement the record with additional analyses of alternatives that may satisfy the needs of the Valley South System. In response, SCE filed an amendment to its application on May 11, 2020, and included a corresponding amended PEA (Application A.09-09-022, second amendment).

1 Introduction

1.1 Project Background

1.1.1 Project History

Southern California Edison (SCE) filed an application (A.09-09-022) for a Certificate of Public Convenience and Necessity (CPCN) with the California Public Utilities Commission (CPUC) on September 30, 2009, to construct the Alberhill System Project (proposed Alberhill Project). SCE filed an amendment to the application on March 15, 2010 (Application A.09-09-022, amended), and filed amended sections of the Proponent's Environmental Assessment (PEA) on April 11, 2011. The proposed Alberhill Project would include a new 500/115-kilovolt (kV) substation (Alberhill Substation), new 500-kV transmission lines, new and modified 115-kV subtransmission lines, and telecommunications system installations. Appendix A provides a full project description of the proposed Alberhill Project, including project location and components.

The CPUC determined that it would be in the public's best interest to consolidate the California Environmental Quality Act (CEQA) analyses for the SCE Valley–Ivyglen Subtransmission Project Petition for Modification application (A. 07-01-031; proposed Valley–Ivyglen Project) and the proposed Alberhill Project CPCN application into a single CEQA document. As the lead agency, the CPUC prepared one Draft and one Final Environmental Impact Report (EIR) to evaluate the environmental impacts of both projects in accordance with the criteria, standards, and procedures of CEQA (Public Resources Code Sections 21000 et seq. and California Code of Regulations Title 14, Sections 15000 et seq.). The Final EIR, including responses to comments, was released in April 2017.

On August 31, 2018, CPUC Decision 18-08-026 granted SCE's petition to modify the permit to construct the Valley–Ivyglen 115-kV Subtransmission Line Project, deconsolidated Application 09-09-022 from Applications 07-01-031 and 07-04-028, and held Application 09-09-022 open to further review SCE's application for a CPCN for the proposed Alberhill Project. Ordering Paragraph 4 of Decision 18-08-026 directed SCE to supplement the record with additional analyses of alternatives that may satisfy the needs of the Valley South System. Table 1 details the supplemental analyses identified in Decision 18-08-026. On April 10, 2020, the CPUC issued an email ruling directing SCE to file: (1) a compliance filing for its additional analyses of alternatives that may satisfy the needs of the Valley South System to supplement the record Application (A.) 09-09-022, pursuant to D.18-08-026; and (2) an amendment to its application consistent with its additional analyses of alternatives that may satisfy the needs of the Valley South System, including a corresponding amended PEA reflecting the additional analyses as appropriate. In response, SCE filed an amendment to its application on May 11, 2020, including a corresponding amended PEA (Application A.09-09-022, second amendment).

Table 1: SCE Proposed Alberhill Project Supplemental Analysis	
Item	Supplemental Information Requested
A	Load forecast including industry accepted methods for estimating load growth and incorporating load reduction programs due to energy efficiency, demand response, and behind-the-meter generation.
B	Identification of all subtransmission planning areas in the SCE system with similar reliability issues.
C	A planning study that supports the project need and includes applicable planning criteria and reliability standards.
D	An analysis of several years of electric reliability performance for the Valley systems to demonstrate existing customer service level.
E	An analysis of outages over the past five years by root cause for the Valley South Systems in comparison to SCE system average and to other subtransmission radial systems.
F	The forecasted impact of the proposed Alberhill Project on service reliability performance, using electric service reliability metrics where applicable.
G	Cost/benefit analysis of several alternatives for enhancing reliability and providing additional capacity, including evaluation of energy storage, distributed energy resources, demand response, or smart grid solutions.
H	Identify capital investments or operational changes effectuated to address reliability issues in the absence of construction of the Alberhill Substation and the associated costs for such actions.
I	Detailed justification of the recommended solution as the best solution, including an explanation of how the proposed Alberhill Project ranks in the SCE capital investment portfolio of infrastructure upgrades.

On September 30, 2020, the assigned CPUC commissioner to the proposed Alberhill Project issued a ruling amending the scoping memo after considering SCE's amended application and PEA, amended protests, and the discussion at the second prehearing conference held on August 18, 2020. In the September 2020 ruling, the assigned CPUC commissioner confirmed the scope of issues identified in the June 19, 2017, scoping memo remained unchanged and determined the CPUC Energy Division (Energy Division) would undertake a review of SCE's amended PEA and any other relevant matters pursuant to CEQA as the procedural next step in the proceeding.

After SCE filed an amendment to its application on May 11, 2020, SCE discovered certain errors that affected the cost-benefit analysis. In an amended motion filed on February 1, 2021 (Application A.09-09-022, Amended Motion), SCE provided updated analyses and corrected information previously submitted into the record on May 11, 2020. Corrected documents included the Planning Study, Forecasted Impact of the proposed Alberhill Project, Cost-Benefit Analysis, and Detailed Justification of the Recommended Solution as the Best Solution (see Table 1 for descriptions of the required supplemental information) (SCE 2021, Items C, F, G, and I). SCE filed a second amended motion (Application A.09-09-022, Second Amended Motion) on June 22, 2021, to correct clerical errors in spreadsheet tabular data in SCE's February 2021 Amended Motion. Corrected documents included the Planning Study, Forecasted Impact of proposed Alberhill Project, and Cost-Benefit Analysis (SCE 2021, Items C, F, and G).

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Each of the parties to the proceeding, including the applicant, were invited to give a presentation at the workshop on their review of the Draft Energy Division Staff Report and the alternatives and justifications in SCE's modified application at the workshop. Following the workshop, the CPUC invited the parties to the proceeding, including the applicant, to submit written comments by January 27, 2022.

Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including:

- The SCE Benefit-Cost Analysis methodology and the metrics and treatment of batteries in the assessment of performance;
- SCE's additional analysis of Valley South to Valley North Plus Centralized Battery Energy Storage project alternatives including BESS sizing;
- The SCE Subtransmission Planning Criteria and Guidelines and the identification of project alternatives that satisfy the basic planning criteria (Capacity N-0, N-1 subtransmission lines, and N-1 transformer outage conditions); and
- The resilience need for the proposed Alberhill Project.

The CPUC also issued a series of data requests (CPUC Supplemental Data Requests 11-17) to support and document the technical forum findings.

The 2022 technical forums also explored additional context regarding SCE's operation of the radial subtransmission Valley South System. As stated in SCE's Comments to the Draft Energy Division Staff

Report for the proposed Alberhill Project, the Valley Substation is the sole source of 115 kV power for both the Valley South and Valley North Systems. The radial Valley South System is isolated, both physically and electrically, and does not have system tie-lines to serve as electrical connections to other SCE systems. SCE explained the importance of having system tie-lines to provide the ability to transfer load between adjacent systems bidirectionally. System tie-lines would enable system operators to use the available capacity of an adjacent system to provide load relief in the event of an unplanned outage of a subtransmission line or a subtransmission transformer. The SCE Planning Study and the service reliability performance of the proposed Alberhill Project, provide additional information about the Valley South System (SCE 2021, Items C and F).

Key milestones of the proposed Alberhill Project process are summarized in Table 2.

Table 2: Proposed Alberhill Project Milestones

Milestone	Date
Application A.09-09-022 Submitted to CPUC	September 30, 2009
Final EIR	April 2017
Oral Argument	May 2018
Decision 18-08-026 Issued - Final EIR Certified. Directed SCE to Supplement the Record with Additional Analyses of Alternatives	August 31, 2018
SCE Filed Amended Application and PEA	May 11, 2020
Receipt of Protests	June 2020
Alberhill CPCN Prehearing Conference	August 18, 2020
Assigned Commissioner's Ruling Amending Scoping Memo	September 30, 2020
SCE Filed Amended Motion to Supplement the Record	February 1, 2021
SCE Filed Second Amended Motion to Supplement the Record	June 22, 2021
Draft Energy Division Staff Report Published	December 3, 2021
CPUC Virtual Workshop on Draft Energy Division Staff Report Findings	January 20, 2022

Receipt of Comments on the Draft Energy Division Staff Report from SCE and Parties to the Proceeding	January 27, 2022
CPUC/SCE Technical Forums	Spring/summer 2022

Key:

CPCN = Certificate of Public Convenience and Necessity

CPUC = California Public Utilities Commission

EIR = Environmental Impact Report

PEA = Proponent's Environmental Assessment

SCE = Southern California Edison

1.2 Project Description

As described in the 2017 Final EIR, the proposed Alberhill Project would include construction of the Alberhill Substation, which would be expandable to a maximum of 1,680 megavolt amperes depending on future need. In addition to construction of a new Alberhill Substation, the proposed Alberhill Project would include the following (see Appendix A for a full project description of the proposed Alberhill Project):

- Construction of two new 500-kV transmission lines (approximately 3.3 miles combined) within a new right-of-way (ROW) to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line;
- Double circuit of approximately 11.75 miles of existing single-circuit 115-kV subtransmission lines with structure replacement primarily in the existing ROW;
- Construction of about 3 miles of single-circuit 115-kV subtransmission lines with distribution lines underbuilt on the subtransmission line structures and the removal of about 3 miles of electrical distribution lines within the existing ROW;
- Installation of a second 115-kV circuit on approximately 6.5 miles of single-circuit 115-kV subtransmission lines (the single-circuit line is to be constructed as part of the proposed Valley–Ivyglen Project);
- Installation of fiber-optic lines overhead (9 miles) on sections of the new or modified subtransmission lines and underground (1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12-kV substations;
- Construction of an approximately 120-foot microwave antenna tower at the proposed Alberhill Substation site; installation of microwave telecommunications dish antennae at the proposed

Alberhill Substation, the existing Santiago Peak Communications Site, and Serrano Substation; and other telecommunications equipment installations at existing and proposed substations; and

- Transfer of five of the 14 Valley South 115-kV System Substations to the proposed Alberhill Project: the Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb 115/12-kV Substations.

1.3 Alternatives Identified in SCE's Supplemental Analysis

Table 3 describes each of the alternatives identified in SCE's supplemental analyses, including the SCE 2020 Planning Study and Second Amendment to the PEA and subsequent revisions to the Planning Study in the February 2021 Amended Motion and June 2021 Second Amended Motion (SCE 2021, Item C). As described in the SCE Planning Study, SCE developed the project alternatives based on inputs from the CPUC in Decision (D.) 18-08-026, previous assessments in the proposed Alberhill Project Final EIR, and public and stakeholder engagement. The project alternatives include the following categories:

- Minimal Investment Alternatives: Alternatives in this category utilize existing equipment and make modest capital investments of <$25 million.
- Conventional Alternatives: Alternatives in this category include substation and wires-based solutions with tie-lines.
- Non-Wires Alternatives: Alternatives in this category include battery energy storage systems (BESS) and the consideration of demand side management and other distributed energy resources (DERs).
- Hybrid Alternatives: Alternatives in this category include a combination of conventional alternatives and non-wires alternatives. The conventional solutions were chosen based on their ability to meet the 10-year load forecast and then paired with BESS to satisfy incremental capacity needs that develop over time.

Table 3: Alternatives Identified in SCE's Supplemental Analysis	
Alternative	Description
Minimal Investment Alternatives	
Utilizing spare transformer for the Valley South System	SCE has temporarily placed a spare 500/115-kV transformer in service at the Valley Substation to provide an additional level of service to the Valley South System under peak loading conditions or as needed. This alternative would continue the current practice of the mitigation plan.[a] This alternative would also require installation of a new spare 500/115-kV transformer (for a total of six transformers within Valley Substation).
Operating existing Valley South System transformers above normal ratings	SCE's Subtransmission Planning Criteria and Guidelines allow operation of A-bank transformers above nameplate for periods of limited duration. This alternative would utilize the Valley South System transformers above normal ratings (i.e., intentionally operate them above the manufacturer nameplate ratings) to serve load in the Valley South System under peak loading conditions.
Loading-Shedding Relays	This alternative would utilize load shedding to maintain system reliability during stressed system conditions that result from peak load conditions that may exceed the ratings of the Valley South System transformers.
Conventional Alternatives	
SDG&E	This alternative includes a new 230/115-kV system looped to the San Diego Gas and Electric (SDG&E) Talega-Escondido 230-kV transmission line. Project components include construction of a new 230/115-kV substation, approximately 9.2 miles of new 230-kV transmission and 115-kV subtransmission lines, and the modification of approximately 7.8 miles of existing 115-kV subtransmission line (17 miles total).
SCE Orange County	This alternative includes a new 220/115-kV system looped to existing San Onofre Nuclear Generating Station-Viejo 220-kV transmission line. Project components include construction

	of a new 220/115-kV substation and approximately 30 miles of new 220-kV transmission and 115-kV subtransmission lines.
Menifee	This alternative includes a new 115-kV system looped to SCE's existing Serrano–Valley 500-kV transmission line. Project components include construction of a new 500/115-kV substation, approximately 5.5 miles of new 500-kV transmission and 115-kV subtransmission lines, and the modification of approximately 7.7 miles of existing 115-kV subtransmission line (13.2 miles total).
Mira Loma	This alternative includes a new 220/115-kV system looped to existing 220-kV transmission lines serving the Mira Loma Substation. Project components include construction of a new 220/115-kV substation and approximately 22.2 miles of new 220-kV transmission and 115-kV subtransmission lines.
Valley South to Valley North	This alternative includes a new 115-kV line and transfers Newcomb and Sun City Substations to the Valley North System. Project components include construction of approximately 5.9 miles of new 115-kV subtransmission line and the modification of approximately 7.7 miles of existing 115-kV subtransmission line (13.6 miles total).
Valley South to Valley North to Vista	This alternative includes a new 115-kV line, transfer Newcomb and Sun City Substations to the Valley North System, and transfer Moreno Substation to Vista 115-kV System. Project components include the construction of approximately 15.9 miles of new 115-kV subtransmission lines and modification of approximately 7.8 miles of existing 115-kV subtransmission line (23.7 miles total).
Non-Wires Alternatives	
Centralized BESS in Valley South	This alternative would reduce peak demand in the Valley South 500/115-kV System via construction of two new 115/12-kV substations with BESS near Pechanga and Auld Substations, which would loop in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.
Hybrid Alternatives	

Valley South to Valley North and Distributed BESS in Valley South	This alternative includes a combination of the Valley South to Valley North Alternative as described under *Conventional Alternatives* and construction of new energy storage components (distributed BESS) within the existing fence lines at three existing SCE 115-kV substations.
SDG&E and Centralized BESS in Valley South	This alternative includes a combination of the SDG&E alternative as described under *Conventional Alternatives* and construction of one new 115/12-kV substation with BESS near Auld Substation with a loop-in of the Auld-Moraga #1 line.
Mira Loma and Centralized BESS in Valley South	This alternative includes a combination of the Mira Loma alternative as described under *Conventional Alternatives* and construction of two new 115/12-kV substations with BESS near Pechanga and Auld Substations, which loop in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.
Valley South to Valley North and Centralized BESS in Valley South and Valley North	This alternative includes a combination of the Valley South to Valley North Alternative as described under *Conventional Alternatives* and construction of a new 115/12-kV substation with BESS that would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line, and a second BESS installed at Alessandro Substation, to offset a portion of the load that is transferred from the Valley South to Valley North System.
Valley South to Valley North to Vista and Centralized BESS in Valley South	This alternative includes a combination of the Valley South to Valley North to Vista Alternative as described under *Conventional Alternatives* and construction of a new 115/12-kV substation with BESS installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line.

Note:

(a) A standby spare 500/115-kV transformer was installed at the Valley Substation in 2011; the spare transformer provides backup transformer capacity in the event of transformer failure at Valley Substation. The spare transformer was installed to comply with SCE's internal *Transmission Planning Criteria and Guidelines*. These guidelines state that all 500/115-kV substations have an on-site three-phase spare transformer available for use in the event of transformer failure. If electrical demand exceeds the operating limits of the existing equipment of the Valley South 115-kV System before the proposed Alberhill Project is operational, the spare transformer will be temporarily put into service as a contingency plan (Valley–Ivyglen 115-kV Subtransmission Line and Alberhill System Projects FEIR 2017).

1.4 SCE's Proposed Alberhill Project Supplemental Analysis Findings

In the Detailed Justification of the Recommended Solution, SCE recommends the proposed Alberhill Project as the best solution to meet the needs of the Valley South System (SCE 2021, Item I). SCE states that the supplemental information filed in the amended application and PEA and subsequent revisions show that the proposed Alberhill Project is superior to all other alternatives in meeting the Project Objectives detailed in SCE's proposed Alberhill Project application. This conclusion is based on:

1. The proposed Alberhill Project's superior performance in meeting identified capacity, reliability, and resiliency needs over both near-term and long-term horizons, as measured by a set of objective system performance metrics;
2. The cost effectiveness of the proposed Alberhill Project as demonstrated in a cost-benefit analysis;
3. Consideration of option value and risk by evaluating the sensitivity of results to uncertainty and volatility in future load growth and alternative DER development and cost scenarios; and
4. Challenges with implementation of alternatives other than the proposed Alberhill Project to meet imminent near-term needs.

Overall, SCE contends that the proposed Alberhill Project is a cost-effective, robust solution that limits the risk of service disruptions to SCE customers during normal and abnormal electrical system events or conditions and minimizes risk of potential delays in implementing an adequate system solution (SCE 2021, Item I, Exhibit I-1).

1.5 Purpose of the Energy Division Staff Report

As directed in the September 2020 Assigned Commissioner's Ruling Amending Scoping Memo, the Energy Division, with support from WSP USA Inc., formerly Ecology and Environment, Inc. (WSP), and Kevala, Inc. (Kevala), undertook a review of SCE's amended PEA and any other relevant matters pursuant to CEQA as the procedural next step in the proceeding. The Energy Division analyzed data provided by SCE in the supplemental information filed in the amended application and PEA, subsequent revisions, and in response to data requests made in 2020 and 2021. The purpose of this Energy Division Staff Report is to provide an independent evaluation of the SCE supplemental analysis and materials provided to the CPUC as part of their response to Decision (D.) 18-08-026. This report details the review and analyses the Energy Division has conducted to date and staff recommendations derived from that review. Table 4 summarizes the analyses conducted and presented in this Energy Division Staff Report. A summary of each report's methodologies and findings are included in Sections 2 through 7 of this Energy Division Staff Report, and the reports in their entirety are included in the appendices for reference.

Table 4: Energy Division Staff Report Analyses		
Energy Division Staff Report Section	Report	Description
2	Preliminary Results: Tie-Line Power Flow Analysis	Analyzes the necessity of the Valley South tie-lines proposed by SCE.
3	Evaluation of SCE's Load Forecast Methodologies and Performance Metrics	Evaluates SCE's methodology and performance metrics used to evaluate the proposed Alberhill Project and its alternatives.
4	Behind-the-Meter Adoption Propensity Analysis for the Valley South System	Applies technological and economic parameters to SCE data to assess the potential likely adopters of behind-the-meter resources.
5	Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System	Expands on findings from the Behind-the-Meter Adoption Propensity Analysis to evaluate impact of distributed energy resources adoption on the load forecast.
6	Review of SCE's Electrical Engineering Analysis for the Alberhill System Project	Electrical engineering analysis on system reliability and expansion on the tie-lines assessment.
7	Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project	Results of an integrated time-series benefit-cost analysis for the proposed Alberhill Project.

A separate proposed Alberhill Project Supplement to the Alternative Screening Report (ASR) is being developed by the Energy Division. Pursuant to CEQA, the Supplement to the ASR supplements the 2017 revision of the ASR by evaluating the alternatives identified by SCE in the supplemental information filed in the amended application and PEA and subsequent revisions. The development of the Supplement to the ASR is ongoing and will be released separately to this Energy Division Staff Report.

2 Preliminary Results: Tie-Line Power Flow Analysis

2.1 Methods of Investigation

As part of the proposed Alberhill Project, SCE stated that tie-lines are a necessary requirement for the project (see Figure 1). Kevala's tie-line analysis considered whether the Valley South tie-lines proposed by SCE as part of the proposed Alberhill Project were necessary to achieve system capacity, reliability, and resiliency in the Valley South service area.

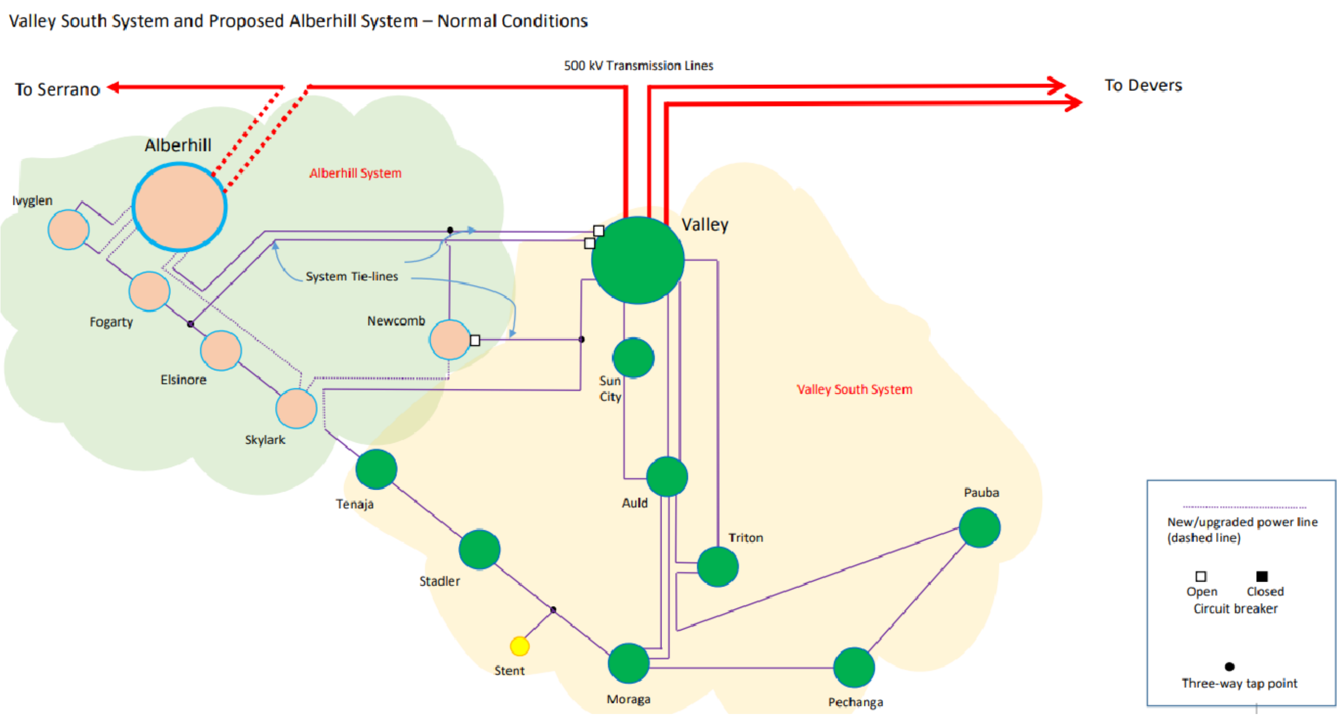

Figure 1: Proposed Alberhill Project Tie-Lines (Proposed Alberhill Project Energy Division Briefing Deck 2018)

To assess how the tie-lines that are proposed as part of the proposed Alberhill Project perform with respect to capacity, reliability, and resiliency, several base cases representing scenarios were studied. These scenario cases represented alternatives that include tie-lines in the Valley South System, distributed battery energy resources, and centralized BESS. This approach enabled comparison of the base case, which represents the Valley South System as it exists today without any new projects or tie-lines, with the following scenarios:

- System performance with the installation of additional tie-lines.
- System performance with the installation of battery energy storage.
- System performance with combination installation of tie-lines and energy storage.

Power flow studies were conducted for each of these scenario cases and the results were compared under normal conditions and contingency conditions based on North American Electric Corporation (NERC) reliability standards.[2]

Using the General Electric Positive Sequence Load Flow software and base cases, power flow studies were conducted under normal and contingency conditions. Single contingencies[3] and double contingencies,[4] where the circuits were on the same tower or in the same ROW, were used to study contingency conditions. The contingencies were obtained from the *Quanta Technical Cost Benefit Analysis of Alternatives* report. The results were assessed based on NERC reliability standards and SCE planning criteria. Power flow results under each of the base cases were compared to assess what impacts the tie-lines have on reliability and resiliency at Valley South Substation. Power flow results obtained for the Valley South (Base) scenario were used as a basis for comparing impacts.

2.2 Results of Report

The findings of this assessment were as follows:

- Tie-lines that transfer substation service from the Valley South to Valley North are effective in mitigating the overload on the Valley South transformers and meet reliability and resiliency requirements. SCE has concluded that the tie-lines in the Valley South to Valley North Alternative are ineffective under double contingencies or a catastrophic event that results in a loss of both transformers in the Valley South System. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted, and the power flow results indicated that this alternative performed effectively.

[2] While SCE's Valley 115-kV system is part of SCE's distribution network and not under the California Independent System Operator (CAISO) control, its reliability performance must still be consistent with general accepted utility practices which are based on NERC Reliability standards. Parts of the NERC reliability Standards are adopted in SCE's Subtransmission Planning Criteria which require that all facilities operate within their continuous ratings under normal system conditions and under emergency ratings under contingency conditions.

[3] Single Contingency (N-1): considers the loss of a single element (a generator or transmission component) in a power system.

[4] Double Contingency (N-1-1): considers the sequential loss of a single element (a generator or transmission component) in a power system, followed by system adjustments, then followed by another loss of an element in a power system.

- It appears that SCE applied a mitigation strategy or special protection scheme (SPS)[5] to the proposed Alberhill Project to demonstrate the effectiveness of the tie-lines included as part of the proposed Alberhill Project. Use of this mitigation strategy alleviates the overload on the Auld-Moraga 115-kV #1 line, which experiences an overload under all configurations, including the current configuration, proposed Alberhill Project, and the alternatives.
- Transferring service for two substations (Newcomb and Sun City) via 115-kV tie-lines to the Valley North System and installing 50 megawatts (MW) of distributed BESS in the Valley South System could also mitigate this overload as effectively as the proposed Alberhill Project while meeting capacity, reliability, and resiliency requirements. This alternative satisfies part of the CPUC's objective to enable electrical service redundancy between the Valley South and a new 115-kV system. The difference is that these tie-lines enable electricity service from the existing Valley North System or from the Valley South System and would achieve the same performance.

As discussed above, it is unclear from the record of SCE's analysis whether SCE applied mitigation strategies and to which alternatives. Selectively applying mitigation strategies to certain alternatives without substantiation of the rationale for doing so can create an unequal comparison between alternatives. Understanding, on the record, SCE's basis for applying a mitigation strategy to the proposed Alberhill Project as opposed to some of the alternatives is important to evaluate how each of the alternatives supports the reliability, resiliency, and capacity needs described by SCE.

See Appendix B, Preliminary Results: Tie-Line Power Flow Analysis (Kevala 2021a), for the complete report.

2.3 Expanded Discussion

Section 2.1 and 2.2 provided a summary of Kevala's tie-line power flow analysis in the Alberhill System Project Draft Staff Report of November 2021 (Draft Staff Report). This section expands on information noted in Sections 2.1 and 2.2 to clarify and incorporate additional information from SCE.

Section 2.1 notes that the results of Kevala's tie-line analysis results were assessed based on NERC reliability standards and SCE planning criteria. The radially operated 115-kV subtransmission component of the Valley South System is not part of the bulk electric system subject to California Independent System Operator (CAISO) authority because it is "used in local distribution of electric energy" pursuant to section 215 of the (153 Federal Energy Regulatory Commission ¶ 61,384). Therefore, SCE is not required to comply to NERC reliability standards and (WECC) criteria for operation of the Valley South 115-kV system. SCE is required to adhere to the SCE Subtransmission Planning Criteria and Guidelines (SCE 2015) and fulfill its obligations of Public Utility Code 451.

[5] NERC defines SPS as an automatic protection system designed to detect abnormal or predetermined system conditions and take corrective actions other than or in addition to the isolation of faulted components to maintain system reliability.

SCE Subtransmission Planning Criteria and Guidelines require examination of unlikely contingencies that could result of loss of load. SCE's planning criteria largely align with the NERC reliability standards. The NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structures), local area events and wide-area events (NERC n.d.), which is analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios" (SCE 2023a) including Flex-1, Flex-2-1, and Flex-2-2. The NERC standards expect system operators and planners, such as SCE, to craft specific system performance metrics that are rooted in transmission system planning event analysis, such as those presented by SCE.[6] Their meaning, use, and purpose are covered in detail in SCE presentations and data request responses provided to CPUC staff since their originally-filed reports (NERC n.d.). Kevala's assessment of SCE's system performance metrics is shown in Section 3, and Kevala specifically explained this further in the March 2022 workshop (SCE 2022a, 18). In this workshop, Kevala noted that "because of the heavy weighting of tie-lines by the metrics, the tie-line power flow analysis was conducted based on NERC reliability standards and WECC criteria to understand how much the metrics weight the prioritization of [the Alberhill System Project]and its alternatives." Energy Division's learnings on this topic since the release of the Draft Staff Report are documented in Section 2.4 below.

SCE did not specify in their original Planning Study the way the transfer of load from Valley South to the proposed Alberhill Project would occur in the event of an Auld-Moraga #1 overload. Based on the review of SCE's studies, Kevala considered the ability of the proposed Alberhill Project to reconfigure its system under outage conditions to be an SPS, at that time. To provide an equal basis for comparison between other projects that did not include, what at that time was believed to be, the benefit of an SPS, that transfer was excluded from Kevala's study.

The Kevala system tie-line analysis (Appendix B) evaluated tie-line function for forecasted load in 2025. SCE conducted additional loads at risk evaluations for the forecasted load in 2028 (i.e., the 10-year project horizon) and for the period ending in 2048.

As detailed in Section 2.2, the primary result of the approach of excluding the tie-line transfer is that Valley South to Valley North Alternative with 50 MW of DBESS[7] (SCE Project I) produced very similar results to the proposed Alberhill Project (see Appendix A in SCE 2021, Item G). Kevala concluded that in relation to the proposed Alberhill Project, Project I satisfies the guideline for all facilities in service (N-0) as well as likely contingency (i.e., one subtransmission line out of service [N-1]) and unlikely contingency for two subtransmission lines out of service on common structure (N-2). This conclusion is based on information and assumptions as presented by SCE in its original proposed project and subtransmission power flow data provided to Energy Division by SCE (SCE 2020a, 2020b). Energy Division studied General Electric's

[6] Multiple CPUC proceedings, such as R.19-09-009, are exploring defining appropriate resiliency scenarios and definitions that may apply to distribution planning in the future, however none have been formally established by the CPUC at this time.

[7] For this report, distributed BESS refer to utility-scale BESS sited at multiple locations around a given region as opposed to one larger and centralized utility-scale BESS being sited at one location.

Positive Sequence Load Flow (PSLF) base cases that were modeled on the data Energy Division requested from SCE in CPUC Supplemental Data Request 6, dated September 16, 2020 (SCE 2020c). Following the release of the Draft Staff Report, further discussions on this topic in 2022 resulted in updated conclusions that are described in Section 2.4.

2.4 Subsequent Findings

Following the release of this Draft Staff Report, SCE provided follow-up on key points in the report via written comments and technical forums[8] that provided SCE with the opportunity to clarify certain elements of its original proposed Alberhill Project, as follows:

- SCE has clarified that the portion of the Valley South radial 115-kV subtransmission is not required to meet NERC reliability standards because these facilities are not part of the CAISO controlled bulk electric transmission system. As noted above in Section 2.3, while SCE's planning criteria largely align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which are analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios" including Flex-1, Flex-2-1, and Flex-2-2 (SCE 2023a, 6).
- Since the Draft Staff Report, SCE clarified that it did not explicitly perform N-1 loss of single transformer contingencies in their Planning Study. SCE commented that the N-1 transformer study was integrated within the Flex 2-2 case. Because of this finding that the SCE Planning Study did not explicitly perform these contingencies, Energy Division and SCE agreed to perform the following actions:
    - In Response to CPUC Supplemental Data Request 011, Question DG-MISC-80, SCE provided data on the impact of N-1 transformer outages on each project alternative and further clarified the method for this determination in the January 2023 Follow-up to this data request (SCE 2023b). Kevala reviewed this data request and follow-up and independently verified the data provided and method of calculation. It should be noted that the quantification of Load at Risk (LAR) in this data request followed a different methodology than the Flex Case 2-2, which means that the LAR values produced cannot be directly compared to the Planning Study results.
    - In June 2022, SCE presented a study (documented in SCE 2022b) to CPUC staff and subconsultants that discussed estimated battery sizes for a Valley South to Valley North Alternative centralized BESS configuration that would be sized to address transformer N-1 contingencies. This additional study indicates that a BESS size of 168 MW without static synchronous compensator (STATCOM) or 158 MW with STATCOM was required to

[8] Technical forums (SCE 2022a, 2023a, and 2022b) were held during 2022 and attended by SCE, CPUC, and CPUC subconsultants (including Kevala). The materials presented in these forums are entered into the record via subsequent data requests.

address the transformer N-1 contingencies, which were previously not studied in SCE's planning studies. BESS sizing was performed for the year 2031, as this is the final year of SCE's current 10-year planning horizon (covering the years 2022 to 2031) (SCE 2022b). Kevala found that the PSLF modeling and the associated results demonstrated in SCE's August 30, 2022, presentation were qualitatively reasonable and in alignment with the results previously shared via data requests and prior presentations for each case and variation.

- Section 2.2 noted that the Valley South to Valley North Alternative line and installation of 50 MW of distributed BESS in the Valley South System could mitigate the Auld-Moraga #1 line overload as effectively as the proposed Alberhill Project while meeting capacity, reliability, and resiliency requirements. The Quanta study from June 2022 demonstrates that the required BESS size should be 168 MW without STATCOM or 158 MW with STATCOM, when transformer N-1 contingencies are considered. The necessary BESS sizing is much greater than the 50 MW considered in the Draft Staff Report.
  - Kevala agrees that this BESS (168 MW without STATCOM or 158 MW with STATCOM) alternative solution does not achieve the same performance as the proposed Alberhill Project. For example, the Valley System is islanded and served from a single point of delivery to the bulk power system, a vulnerability which addition of BESS would not alleviate. In a contingency where Valley Substation loses its source of supply, both Valley South and Valley North would lose power. The battery energy storage system would have no way to recharge after it discharges during such a contingency event.
- In the Planning Study, SCE does not specify the way the transfer of load from Valley South to proposed Alberhill Project would occur to remedy an Auld-Moraga #1 overload in the event of a contingency. SCE clarified in the Draft Staff Report comments that this transfer of load would be a manual action, as opposed to an automated scheme (SCE 2022c). Because of this learning that this transfer of load would be a manual action, the following conclusions were determined in 2022:
  - Based on the NERC definition of an SPS (NERC 2013), this transfer of load from Valley South to the proposed Alberhill Project is not an SPS because it is performed manually. Kevala interprets this manual transfer specification for the proposed Alberhill Project as being common practice for SCE when a tie-line transfers load.
  - In the Draft Staff Report comments, SCE states that addressing the Auld-Moraga #1 overload "is not a project objective of the ASP and in the near term, the Auld-Moraga #1 overload can be addressed by simply reallocating distribution load with load transfers using circuit ties between existing distribution circuits and substations" (SCE 2020a, 2020b). This distinction from SCE clarifies the original filing: that the proposed project and alternatives handled this overload either by tie-line transfer or reconductoring of the Auld-Moraga #1 line, rather than reallocation of distribution load with load transfers.
  - The Appendix B power flow study, completed by Kevala in April 2021, concluded that that tie-lines were effective at resolving double-line contingencies, which differed from the results

of SCE's Planning Study. SCE's Planning Study concluded that tie-lines would not be effective in resolving double contingencies or a catastrophic loss of both transformers in the Valley South System. As previously discussed in Section 2.3, Kevala assumed that tie-line transfers occurring were an SPS and so excluded those transfers from the power flow study. This exclusion and evaluation for different forecast years fundamentally altered the results of the power flow study, creating the difference between the Kevala and SCE conclusions.

- As supplemental analysis to the April 2021 power flow study (Appendix B), SCE and Energy Division validated load transfer capability of several alternatives during an N-1 loss of single transformer through a shared power flow model demonstration. This analysis confirmed that the Valley South to Valley North project alternatives, such as the alternatives defined in the Response to CPUC Supplemental Data Request 013, Question DG-MISC-82 (SCE 2022d), could not transfer meaningful amounts of load during such a contingency to avoid a substantial outage (SCE 2022b).
- SCE demonstrated that the Valley South to Valley North project alternatives are less effective in their ability to transfer load via system tie-lines compared to proposed Alberhill Project. Staff noted that some project alternatives accumulated more LAR due to N-1 loss of subtransmission line compared to the proposed Alberhill Project during years 2028 to 2048. The basis for the differences in LAR accumulations at year 2048 are attributable to the designs of the solutions. Every derivative of the Valley South to Valley North alternatives may experience a future Subtransmission line overload after 2028. Under those conditions, each of those Valley South to Valley North project alternatives is only able to transfer load that was being served in the northern part of the Valley System. Most of the N-1 subtransmission line overloads occurred farther downstream in the system. Under the same conditions, the proposed Alberhill Project can transfer loads of three additional distribution substations (i.e., Tenaja, Stadler, and Stent) to avoid loss of load and experience less LAR than all Valley South to Valley North alternatives (SCE 2022e).[9] These results reflect the performance of the project alternatives based on their design.[10]
- In consideration of the changed understanding of the nature of the load transfer, discussed above, Energy Division staff concludes that Valley South to Valley North and Centralized BESS (CBESS) in Valley South and Valley North) would not be effective at resolving double contingencies nor catastrophic events that results in a loss of both transformers in the Valley South System.

[9] See slide 66.

[10] In Response to CPUC Supplemental Data Request 014, Question DG-MISC-84, SCE states on page 4: "On slides 57 and 58 of SCE's August 30, 2022 presentation, the intent was only to demonstrate that the overload on the Auld-Moraga #1 line during an outage of the Auld-Moraga #2 line would not be solved by using the system tie-line capacity of the Valley South to Valley North alternatives and that the overload could be remedied by upgrading the conductor of the Auld-Moraga #1 line."

3 Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

3.1 Methods of Investigation

Kevala assessed SCE's load forecasting methodology and performance metrics for the proposed Alberhill Project and alternatives. To conduct this evaluation, Kevala reviewed SCE's Revised Planning Study (SCE 2021, Item C) and the Quanta Technology (Quanta) reports released by SCE in their February 1, 2021, Amended Motion to Supplement the Record as well as researched and analyzed the load forecasting methodologies used by the California Energy Commission, Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E). These methodologies were then compared to those utilized by SCE for evaluation.

3.2 Results of Report

The findings of this assessment were as follows:

- The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and SDG&E. Some metrics used by SCE, such as LAR, were not being practiced by other utilities in the industry. The Loss of Load Expectation (LOLE) metric is a commonly used metric in the industry. Both LOLE and LAR are comparable in that they account for loss of load. The LOLE metric calculates the expected average number of days per year during which the load exceeds available generating capacity due to outages or other system conditions. In contrast, the LAR metric calculates the energy in megawatt hours (MWh) potentially at risk of not being served due to a variety of system conditions under normal and contingency conditions.
- Although some of the metrics were uncommon, the overall performance metrics developed by SCE have sufficient basis in other metrics commonly used by utilities, such as LOLE. Research of typical performance metrics by comparable utilities revealed no examples of utilities using LAR as a performance metric nor was it discussed in research papers as a performance metric. Additionally, a survey of other projects under CEQA review did not uncover projects using these metrics. It was not clear why SCE used less common metrics. Overall, however, the metrics and methodologies SCE used were reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.
- Prior to choosing LAR as the primary performance metric, SCE used Expected Energy Not Served (EENS). Only one utility had used the EENS metric (British Columbia Hydro in Vancouver, British

Columbia). All other publications that used EENS as a performance metric were research and academic publications.

See Appendix C, Evaluation of SCE's Load Forecast Methodologies and Performance Metrics (Kevala 2021b), for the complete report.

3.3 Subsequent Findings

Following the release of this Alberhill System Project Draft Staff Report in November 2021, SCE followed up on key points in the report via written comments and technical forums that presented follow-on studies and clarifications. The findings of these documents and presentations were as follows:

- Section 3.2 in the Draft Staff Report assessed the performance metrics used by SCE, including LAR. Since the release of the Draft Staff Report in November 2021, SCE provided further context around their selection and use of LAR in technical discussions throughout 2022. During a technical session that occurred on May 4, 2022, SCE detailed and explained the selection of LAR criteria, citing the need for a metric that compared cost effectiveness of projects (SCE 2023a). These comparison criteria included a metric that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration (SCE 2023a, 7).
- SCE considered LAR, EENS, and metrics commonly used in resource adequacy studies such as LOLE (SCE 2023a, 8–10). Of these metrics, SCE preferred LAR, which they defined as "total load required to be curtailed during periods of time in which subtransmission operating criteria were not met," and EENS, which they defined as "LAR that is probability-weighted for specific events and scenarios" (SCE 2023a, 8).
- The probabilities SCE used for an extreme event that results in loss of service at the Valley Substation for the EENS metric calculation were also discussed extensively (SCE 2022b). Due to lack of an industry standard for appropriate probabilities for contingency events to occur, the additional analysis of Valley South to Valley North with a CBESS and a STATCOM were shown with LAR values calculated but not EENS values.

4 Behind-the-Meter Adoption Propensity Analysis for the Valley South System

4.1 Methods of Investigation

Kevala conducted a behind-the-meter (BTM) adoption propensity analysis to identify the likely levels of adoption of BTM storage and photovoltaic (PV) systems in the Valley South area given economic and technological parameters. Using its Network Assessor platform, Kevala analyzed BTM DERs adoption propensity in support of the CPUC with the goal of determining whether DERs, beyond those included in the base assessment by SCE, might reduce the magnitude and duration (i.e., shape of the need) or the viability of certain proposals.

This analysis is a techno-economic approach to identify economically feasible adoption of BTM resources at the customer-sited level (i.e., at existing residential and commercial and industrial parcels). BTM resources include solar plus storage and storage-only systems. The propensity for adoption of BTM resources is based on an individual customer's load profile, the payback period for the investment in BTM resources, Value of Lost Load, and other factors. The analysis included evaluation of full 8,760 time-series hourly load profiles (i.e., 365 days times 24 hours per day) for approximately 102,000 customer meters.

Kevala used its proprietary Network Assessor platform to ingest data provided by SCE and run analytics related to grid infrastructure, load, generation, and price. Specifically, the advanced metering infrastructure (AMI) data was used for the rates analytics and the storage algorithm within the Network Assessor platform. These ultimately identified economically efficient BTM adoption customers under five different scenarios for residential customers and three different scenarios for commercial and industrial customers.

4.2 Results of Report

There is considerable potential for BTM resource adoption across the Valley South area. The findings indicate that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the Scenario 4 (four outages at 1 hour duration) adoption propensity for residential customers as shown in Table 5 below. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery as shown in Table 6 below. These scenarios model different levels of adoption and indicate that with incentivization, it would be economically efficient for this amount of DERs to be interconnected.

See Appendix D, Behind-the-Meter Adoption Propensity Analysis for the Valley South System (Kevala 2021c), for the complete report.

Table 5: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers	4%	8%	21%	49%	82%
Sum of Total Photovoltaic (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610

Key:

BESS = distributed battery energy storage system

BTM = behind-the-meter

MW = megawatts

MWh = megawatt hours

4.3 Expanded Discussion

Sections 4.1 and 4.2 of the Draft Staff Report provide background and summary of Kevala's BTM adoption propensity analysis. The CPUC's Independent Professional Engineer prepared clarifying questions about this portion of the work and reviewed them with Kevala on February 16, 2022. The responses to those questions are summarized below and include further detail on Kevala's initial study. This discussion includes input on how to contextualize Kevala's BTM adoption propensity analysis, further detail on Kevala's Network Assessor platform and associated analytical tools, the outage scenarios considered, and further detail on how SCE rates were considered in the analysis.

4.3.1 Contextualizing Analysis Results

Kevala's BTM adoption propensity analysis was a sensitivity analysis and was not meant to provide alternate solutions. The total number of customers and resulting solar and storage sizes indicated does not mean that each customer would purchase a system in a real setting. The study provided a sensitivity analysis around the *potential* for commercial and industrial (C&I) and residential customers to adopt PV and BTM storage under specific economic incentives.

This study defined economically efficient BTM adoption as the value yielded by a PV and storage system (or storage only) supported by current policies and incentive structures. This definition is consistent with those used by the CPUC in the 2019 to 2020 integrated resource planning process within a defined payback period. The size of the system was optimized based on this payback period and 2019 historical AMI data providing the customer demand profile at the customer level (i.e., shape of need). This translates to the study providing a defined number of customers economic benefit to adopt one of these systems if SCE were to offer an annual incentive depending on the outage use case. Section 4.2 summarizes the amount of residential solar, residential storage, and C&I storage that Kevala's BTM adoption propensity analysis indicated would be economically efficient.

- Given that Kevala's analysis was a sensitivity analysis meant to determine economically efficient BTM adoption, the amount of solar and storage summarized in Section 4.2 is not meant to represent alternative solutions to be compared directly to alternatives in SCE's studies (SCE 2023a). Two limitations of this portion of the study and its results are noted below: Kevala's analysis only considered passive systems, which means that the batteries were not assumed to be dispatchable. Operational performance requirements satisfying the need to schedule BESS operation with the ability to meet charging and discharging needs based on the full historic 2019 customer AMI profile were out of scope of the assessment. While the amount of solar and storage in Kevala's analysis is estimated to be economically efficient, these sensitivity scenarios were not evaluated for their ability to be dispatched to meet a system need.
- On page 18 of the "Comments to the Draft Energy Division Staff Report for the Alberhill System Project" (January 27, 2022), SCE provides their perspectives on the challenges related to BESS operation (SCE 2022c). SCE points out concerns around implementing a large-scale BTM DER Alternative as it would require the utility to obtain additional monitoring, control, and cybersecurity infrastructure. They highlight that the industry has never implemented a BTM BESS solution at the scale that Kevala's analysis indicates would be economically efficient. This reaffirms the status of Kevala's study as a sensitivity analysis rather than an alternative for comparison to project alternatives presented in SCE's studies (SCE 2023a).

4.3.2 Kevala Network Assessor Platform and Associated Analytical Tools

To complete the BTM adoption propensity analysis, Kevala used its Network Assessor platform to ingest data provided by SCE and run advanced analytics related to grid infrastructure, load, generation, and price. At a high level, Kevala's Network Assessor platform ingests and employs data across three key areas: load, generation, and infrastructure. Additional details about this analysis method are provided in Kevala's Behind-the-Meter Adoption Propensity Analysis for the Valley South System report (Kevala 2021c).

- **Load:** Kevala ingested SCE-provided meter data for the year 2019 to create an 8760 time-series load profile for each premise in SCE territory.
- **Generation:** Kevala used generation data for SCE at both the bulk-power level and for DERs, including generator nameplate capacity and associated feeder. These data were used to estimate local energy supply and forecasted production profiles.
- **Infrastructure:** Kevala used SCE-provided geospatial files on electric infrastructure.

To detect existing residential PV system locations and estimate installed capacity, Kevala used an internal proprietary tool called "Sun Spot." Parcel data were used to determine primary usage by identifying the customer type, building footprint, and load, but the tool did not calculate roof space, roof direction, or individual location shading. A standard direction, tilt, and azimuth was used for adoption propensity across all systems.

4.3.3 Outage Scenarios and Approach

The outage scenarios considered for the residential and C&I studies were based on SCE's value of service study where values of service associated with specific outage definitions are provided (referenced specifically according to the use case below). This study then incremented the number of outages corresponding to the specific definition being studied to maintain the use of the value provided. The result is a sensitivity that provides an adoption forecast based on the number of outages. This study with results including a sensitivity that provides an adoption forecast based on the number of outages can facilitate additional study based on this further detail about outages in the region. Note that these are short duration outages of 1 hour and not the extended outages that SCE considered for other project alternatives, such as through the Flex-2-1 and Flex-2-2 metrics (SCE 2021, Item C.)

For residential customers, Kevala mimicked SCE's approach to monetizing outages. The document states that use of a 1-hour outage stems from "SCE's practice to minimize the impact of an extended outage to any single customer by periodically rolling the outages within the system" (SCE 2021, Item C, 65). This meant applying the Value of Service (VOS) of $9.47/kWh for residential customers based on a 1-hour outage (SCE 2021, Item C, Table 8-4). VOS represents the overall impact to customers on the system, or the estimated monetary value to unserved customer load. Mimicking SCE's approach here captures the potential for new customers to adopt solar plus storage systems and the potential for existing residential solar owners to adopt an incremental BTM storage system. Five scenarios of quantity and duration of annual outages were considered, including:

1. No outages
2. 1 outage, 1 hour duration
3. 2 outages, 1 hour duration
4. 3 outages, 1 hour duration
5. 4 outages, 1 hour duration

Kevala examined the potential for C&I customers without existing DER to adopt new BTM storage systems with the incentive to reduce demand charges. This part of the analysis aimed to align the value of loss load (VOLL) outage scenarios with SCE's own outage scenarios. VOLL is the estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service, or the value to the individual customer adopting a BESS system. A value of $46.95/kWh was used for C&I customers based on a 4-hour outage. Kevala adopted the scenarios presented in SCE's VOS Study (SCE 2021, Item C, Figure 8-1). The scenarios studied for VOLL were:

- **Low Scenario:** Four outages, 4-hour duration each
- **Medium Scenario:** Six outages, 4-hour duration each
- **High Scenario:** Eight outages, 4-hour duration each

Kevala found that, for both residential and C&I customers, as the number of outages increased, the likelihood that a customer would adopt went up. In the case of C&I customers, the number of customers adopting remained constant across the scenarios, but the average payback period did decrease.

4.3.4 Rates

Kevala's Adoption Propensity analysis looked at the likelihood of adopting a resource given a certain set of rates, the CPUC's Self-Generation Incentive Program incentives, and outage scenarios. It did not consider the time it takes for the systems to get installed. The battery costs were fixed in this analysis, approximately $12,600 for total storage system cost with hardware and installation, and did not consider decreasing BESS costs, which made this analysis a conservative assessment of BESS adoption. The analysis also used the lifespan associated with current BESS warranties to inform the lifespan used in the analysis. These lifespans range from 10 to 20 years and the conservative value of 10 years was used. Readoption of BESS end-of-life was not considered. This could provide value (i.e., be facilitated) through the continued utilization of system parts, excluding the battery, to make a subsequent readoption less costly. The selling of these system parts was also not considered.

The assessment considered time-of-use rates for C&I and residential adoption, which assumes customers will shift load to maximize bill savings. In a similar fashion, the outage cases in the study corresponded to maximizing the VOLL with the outage occurring during peak value timing. The same 2019 demand profiles used by SCE for the substations within the Valley South System were used to define the specific shape and magnitude of the demand profiles associated with the outage scenario. These approaches were performed to align with SCE's approach that also used the peak values when assessing the viability of the proposed Alberhill Project and the alternatives.

Table 6: Commercial and Industrial BTM Adoption Propensity			
4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	Medium	High
Total Commercial and Industrial Customers	869	869	869
Commercial Customers	869	869	869
Industrial Customers	-	-	-
Total Power (MW)	5.03	5.03	5.03
Total Capacity (MWh)	18.10	18.10	18.10

Key:

BTM = behind-the-meter

MW = megawatts

MWh = megawatt hours

5 Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System

5.1 Methods of Investigation

This report builds on Kevala's prior analysis of potential adoption of BTM solar plus storage in the *Behind-the-Meter Adoption Propensity Analysis for the Valley South System* (Kevala 2021c) report and quantifies the impacts of BTM DER on the load forecasts used by SCE in its support of the proposed Alberhill Project application.

Kevala analyzed how peak loads in this area will change with targeted DER procurement efforts beyond the DER adoption propensity forecasted in the proposed Alberhill Project and its alternatives. The Valley South System load forecast was modified based on the DER capacities determined through the BTM DER propensity analysis. Because SCE peak load coincides with PV system peak production, BESS were utilized for their dispatchability, which enables effective peak load reduction. After determining the new peak loads from the BTM adoption propensity results, power flow analyses were performed to determine the new system impacts, quantifying the peak load reduction based on capacity of DER as modeled in each of the scenarios.

5.2 Results of Report

When power flow analyses were run on the residential BTM adoption propensity scenarios, Kevala noted that the initial load forecasts resulted in a significant number of network violations.[11] The network violations were observed in power flow analyses when the load forecast was reduced by 316 MW (DER adoption levels under Scenario 4). Power flow analyses also indicated that reducing the peak load by 188 MW instead, as modeled under Scenario 3 (see Table 5 above), resulted in a reduction of overloads on the Valley South transformers without high voltage violations. With the addition of voltage regulation equipment, higher penetration levels of DERs could potentially be incorporated into the Valley North and Valley South Systems, further reducing the load beyond 188 MW to 316 MW of DER-driven load reduction.

See Appendix E, Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System (Kevala 2021d), for the complete report.

[11] Capacity and voltage violations based on equipment ratings of the network.

6 Review of SCE's Electrical Engineering Analysis for the Alberhill System Project

6.1 Methods of Investigation

Kevala compared SCE's electrical engineering analysis of the proposed Alberhill Project to power flow study approaches used at similar electric utilities such as PG&E and SDG&E. In addition, Kevala further expanded on the preliminary tie-line analysis documented in the *Preliminary Results: Tie-Line Power Flow Analysis* (Kevala 2021a) report to identify the right sizing of BESS. Power flow studies consist of a numerical analysis of the flow of electric power in the interconnected electrical system, in this case the Valley South System.

To assess how the tie-lines that are proposed as part of the proposed Alberhill Project perform with respect to capacity, reliability, and resiliency, several scenarios (i.e., base cases) were studied using General Electric's PSLF software. These scenario cases represented alternatives that include tie-lines in the Valley South System, distributed battery energy resources, and centralized BESS. This approach enabled comparison to the Valley South System as it exists today without any new projects or tie-lines (i.e., the base case), with the following scenarios:

- Tie-line performance.
- Battery energy storage performance.
- Combination of tie-lines and energy storage.

6.2 Results of Report

Kevala's review found SCE's power flow analysis to be consistent with widely used study approaches. Once SCE obtained results from their analysis, performance metrics developed by SCE were applied to assess and rank the proposed Alberhill Project and its alternatives. Although the SCE-developed metrics were a variation on common industry metrics as described in Section 3, they were found to be reasonable. Consequently, alternatives that included tie-lines were ranked more favorably than alternatives without tie-lines. Moreover, among the projects with tie-lines, SCE favors larger projects (i.e., proposed Alberhill Project) over the smaller projects (i.e., Valley South to Valley North Alternative). Kevala found tie-lines to be beneficial; however, the smaller projects with tie-lines are just as effective as the large projects with tie-lines.

Kevala's power flow analyses found that the Auld-Moraga 115-kV #1 line in the Valley South System experiences overloads following the worst single contingency and the worst double contingency in the Valley South System. This overload is observed with all the power flow cases, including the current configuration of the do-nothing case, the proposed Alberhill Project, and the alternatives. This overload appears unrelated to the proposed Alberhill Project, indicating that a mitigation project or an SPS should be studied to address this overload. As discussed above, selectively applying a mitigation strategy to certain alternatives and not to others without substantiation of the rationale for doing so can lead to an unequal comparison between alternatives. Therefore, understanding SCE's basis for applying an SPS to the proposed Alberhill project as opposed to some of the alternatives is important within the scope of this proceeding and application to evaluate how each of the alternatives supports the reliability, resiliency, and capacity needs described by SCE.

With respect to the expansion on the preliminary tie-line analysis to identify the right sizing of BESS, consistent with the scenario cases discussed above, a 143-MWh centralized BESS that is capable of operating for up to 6.5 hours is the appropriate size to cover the forecasted load peaks at the Valley South Substation over the course of the year under single and double contingencies.

See Appendix F, Review of SCE's Electrical Engineering Analysis for the Alberhill System Project (Kevala 2021e), for the complete report.

6.3 Subsequent Findings

Following the release of the Draft Staff Report, SCE followed up on key points in the report via written comments and technical forums that presented follow-on studies and clarifications. The findings of these documents and presentations were as follows:

- Sections 6.1 and 6.2 discuss sizing of BESS. Through discussions in 2022, SCE shared that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a CBESS was a more realistic consideration. SCE prepared and presented additional analysis that reviewed an alternative that included CBESS paired with a STATCOM. This additional analysis estimated that to satisfy the N-0 and N-1 minimum planning criteria, including the loss of a Valley South transformer, a 168 MW BESS without STATCOM or 158 MW BESS with STATCOM power rating would be required (SCE 2022b).
- Section 6.2 of the Draft Staff Report raised a question about whether an SPS is applied to the proposed Alberhill System Project. As described above in Section 2.4, SCE does not specify the manner in which the transfer of load from Valley South to proposed Alberhill Project would occur to remedy an Auld-Moraga #1 overload in the event of a contingency in their planning study. SCE clarified in the Draft Staff Report comments that this transfer of load would be a manual action, as opposed to an automated scheme (SCE 2022c). Based on the NERC definition of an SPS (NERC 2013), this means that this transfer is not an SPS.

7 Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project

7.1 Methods of Investigation

WSP reviewed SCE's *Benefit-Cost Analysis of Alternatives for SCE's Alberhill System Project* (SCE 2021, Item G) to validate whether the benefit-cost analysis (BCA) for each alternative had been properly conducted, documented, and completed and to document any other findings that would warrant a more detailed review.

Step 1. Review of SCE's BCA(s): Upon review, WSP found the SCE BCA(s) (both the May 2020 SCE Amended Application and PEA and February 2021 SCE Amended Motion to Supplement the Record BCAs and the supporting spreadsheets, *Effective PV Forecast*, *PV Watts Forecast*, and *Spatial Base Forecast*) were not appropriately developed over the actual project timeline and the calculations of the Present Value Revenue Requirement (PVRR) total costs were not shown. While project benefits were treated appropriately in terms of traditional capital analysis ("net present valuation procedures,") project costs were derived through the use of an external program-based ("present value revenue requirement") process. Using this method to compute project costs externally made it unclear whether the total project costs and annual project costs were calculated appropriately. Further, there were no linkages to annual operations and maintenance (O&M) costs included in the Project cost stream (O&M was found in the separate Excel project cost sheet, but not linked to the analysis). In addition, the year the project construction was expected to start and the year benefits would begin accruing were not placed into the timeline correctly. For all alternatives, the project benefits and O&M costs designated within the model were accruing in years before the project was constructed (prior to the facility operational in-service date), thus yielding an erroneous BCA comparison among the alternatives under review.

Accordingly, the tasks described below were undertaken to gain a clear understanding of actual benefits and costs associated with the various alternatives.

Step 2. Implementation of Independent BCA: Using data from the SCE February 2021 BCA and the associated spreadsheets, three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. Each analysis employed integrated appropriately timed benefit streams extending over the respective operational period(s). Total project costs were either based on SCE's PVRR cost or on an appropriately timed Net Present Value of cost streams with and without uncertainty and battery revenues. To evaluate the different cost effects (PVRR or Net Present Value), the resulting net benefits and benefit-cost ratios were compared to those of the SCE February 2021 BCA and associated spreadsheets submission.

All BCAs involved an integrated time series (wherein the time series of the costs and benefits of each alternative were appropriately integrated with their construction and O&M timeline). This procedure adhered to a traditional capital improvement BCA (OMB n.d.; USDOT 2012, 2022).

Step 3: Review of SCE's June 2021 SCE Second Amended Motion to Supplement the Record: WSP examined updates to the SCE BCA spreadsheets submitted as part of the June 2021 SCE Second Amended Motion to Supplement the Record. Specific figures had received some minor SCE edits; these were mostly clerical or in the form of linkages to a database.

7.2 Results of Report

Three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. The analysis also used the revised O&M costs, PVRR construction costs, and benefits (e.g., the four main benefit categories used for monetization are EENS under N-0 normal conditions (i.e., N-0); EENS under single contingency conditions; Flex-1; and Flex-2) of each proposed Alberhill Project alternative (as provided by SCE). WSP then aligned the costs and benefits within a traditional BCA capital analysis in terms of when they would realistically occur (based on the construction schedule and the facility's expected operational in-service date). WSP's analysis continued to use the unaltered SCE annual PVRR cost and benefit streams (these were simply applied to the realistic implementation timeframe described above). The objective was to examine how realigning the data in the time series would affect the final benefit-cost ratios of each alternative and the relative ranking of each alternative in terms of overall net benefits and benefit-cost ratios. In comparing the result with SCE's models, this analysis resulted in a substantial reduction in benefits, cutting benefits by about half. Figure 2 displays a summary of the differences. The differences are mainly due to the timing of benefits in SCE's model (occurring prior to completion of the project facility); however, there is still uncertainty with the PVRR computations, given the calculations were not disclosed by SCE. Also, there is uncertainty in exactly how the O&M costs were incorporated into the total project cost for the same time-series computational reasoning by SCE.

Based on the retiming of benefits beginning to accrue on the appropriate Project in-service date, the most attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by SDG&E (seventh place) and Mira Loma (eighth place).

MIXED BENEFIT COST ANALYSIS - USING "SCE" PVRR COSTS AND CAPITAL ANALYSIS BENEFITS
Includes Uncertainty and Battery Revenues
Millions of ($2019 dollars)

	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	SCE PVRR COSTS	Capital Analysis Benefits NPV	Net Benefits	BCR	BCR RANK	PVRR COSTS	Net Benefits	BCR	BCR Rank
Valley South to Valley North	$207	$1,106	$899	5.3	1	$207	$2,156	10.4	2
Menifee	$331	$1,702	$1,371	5.1	2	$331	$3,648	11.0	1
VS to VN & Distributed BESS VS	$232	$1,111	$879	4.8	3	$232	$2,165	9.3	3
VS to VN to VST & Cen BESS VS	$289	$1,266	$977	4.4	4	$289	$2,468	**8.5**	6
Valley S to Valley N to Vista	$290	$1,268	$978	4.4	5	$290	$2,470	8.5	7
Alberhill System Project	**$474**	**$1,996**	**$1,521**	**4.2**	**6**	**$474**	**$4,282**	**9.0**	**4**
SDG&E	$453	$1,867	$1,414	4.1	7	$453	$4,001	8.8	5
Mira Loma	$309	$1,214	$905	3.9	8	$309	$2,601	8.4	8
VS to VN & Central BESS VS VN	$367	$1,304	$937	3.6	9	$367	$2,542	**6.9**	10
SDG&E and Centralized BESS in VS	$531	$1,885	$1,354	3.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$560	$1,461	$901	2.6	11	$560	$3,132	5.6	11
Centralized BESS in VS	$525	$1,301	$776	2.5	12	$525	$2,535	4.8	13
SCE Orange County	$747	$1,705	$958	2.3	13	$747	$4,021	5.4	12

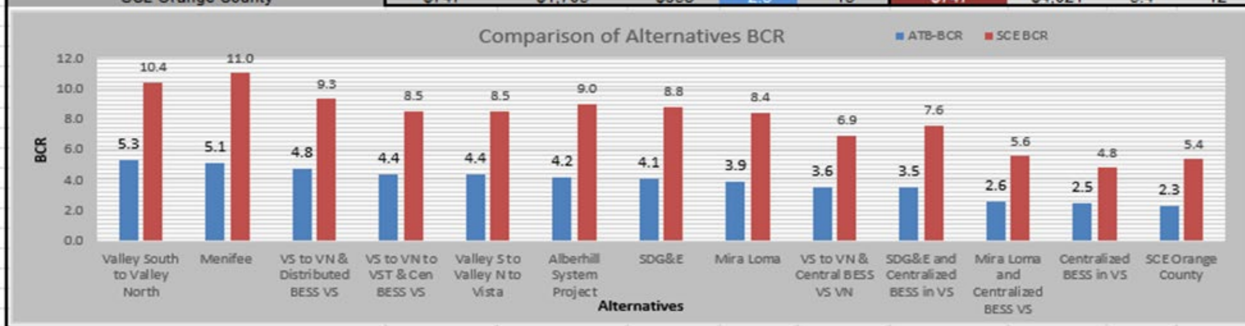

Figure 2: Differences in Independent Capital Analysis BCA and SCE's PVRR Analysis BCA

SCE documentation emphasizes that the proposed Alberhill Project supplies the best solution in meeting the energy needs of the future, based on its reliability performance. This is paramount to the proposed Alberhill Project's attractiveness and ultimately displaced all other alternatives as the preferred alternative. Although the reliability of energy capacity needs may justify the proposed Alberhill Project as the best solution, it is also a very costly solution, at $474 million. In comparison, Valley South to Valley North (first place in terms of WSP's BCA ranking) costs are only $207 million; however, it is unclear how this and other alternative systems would perform giving equal consideration to their cost effectiveness, reliability performance, and capacity over time.

From a purely economic perspective, other alternatives could be explored, possibly including incremental implementation. For instance, the equivalent monetary investment of two smaller-scaled systems (i.e., similar to the scale of the Valley South to Valley North Alternative) might be installed, providing a short-term energy solution (say over 5 to 10 years), saving $60 million dollars in upfront costs. CPUC held additional technical forums with SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including smaller-scaled systems such as the Valley South to Valley North Alternative. SCE performed preliminary analysis of the transformer N-1 contingency (SCE 2022b). SCE's study looked at various configurations of CBESS in combination with Valley South to

Valley North connections to calculate the CBESS size requirements. See Section 3 for additional information on the results of this analysis from a technical perspective.

The three primary metrics evaluated in the SCE economic analysis were the benefit-cost ratio, the reliability score, and the annual capacity (in megawatt hours) produced versus need. These three factors were used by SCE as the criteria by which all alternatives should be evaluated. This led SCE to identify the proposed Alberhill Project as the favored solution, primarily because it meets required future megawatt needs and was deemed the most reliable solution.

WSP examined updates to the SCE BCA spreadsheets submitted as part of the June 2021 SCE Second Amended Motion to Supplement the Record. Additionally, WSP requested and received tracked changes versions of the spreadsheets. Initially, the proposed Alberhill Project and the Valley South to Valley North Alternative were reviewed for impacts influencing the bottom-line benefit-cost ratios or net benefits (February 2021 SCE Amended Motion to Supplement the Record spreadsheets were compared to the June 2021 SCE Second Amended Motion to Supplement the Record spreadsheets).

WSP found for most alternatives, while certain underlying inputs (figures in interior cells) were slightly changed, they were not changed to an order of magnitude that would affect the integrated time-series BCA results documented above. Project costs for all alternatives remained unchanged. However, for the Menifee Alternative, the changes in the benefit cells resulted in a 6.4 percent increase in overall benefits. With this being the case, WSP input the new Menifee Alternative benefits into WSP's independent Capital Analysis BCA (where benefits start occurring once the project is in service) and found, in terms of benefit-cost ratio, the increased benefits resulted in the Menifee Alternative moving to first place (switching places with Valley South to Valley North Alternative, from that shown in the Figure 2). Importantly, these assessments were made from a purely benefit-cost ratio standpoint, but do not consider the engineering ability of alternatives to resolve planning criteria contingencies, such as an N-1 Loss of Transformer contingency. No other changes (from the June 2021, or third version spreadsheets) were applied to the integrated time-series BCA because the other changes were minor, and since SCE hadn't adjusted the timing of accruing benefits before the Project is in service, making the changes inconsequential.

During this review, WSP also observed that the data linking to computations of benefits was missing or not supplied. These cells were previously linked to supplied Excel spreadsheet data titled *Cost Assumptions*. However, in both the tracked and untracked latest versions of spreadsheets, the benefit cells were linked to *Cost Data & Assumptions* (as referred to in cells), but Excel spreadsheet data was missing or not supplied, meaning the computation of benefit cells could not be linked to their source. These cells were also password protected, limiting disclosure and the scope/tracking of review.

Based on discussions at the Energy Division virtual workshop on January 20, 2022, regarding the Draft Energy Division Staff Report findings and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including the SCE BCA methodology. Through technical forums with

CPUC and SCE in May 2022, it appears that SCE conducted a life cycle cost analysis (LCCA) in the course of preparing their economic analysis, instead of a BCA.

An LCCA is a subset of a BCA. An LCCA may be used to determine the most cost-effective way to accomplish a project's objectives by comparing life cycle costs of alternatives that have the same study period, base date, and service date. Unlike LCCA, BCA considers variable benefits of project alternatives as well as its costs (USDOT 2002). BCA allows for the evaluation and comparison of alternatives with different in-service dates, and life cycles, depending on the timing of costs and benefits as they are realistically incurred. A BCA can be used to compare alternatives that do not yield identical benefits (e.g., energy utility alternatives that have varying levels of supply or alternatives that accrue benefits at different stages in the analysis). Table 7 provides a comparison of elements typically included in LCCA and BCA.

Table 7: Comparison of Analysis Elements: LCCA Versus BCA

Project Element	LCCA	BCA
Construction and maintenance expenditures	Yes	Yes
Costs during construction, rehabilitation, or maintenance	Yes	Yes
Costs during normal operations	Yes	Yes
Benefits resulting from project	No	Yes
Other external effects resulting from project	No	Yes

Source: USDOT 2022

In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Though the SCE economic analysis adheres to the criteria for comparing alternatives within an LCCA (finding the least cost option between alternatives that have the same service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA.

See Appendix G, Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project, for the WSP memoranda.

8 Conclusions

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer of 2022. The main findings, decisions, and actions in 2022 are described below.

SCE noted via letter (SCE 2022c, 13) that tie-lines in the proposed Alberhill Project that could be engaged following a contingency would be operated manually and therefore do not constitute an SPS. Kevala agrees that manual operation of a tie-line does not constitute an SPS or mitigation strategy.

Since the Draft Staff Report, Kevala has learned that the portion of SCE's 115 kV system included in the proposed Alberhill Project is not required to be planned to meet NERC reliability standards. As noted above in Section 2.3, while SCE's planning criteria align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which is analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios," (SCE 2023a, 6), including Flex-1, Flex-2-1, and Flex-2-2. It is reasonable to expect SCE to craft specific system performance metrics that are rooted in transmission system planning event analysis.

In the absence of the CPUC defining a standardized evaluation approach, the Energy Division finds it reasonable for SCE to define performance metrics and scenarios to use in evaluating unlikely contingencies that may result in loss of load. This form of reliability/resilience assessment is nascent in the electric utility industry and Energy Division has seen examples of this form of assessment under development by Department of Energy National Laboratories, other utilities examining investment plans for extreme events, and in white papers or journal articles from the Institute of Electrical and Electronics Engineers and others. The Federal Energy Regulatory Commission, NERC, and WECC have opened proceedings or opined in annual reports on the need for alternative planning based on high-impact, low-frequency events.

Although SCE is not mandated to follow NERC standards, SCE has provided an evaluation method that is rooted in transmission system planning event analysis. In NERC regulation, the regulatory agency expects the transmission operator to exercise its engineering judgment and operating experience to choose relevant events to study and to provide rationale justifying the events studied. NERC does not specify the duration of study periods in its regulation. Similarly, the CPUC expects SCE to use its engineering judgment and operating experience to evaluate unlikely contingencies at the subtransmission/distribution level even if CPUC has not dictated a standardized evaluation approach by regulation, rule, or order.

Energy Division finds that it is reasonable for SCE to use these evaluation methods involving novel reliability/resilience metrics and modeling as an additional screening method for resilience because high-impact, low-frequency events impacts to this subtransmission system could severely affect a significant number of customers.

SCE expressed concerns that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a CBESS was a more realistic consideration. SCE prepared and presented additional analysis that looked at an alternative (with needed system sizing) that included CBESS paired with a STATCOM.

Kevala found that the PSLF modeling and associated results demonstrated in SCE's August 30, 2022, presentation to the Energy Division were qualitatively reasonable and in alignment with the results previously shared via data requests and prior presentations for each case and variation, including analysis of placing CBESS both with and without a STATCOM within the Valley South System.

SCE presented further background on how and why they chose certain performance metrics. They considered LAR, EENS, and metrics commonly used in resource adequacy studies, such as LOLE. SCE wanted a metric that could compare cost effectiveness of solutions and that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration. These criteria led to SCE's selected use of LAR and EENS.

The Energy Division and its consultants extensively discussed the probabilities SCE used for an extreme event that results in loss of service at the Valley Substation which was incorporated in calculations of the EENS metric. Due to lack of industry standard and lack of consensus on the appropriate probabilities for such contingency events, the Energy Division reported the additional analysis of Valley South to Valley North with a CBESS and a STATCOM using LAR values calculated but not EENS values to avoid use of probabilities in comparative metrics.

As shown by the calculated LAR values, BESS cannot defer the proposed Alberhill Project's need alone to meet the Flex-2-1 planning case because the Valley System is a radially operated subtransmission system that would need to be operated as an islanded microgrid (i.e., a stand-alone electrical system disconnected from the main grid). The facilities and approach for operating Valley System like an islanded microgrid has not been tested nor operated at scale for a system this size. The Valley System would remain vulnerable to loss of its source of supply under a high-impact, low-probability event—which is undesirable for a high-density urban load area subject to extreme heat events.

The WSP economic analyses found that SCE's proposed Alberhill Project's BCA of alternatives is not an equitable comparison of alternatives or calculation of each benefit-cost ratio because the benefits and costs for each alternative were not correctly timed in terms of when they would realistically occur. SCE's BCA incorrectly identifies accrual of project benefits before the proposed Alberhill Project has been constructed or placed in service (instead, it is based on a project need date). It is also not clear how O&M costs were incorporated into SCE's timeline or analysis as they are not linked, and the calculation of costs is not traceable.

Through technical forums with CPUC and SCE in May 2022, it appears that SCE conducted a lifecycle cost analysis in the course of preparing their economic analysis, instead of a BCA. An LCCA is a subtype of BCA. The LCCA is a cost comparison of competing project alternatives that is used to compare total life cycle costs across project alternatives that have equivalent benefits. In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Although the SCE economic analysis appears to adhere to the criteria for comparing alternatives within an LCCA (determining the most cost-effective option among alternatives with identical in-service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA (Kneifel and Webb 2020; OMB n.d.; USDOT 2002, 2012, 2022).

WSP, on behalf of the Energy Division, conducted economic analysis to re-time the benefits to align with BCA methodologies. Based on the re-timing of benefits beginning to accrue on the appropriate Project in-service date, the most purely economically attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by SDG&E (seventh place) and Mira Loma (eighth place). Importantly, these rankings necessarily retain the probability-weighting SCE used in its original EENS calculations for the contingency events and is agnostic as to whether the alternatives analyzed may be potentially infeasible or undesirable.

Commission Decision D.18-08-026 did not prescribe the specific method for preparation of the BCA.

Overall, while some of SCE's analyses focused on metrics which incorporate data lacking consensus (i.e., the probability weighting for EENS), many of the SCE supplemental analysis conclusions are, in the professional opinion of the Energy Division, still qualitatively sound. Significantly, the Energy Division finds that though unlikely to occur, the high-impact total loss of the Valley Substation contingency considered by SCE in its planning criteria is compelling when weighing the resiliency needs the proposed Alberhill System Project seeks to address. Determining the probability of such a high impact but unlikely event to monetize EENS is a challenging endeavor because there is little SCE and industry operational data regarding such events. Energy Division elected to compare the LAR predicted for project alternatives under normal conditions with all facilities in service, likely contingencies, and unlikely contingencies. Energy Division did not rely upon a fully probability-weighted metric such as EENS for making a quantitative economic assessment of all benefits. Furthermore, SCE has convincingly shown that many of the reliability and resiliency challenges potentially faced by the Valley South System may not be fully addressed by addition of BESS and limited tie-lines to the Valley North System, particularly when looking at high-impact contingency events.

SCE's analysis of the thirteen project alternatives in comparison to basic planning criteria for normal conditions with all facilities in service and likely contingency conditions of single loss of transformer clarified to Energy Division, in concert with information shared with Energy Division during the technical forums and from data request responses, that the five lowest cost alternatives based on SCE PVRR costs, and at least two of the substation project alternatives, do not meet SCE's basic planning criteria. The Menifee Alternative does not meet SCE's basic planning criteria under loss of single transformer (N-1) contingency in 2031 because Menifee experiences LAR. The Mira Loma alternative does not meet basic planning criteria for normal conditions with all facilities in service (N-0) nor likely contingency conditions for loss of single transformer (N-1) in 2031. [12]

The Energy Division concludes that the additional supplemental analysis performed by SCE through the technical forums to evaluate Valley South to Valley North with Distributed BESS with and without STATCOM fulfilled the analytical needs suggested by Kevala for the uses distributed BESS and a fewer number of tie-lines.

After considering the additional supplemental analysis performed through a series of technical forums with SCE to evaluate the Valley South to Valley North with Centralized BESS (both with and without STATCOM), the Energy Division has determined that the potential alternative does not adequately address the effect on system performance of a high-impact, low-probability contingency event such as a total loss of the Valley Substation. Consequently, at this time, Energy Division does not conclude that two smaller-scaled systems or a different project alternative involving distributed battery energy storage would provide a reliable short-term energy solution that is more cost-effective than other project alternatives. The analysis did not support the hypothesis that two smaller-scaled systems a different project alternative involving distributed battery energy storage would provide a short-term energy solution that would save millions of dollars in upfront costs, which Energy Division posited in its Draft Staff Report.

[12] SCE Response to Energy Division Data Request No. 11, question DG-MISC-80.

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Appendices

Appendix A – Project Description of the Proposed Alberhill Project

Appendix A

The following text is excerpted from the Final Environmental Impact Report (2017) for the Valley–Ivyglen 115-kV Subtransmission Line and Alberhill System Projects. Project description excerpts pertain to the proposed Alberhill Project.

1.0 Alberhill Project Overview

The proposed Alberhill Project would include construction of a new 1,120 megavolt ampere (MVA) 500/115-kV substation (Alberhill Substation), which would be expandable to a maximum of 1,680 MVA depending on future need. In addition to construction of a new Alberhill Substation, the proposed Alberhill Project would include the following:

- Construction of two new 500-kV transmission lines (approximately 3.3 miles, combined) within a new ROW to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line;
- Double-circuit approximately 11.75 miles of existing single-circuit 115-kV subtransmission lines with structure replacement primarily in the existing ROW;
- Construction of about 3 miles of single-circuit 115-kV subtransmission lines with distribution lines underbuilt on the subtransmission line structures and removal of about 3 miles of electrical distribution lines within the existing ROW;
- Installation of a second 115-kV circuit on approximately 6.5 miles of single-circuit 115-kV subtransmission lines (the single-circuit line is to be constructed as part of the proposed Valley–Ivyglen Project);
- Installation of fiber optic lines overhead (9 miles) on sections of the new or modified subtransmission lines and underground (1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12-kV substations;
- Construction of an approximately 120-foot microwave antenna tower at the proposed Alberhill Substation site; installation of microwave telecommunications dish antennas at the proposed Alberhill Substation, the existing Santiago Peak Communications Site, and Serrano Substation; and other telecommunications equipment installations at existing and proposed substations; and

The applicant estimates that construction of the proposed Alberhill Project would take approximately 28 months.

2.0 Alberhill Project Location

The Alberhill Substation is proposed to be built on 34 to 40 acres of a 124-acre property located north of I-15 and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County. The two new 500-kV transmission lines would each extend approximately 1.5 miles northeast to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission

Line. The two 500-kV transmission lines would be constructed primarily in unincorporated Riverside County, although the transmission lines would pass through the City of Lake Elsinore.

The proposed 115-kV line modifications and construction would occur southeast from the proposed Alberhill Substation to Skylark Substation (approximately 11.5 miles) and from Skylark Substation to Newcomb Substation (approximately 9 miles). The subtransmission lines would be modified or constructed in unincorporated Riverside County and in the Cities of Lake Elsinore, Wildomar, and Menifee.

Fiber optic lines would be installed overhead on the structures modified or constructed as part of the proposed Alberhill Project. In a few locations, fiber optic lines would also be installed in a new underground conduit. Telecommunications equipment would be installed within the telecommunications rooms at the applicant's Barre, Fogarty, Ivyglen, Mira Loma, Newcomb, Serrano, Skylark, Tenaja, Valley, and Walnut Substations. Telecommunications systems would also be upgraded at the Box Springs Communications Site, which is located northwest of the City of Moreno Valley, California, and the applicant's Irvine Operations Center in southeastern Irvine, California.

One new approximately 120-foot microwave antenna tower would be installed at the proposed Alberhill Substation; one new microwave dish antenna would be installed at Serrano Substation in the City of Orange in Orange County; and two new dish antennas would be installed at the Santiago Peak Communications Site, which is located on land managed by the United States Forest Service within the Cleveland National Forest.

3.0 Components of the Proposed Alberhill Project

The components of the proposed Alberhill Project are summarized in Table 3-1.

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Alberhill Substation		
New 1,120 MVA 500/115-kV substation expandable to 1,680 MVA	• Up to three 500 MVA transformers in service and one spare transformer [a]	• 34 to 43 acres [b] • 33,550 gallons of oil per transformer • 37-foot-high transformers
500-kVA backup generator	1	• 960 gallons of diesel fuel
500-kV switchrack	• One gas-insulated switchrack • Space for second 500-kV switchrack and enclosure • Space for two future 500-kV capacitor banks	• One 350-foot-long, 49-foot-high steel enclosure • Up to 50,000 pounds of SF_6
115-kV switchrack and future 12-kV switchrack	• One open-air insulated switchrack	• One 60-foot-high dead-end structure

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
	• Space for additional positions on switchrack • Space for future 12-kV switchrack and 115/12-kV transformers • One 115-kV capacitor bank • Space for three future 115-kV capacitor banks	• One 43-foot-high dead-end structure • Space for additional dead-end structures • Up to 1,200 pounds of SF_6 (circuit breakers)
Control building	• Substation monitoring equipment	• 20-feet high, 7,040 square feet
Parking area and multiple driveways	n/a	• 7,600-square-foot parking area • 30-foot to 45-foot-wide driveways • 156,000 square feet of road surface [c]
Agricultural water pipe relocation	n/a	• 27-inch-diameter pipe • 1,700 feet long
Transmission Lines (Overhead)		
Line SA: New 500-kV transmission line to connect the proposed Alberhill Substation to existing Serrano–Valley 500-kV Transmission Line	• 6 LSTs (1 LST removed) [d]	• 1.6 miles long • 250-foot to 2,100-foot spans between LSTs • 200-foot-wide ROW (new) [e]
Line VA: New 500-kV transmission line to connect the proposed Alberhill Substation to existing Serrano–Valley 500-kV Transmission Line (overhead)	• 6 LSTs No structures removed	• 1.7 miles long • 250-foot to 2,100-foot spans between LSTs • 200-foot-wide ROW (new) [e]
New overhead ground wires installed on 500-kB Lines AS and VA	n/a n/a	• 3.3 miles
Subtransmission Line Segments (Overhead)		
Segment ASP1: New double-circuit 115-kV subtransmission line at proposed substation site	• 7 TSPs • 3 LWS poles No structures removed	• 0.22 miles • On proposed substation site
	• 4 LWS poles • 8 TSPs	• 0.5 miles

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Segment ASP1.5: New double-circuit 115-kV subtransmission line and removal of existing single-circuit section of Valley–Elsinore–Fogarty 115-kV line	• 2 existing TSPs to be modified (4 wood poles removed)	• 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures [f]
Segment ASP2: Double-circuit Valley–Ivyglen 115-kV line segment [g]	• 4 LWS • 2 TSP (4 LWS removed)	• 6.27 miles • 60-foot to 100-foot-wide ROW (existing). Existing distribution line underbuilt to be relocated to new 115-kV structures.
Segment ASP3: New double-circuit 115-kV line segment and removal of existing single-circuit section of Valley–Elsinore–Fogarty 115-kV line	• 13 LWS poles • 3 TSPs • 2 existing TSPs to be modified • 1 LWS guy stub (13 wood poles and 1 TSP)	• 0.48 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures [f]
Segment ASP4: New double-circuit 115-kV subtransmission line and removal of existing single-circuit sections of Elsinore–Skylark 115-kV lines	• 101 LWS poles • 12 TSPs • 12 LWS guy stubs • 3 Wood (modified) (112 wood poles, 1 LWS, and 1 TSP removed)	• 4.24 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures [f]

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Segment ASP5: New double-circuit 115-kV subtransmission line segment and removal of existing single-circuit section of Valley–Newcomb–Skylark 115-kV line	• 109 LWS poles • 11 TSPs • 10 H-frame structures (h) • 1 TSP (modified) • 13 LWS guy stubs (119 wood, 2 LWS, 2 wood H-frame(h), 8 LWS H-frame(h))	• 5.5 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP6: New single-circuit 115-kV subtransmission line segment along existing distribution line route	• 100 LWS poles • 1 TSP (modified) • 7 LWS guy stubs (3 wood poles removed)	• 3 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line to be relocated to new 115-kV structures
Segment ASP7: New double-circuit 115-kV subtransmission line segment and removal of existing single-circuit section of Valley–Newcomb–Skylark 115-kV line	• 9 LWS poles • 4 TSPs • 3 LWS guy stubs (6 wood poles and 2 TSPs removed)	• 0.25 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP8: Connect Valley–Ivyglen and Valley–Newcomb single-circuit 115-kV lines	• 3 LWS poles • 4 TSPs (3 wood poles removed)	• 0.06 miles or 300 feet • 260-foot to 390-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Telecommunications Equipment and Fiber Optic Lines (Overhead and Underground)		
New microwave tower at Alberhill Substation	• 1 antenna tower	• 120 feet tall
New dishes at the proposed Alberhill Substation (one), Serrano Substation (one), and the Santiago Peak Communications Site (two)	• 4 microwave dish antennas	• 10 feet wide (each)
New fiber optic telecommunication line installed on two 115-kV line taps into the proposed Alberhill Substation	n/a	• 2,000 feet • 650 feet underground

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
New fiber optic telecommunication line installed on 115-kV Segments ASP1, ASP 1.5, ASP5, ASP6, and ASP7	n/a	• 8.66 miles • 1.11 miles underground
New telecommunications equipment installed inside existing substations (e.g., microwave radios)	n/a	n/a
Totals		
New 500-kV transmission line	n/a	3.3 miles
New or modified 115-kV subtransmission line	n/a	20.42 miles
New fiber optic line	n/a	8.66 miles (1.11 miles in new underground conduit)
New 500-kV ROW to be acquired	n/a	3.3 miles (200 feet wide)
Number of transmission and subtransmission structures by structure type	• 12 LSTs installed • 3 Wood Poles (modified) • 346 LWS poles installed • 10 H-frame structures installed • 51 TSPs installed • 36 LWS guy stubs installed • 4 existing TSPs to be modified • 2 TSPs (modified) (1 LST, 260 wood poles, 7 LWS poles, 3 TSPs, 2 wood H-frames and 8 LWS H-frames removed)	• 95 feet to 190 feet tall, four concrete footings • 75 feet to 100 feet tall, 1.5 to 2.5 feet in diameter at ground level • 70 feet to 80 feet tall, two 1.5 to 2.5 feet diameter LWS poles at ground level • 70 feet to 115 feet tall, 5 to 8 feet in diameter at ground level (including foundation)

Source: SCE 2011
Key: kV = kilovolt, kVA = kilovolt ampere, LST = lattice steel tower, LWS = lightweight steel, MVA = megavolt ampere, n/a = not applicable, SF_6 = sulfur hexafluoride gas, ROW = right-of-way, TSP = tubular steel pole
Notes:

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications

[a] The initial build would include the installation of two transformers, with one of the two a spare. Space would be available for the installation of two additional transformers, for a maximum of three in-service transformers and a spare, if needed in the future.
[b] Approximately 34 acres would be needed for construction of the Alberhill Substation, including landscaping and access roads. If the applicant elects to excavate 5.2 acres of land adjacent to the northeast corner of the proposed substation site to obtain fill under Import Soil Option 1, then the land required for construction of the proposed substation would increase from 34 acres to approximately 40 acres (Section 2.4.6.2).
[c] Road surfaces inside and surrounding the proposed Alberhill Substation would be asphalt, concrete, or gravel (Class II Aggregate).
[d] One 500-kV tower would be removed from the Serrano–Valley 500-kV Transmission Line.
[e] Refer to Tables 2-6 and 2-7 for disturbance area by project component.
[f] A number of the existing single-circuit 115-kV structures to be replaced with double-circuit 115-kV structures have existing distribution and telecommunications lines underbuilt on (installed on the lower position of) the single-circuit 115-kV circuit structures. The existing distribution and telecommunications lines would be relocated to and underbuilt on the proposed double-circuit 115-kV structures.
[g] Placing a second circuit on this proposed Alberhill Project 115-kV segment requires that proposed Valley–Ivyglen Project 115-kV Segments VIG4 and VIG5 are constructed.
[h] H-frame structures are constructed using two LWS poles. Existing H-frame structures to be removed consist of two wood poles or two LWS poles. See figure 2-8 for a diagram of the H-frame structure.
[i] Two parallel overhead ground wires would be installed on the top of each of the proposed 500-kV towers.

3.1 Alberhill Substation

The proposed 1,120 MVA 500/115-kV Alberhill Substation would be expandable to a maximum of 1,680 MVA, with space for three in-service 560 MVA 500/115-kV transformers and one spare, depending on future need. Up to five 500-kV transmission lines may connect to the final build of the substation, as needed. The substation would be unstaffed and automated. The initial build of the proposed Alberhill Substation would connect to an existing 500-kV transmission line via new segments and include the following:

- Two 560 MVA 500/115-kV transformers with one used as a spare;
- 500-kV switchrack with gas-insulated switchgear;
- 115-kV switchrack;
- 115-kV capacitor bank;
- Control building with basement;
- Electrical power sources including a backup generator;
- Lighting;
- Entrance, gates, driveways, parking, and a perimeter wall that is a minimum of 8 feet tall and a maximum of 14 feet tall; and
- Restroom, septic system, water supply, and landscaping irrigation.

Five 115-kV lines would extend from the initial build of the proposed Alberhill Substation. If the proposed substation is expanded in the future and two or up to three load-serving 500/115-kV transformers are installed, up to 10 115-kV lines may ultimately extend from the proposed substation. To allow for construction of the substation, a 27-inch agricultural water pipeline would be relocated to the perimeter of the proposed Alberhill Substation property.

TRANSFORMERS

The proposed Alberhill Substation would include the installation of two 560 MVA 500/115-kV transformers as part of the initial build. Because the total load that would be transferred initially from the Valley Substation to the proposed Alberhill Substation would be less than the capacity of one of the installed transformers (560 MVA), the second transformer would be energized and available for service as the spare for the purposes of the initial build.

The proposed Alberhill Substation would be constructed with enough space for two additional 560 MVA 500/115-kV transformers. When the electrical load exceeds 560 MVA, the first two transformers would serve the load and a third transformer would be installed as a spare. Based on the applicant's projections, the load may exceed 560 MVA between 2024 and 2029. A fourth transformer would be installed as a spare and the first three transformers would serve the load when the electrical load exceeds 1,120 MVA. The applicant projects that the load may exceed 1,120 MVA between 2037 and 2050, depending on annual growth in electrical demand. Each of the 560 MVA 500/115-kV transformers would be approximately 37 feet high and contain approximately 33,550 gallons of transformer oil (mineral oil). There would also be space reserved for the future installation of 115/12-kV transformers.

SWITCHRACKS

500-kV Switchrack (Gas Insulated)

The 500-kV switchgear would be housed in a steel enclosure that is approximately 350 feet long, 60 feet wide, and 49 feet high. There would be space reserved at the proposed Alberhill Substation for a future 500-kV switchrack. The 500-kV switchrack would consist of six positions with two operating buses arranged in a breaker-and-a-half configuration. The operating buses would have six 500-kV gas-insulated potential-transformers. Initially, four positions would be installed. Three positions would be equipped for two 500-kV line positions and two transformer bank positions. The two 500-kV line positions and two bank positions would be equipped with line/bank dead ends. The 500-kV transmission lines and transformer bank leads would have twelve 500-kV lightning arresters.

115-kV Switchrack and Future 12-kV Switchrack (Open-Air Insulated)

The 115-kV switchrack would use open-air-insulated switchgear. Five 115-kV lines would extend from the proposed 115-kV switchrack. There would be space reserved at the proposed Alberhill Substation for an extension of the 115-kV switchrack. If the proposed substation is expanded in the future and up to three load-serving 500/115-kV transformers are operational, it is estimated that up to 10 115-kV lines may ultimately extend from the 115-kV switchrack. The 115-kV operating buses would have eighteen 115-kV lightning arresters. The initial-build of the 115-kV switchrack would connect to two *dead-end structures*.[1] Space would be reserved at the proposed Alberhill Substation for a future 12-kV switchrack.

CAPACITOR BANKS

One 115-kV capacitor bank would be installed in the initial build of the proposed Alberhill Substation with a circuit breaker and a disconnect switch. The capacitor bank would be approximately 14 feet high. Space would be reserved for three additional 115-kV capacitor banks and two 500-kV capacitor banks.

CONTROL BUILDING

Monitoring equipment for the proposed Alberhill Substation would be located in a permanent control building that would be constructed of prefabricated metal and include a full basement. The control building (7,040 square feet) would be approximately 64 feet wide, 110 feet long, and 20 feet high.

3.2 500-kV Transmission Lines

The applicant proposes to construct two new 500-kV transmission lines (500-kV Line SA and 500-kV Line VA) to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line . Line SA would be 1.6 miles long and Line VA would be 1.7 miles long. Construction of the 500-kV transmission lines would require the removal of one 500-kV lattice steel tower (M13-T4) and installation of 12 new lattice steel towers (500-kV towers SA1 to SA6 and VA1 to VA6).

The lattice steel tower footings would require four excavated holes 3 feet to 6 feet in diameter and 20 feet to 45 feet deep. On average, footings extend above the ground between 1 and 4 feet. The two lattice steel towers installed nearest to the proposed Alberhill Substation would be taller, double-circuit towers, but the conductor would be installed only on one side of the towers as part of the proposed Alberhill Project. The other 10 lattice steel towers installed would be single-circuit towers.

3.3 115-kV Subtransmission Lines (Segments ASP1 through ASP8)

The proposed Alberhill Project would involve the construction of new 115-kV subtransmission lines and modification of existing 115-kV subtransmission lines. LWS poles, TSPs, guy stubs and H-frames would be used for construction of the new 115-kV subtransmission lines. Each of the proposed 115-kV structures would support polymer insulators, 954-kcmil stranded aluminum conductor (SAC), and 4/0 ACSR for grounding. If needed, 954-kcmil ACSR would be used at locations requiring higher tension.[2] The normal

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1 *Dead-end structures* are higher-strength structures used at the termination point of powerlines that are designed to support the high-tension forces associated with the length of the line leading up to the termination point. Higher-strength structures are also installed where powerlines change direction.

2 Stranded aluminum 954-kcmil conductor has a diameter of approximately 1.1 inches. The American Wire Gauge conductor size 4/0 is equivalent to 212-kcmil conductor, which is approximately 0.5 inches in diameter. Aluminum steel-reinforced 954-kcmil conductor, which is composed of strands of aluminum on the outer shell of the conductor cable and strands

rating (in clear atmospheric conditions, with an ambient temperature of 104 degrees Fahrenheit, at an elevation of 500 feet, and with a wind speed of 4 feet per second) of the proposed 954-kcmil SAC is 1,090 amps when in continuous operation. The emergency rating, assuming 4 hours of operation, is 1,470 amps. The 115-kV lines that would be replaced along 115-kV Segments ASP3, ASP4, ASP5, and ASP7 use 653-kcmil ACSR with a normal rating of 920 amps and emergency rating of 1,240 amps under the same conditions identified for the proposed 954-kcmil SAC previously described.

115-KV SEGMENT ASP1

115-kV Segment ASP1 would be a new double-circuit 115-kV subtransmission line at the proposed Alberhill Substation site that would connect the substation to 115-kV Segment ASP2. New TSPs and LWS poles would be installed (Table 3-1). The new double-circuit 115-kV line would connect to the 115-kV switchrack at the western end of the proposed Alberhill Substation. The line would exit the proposed substation near the main entry gate, turn south, and then parallel the substation perimeter south to Temescal Canyon Road. The line would continue southeast along Temescal Canyon Road to Concordia Ranch Road.

115-KV SEGMENT ASP1.5

The 115-kV Segment ASP1.5 would connect to the new 115-kV switchrack at the western end of the proposed Alberhill Substation. The segment would exit the proposed substation near the main entry gate, turn south/southwest, and then cross Temescal Canyon Road to a point along the existing Fogarty–Ivyglen 115-kV line alignment. The 115-kV Segment ASP1.5 would then extend southeast along Temescal Canyon Road and cross I-15. The 115-kV Segment ASP1.5 would be a double-circuit subtransmission line.

115-KV SEGMENT ASP2

The 115-kV Segment ASP2 would place a second circuit on an approximately 6.3-mile section of the proposed Valley–Ivyglen 115-kV line (115-kV Segments VIG4 and VIG5; Figures 2-2a and 2-2b). As part of the proposed Valley-Ivyglen Project, four LWS poles would be installed on the south side of Concordia Ranch Road to avoid conflicts that would occur during construction of the proposed Alberhill Substation. As part of the proposed Alberhill Project, three replacement LWS poles and two TSP would be installed on the north side of Concordia Ranch Road (Table 3-1). The final location of the five poles on the north side of Concordia Ranch Road would accommodate 115-kV circuits that would exit Alberhill Substation to the east on poles constructed as part of the Valley–Ivyglen Project. No other structure installation or replacement would be required along 115-kV Segment ASP2 as part of the proposed Alberhill Project. The proposed Valley–Ivyglen 115-kV line is designed to support two circuits. To add the second circuit along 115-kV Segment ASP2, the proposed Valley–Ivyglen 115-kV line structures would require the addition of crossarms, anchors, insulators and conductor.

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of steel in the core, is generally a few millimeters in diameter wider than 954-kcmil stranded aluminum conductor, which does not contain a steel core (Grigsby 2001).

Double-circuiting would begin at the southeastern end of 115-kV Segment ASP1 and follow Concordia Ranch Road east to its terminus. From there it would cross I-15 south to Temescal Canyon Road and then continue east to Lake Street. From Lake Street, it would continue south to Nichols Road. The line would then follow Nichols Road to Pierce Street and then turn southeast on Baker Street and continue to Riverside Avenue (SR-74). The line would follow Riverside Avenue northeast and then pass southeast over land to Pasadena Avenue. It would continue along Pasadena Avenue and then turn northeast onto Third Street and continue to Collier Avenue.

115-KV SEGMENT ASP3

Along 115-kV Segment ASP3, a second circuit along a section of the Valley–Elsinore–Fogarty 115-kV line would be installed and the existing single-circuit section of the line would be removed. New structures capable of supporting two circuits would be installed. The new LWS poles and several TSPs would be installed to enable the crossing of I-15 (Table 3-1). Wood poles and the existing TSPs adjacent to I-15 would be replaced in the City of Lake Elsinore between the intersections of Third Street and Collier Avenue and Second Street and Camino del Norte.

115-KV SEGMENT ASP4

115-kV Segment ASP4 includes installation of new double-circuit LWS poles along a section of the Elsinore-Skylark 115-kV lines as well as removal of the existing single-circuit sections of the lines (Table 3-1). From East Hill Street southwest to East Pottery Street, structures would be constructed and removed along a section of the Elsinore–Skylark 115-kV line. From East Pottery Street east to East Franklin Street and then southeast to Skylark Substation, structures would be constructed and removed on the Elsinore–Skylark 115-kV line. The line would continue from East Franklin Street over land and then along Auto Center Drive, Casino Drive, Malaga Road, and Mission Trail to Skylark Substation.

115-KV SEGMENT ASP5

115-kV Segment ASP5 includes installation of new double-circuit LWS poles and H-frame structures along a section of the Valley–Newcomb–Skylark 115-kV line (Table 2-2). The existing 115-kV LWS poles, H-frame structures, and wood poles would be removed. This segment would pass through the cities of Wildomar and Menifee.

Starting at Skylark Substation, the double-circuit lines would continue east across Mission Trail Road to Waite Street. It would follow Waite Street and then turn north onto Almond Street and continue to Lemon Street. It would cross I-15 and continue east along Lemon Street to where the street turns into Lost Road. It would continue northeast on Lost Road and then turn east and cross open land and multiple roads to Beverly Street. It would follow Beverly Street and then continue east along Bundy Canyon Road to Scott Road.

115-KV SEGMENT ASP6

115-kV Segment ASP6 includes construction of LWS poles for a new single-circuit 115-kV subtransmission line north from the intersection of Scott Road and Murrieta Road to Newport Road. An existing distribution line with wood poles along Murrieta Road would be removed, and the distribution line conductor would be transferred to and underbuilt on the new 115-kV structures (installed below the new 115-kV circuit).

115-KV SEGMENT ASP7

115-kV Segment ASP7 includes installation of new double-circuit LWS poles and TSPs along a section of the Valley–Newcomb–Skylark 115-kV line north of the intersection of Newport Road and Murrieta Road to Newcomb Substation in Menifee. Existing 115-kV wood structures would be removed. In addition, the circuit breaker at Newcomb Substation that connects the substation to Valley Substation would be opened, which would disconnect Newcomb Substation from Valley Substation.

115-KV SEGMENT ASP8

115-kV Segment ASP8 includes installation of new LWS poles and TSPs along a 300-foot section at the intersection of Murrieta Road and McLaughlin Road in Menifee to connect the Valley–Newcomb 115-kV line to the proposed Valley–Ivyglen 115-kV line (Figure 2-2f). Existing 115-kV wood structures would be removed. The circuit breaker that connects the proposed Valley–Ivyglen 115-kV line to Valley Substation would be opened to ensure that the line is deenergized from Valley Substation.

3.3 Telecommunications

The proposed Alberhill Substation would require the installation of new telecommunication infrastructure to provide protective relaying, data transmission, and telephone services to the substations served by the proposed Alberhill System. These new facilities include modifications to the applicant's existing microwave system and the addition of new fiber optic cable. The proposed Alberhill Project would include the installation of new telecommunication infrastructure required for communication with the substations served by the proposed Alberhill 115-kV System. New microwave components, fiber optic cable, and other telecommunications equipment installations would be part of the proposed Alberhill Project.

3.4 Access Roads

Each of the proposed 500-kV transmission line tower sites could require 24-hour vehicular access during operation of the proposed Alberhill Project for emergency and maintenance activities. The applicant would install gates to restrict general and recreational vehicular access roads. The applicant would construct approximately 3 miles of new or modified access roads to access the proposed 500-kV transmission line structures if the conventional method of construction is used for the 500-kV transmission line. The proposed Alberhill 115-kV segments would not require new or modified access roads.

References

SCE (Southern California Edison). 2011. Proponent's Environmental Assessment: Alberhill System Project (April 11), as amended by responses from SCE to CPUC requests for additional information.

Appendix B – Preliminary Results: Tie-Line Power Flow Analysis

Portions of this report have been redacted based on Southern California Edison's claims of confidentiality based on critical infrastructure information and other legal privileges.

Alberhill System Project

Preliminary Results:
Tie-Line Power Flow Analysis

April 12th, 2021

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Executive Summary

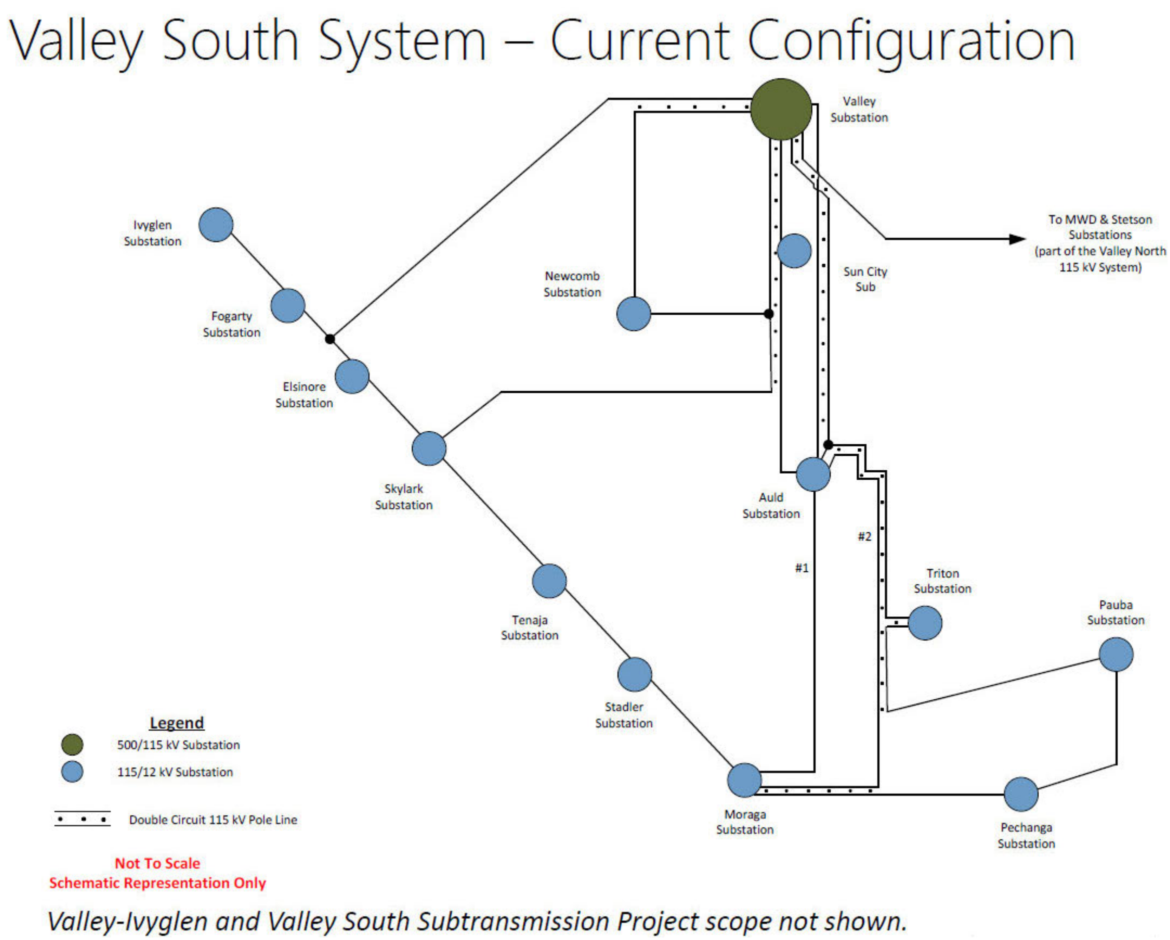
This report presents the results of the tie-line analysis conducted to understand whether the Valley South tie-lines proposed by SCE as part of the Alberhill System Project were necessary in order to achieve system capacity, reliability, and resiliency in the Valley South service area. Four power flow base cases that represent alternatives containing tie-lines and a base case were used for this analysis. Following a review of the preliminary results, additional scenario cases were developed to further study the effects that tie-lines alone, energy storage alone, or a combination thereof have on the Valley South system. The findings of this assessment were as follows:

- Tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers and meet reliability and resiliency requirements. SCE has concluded that the tie-lines in this alternative are ineffective under double contingencies or a catastrophic event that results in a loss of both Valley South transformers.
- Transferring service for two substations (Newcomb and Sun City substations) via 115 kV tie-lines to the Valley North system and installing 50 MW of distributed battery energy storage system (BESS) in the Valley South system could also mitigate this overload as effectively as the Alberhill System Project while meeting capacity, reliability, and resiliency requirements. This alternative satisfies part of the CPUC's objective to enable electricity service from Valley South or from a new 115 kV system. The difference is that these tie-lines enable electricity service from the existing Valley North system or from the Valley South system and would achieve the same performance.
- SCE concluded that the tie-lines in this alternative are ineffective in the event there is a double contingency or in the event that a catastrophic event occurs that results in the loss of both Valley South transformers. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted and the power flow results indicated that this alternative performed effectively.

Background

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the two 560 MVA Valley South 500 kV transformers to become overloaded in 2023. As part of supporting and informing the CEQA process, several technical analyses are being conducted. One of these is an analysis of the tie-lines proposed as part of ASP. This report discusses the analysis conducted and the results. Figure 1 depicts the current configuration of the Valley South system without tie-lines.

Figure 1: Current Valley South System Configuration.[1]



Valley South Service Area Socio-economic Profile

Valley South substation is located in Menifee, CA and its service area comprises approximately 380 square miles in the southwestern portion of Riverside County. SCE estimates that the Valley South substation serves approximately 560,000 people[2] in the unincorporated areas of Riverside County and in the cities of Elsinore, Menifee, and Wildomar. According to the 2019 Census data, the population that would be impacted by this project are relatively young families. The census data for this area indicates that the population on average are in their thirties and about a quarter have earned a bachelor's degree or higher. Home

[1] *Source: Quanta Technology Reliability Analysis of Alberhill System Project report*.

[2] *A0909022-SCE-ASP Amended Motion to Supplement – Exh C-2.pdf, page 8.*

ownership rates are about 70 percent with about a quarter having moved into their homes in the 2000s. In the cities within the Valley South service area, the median household income ranges from $73,000 to $77,000 and poverty rates range from 8 to 12 percent. For context, the statewide median household income is $80,440 and the poverty rate is 11.8 percent.

Proposed Alberhill System Project

The ASP consists of a new 500/115 kV substation and two new 500 kV lines to connect the Alberhill System to the Serrano 500 kV substation to the west and the Valley 500 kV substation to the east. On the 115 kV side of ASP, one new 115 kV line would be built, and four existing 115 kV lines would be modified to connect Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb substations to ASP. As part of this project, some of the 115 kV line modifications would be for the purpose of creating system tie-lines in the Valley South 115 kV system to increase system flexibility and resiliency. Figure 2 depicts the Alberhill System Project.

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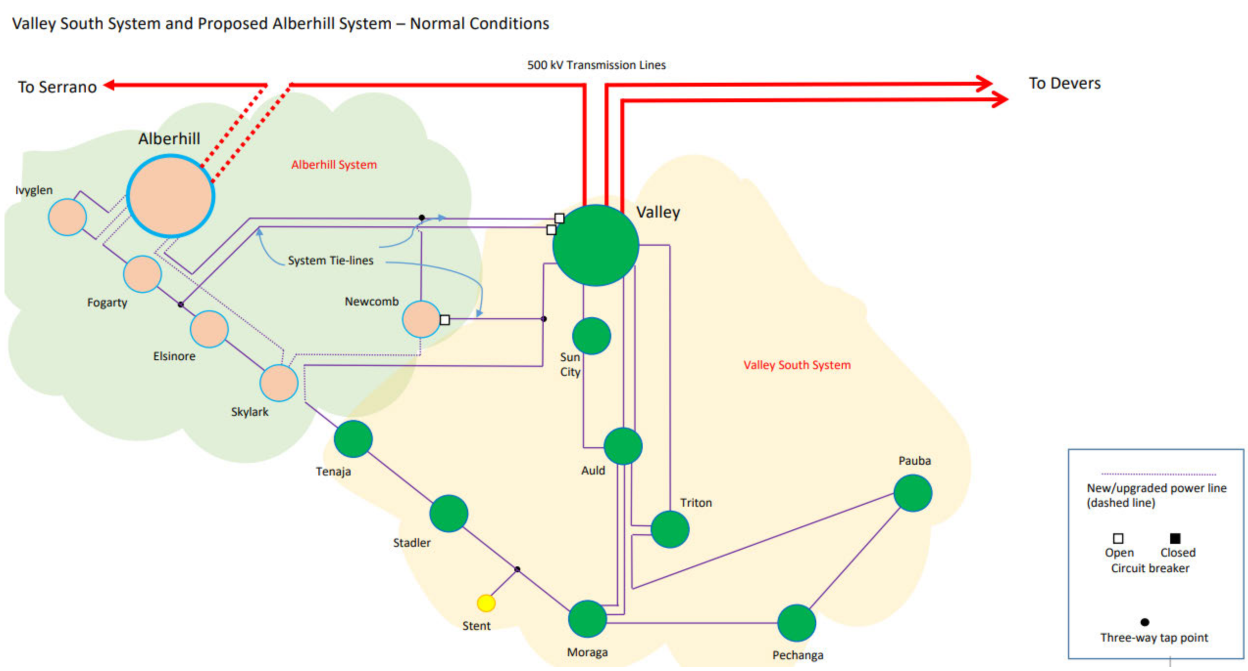
Figure 2: ASP Tie-lines.[3]



Objective and Technical Approach

Objective

The objective of this analysis is to assess whether the Valley South tie-lines result in power flow impacts that affect Valley South substation's reliability and resiliency.

Technical Approach

To assess how the tie-lines that are proposed as part of ASP perform with respect to capacity, reliability, and resiliency, several base cases representing scenarios were studied. These scenario cases represented alternatives that include tie-lines in the Valley South system, distributed battery energy resources, and centralized battery energy storage systems. This approach enabled comparison of the base case, which represents the Valley South system as it exists today without any new projects or tie-lines, with the following scenarios:

- Tie-line performance
- Battery energy storage performance

[3] Source: 20210218 ASP Energy Division Briefing Deck 0218 Final

- Combination of tie-lines and energy storage.

Power flow studies were conducted for each of these scenario cases and the results were compared under normal conditions and contingency conditions based on NERC reliability standards[4].

CPUC and SCE Objectives of ASP

As part of this analysis, ASP objectives from SCE and from the CPUC were considered. The CPUC developed the following objectives for ASP to provide a basis for developing a reasonable range of alternatives pursuant to the CEQA process.[5]

1. Relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers;
2. Construct a new 500/115 kV substation within the Electrical Needs Area that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

The power flow analysis conducted as part of this tie-line analysis addressed the CPUC's first and third objectives.

SCE listed the following project objectives in their planning study report and chose ASP as the preferred project based on its performance relative to the other twelve alternatives:

1. Serve current and long-term projected demand requirements.
2. Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer to substations from the current Valley South system.

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[4] While SCE's Valley 115 kV system is part of SCE's distribution network and not under CAISO control, its reliability performance must still be consistent with general accepted utility practices which are based on NERC Reliability standards. Parts of the NERC reliability Standards are adopted in SCE's Subtransmission Planning Criteria which require that all facilities operate within their continuous ratings under normal system conditions and under emergency ratings under contingency conditions.

[5] https://www.cpuc.ca.gov/environment/info/ene/alberhill/Docs/1.0%20ASP-VIG%20Introduction.pdf

3. Transfer a sufficient amount of demand from the Valley South system to maintain reserve capacity through the ten-year planning horizon.
4. Provide reliable service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
5. Increase system reliability by constructing a project in a location suitable to serve the existing Valley South service area.
6. Meet project needs while minimizing environmental impacts.
7. Meet project needs in a cost-effective manner.

While most of SCE's project objectives are typical and similar to objectives stated by other utilities proposing similar projects, objective number 2, the specification of tie-lines, appears prescriptive and could potentially result in alternatives without system ties being dropped from further consideration even if they meet the other six objectives.

SCE's Objective number 4 refers to the Subtransmission Planning Criteria which covers a range of operational conditions and exceptions to the criteria, some of which are not applicable to Valley South Substation. This is typical of utility planning criteria which are generally based on NERC Reliability Standards, but may take their unique system configurations into consideration when developing exceptions. The portions of this criteria that are applicable to the Valley South transformers are the requirements for component overloads under emergency conditions. The Subtransmission Guidelines contain several guidelines that are applicable to the Valley South system configuration and its performance under normal and contingency conditions. These include maintaining sufficient transformer capacity under normal and contingency conditions and tie-lines to facilitate load transfer to limit the durations of customer interruptions. In the context of the Valley South system, these are applicable guidelines as the Valley South transformer is expected to overload under normal conditions starting in 2023. Neither the SCE Subtransmission criteria nor the guidelines as presented by SCE are currently being violated.

The power flow analysis conducted as part of this tie-line analysis addressed SCE's first, second, third, and fourth objectives.

Power Flow Assessment

Methodology and Assumptions

Using the General Electric (GE) Positive Sequence Load Flow (PSLF) software and PSLF base cases, power flow studies were conducted under normal and contingency conditions. Single contingencies and double contingencies where the circuits were on the same tower or in the same right-of-way were used to study contingency conditions. The contingencies used are shown below, in Table 1, and were obtained from the Quanta Technical Cost Benefit Analysis of Alternatives report[6]. The results were assessed based on NERC reliability standards and SCE planning criteria. Power flow results under each of the base cases described below were compared to assess what impacts the tie-lines have on reliability and resiliency at Valley South substation. Power flow results obtained for the Valley South (Base) scenario were used as a basis for comparing impacts.

Table 1: Single and Double Contingencies

Single Contingencies (N-1)	Double Contingencies (N-2)
Auld-Moraga #1	Auld-Moraga #2 & Valley-Triton
Auld-Moraga #2	Valley EFG-Auld #1 & Valley EFG-Auld #2
Valley EFG-Newcomb-Skylark	Auld-Moraga #2 & Pauba-Triton
Skylark-Tenaja	Valley EFG-Auld #2 & Valley EFG-Triton
Valley EFG-Elsinore-Fogarty	Valley EFG-Sun City & Valley EFG-Newcomb-Skylark
Valley EFG-Auld #1	Auld-Sun City & Valley EFG-Newcomb-Skylark
Valley EFG-Auld #2	Auld-Moraga #2 & Moraga-Pechanga
Valley EFG-Sun City	Valley EFG-Triton & Pauba-Triton
Valley EFG-Newcomb	Valley EFG-Elsinore-Fogarty & Valley-Newcomb

[6] Quanta Technology (January 27, 2021) Reliability Analysis of Alberhill System Project Report (Version 2).

Moraga-Pechanga	Fogarty-Ivyglen & Valley EFG-Ivyglen
Valley EFG-Ivyglen	
Valley EFG-Triton	

Power Flow Case Descriptions

[redacted]

[redacted]

[redacted]

[redacted]

7 *Source: SCE PSLF Load Allocation Percentages Spreadsheet*

[redacted]

[redacted]

[redacted]

[redacted]

[8] *Source: Exh C-2 SCE Planning Report.*

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[redacted]

[redacted]

[redacted]

[redacted]

[10] *Exh C-2 SCE Planning Report.*

[redacted]

[redacted]

[11] *Source: Exh C-2 SCE Planning Report.*

[redacted]

[12] *Exh C-2 SCE Planning Report.*

Results

Power flow studies were conducted to assess system performance with system load modelled at the forecasted load for 2025. The following sections discuss results under normal system conditions, single contingency conditions, and double contingency conditions.

Normal Conditions

[redacted]

[redacted]

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[redacted]

Single Contingency Conditions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Double Contingency Conditions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

Conclusions

The power flow studies conducted for this assessment were conducted using PSLF base cases provided by SCE and the assumptions were based on information obtained from both the SCE Planning Report, the Quanta Technical Reliability Analysis of Alberhill System Project report, and the Quanta Technical Cost Benefit Analysis of Alternatives report. The base cases were modified to reflect the 2025 load forecasts and to differentiate between the results more precisely. Several scenario cases were developed for this tie-line analysis. The results of this analysis conclude that:

- An overload occurs on the Valley South transformers under normal system conditions. Tie-lines that transfer substation service from Valley South to Valley North are effective in mitigating this overload. Transferring service for Newcomb and Sun City substations to Valley North and installing 50 MW of distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements. This alternative also meets the CPUC's objectives of relieving demand that overloads the Valley South Transformers; and partially meets the objective of enabling electricity service from Valley South or from a new 115 kV system.
- An assessment using both the worst single contingency and the worst double contingency showed that the transformers do not experience overloads, and in fact, their flows are significantly reduced. Other 115 kV lines in the Valley South system do experience overloads under contingency conditions. However, those appear unrelated to the Valley South transformer overloads.
- BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is most effective when combined with tie-lines.
- SCE concluded that the tie-lines in this alternative are ineffective in the event there is a double contingency or in the event that a catastrophic event occurs that results in the loss of both Valley South transformers. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted and the power flow results indicated that this alternative performed effectively.

Appendix C – Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

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Alberhill System Project

Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

June 11, 2021

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Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP).

In this analysis, SCE's load forecasting methodologies were assessed relative to typical load forecasting methodologies and were found to be comparable to those used by similar utilities, including Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E). Kevala determined the methodologies to be reasonable and will further assess the impact of the load forecast methodologies in the electrical engineering analysis[13].

The performance metrics used by SCE to evaluate and rank the proposed project and each alternative were also assessed relative to performance metrics used by PG&E and SDG&E. Kevala determined the performance metrics to be reasonable, though several were considered to be uncommon, including the Load at Risk (LAR), flexibility-1, and flexibility-2 metrics[14]. SCE's adaptation of loss of load expectation (LOLE) into the metrics that were developed for assessing the ASP and alternatives (such as LAR, flexibility-1, and flexibility-2) affected the relative ranking of the ASP proposal over some alternatives. While LOLE is commonly used in other analyses, the use of LAR over alternative metrics likely caused proposals with tie-lines to be ranked higher than alternatives without them. The metrics developed by SCE have sufficient basis in acceptable metrics to be reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.

[13]The electrical engineering analysis will be reported in *Review of SCE's Electrical Engineering Analysis for the Alberhill System Project* (June, 2021)

[14] Note that all of the Flexibility-1 and Flexibility-2 metrics also use LAR as part of their calculation.

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Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the two 560 MVA Valley South 500 kV transformers to become overloaded in 2023.

This report documents a review of SCE's load forecasting methodology for the Alberhill System Project. Additionally, this analysis considered SCE's reported peak load, the implications of the load forecast trend, and the potential modifications to the forecasted load by the proposed project.

Additionally, the performance metrics defined by SCE were compared to metrics typically used in the industry to evaluate whether they are comparable and reasonable. Kevala reviewed the documents released by SCE in their refiling, including SCE's *Revised Planning Study* (February 1, 2021) and the Quanta Technology's (Quanta) report, *Reliability Analysis of Alberhill System Project* (February 1, 2021)[15]. SCE's load forecasting methodology was then compared to load forecasting methodologies used by the California Energy Commission (CEC), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E). Lastly, additional research was conducted to determine whether the performance metrics used by SCE are commonly used by other comparable utilities, such as Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E).

[15] SCE's *Revised Planning Study* (February 1, 2021) is available on the CPUC website.

SCE Load Forecasting Methodologies

Overview

Kevala reviewed SCE's *Revised Planning Study* (February 1, 2021), Quanta's *Reliability Analysis of Alberhill System Project* (February 1, 2021), CEC's load forecast methodology, PG&E's load forecasting methodology, and SDG&E's load forecasting methodology.

Three load forecast methodologies were presented by SCE:

- SCE's load forecasting methodology
- Quanta's conventional load forecasting methodology
- Quanta's spatial load forecasting methodology

Load Forecasting Methodology Summary

SCE develops a 10-year peak load forecast based on peak load values collected from historical data which is then normalized to a common temperature base to account for variations in peak temperatures from year to year. Customer load growth and Distributed Energy Resource (DER) forecasts were also utilized to develop the peak load forecast. The DER considered include:

- Energy efficiency (EE)
- Energy storage (ES)
- Demand response (DR)
- Electric vehicle (EV) charging
- Distributed generation (DG)

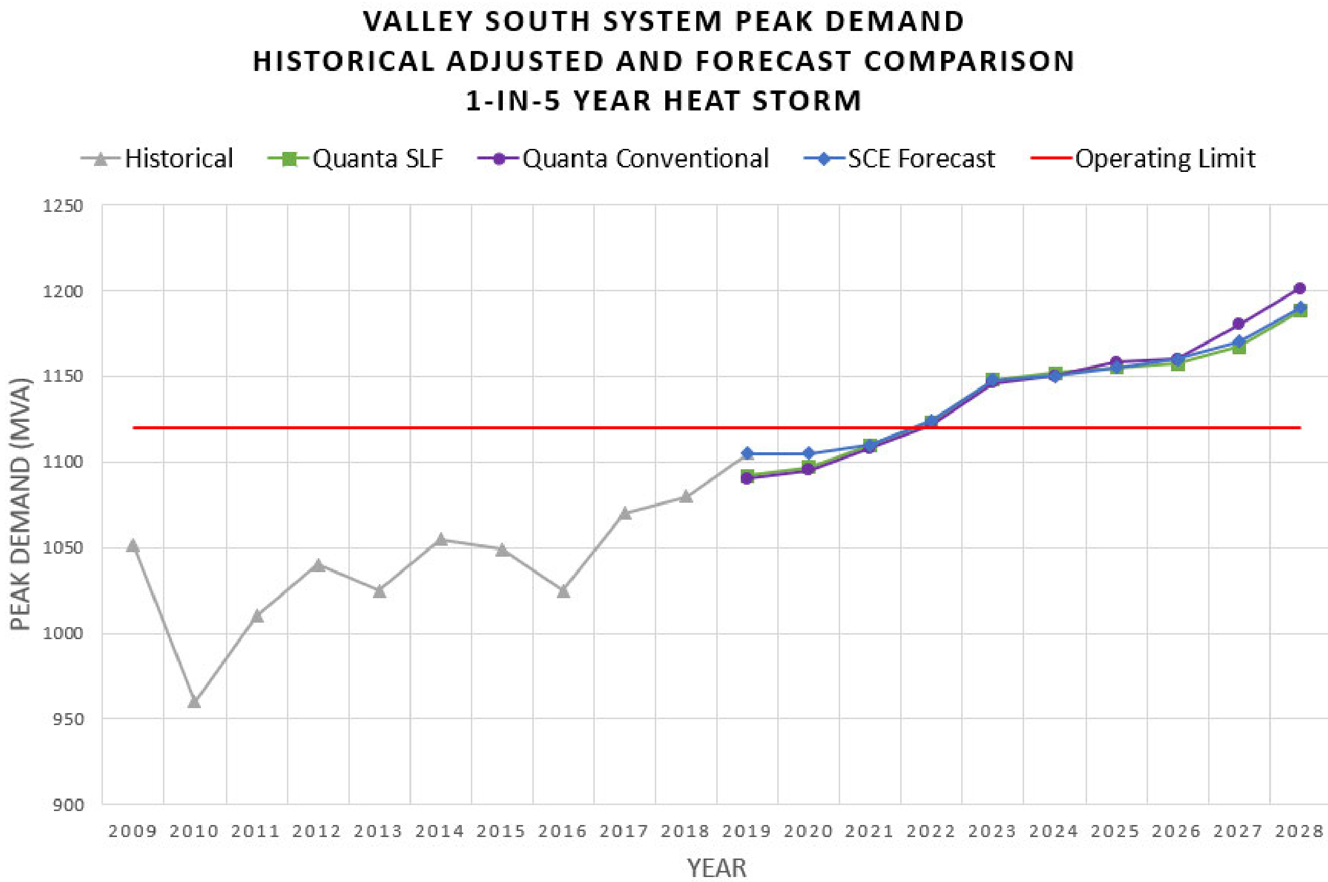
At the distribution level, SCE uses the CEC's Integrated Energy Policy Report (IEPR) that is derived from the California Energy Demand (CED) forecast to determine base load growth. SCE uses customer advanced metering infrastructure (AMI) data to inform load disaggregation of the CED forecast. This allows for DER and other load reducing programs to more accurately be considered when accounting for local and specific electrical needs. Moreover, as appropriate, any additional load growth that is not reflected in the CED forecast is appropriately incorporated into SCE's forecast.

For the second and third load forecasting methodologies that were reviewed, Quanta developed load forecasts based on other methodologies and sensitivities. These included:

- Extension of Conventional 10-year load forecast: A methodology in which the conventional 10-year load forecast was extended to produce a 30-year (2019-2048) 1-in-5 year peak load forecast based on historical substation load normalized to a common temperature.
- Spatial load forecast: A sensitivity that produced a 30-year (2019-2048) net peak system load. This involves the forecasting of peak load, customer count (based on zoning and land-use data), and customer energy consumption within a particular needs area. Non-traditional factors such as PV, EV adoption, and EE were incorporated by disaggregating CEC's CED forecast at the subdivision level.
- Spatial Base forecast: a sensitivity where DERs are assumed to continue historical trends, a Spatial Effective PV forecast where DERs are varied based on the California Energy Demand forecast developed at the CEC, and a spatial PV Watts sensitivity forecast which incorporates the unadjusted CED PV forecast.

The Spatial Effective PV load forecast methodology (a sensitivity as part of the Spatial Base forecast) was ultimately used by SCE to develop the forecast used to conduct the cost-benefit analysis for the ASP. Quanta selected the Spatial Effective PV load forecast as the likely future long-term load forecast scenario and used the extended 2019-2048 forecast to conduct analyses. A 10-year comparison of the SCE and Quanta load forecasts is depicted in the figure below.

Figure 1: SCE load forecasts and Quanta load forecasts



Assessment

The methodologies used by SCE in developing their load forecast for evaluating the ASP and its alternatives range from comparable to less commonly used. For example, SCE's 10-year peak load forecast uses a methodology that is comparable to that used by PG&E and SDG&E. All three utilities use historical loads, weather data, economic data, and demographic data as inputs. The difference is that where PG&E and SDG&E start with the CEC's CED forecast and then apply factors unique to their service territories to create a long-term forecast, SCE starts with historical load data and then uses the CED forecast to determine DER proportions in the long-term forecast. As a result, a direct comparison of SCE's load forecast methodology to the CED forecast methodology is not possible as SCE did not use the CED as the basis for its long-term forecast. Furthermore, the CED forecast produces a single forecast for SCE territory, whereas for the ASP, SCE developed a forecast specifically for the Valley South substation. SCE's load forecast incorporated the CEC's DER projections and this is consistent with the approach used by PG&E and SDG&E.

Kevala did not perform an assessment of the Quanta load forecasts as SCE retained Quanta to develop independent forecasts to validate the SCE forecast and to demonstrate that other independently developed methodologies arrived at forecasts that were similar to SCE's.

Performance Metrics

Overview

To assess the performance metrics used by SCE in evaluating the ASP and each of the alternatives, Quanta's report, *Reliability Analysis of Alberhill System Project* (February 1, 2021), was reviewed. Kevala conducted further research to find other instances where these performance metrics were used in evaluating and ranking projects and alternatives. This research included a review of the Expected Energy Not Served (EENS) Literature Search provided by SCE via email on July 13, 2020.

SCE used several different performance metrics as shown in Table 1. Some of these metrics are accepted industry standards while others are newer metrics that require evaluation.

Table 1: Definitions of SCE's performance metrics

System Performance Metric	Description
Load at Risk (LAR)	Calculated as MWh at risk during thermal overload and voltage violation periods under N-0 and N-1 conditions.
Expected Energy Not Served	This metric was formerly known as LAR. It was revised and renamed LAR in the reports included in the February 1, 2021 filing.
Maximum Interrupted Power (IP)	Calculated as maximum MW that would need to be curtailed during thermal overload and voltage violation periods under N-0 and N-1 conditions.
Flexibility 1 (Flex-1)	Calculated as the summation of LAR for all possible N-2 line contingencies. Results are probabilistically weighted to reflect the actual frequency of each N-2 contingency.
Flexibility 2 (Flex-2-1)	● Calculated as LAR resulting from loss of all transformers in the Valley South substation. ● Assumes a two-week period that randomly occurs throughout the year.
Flexibility 2 (Flex-2-2)	● Summation of LAR when the Valley South transformers are unavailable due to a fire. ● Assumes a two-week period that randomly occurs throughout the year.

Period of Flexibility Deficit (PFD)	Calculated as LAR resulting when the system tie-lines do not provide the required flexibility capacity under N-0 and N-1 conditions.

- **Normal overloads:** Defined as overloads that exceed 100% of normal ratings. The criteria require the loading of all transmission system facilities (transmission lines and transformers) to be within their normal ratings under normal operating conditions.
- **Emergency overloads:** Defined as overloads that exceed 100% of emergency ratings following single element contingencies and multiple element contingencies. The criteria require all transmission facilities to remain within their emergency ratings during single or multiple contingency conditions.
- **Voltage deviations:** Defined as deviations that should not exceed 5% from pre-contingency levels under single element contingencies, and 10% from pre-contingency levels under multiple element contingencies.

Assessment

Research of typical performance metrics by comparable utilities revealed no examples of utilities using LAR as a performance metric nor was it discussed in research papers as a performance metric. Additionally, a survey of other projects under CEQA review did not uncover projects using these metrics.

Prior to choosing LAR as the primary performance metric, SCE used EENS. Only one utility had used the EENS metric (British Columbia Hydro in Vancouver, British Columbia). All other publications that used EENS as a performance metric were research and academic publications.

The Flexibility 1 and Flexibility 2 metrics were developed by SCE to create a methodology that takes different contingency events and their probabilities into account while evaluating the performance of the alternative solutions relative to the ASP. These are not sufficiently comparable to other metrics used in industry such as loss of load and therefore do not provide clarity into the ranking and selection process. Although the metrics themselves are uncommon, the approach of using the metrics as a high-level comparison tool does enable a juxtaposition of the alternatives against each other based on a common metric.

The IP metric is a commonly used metric for calculating necessary curtailments to relieve overloads under normal or contingency conditions. Its use is appropriate as a metric for comparing the ASP and each of the alternatives.

The PFD metric is not a commonly used metric and appears to have been created for the purpose of giving more weight in the rankings to alternatives using tie-lines that provide more flexibility capacity based on their performance under normal and contingency conditions.

The Loss of load expectation (LOLE) metric is a commonly used metric in the industry, however, it appears that SCE may have adapted the LOLE metric into LAR in an effort to suit their particular system. Both LOLE and LAR are comparable in that they account for loss of load. The LOLE metric calculates the expected average number of days per year during which the load exceeds available generating capacity due to outages or other system conditions. In contrast, the LAR metric calculates the energy (MWh) potentially at risk of not being served due to a variety of system conditions, under normal and contingency conditions. The Flexibility-1 and Flexibility-2 metrics are also calculated based on the LAR resulting from the loss of the Valley South transformers. For this reason, the metrics developed by SCE appear to have been designed to give favorable weighting to alternatives with tie-lines relative to those without tie-lines.

SCE achieved this by assuming a two week duration for the loss of the Valley South transformers which results in higher levels of LAR. Although this contingency may be a low probability event, its duration contributes to the large magnitude of the LAR. This metric supports SCE's project objective to increase operational flexibility and maintain system reliability by creating system tie-lines that establish the ability to transfer substations from the current Valley South system.

It is possible that an application of LOLE without the SCE adaptation to favor tie-lines could have boosted the ranking of alternatives that create capacity on the Valley South transformers through the interconnection of PV and battery energy storage system (BESS) in the Valley South system or by transferring load away from Valley South substation. Namely, these are:

- The Centralized BESS in Valley South alternative
- The Valley South to Valley North and Distributed BESS in Valley South alternative

- The Valley South to Valley North and Centralized BESS in Valley South and Valley North alternative
- The Valley South to Valley North alternative
- The Valley South to Valley North to Vista alternative

The SCE alternatives and capacity improvements are available in Table 2, taken from SCE's *Revised Planning Study* (February 1, 2021), the alternatives listed show a 100% improvement under the Capacity Improvement column. However, they show an improvement of 1% or 3% under the Reliability/Resiliency Improvement column (compared to the ASP at 98%). This poor showing is due to the favorable weighting of tie-lines in the metrics developed by SCE. Kevala's report, *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021) provides an analysis of the reliability and resiliency of alternatives that consist of tie-lines. The tie-line power flow analysis was conducted based on North American Electric Reliability Corporation (NERC) reliability standards and Western Electricity Coordinating Council (WECC) criteria. The analysis demonstrated that alternatives that transferred load from two substations via tie-lines performed as well as alternatives with BESS under normal system conditions and slightly better under contingency conditions. The large difference in reliability/resiliency improvement results shown in the table below were not reflected in the power flow results.

Table 2: SCE alternatives and capacity improvement

Alternative	Results Through 2028		Results Through 2048	
	Capacity Improvement	Reliability/ Resiliency Improvement	Capacity Improvement	Reliability/ Resiliency Improvement
No Project	0%	0%	0%	0%
Alberhill System Project	100%	98%	99%	97%
SDG&E	100%	87%	99%	82%
SCE Orange County	99%	85%	93%	79%
Menifee	100%	67%	92%	62%
Mira Loma	100%	36%	77%	34%
Valley South to Valley North	100%	3%	78%	6%
Valley South to Valley North to Vista	100%	3%	89%	6%
Centralized BESS in Valley South	100%	1%	100%	3%
Valley South to Valley North and Distributed BESS in Valley South	100%	3%	81%	7%
SDG&E and Centralized BESS in Valley South	100%	87%	100%	83%
Mira Loma and Centralized BESS in Valley South	100%	36%	100%	35%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	100%	3%	95%	6%
Valley South to Valley North to Vista and Centralized BESS in Valley South	100%	3%	92%	6%
Note: Performance improvements for each alternative represent the percentage of LAR reductions over the No Project Scenario. LAR N-0 and LAR N-1 are capacity metrics, while Flex-1, Flex 2-1, and Flex-2-2 are reliability/resiliency metrics.				

The standards used in the power flow analyses by SCE are common and are in fact required as part of compliance with WECC and NERC regulations. All utilities in the WECC and NERC regions must comply with these criteria and standards.

Alberhill System Project Effect on the Load Forecast

Power flow studies conducted using SCE's load forecast confirmed that overloads on the Valley South transformers do occur in 2023. Similarly, simulations of the ASP in the power flow cases show a significant reduction in the flows through the Valley South transformers. All of the alternatives (except for the no-project alternative) also provide varying levels of reduction in power flows and bring the Valley South transformers within their normal ratings. This same forecast when projected long-term to thirty years becomes less certain as a thirty-year outlook is almost impossible to predict. Consequently, results showing when the Valley South transformers may become overloaded again under the ASP and each of the alternatives is highly speculative beyond the ten-year period. The normal practice is to use the 10-year forecast for planning projects and to use the 20-year forecast as an informative screening tool.

Conclusions

This report assesses SCE's load forecasting methodology and performance metrics for the ASP and proposed alternatives. Kevala reviewed SCE's Revised Planning Study and the Quanta Technology (Quanta) reports released by SCE in their February 1, 2021 refiling as well as researched and analyzed the load forecasting methodologies used by the CEC, PG&E, and SDG&E. These methodologies were then compared to those utilized by SCE for evaluation. Kevala determined that some metrics, such as LAR, were not being practiced elsewhere.

The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and at SDG&E. This assessment also ascertained that SCE may have used a common performance metric, LOLE, and adapted it to create a similar metric, LAR, in order to suit their system. Consequently, project alternatives with tie-lines were weighted more heavily than alternatives without. Although some performance metrics were uncommon due to this adaptation, the overall performance metrics developed by SCE have sufficient basis in other metrics commonly used by utilities. Kevala determined that the metrics and methodologies used by SCE to be reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.

Appendix D – Behind-the-Meter Adoption Propensity Analysis for the Valley South System

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Alberhill System Project

Behind-the-Meter Adoption Propensity Analysis for the Valley South System

April 16th, 2021

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Table of Contents

Executive Summary

The California Public Utilities Commission (CPUC), through the consultants Ecology and Environment (E&E, now WSP), is performing a California Environmental Quality Act ("CEQA") analysis of Southern California Edison's ("SCE") application for a Certificate of Public Convenience and Necessity ("CPCN") as part of the proposed Alberhill System Project (ASP). Kevala, Inc. (Kevala) prepared this report for the CPUC Energy Division to support the 2021 Draft Alternatives Screening Report (ASR) which WSP is preparing as part of the CPUC's CEQA review of the ASP.

As part of the proposed Alberhill System Project, SCE identified an initial list of 16 project alternatives: three minimal investment alternatives, seven conventional alternatives, one Non-Wire Alternatives (NWAs), and five hybrid alternatives. The purpose of this report is to provide additional data on the potential for behind-the-meter (BTM) solar + storage to serve as an alternative to components of the proposed project.

Kevala's analysis applied a bottom-up economic propensity for adoption modeling to identify customers in the Valley South System who would be likely adopters of BTM resources. This techno-economic analysis utilized technological parameters (e.g., BTM storage system size and performance) and economic inputs (e.g., installation cost) to consider how these factors impact a customer's utility bill and the likelihood of them interconnecting Distributed Energy Resources (DER).

This report provides details on the potential of DER throughout the Valley South system and identifies the amount of electric capacity that could be provided by BTM resources. Kevala's methodological approach, including economic and capacity implications for different scenarios of adoption levels of BTM alternatives, are detailed in this report. The range of adoption propensity scenarios was driven by SCE's value of service and outages, then utilized to model a potential BTM solar + storage adoption.

Introduction

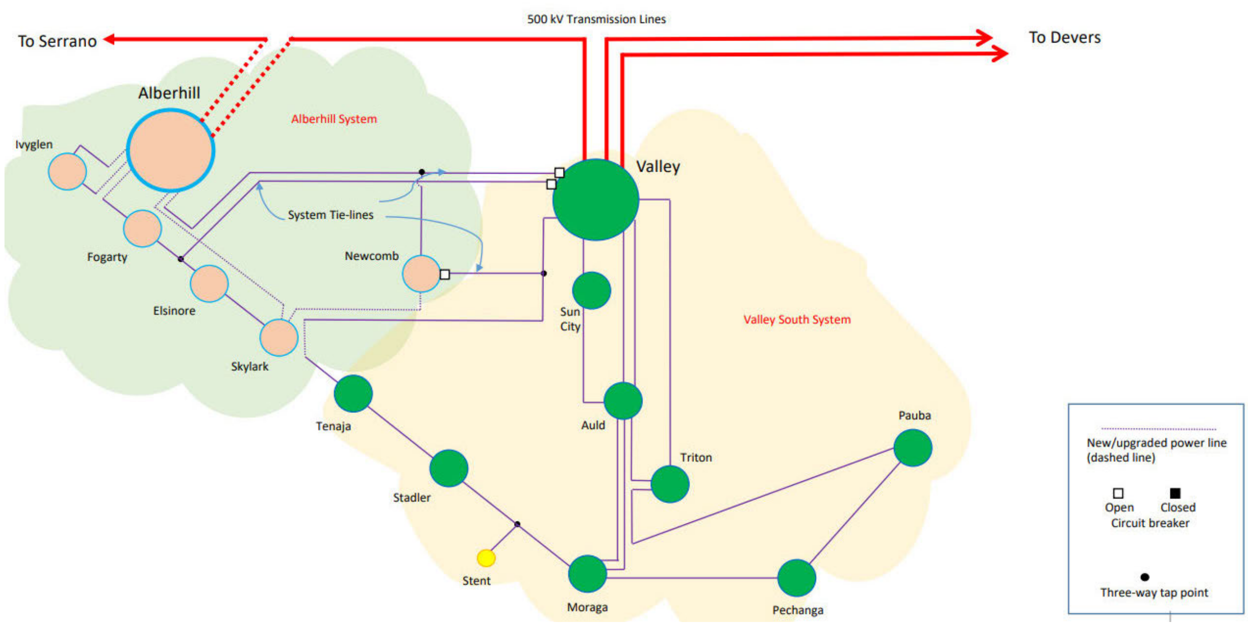
Southern California Edison (SCE) submitted an application for the Alberhill System Project (ASP) on September 30, 2009 as part of Application A.09-09-022. An amended Proponent's Environmental Assessment (PEA) was later submitted by SCE on April 11, 2011.

According to SCE's Planning Study, the Valley South system currently serves over 187,000 customers. The Planning Study also stated that forecasted load growth in the area will experience peak demand that exceeds the transformer capacity by the year 2022. The proposed Alberhill project is intended to alleviate capacity constraints in the Valley South system and will serve the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Hot Springs, Temecula, and Wildomar, and unincorporated Riverside County.

Project Overview

SCE's proposed Alberhill System Project is an upgrade to the Valley System located in the San Jacinto Region in Riverside, California. The Valley System consists of two distinct electrical systems: The Valley North and the Valley South. The ASP focuses on the Valley South system, which includes 14 substations (Ivyglen, Fogarty, Elsinore, Skylark, Tenaja, Stadler, Stent, Moraga, Newcomb, Sun City, Auld, Triton, Pauba, and Pechanga). The proposed ASP is illustrated in Figure 1 below.

Figure 1: Proposed Alberhill System Project



The ASP would consist of three main components. The first is construction of a new 500/115 kV electrical substation. The second is construction of two 500 kV transmission line segments, each about 1.7 miles long, that would connect the Alberhill substation to the existing Valley-Serrano 500 kV transmission line. The last component includes the addition of one new 115 kV transmission line and upgrades to four existing 115 kV transmission lines to transfer five existing substations from the Alberhill substation.

SCE identified and proposed the following project objectives in the Alberhill System Project Planning Study:

- Serve current and long-term projected electrical demand requirements in the Electrical Needs Area.
- Increase system operational flexibility and maintain system reliability by creating system tie lines that provide the ability to transfer substations from the current Valley South System.
- Transfer (or relieve) a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through the 10-year planning horizon.
- Provide safe and reliable electrical service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
- Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).
- Meet project needs while minimizing environmental impacts.
- Meet project needs in a cost-effective manner.

Alberhill System Proposed Alternatives

SCE developed the Alberhill System Project Planning Study[16], which identifies 13 project alternatives categorized as conventional alternatives, non-wire alternatives, and hybrid alternatives. The conventional alternatives are designed with transmission and/or subtransmission build-outs with system tie lines to neighboring systems. The non-wire alternatives utilize a centralized battery energy storage systems (BESS) design. Lastly, hybrid alternatives utilize non-wire alternatives to meet incremental capacity needs but also include conventional alternative approaches to meet the remaining capacity needs that develop.

The only proposed alternative incorporating distributed BESS is the Valley South to Valley North and Distributed BESS in Valley South hybrid solution. This alternative proposes transferring SCE's existing Newcomb and Sun City substations from the Valley South to the Valley North system and interconnecting three 12 kV BESS at the Auld, Elsinore, and Moraga substations. None of the proposed alternatives

[16] SCE's Exhibit C-2 Revised Alberhill System Project Planning Study, submitted on February 1, 2021

considered the impact of more granular adoption of BTM DERs, such as individual customers adopting solar + storage.

CPUC Objectives

As part of this analysis, ASP objectives from the CPUC were considered. The CPUC developed the following objectives for ASP to provide a basis for developing a reasonable range of alternatives pursuant to the CEQA process.[17]

- Relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers
- Construct a new 500/115 kV substation within the Electrical Needs Area that provides safe and reliable electrical service pursuant to NERC and WECC standards
- Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems

Kevala's Role

In its August 31, 2018 decision, the CPUC ordered SCE to revisit its application and consider Distributed Energy Resources ("DERs") including battery storage systems as part of the CEQA process. Kevala is further supporting the CEQA process by conducting an analysis of the amount of potential DERs that may produce an environmentally superior alternative under the SCE's application. The alternative considered in this report outlines likely DER adoption propensity based on economic and technological parameters.

Using its Network Assessor platform, Kevala analyzed BTM DER adoption propensity in support of the CPUC with the goal of determining if DERs, beyond those included in the base assessment by SCE, might reduce the magnitude and duration (i.e., shape of the need) or the viability of certain proposals.

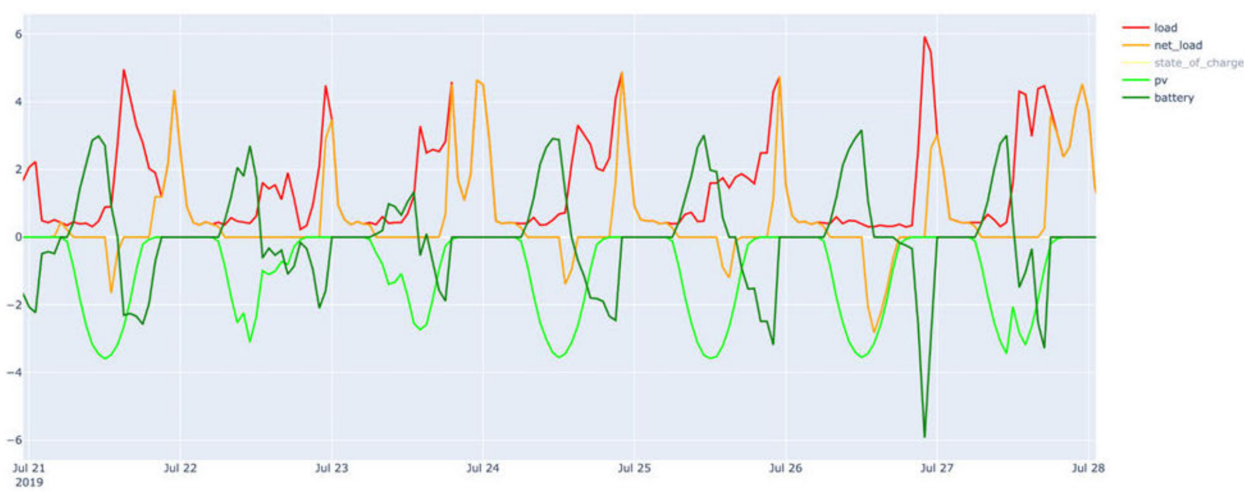
[17] https://www.cpuc.ca.gov/environment/info/ene/alberhill/Docs/1.0%20ASP-VIG%20Introduction.pdf

Methodology

This analysis is a techno-economic approach to identify economically feasible adoption of BTM resources at the customer-sited level (i.e., at existing residential and commercial and industrial (C&I) parcels). BTM resources include solar + storage and storage-only systems. The propensity for adoption of BTM resources is based on an individual customer's load profile, the payback period for the investment in BTM resources, Value of Lost Load (VOLL), and other factors. The analysis included evaluation of full 8760 time-series hourly load profiles (i.e., 365 days times 24 hours per day) for approximately 102,000 customer meters.

BTM storage systems function by either directly reducing the customer's own grid consumption (i.e., discharging to meet the customer's electrical demand, especially during peak demand periods), or sending excess stored power back to the grid, often in response to a price or event signal. When paired with solar, BTM storage can store excess generation to be used when solar goes offline (e.g. when the sun goes down). This allows solar + storage customers to further reduce consumption from the grid during times of peak demand, and likely save costs on their electricity bill through time-of-use rate arbitrage. DER behavior and impact on a residential customer's load profile is visualized in Figure 2 below.

Figure 2: Sample Load Profile for Residential Customer--July, 2019



As illustrated in Figure 2, the difference between load (red) and net load (orange) is the sum of the behavior of the PV system and the battery system. The payback period is calculated based on the tariff applied to each line to produce a monthly bill difference. The greater the bill savings, the shorter the payback period for the BTM resource.

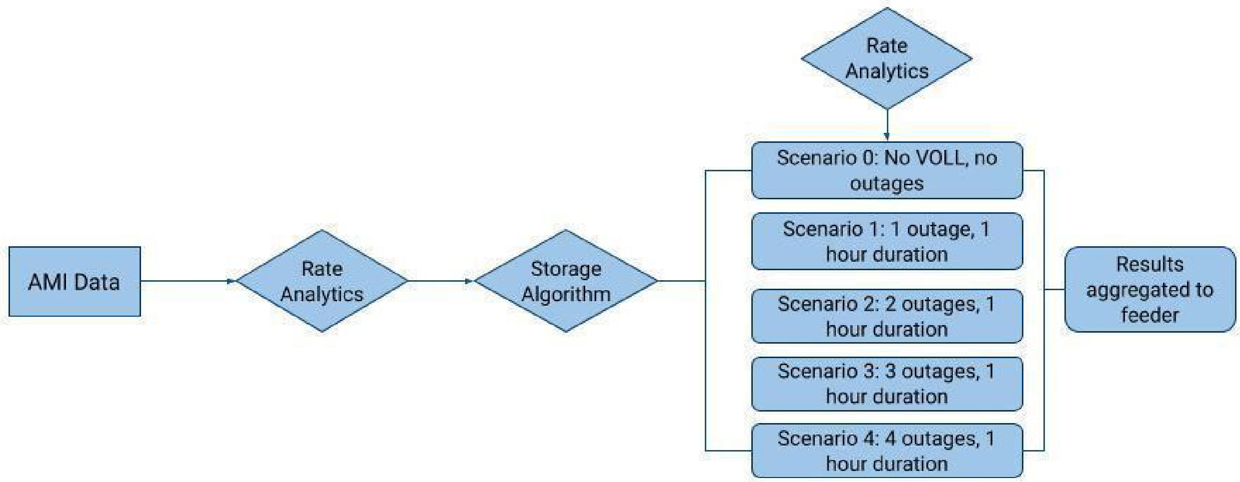
Approach

Kevala used its Network Assessor platform to ingest data provided by SCE and run advanced analytics related to grid infrastructure, load, generation, and price. At a high level, Kevala's Network Assessor platform ingests and employs data across the following three key areas:

- Load: In Kevala's Assessor platform load is typically provided as time series data (i.e. the magnitude of demand for electricity for every individual hour or 15 minute interval of a year). While time series data is generally incompatible with grid planning tools or geospatial (GIS) datasets, Kevala's platform is designed specifically to handle the volume of data associated with time series data. Kevala ingested SCE provided metered data to create an 8760 time series load profile for each building and, as needed, aggregated the data to the feeder level for analysis in power flow software.
- Generation: This includes both data at the bulk power level and DERs including, nameplate capacity and the associated feeder. Kevala uses this dataset to estimate local energy supply and forecasted production profiles.
- Infrastructure: For this project, Kevala used SCE-provided geospatial files on electric infrastructure.

Kevala's approach to the residential analysis is shown in Figure 3 below. The Advanced Metering Infrastructure (AMI) data was utilized for the rates analytics and the storage algorithm. These ultimately identified economically- efficient BTM adoption customers under five different scenarios, for residential customers, and three different scenarios for commercial and industrial customers.

Figure 3: Process of Kevala's BTM Analysis



These scenarios model the number and duration of outages annually. The number of outages was then assessed by determining where the sensitivity in likely DER adoption occurs. Because of this, the two analyses modeled different scenarios:

The residential scenarios modeled in the analysis are as follows:

- Scenario 0: No VOLL, no outages
- Scenario 1: 1 outage, 1 hour duration each
- Scenario 2: 2 outages, 1 hour duration each
- Scenario 3: 3 outages, 1 hour duration each
- Scenario 4: 4 outages, 1 hour duration each

The commercial and industrial analysis applied the following scenarios:

- Low Scenario: 4 outages, 4-hour duration each
- Medium Scenario: 6 outages, 4-hour duration each
- High Scenario: 8 outages, 4-hour duration each

Separate analyses of the types of resources adopted were also performed for residential customers and C&I customers. The residential analysis considered the potential for new customers to adopt solar + storage systems, as well as the potential for existing residential solar owners to adopt an incremental BTM storage system. In contrast, the C&I analysis looked solely at the potential for customers without existing DER to adopt new BTM storage systems, incentivized largely by a desire to reduce demand charges.

Inputs and Assumptions

To conduct the BTM analysis, Kevala modeled performance of BTM storage resources at the customer level, utilizing historical AMI data for the 2019 calendar year. The analysis was optimized for size to meet payback period requirements. Inputs used in the analysis (e.g., performance and cost of battery storage systems and current policies and incentive structures) are consistent with those used by the CPUC in the 2019 - 2020 Integrated Resource Planning (IRP) process. Table 1 summarizes the inputs and assumptions used in the residential and C&I analyses.

Table 1: Residential Analysis Inputs and Assumptions

Input	Residential Assumptions
Rate	Customers subject to SCE's 2020 time-of-use rate Peak: 4:00pm-9:00pm: **Summer:** June-September **Winter:** October-May
PV System Size, Performance, and Cost	Photovoltaic kilowatt (kW) size is optimized based on household energy consumption. A minimum threshold of 3 kW of PV system capacity was applied for the analysis. PV performance is modeled using National Renewable Energy Lab (NREL) PV Watts. PV system cost is aligned with the Integrated Resource Plan 90(IRP) assumptions on dollars per watt ($/W) for 2020.
Storage System Size, Performance, and Cost	7 kW/13.5 kWh lithium ion Adoption for number of batteries is optimized for each customer based on historic load and payback period Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is about $12,600

Policy Assumptions	Customers are eligible to benefit from the solar investment tax credit (ITC) and Self-Generation Incentive Program (SGIP) based on current program incentive levels and rules for enrollment.
Payback Period	10 years or fewer
Value of Loss Load	Scenarios are tested at a value of $9.47/kWh based on SCE's Value of Service Study assumptions for 1-hour outages. ● Scenario 0: No VOLL, 0 outages ● Scenario 1: 1 outage, 1 hour duration ● Scenario 2: 2 outages, 1 hour duration ● Scenario 3: 3 outages, 1 hour duration ● Scenario 4: 4 outages, 1 hour duration

Table 2: Commercial and Industrial (C&I) Analysis Inputs and Assumptions

Input	C&I Assumptions
Rate	Customers are subject to appropriate SCE rates based on load and to demand charges.
PV System Size, Performance, and Cost	N/A
Storage System Size, Performance, and Cost	Adoption for number of batteries is optimized for each customer based on historic load and payback period. Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is about $12,600
Policy Assumptions	Customers are eligible to participate through SGIP, based on current incentive levels in SCE territory. Customers are not additionally incentivized through participation in other markets (i.e., demand response).
Payback Period	8 years or fewer

Value of Loss Load	• Low Scenario: 4 outages, 4-hour duration each • Medium Scenario: 6 outages, 4-hour duration each • High Scenario: 8 outages, 4-hour duration each

Results and Discussion

Detailed results for the BTM adoption propensity analysis (disaggregated by feeder) are provided in Appendix A.

Residential Results

The aggregated results for residential BTM Adoption Propensity are identified below in Table 3.

- Total Customers: the number of customers in which it would be economically efficient to adopt solar + storage under the respective scenarios.
- Total Customers (%): "Total Customers" as percentage of the total number of AMI records run in the analysis (i.e. Total Customers/ total number of AMI records)
- Sum of Total PV: Sum of expected PV capacity (MW) if all customers in "Total Customers" adopted DERs
- Storage (MW and MWh): Sum of expected storage if all customers in "Total Customers" adopted DERs
- Annual VOLL ($): annual dollar value for incentivizing customers to adopt DERs

The annual value of loss load (VOLL) can represent the annual dollar value for these customers to be incentivized to adopt BTM solar + storage. For example, Scenario 1 has an annual average VOLL of $127.85. If SCE offered every customer an incentive of $127.85 annually for the total payback period of the system, then it would be economically-efficient for 4,592 customers to adopt BTM resources. As the annual VOLL figure increases, it becomes more economically-efficient for more customers to adopt these resources.

The dollar value for VOLL in Table 3 was calculated using SCE's value of service. Per SCE's Value of Service Study[18], SCE assumed a cost of $9.47/kWh for a 1-hour outage for residential customers. This dollar value was applied to the different scenario calculations to produce the cost in which it would be economically viable for customers to adopt BTM solar + storage.

[18] This value of service is provided in Table 8-4 of the February 1, 2021SCE revised Planning Study.

Table 3: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

As shown in Table 3, there is considerable potential for BTM resource adoption across the Valley South area. Under Scenario 0, which models no outages and no VOLL, about 1,966 residential customers meet the criteria for economically efficient adoption and could potentially be incentivized to adopt BTM resources through an RFP process. If all of these customers adopted BTM solar and/or storage technology with the parameters outlined in this report, this would equate to approximately 4 MW of solar and 14 MW of storage.

This adoption rate increases very quickly as additional scenarios model an increasing number of outages. In contrast, Scenario 4 models a total of four hours of outages annually and has the greatest potential for adoption of BTM resources. Under this scenario, approximately 45,210 economically efficient customers were identified as potential adopters, equating to 350 MW of solar and 316 MW/610 MWh of storage.

Note that the dollar value for VOLL in Table 3 was calculated using SCE's value of service. Per table 5-6 of the SCE Value of Service Study, SCE assumed a cost of $9.47/kWh for a 1-hour outage for residential customers. This dollar value was applied to the different scenario calculations to produce the cost in which it would be economically viable for customers to adopt BTM solar + storage.

These economic values are broken down further by substation in Table 4 below. The proposed incentive identified is an aggregate cost of the VOLL for the entire payback period for each customer on a given feeder.

Table 4: Economic Outputs of Residential Records by Substation

Scenario 1														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	528	435	239	318	84	143	419	470	529	260	225	264	192	486
Avg. payback (yrs)	9.7	9.6	9.6	9.7	9.6	9.7	9.7	9.6	9.6	9.5	9.5	9.7	9.6	9.7
Total Incentive Cost ($)	652,187	32,988	294,030	393,347	104,084	175,714	519,089	576,709	653,437	319,260	276,693	327,184	236,023	599,883
Scenario 2														
Values	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	1398	953	596	898	235	280	1222	990	1323	633	573	787	417	1263
Avg. payback (yrs)	9.59	9.54	9.61	9.59	9.53	9.57	9.66	9.57	9.65	9.53	9.53	9.64	9.57	9.63
Total Incentive Cost ($)	1,257,139	1,032,213	567,779	756,952	201,093	340,493	999,829	1,117,248	1,260,173	617,851	534,022	630,555	455,799	1,157,449
Scenario 3														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	3264	2015	1383	2055	653	523	3222	2038	3056	1442	1503	1831	917	2902

Avg. payback (yrs)	9.50	9.49	9.51	9.47	9.56	9.36	9.53	9.48	9.50	9.37	9.54	9.51	9.38	9.52
Total Incentive Cost ($)	1,819,899	1,501,050	823,383	1,094,165	291,780	495,383	1,446,418	1,625,124	1,825,210	897,807	774,069	912,686	661,033	1,677,162

Scenario 4														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	5120	3200	2196	3507	1370	794	6117	3289	5043	2463	2917	2826	1415	4953
Avg. payback (yrs)	9.25	9.25	9.25	9.19	9.36	9.11	9.28	9.26	9.26	9.23	9.33	9.23	9.24	9.29
Total Incentive Cost ($)	2,345,508	1,942,835	1,062,945	1,408,259	376,894	641,444	1,863,069	2,103,792	2,353,456	1,161,172	998,869	1,176,172	853,394	2,163,447

A further breakdown of the adoption propensity by substation is presented in Table 5 below. As displayed in the table, the Newcomb and Auld substations are associated with the greatest BTM adoption potential. Under the Scenario 0 analysis, there is potential for adoption of 5 MW of PV and 1MW/2MWh of storage along the feeders connected to the Newcomb substation and 4 MW of PV and 1MW/3MW of storage along feeders connected to the Auld substation. This potential increases under Scenario 4 to 41 MW of PV and 43 MW/83 MWh of storage for the Newcomb substation and to 36MW of PV and 36 MW/69 MWh of storage for the Auld substation.

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Table 5: Residential Adoption Propensity by Substation

Scenario 0															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 0 Total
Total Customers	206.0	223.0	109.0	109.0	27.0	72.0	141.0	253.0	212.0	128.0	102.0	95.0	85.0	204.0	1966.0
Total Customer (%)	4%	6%	4%	3%	2%	8%	2%	6%	4%	4%	3%	3%	5%	3%	4%
Total PV Installed (MW)	4.3	11.1	2.9	3.6	4.8	2.2	5.1	6.7	6.1	3.7	9.5	3.7	1.8	9.0	74.0
Sum of Total BESS (MW)	1.4	1.6	0.8	0.8	0.2	0.5	1.0	1.8	1.5	0.9	0.7	0.7	0.6	1.4	14.0
Sum of Total BESS (MWh)	2.8	3.0	1.5	1.5	0.4	1.0	1.9	3.4	2.9	1.7	1.4	1.3	1.2	2.8	27.0
Scenario 1															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 1 Total
Total Customers	528.0	435.0	239.0	318.0	84.0	143.0	419.0	470.0	529.0	260.0	225.0	264.0	192.0	486.0	4592.0
Total Customer (%)	9%	11%	9%	8%	5%	15%	5%	12%	9%	9%	6%	8%	12%	8%	8%
Sum of Total PV (MW)	7.7	13.5	4.3	5.7	5.4	3.1	8.1	9.2	9.4	5.2	10.8	5.4	2.9	12.0	103.0
Sum of Total BESS (MW)	3.7	3.1	1.7	2.2	0.6	1.0	2.9	3.3	3.7	1.8	1.6	1.9	1.3	3.4	32.0

Sum of Total BESS (MWh)	7.1	5.9	3.2	4.3	1.1	1.9	5.7	6.4	7.1	3.5	3.0	3.6	2.6	6.6	62.0

Scenario 2															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 2 Total
Total Customers	1398.0	953.0	596.0	898.0	235.0	280.0	1222.0	990.0	1323.0	633.0	573.0	787.0	417.0	1263.0	11568.0
Total Customer (%)	24%	24%	23%	21%	13%	30%	15%	25%	22%	21%	16%	24%	26%	21%	21%
Sum of Total PV (MW)	15.0	17.9	7.3	10.4	6.7	4.3	14.7	14.1	16.3	8.5	13.7	9.8	4.9	18.5	161.9
Sum of Total BESS (MW)	9.8	6.7	4.2	6.3	1.7	2.0	8.6	6.9	9.3	4.4	4.0	5.5	2.9	8.8	81.0
Sum of Total BESS (MWh)	18.9	12.9	8.1	12.1	3.2	3.8	16.5	13.4	17.9	8.6	7.7	10.6	5.6	17.1	156.2
Scenario 3															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 3 Total
Total Customers	3264.0	2015.0	1383.0	2055.0	653.0	523.0	3222.0	2038.0	3056.0	1442.0	1503.0	1831.0	917.0	2902.0	26804.0
Total Customer (%)	55%	51%	53%	49%	36%	56%	41%	52%	50%	47%	41%	56%	56%	48%	49%
Sum of Total PV (MW)	27.0	24.9	12.4	17.4	9.5	6.0	27.4	21.4	27.9	13.8	19.6	16.5	8.2	29.2	261.0

Sum of Total BESS (MW)	22.9	14.1	9.7	14.4	4.6	3.7	22.6	14.3	21.4	10.1	10.5	12.8	6.4	20.3	188.0
Sum of Total BESS (MWh)	44.1	27.2	18.7	27.7	8.8	7.1	43.5	27.5	41.3	19.5	20.3	24.7	12.4	39.2	362.0

Scenario 4															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 4 Total
Total Customers	5120.0	3200.0	2196.0	3507.0	1370.0	794.0	6117.0	3289.0	5043.0	2463.0	2917.0	2826.0	1415.0	4953.0	45210.0
Total Customer (%)	86%	81%	85%	84%	75%	85%	77%	83%	83%	80%	79%	86%	87%	82%	82%
Sum of Total PV (MW)	36.2	30.7	16.3	24.1	12.9	7.4	40.9	27.7	37.8	18.8	26.3	21.2	10.7	39.2	350.0
Sum of Total BESS (MW)	35.8	22.4	15.4	24.5	9.6	5.6	42.8	23.0	35.3	17.2	20.4	19.8	9.9	34.7	316.0
Sum of Total BESS (MWh)	69.1	43.2	29.6	47.3	18.5	10.7	82.6	44.4	68.1	33.3	39.4	38.2	19.1	66.9	610.0

Figures 4 and 5 below depict the shape profiles of the PV system, storage system, customer demand before adopting DERs, and the customer net load after adopting DERs. These samples represent a residential customer for the months of July and March, respectively. Each line represents the following datasets:

- Red line: customer load before any DERs are interconnected
- Orange line: customer load after DERs are interconnected
- Light green line: State of PV (e.g., when it's generating energy).
- Dark green line: State of BESS (e.g., when the battery is charging and discharging)

The DERs behave so that the BESS is charging while the PV system is generating energy and discharging when demand peaks. With the adoption of DERs, the net load illustrates a reduction in the customer's energy demand as well as a shift in when the peak demand occurs.

Figure 4: Sample Load Profile for Residential Customer--July, 2019

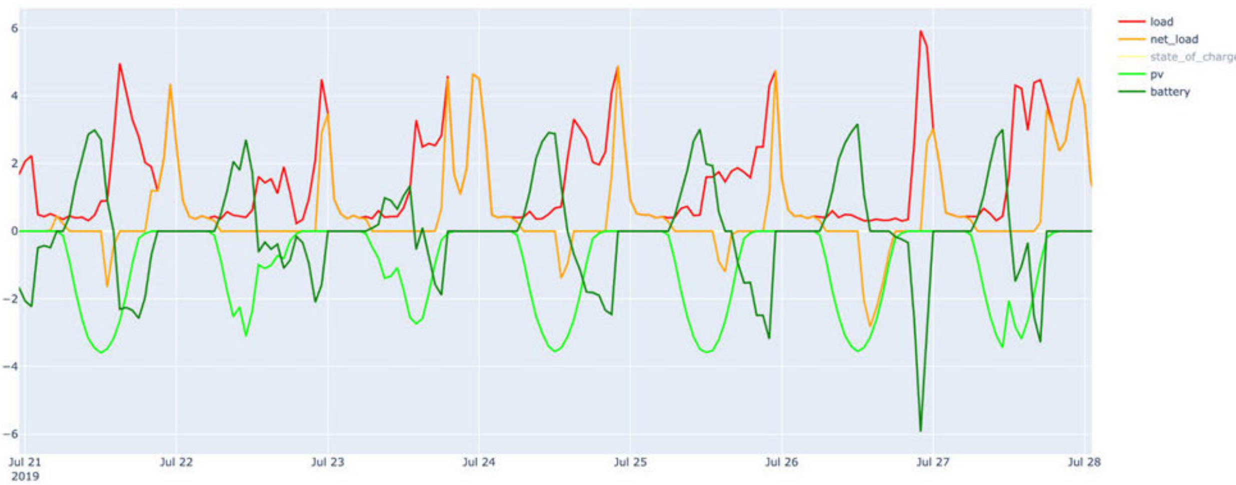
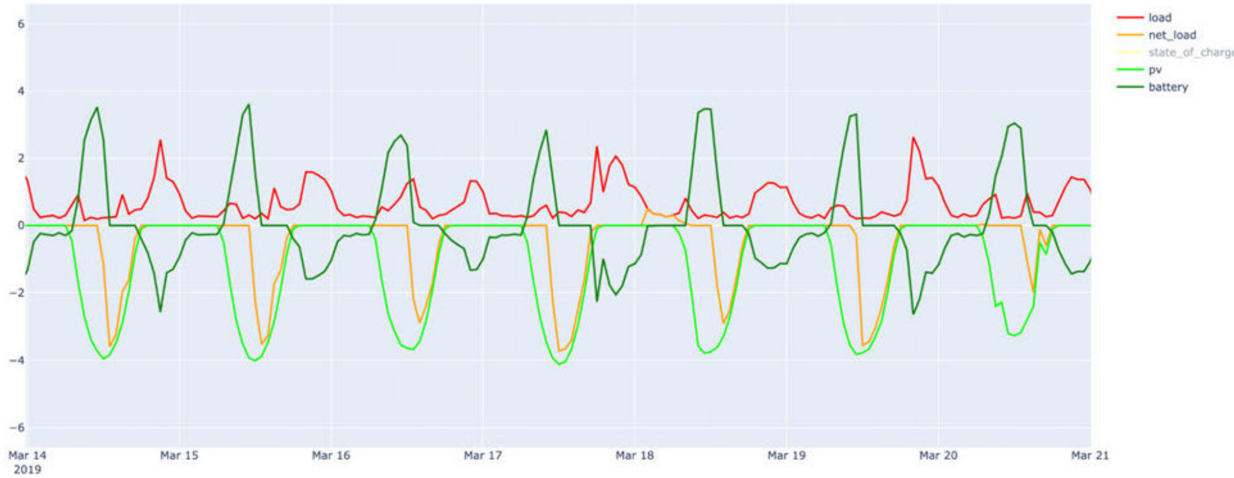


Figure 5: Sample Load Profile for Residential Customer--March, 2019



The interconnection of BTM solar + storage has considerable impact on a customer's load. The sample parcel in July shows significant reduction in demand during the highest peak times. In March, when there is generally lower demand on the grid, the sample parcel has a negative net load after interconnecting DERs.

Commercial & Industrial Results

Commercial and industrial customers represent a much smaller portion of the Valley South area and represent a much smaller portion of potential BTM adopters. The different scenarios run for C&I customers did not impact the number of customers to the point where it would be economically viable for additional customers to adopt BTM resources (i.e., the total number of customers in which it would be economically efficient to adopt BTM storage is a constant 520 customers for the low, medium, and high scenarios, as seen in Table 6 below). Modeling an increase in the number of outages annually had the greatest effect on the average payback period, which decreases gradually as the number of outages increases.

Table 6: C&I 2-Hour Battery Adoption Propensity

2-Hour Battery BTM Adoption Propensity	Scenario		
	Low	**Medium**	**High**
Total C&I customers	520	520	520
Commercial customers	520	520	520
Industrial customers	-	-	-
Total power (MW)	0.81	0.81	0.81
Total capacity (MWh)	1.45	1.45	1.45
Average payback period (yr)	1.41	0.93	0.70

Table 7: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	**Medium**	**High**
Total C&I customers	869	869	869
Commercial customers	869	869	869
Industrial customers	-	-	-
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

Overall, the results indicate that the greatest potential for DER adoption propensity is driven by residential customers adopting new solar + storage systems while C&I customers adoption storage is not as impactful. The C&I results disaggregated by feeder are provided in Appendix A.

Conclusions

This report uses Kevala's Network Assessor platform to analyze BTM solar + storage adoption propensity in the Valley system area of the San Jacinto region in support of the CPUC's CEQA analysis for the proposed Alberhill System Project. The findings indicate that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the Scenario 4 (4 outages, at 1 hour duration) adoption propensity for residential customers. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery.

Though the total number of customers economically advantaged by adopting BTM resources at different levels of incentive does not determine how many customers will definitively adopt them, it does indicate that there is a quantifiable increase in the number of economically beneficial adopters as the capacity payment or a perceived value of avoided loss load increases.

As stated previously, one of the objectives of the Alberhill System Project is to increase system operational flexibility and maintain system reliability by creating system tie lines that establish the ability to transfer to substations from the current Valley South System. Due to this objective, adoption of BTM resources on their own could not meet all the project objectives.

However, customers in the Valley South interconnecting solar + storage could alleviate capacity constraints on the Valley System. This is evident from Figures 4 and 5, in which a residential customer adding DERs observed reduced peak demands as well as a shift in the occurrence of peak demand.

Next Steps

The next phase of work will consist of a consideration of potential impacts of forecasted loads and DER adoption to the SCE ASP and proposed alternatives. Kevala will analyze how peak loads in the Valley South will shift with targeted DER procurement efforts beyond the DER adoption forecasted in the ASP and SCE proposed alternatives. Moreover, the effects that targeted procurements would have on the size and economics of the proposed alternatives will also be analyzed.

The results outlined in this report from the BTM Solar + Storage Adoption Propensity Analysis will be utilized to understand the impacts.

Appendix A: Commercial & Industrial Results

2 Hour C&I: Low						
Feeder	**Total C&I customers**	**Commercial customers**	**Industrial customers**	**Total power (kW)**	**Total capacity (kWh)**	**Average Payback (Years)**
CARISO	191	191	-	153.34	276.02	1.44
CARMEL	2	2	-	204.44	368.00	1.38
KELLER	1	1	-	156.27	281.28	1.46
RIDGEMOOR	326	326	-	294.12	529.42	1.35

2 Hour C&I: Medium						
Feeder	**Total C&I customers**	**Commercial customers**	**Industrial customers**	**Total power (kW)**	**Total capacity (kWh)**	**Average Payback (Years)**
CARISO	191	191	-	153.34	276.02	0.95
CARMEL	2	2	-	204.44	368.00	0.92
KELLER	1	1	-	156.27	281.28	0.96
RIDGEMOOR	326	326	-	294.12	529.42	0.89

2 Hour C&I: High						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average Payback (Years)
CARISO	191	191	-	153.34	276.02	0.71
CARMEL	2	2	-	204.44	368.00	0.69
KELLER	1	1	-	156.27	281.28	0.72
RIDGEMOOR	326	326	-	294.12	529.42	0.67

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4 Hour C&I: LOW						
Feeder	**Total C&I customers**	**Commercial customers**	**Industrial customers**	**Total power (kW)**	**Total capacity (kWh)**	**Average payback period (yr)**
ARGONAUT	1	1	-	71.47	257.28	1.37
BLITZ	13	13	-	135.22	486.80	1.32
CALLAWAY	1	1	-	155.56	560.00	1.30
CAPELIN	4	4	-	251.11	904.00	1.14
CARISO	195	195	-	329.10	1,184.76	1.30
CARMEL	2	2	-	327.11	1,177.60	1.05
CHAWA	1	1	-	111.00	399.60	1.33
COLLIER	4	4	-	323.52	1,164.66	1.34
CONESTOGA	13	13	-	419.14	1,508.92	1.38
DORMAN	13	13	-	383.94	1,382.20	1.31
GRIDIRON	1	1	-	81.33	292.80	1.38
GRUWELL	22	22	-	90.60	326.16	1.40
HORTON	89	89	-	99.20	357.14	1.37
KELLER	1	1	-	243.2	875.52	1.20
LAKELAND	131	131	-	192.87	694.32	1.35
LIMITED	1	1	-	134.22	483.20	1.41
MERLOT	1	1	-	69.60	250.56	1.39
POTTERY	1	1	-	120.00	432.00	1.29
REFEREE	1	1	-	85.33	307.20	1.37
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.89
ROCKRIDGE	3	3	-	80.79	290.84	1.36
SERNA	9	9	-	289.47	1,042.08	1.30
SUNDANCE	4	4	-	227.19	817.88	1.17
SUNGLASSES	1	1	-	89.07	320.64	1.37
VIA NORTE	30	30	-	127.70	459.72	1.31
VINE	1	1	-	143.33	516.00	1.30

4 Hour C&I: Medium						
Feeder	**Total C&I customers**	**Commercial customers**	**Industrial customers**	**Total power (kW)**	**Total capacity (kWh)**	**Average payback period (yr)**
ARGONAUT	1	1	-	71.47	257.28	0.92
BLITZ	13	13	-	135.22	486.80	0.88
CALLAWAY	1	1	-	155.56	560.00	0.86
CAPELIN	4	4	-	251.11	904.00	0.76
CARISO	195	195	-	329.10	1,184.76	0.86
CARMEL	2	2	-	327.11	1,177.60	0.70
CHAWA	1	1	-	111.00	399.60	0.89
COLLIER	4	4	-	323.52	1,164.66	0.90
CONESTOGA	13	13	-	419.14	1,508.92	0.91
DORMAN	13	13	-	383.94	1,382.20	0.88
GRIDIRON	1	1	-	81.33	292.80	0.92
GRUWELL	22	22	-	90.60	326.16	0.92
HORTON	89	89	-	99.20	357.14	0.91
KELLER	1	1	-	243.2	875.52	0.79
LAKELAND	131	131	-	192.87	694.32	0.90
LIMITED	1	1	-	134.22	483.20	0.92
MERLOT	1	1	-	69.60	250.56	0.93
POTTERY	1	1	-	120.00	432.00	0.87
REFEREE	1	1	-	85.33	307.20	0.92
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.59
ROCKRIDGE	3	3	-	80.79	290.84	0.91
SERNA	9	9	-	289.47	1,042.08	0.87
SUNDANCE	4	4	-	227.19	817.88	0.78

SUNGLASSES	1	1	-	89.07	320.64	0.91
VIA NORTE	30	30	-	127.70	459.72	0.87
VINE	1	1	-	143.33	516.00	0.86

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4 Hour C&I: High						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average payback period (yr)
ARGONAUT	1	1	-	71.47	257.28	0.92
BLITZ	13	13	-	135.22	486.80	0.88
CALLAWAY	1	1	-	155.56	560.00	0.86
CAPELIN	4	4	-	251.11	904.00	0.76
CARISO	195	195	-	329.10	1,184.76	0.86
CARMEL	2	2	-	327.11	1,177.60	0.70
CHAWA	1	1	-	111.00	399.60	0.89
COLLIER	4	4	-	323.52	1,164.66	0.90
CONESTOGA	13	13	-	419.14	1,508.92	0.91
DORMAN	13	13	-	383.94	1,382.20	0.88
GRIDIRON	1	1	-	81.33	292.80	0.92
GRUWELL	22	22	-	90.60	326.16	0.92
HORTON	89	89	-	99.20	357.14	0.91
KELLER	1	1	-	243.2	875.52	0.79
LAKELAND	131	131	-	192.87	694.32	0.90
LIMITED	1	1	-	134.22	483.20	0.92
MERLOT	1	1	-	69.60	250.56	0.93
POTTERY	1	1	-	120.00	432.00	0.87
REFEREE	1	1	-	85.33	307.20	0.92
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.59
ROCKRIDGE	3	3	-	80.79	290.84	0.91
SERNA	9	9	-	289.47	1,042.08	0.87
SUNDANCE	4	4	-	227.19	817.88	0.78
SUNGLASSES	1	1	-	89.07	320.64	0.91
VIA NORTE	30	30	-	127.70	459.72	0.87
VINE	1	1	-	143.33	516.00	0.86

Appendix E – Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System

Portions of this report have been redacted based on Southern California Edison's claims of confidentiality based on critical infrastructure information and other legal privileges.

Alberhill System Project

DER Adoption and Impact on Load Forecast in Valley South System

May 27, 2021

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Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP). This report builds on Kevala's prior analysis of potential adoption of behind-the-meter (BTM) solar+storage in the report *Behind-the-Meter Adoption Propensity Analysis for the Valley South System* (April 16, 2021) and quantifies the impacts of BTM distributed energy resources (DER) on the load forecasts used by SCE in its support of the ASP application.

In that report, Kevala analyzed modifications to load forecasts by potential DER adoption. The analysis indicated that up to 350 megawatts (MW) of photovoltaics (PV) and up to 316 MW of storage could potentially be adopted by residential customers in SCE territory. If realized, these DER penetration levels could greatly impact the power flows in the Valley South system, potentially reducing peak loading.

This report finds that the initial load forecasts result in a significant number of violations in power flow analysis when reduced by incremental DER adoption. Specifically, reducing the peak load by 188 MW via incremental DER adoption in the region results in a reduction of flows on the Valley South transformers. Power flow modeling of DER penetration at this level does not cause high voltage violations. With the addition of voltage regulation equipment, higher penetration levels of DERs could potentially be incorporated into the Valley North and Valley South systems, further reducing the load beyond 188 MW to 316 MW of DER-drive load reduction.

This report does not consider the potential impacts of the load reductions on the ASP or SCE's proposed alternatives. However, in subsequent reports, Kevala will analyze these alternative proposals and their potential to reduce or eliminate certain power flow violations in the Valley South and Valley North systems.

Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) application process. The project is driven by forecasted load growth that SCE expects to overload the two 560 mega volt-amps (MVA) Valley South 500 kilovolt (kV) transformers in 2023.

To support the CEQA process, several technical analyses are being conducted. In the report, *Behind-the-Meter Adoption Propensity Analysis for the Valley South System (April 16, 2021)*, Kevala examined the potential for customers in the Valley South system interconnecting behind-the-meter (BTM) distributed energy resources (DER) (e.g., photovoltaic (PV) and battery energy storage systems (BESS)). The analysis was conducted to evaluate the effect of targeted BTM DER procurement.

This report expands on the findings from the BTM adoption propensity analysis to consider the impact of DER adoption on peak load. Kevala analyzed how peak loads in this area will change with targeted DER procurement efforts beyond the DER adoption propensity forecasted in the ASP and SCE proposed alternatives. After determining the new peak loads from the BTM adoption propensity results, a power flow analysis was performed to determine the new system impacts.

Project Overview

SCE developed the Alberhill System Project Planning Study, which identified project alternatives categorized as conventional alternatives, non-wire alternatives, and hybrid alternatives. The conventional alternatives are designed with transmission and/or subtransmission build-outs with system tie lines to neighboring systems. The non-wire alternatives utilize a centralized BESS design. Hybrid alternatives utilize non-wire alternatives to meet incremental capacity needs but also include conventional alternative approaches to meet the additional capacity needs that could develop.

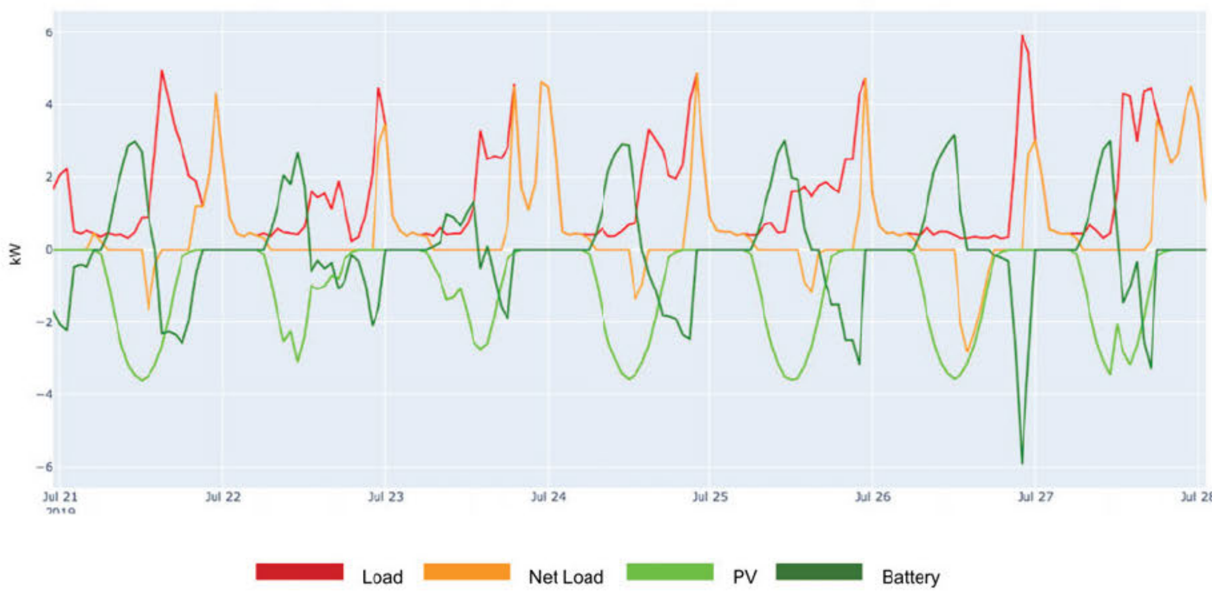
The only proposed alternative that incorporated distributed BESS is the Valley South to Valley North and Distributed BESS in Valley South hybrid solution. This alternative proposes transferring SCE's existing Newcomb and Sun City substations from the Valley South system to the Valley North system and interconnecting three 12 kV BESS at the Auld, Elsinore, and Moraga substations. None of the proposed alternatives considered the impact of more granular adoption of BTM DERs, such as individual customers adopting solar + storage.

Kevala BTM Adoption Propensity Analysis

BTM battery energy storage systems (BESS) can be used to directly offset the customer's energy usage by discharging energy from the battery to reduce the customer's electrical demand, especially during peak demand periods. Another typical application is to send excess stored power back to the grid, often in response to a price or event signal. When paired with solar, BTM storage can store excess generation for use when solar goes offline (e.g., when the sun goes down). This allows for solar + storage customers to further reduce grid-supplied energy consumption during times of peak demand, and likely save costs on their electricity bill through time-of-use rate arbitrage.

Representative solar + storage DER behavior and the resulting impact on a residential customer's load profile is modeled and visualized in Figure 1 below.

Figure 1: Sample Load Profile for Residential Customer



As illustrated in Figure 1, the difference between load (indicated in red) and net load (indicated in orange) is the sum of the electrical output of the PV system and BESS. For residential customers, BESS was modeled so that batteries charge during PV generation and discharge during time-of-use rate periods. Commercial and industrial (C&I) customers were modeled so that batteries discharge to reduce utility demand charges.

The payback period is calculated based on the tariff applied to the load and net load, separately, to produce a monthly bill difference. The greater the bill savings, the shorter the payback period for the BTM resource.

Approach

Kevala utilized their Network Assessor (NA) platform to perform the BTM solar + storage adoption propensity analysis. SCE provided Advanced Metering Infrastructure (AMI) data for the year 2019 which was ingested and stored in the NA platform. Advanced analytics related to grid infrastructure, load, generation, and price were then run to attain solar + storage adoption results. The analysis was optimized for PV and BESS system size to meet payback period requirements.[19]

Ultimately, the analysis identified customers for whom it would be economically efficient to interconnect BTM resources. Inputs of performance, cost of battery storage systems, and current policies and incentive structures correspond to those used by the CPUC in the 2019 - 2020 Integrated Resource Planning (IRP) process. Different scenarios were modeled to demonstrate value of loss load for residential customers and commercial and industrial customers.

The residential scenarios modeled in the analysis are as follows:

- **Scenario 0**: No Value of Loss Load (VOLL), no outages
- **Scenario 1**: 1 outage, 1 hour duration each
- **Scenario 2**: 2 outages, 1 hour duration each
- **Scenario 3**: 3 outages, 1 hour duration each
- **Scenario 4**: 4 outages, 1 hour duration each

The commercial and industrial scenarios modeled in the analysis are as follows:

- **Low Scenario**: 4 outages, 4-hour duration each
- **Medium Scenario**: 6 outages, 4-hour duration each
- **High Scenario**: 8 outages, 4-hour duration each

Results

Kevala's BTM adoption propensity analysis indicated that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be

[19] The complete list of parameters applied to the analysis is provided in Appendix A.

economically efficient if adopted under the Scenario 4 (4 outages, at 1 hour duration) adoption propensity for residential customers. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery.

Table 1: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

Table 2: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	Medium	High
Total C&I customers	869	869	869
Commercial customers	869	869	869
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

The total number of customers that would receive economic benefits by adopting BTM resources at different levels of incentive does not determine how many customers will ultimately adopt these resources. It does indicate a quantifiable increase in the number of economically beneficial adopters as the capacity payment or a perceived value of avoided loss load increases.

The full description of the methodology and analysis of the results is available in the report, *Behind-the-Meter Adoption Propensity Analysis for the Valley South System (April 16, 2021)*.

Valley South System Load Forecast

Due to forecasted load growth, SCE developed ASP and the alternatives to address overloads expected to occur in 2023 on the two 500 kV Valley South transformers. A review of SCE's load forecasting methodology revealed that SCE developed a 10-year peak load forecast based on peak load values that were collected from historical data. The forecast was then normalized to a common temperature base to account for variations in peak temperatures from year to year. Customer load growth and DER forecasts (including energy efficiency (EE), energy storage (ES), demand response (DR), electric vehicle (EV) charging, and distributed generation (DG)) were used to develop the peak load forecast. At the distribution level, SCE used the California Energy Demand (CED) forecast, derived from the California Energy Commission's (CEC) Integrated Energy Planning Report (IEPR), to determine the base load growth. SCE used customer AMI data to inform load disaggregation of the CED forecast to achieve the granularity necessary to account for local area specific electrical needs. Additionally, as appropriate, SCE incorporated any additional load growth that is not reflected in the CED forecast.

SCE retained Quanta Technology to conduct several technical analyses including a cost benefit analysis and several load forecasts based on different methodologies and sensitivities. These included:

- A conventional 10-year load forecast which was extended to produce a 30-year (2019 to 2048) 1-in-5-year peak load forecast that was based on historical substation load normalized to a common temperature.
- A spatial load forecast which produced a 30-year (2019 to 2048) net peak system load. This involved the forecasting of peak load, customer count (based on zoning and land-use data), and customer energy consumption within a particular electrical needs area. Non-traditional factors such as PV, EV adoption, and EE were incorporated by disaggregating the CEC's CED forecast at the subdivision level.
- A spatial base load forecast where DERs were assumed to continue historical trends
- Spatial effective PV load forecast where DERs were varied as reflected in the CED

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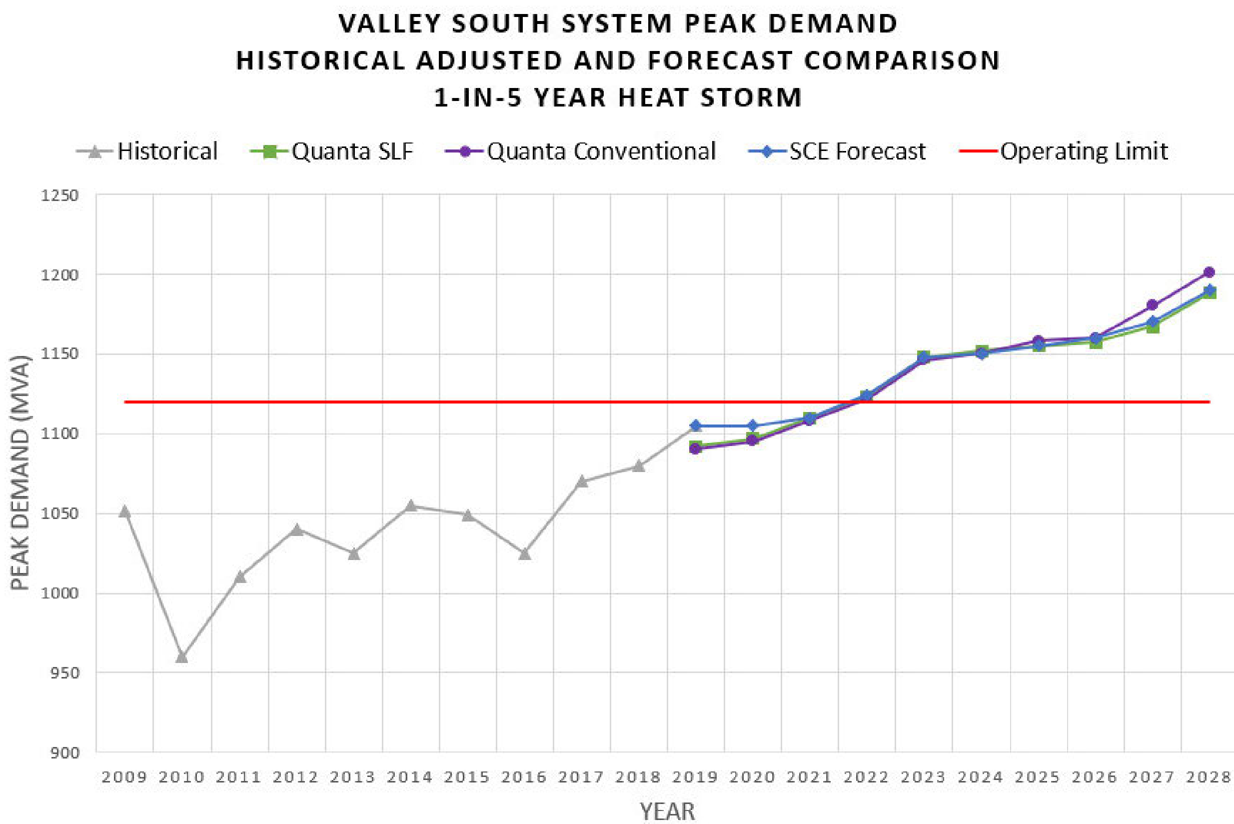
- Spatial PV Watts sensitivity forecast in which the unadjusted CED PV forecast was incorporated.

Quanta selected the Spatial effective PV load forecast as the likely future long-term load forecast scenario and used the extended 2019-2048 forecast to conduct their analyses. A comparison of the SCE and Quanta 10-year load forecasts are depicted in the figure below and further assessed in Kevala's load forecast analysis[20].

Figure 2: Graph representation of the Valley South system peak demand forecast



[20] *Review of SCE's Load Forecast and Performance Metrics (June 2021)*

DER Adoption Impact on Load Forecast

The Valley South system load forecast was modified based on the DER capacities determined through the BTM DER propensity analysis. As SCE peak load does coincide with PV system peak production, BESS were utilized for their dispatchability which enables effective peak load reduction. The PV capacities determined in the propensity analysis were significant. However, PV production peaks earlier in the day than the system peak and were therefore helpful in reducing the overall energy consumption throughout the day. Because of this, only the BESS capacity was used to model the reduction in peak load as the PV capacity would not be available during SCE's peak load period.

Table 3 below shows the reduced peak load based on the potential BESS capacity under each scenario. As the BTM DER propensity is driven by several factors including incentives, it is difficult to predict when the full potential capacity represented under each scenario could be adopted. To account for the uncertainty in rate of adoption, the scenarios were applied over the course of several study years representing load forecasts spanning 2022 to 2028. This study period allows for an analysis of the power flow impacts and considers whether BTM DER adoption occurs over the course of months or years. This approach also identified the BTM DER adoption level at which system impacts were observed.

The results of the power flow analysis of the impacts of BTM DER are summarized in Table 3 below.

Table 3: Peak Load Reduction Based on Capacity of BTM DER

Scenario	Total BESS (MW)	2022 Net Load (MW)	2023 Net Load (MW)	2024 Net Load (MW)	2025 Net Load (MW)	2026 Net Load (MW)	2027 Net Load (MW)	2028 Net Load (MW)
Scenario 0	14	1118	1132	1138	1145	1152	1160	1169
Scenario 1	32	1100	1114	1120	1127	1134	1142	1151
Scenario 2	81	1051	1065	1071	1078	1085	1093	1102
Scenario 3	188	944	958	964	971	978	986	995
Scenario 4	316	816	830	836	843	850	858	867

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System Voltages

In addition to the system capacity, the voltages were also assessed. As BTM DER installations increase, voltages on the system begin to rise on the 115 kV system. Consequently, the voltage violations are highlighted to ensure they are addressed as part of the DER interconnection process. Any costs associated with required voltage regulation equipment would need to be considered.

The high voltages were observed in the alternative case, but not in the base case or in the ASP case. Transferring load service for the Newcomb and Sun City substations represented a 195.8 MW load reduction on the Valley South system. This transfer, compounded by the further reduction in peak loads, results in high voltages in the Valley South system. Under scenarios 0, 1, 2, and 3, the magnitudes of the voltages on two buses steadily increased as more capacities of DER were installed. Under scenario 4 when the peak load is reduced by 316 MW, eleven buses were in violation of voltage criteria in the alternative case.

It was found that scenario 3 is the appropriate level of DER installations that can be achieved without needing to install voltage regulation equipment to mitigate high voltages. To mitigate high voltages above and beyond the scenario 3 levels of DER, SCE could include requirements in the DER interconnection process to ensure that new DER installations do not result in voltage violations. These could include specifying power factor or volt-var operating threshold values and requiring the installation of inverters with grid responsive features. More traditional methods such as voltage regulators or reactors can also be implemented to mitigate the high voltages.

No low voltages were observed on the base, alternative, or ASP cases under any of the DER adoption propensity scenarios.

Conclusions

In scenario 4 of Kevala's BTM DER propensity analysis, Kevala demonstrated that up to 350 MW of PV and up to 316 MW of battery energy storage could potentially be adopted by residential customers in SCE territory. This report determined that these levels of potential DER adoption substantially affect load and could make an impact on the power flows in the Valley South system. The BTM DER propensity analysis identified DER capacities which were then applied to the peak load forecast and power flow analyses. The results indicated that with the current configuration and no other projects, 188 MW of BTM BESS could eliminate the overloads on the Valley South transformers under normal system conditions. Overloads were not observed on the Valley South transformers under the worst single contingency or under the worst double contingency.

In the alternative case where service for Newcomb and Sun City substation loads were transferred to the Valley North substation, power flows over the Valley South transformers were sufficiently reduced such that they did not overload under normal or contingency conditions. Voltage criteria violations were also assessed. Eleven buses were observed to experience voltages at 5 percent above their nominal voltage in scenario 4 when the peak load was reduced by 316 MW. In scenarios 0 through 3, two buses had voltages at 5 percent above their nominal voltage. No low voltages were observed in the base case, alternative case, or under any of the DER adoption propensity scenarios.

Power flow results indicate that the BTM DER propensity that can be installed without causing negative impacts on the system is scenario 3. This scenario outlines the situation where DER is adopted to mitigate 3 outages for 1 hour duration each, totaling 188 MW of BESS and 261 MW of PV. The BESS capacity was used to model the reduction in peak load as the PV capacity would not be available during SCE's peak load period. This 188 MW reduction in peak load relieves the overload on the Valley South transformers and does not cause high voltages on the 115 kV system. Therefore, it appears that scenario 3 is the appropriate level of DER installations that can be achieved without needing to install voltage regulation equipment to mitigate high voltages.

These results confirm the findings of the tie-line analysis, whereby some tie-lines in combination with distributed PV and BESS yield results comparable to the ASP. In the tie-line analysis, the minimum DER required to relieve the overloads on the Valley South transformers was modeled. This analysis goes further and determines the BTM DER propensity, then evaluates what the impacts to the system would be with increased installed capacity.

From the power flow results under each of the BTM DER propensity scenarios, it appears that scenario 3 may be the appropriate level of DERs where the maximum benefits of load reduction are derived and at scenario 4, costs associated with projects to mitigate high voltages would need to be considered.

The two remaining Kevala analyses will do the following:

- Assess the load forecasting methodology and system performance metrics used by SCE in evaluating and ranking the alternatives
- Provide an electrical engineering analysis which will review the system reliability and resiliency metrics used by SCE to evaluate ASP and the alternatives. This will incorporate the power flow analyses conducted for the tie-line analysis and the BTM DER propensity analysis.

Appendix A: Full List of Parameters for BTM Adoption Propensity Analysis

Table 10: Residential Analysis Inputs and Assumptions

Input	Residential Assumptions
Rate	Customers subject to SCE's 2020 time-of-use rate Peak: 4:00pm-9:00pm Summer: June-September Winter: October-May
PV System Size, Performance, and Cost	Photovoltaic kilowatt (kW) size is optimized based on household energy consumption. A minimum threshold of 3 kW of PV system capacity was applied for the analysis. PV performance is modeled using National Renewable Energy Lab (NREL) PV Watts. PV system cost is aligned with the Integrated Resource Plan (IRP) 90 assumptions on dollars per watt ($/W) for 2020.
Storage System Size, Performance, and Cost	7 kW/13.5 kWh lithium-ion battery Adoption for number of batteries is optimized for each customer based on historic load and payback period Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate

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	Storage system total cost (hardware plus installation) is approximately $12,600
Policy Assumptions	Customers are eligible to benefit from the solar investment tax credit (ITC) and Self-Generation Incentive Program (SGIP) based on current program incentive levels and rules for enrollment.
Payback Period	10 years or fewer
Value of Loss Load	Scenarios are tested at a value of $9.47/kWh based on SCE's Value of Service Study assumptions for 1-hour outages. ● Scenario 0: No VOLL, 0 outages ● Scenario 1: 1 outage, 1 hour duration ● Scenario 2: 2 outages, 1 hour duration ● Scenario 3: 3 outages, 1 hour duration ● Scenario 4: 4 outages, 1 hour duration

Table 11: Commercial and Industrial (C&I) Analysis Inputs and Assumptions

Input	C&I Assumptions
Rate	Customers are subject to appropriate SCE rates based on load and to demand charges.
PV System Size, Performance, and Cost	N/A
Storage System Size, Performance, and Cost	Adoption for the number of batteries is optimized for each customer based on historic load and payback period. Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is approximately $12,600
Policy Assumptions	Customers are eligible to participate through SGIP, based on current incentive levels in SCE territory. Customers are not additionally incentivized through participation in other markets (i.e., demand response).
Payback Period	8 years or fewer
Value of Loss Load	● Low Scenario: 4 outages, 4-hour duration each ● Medium Scenario: 6 outages, 4-hour duration each ● High Scenario: 8 outages, 4-hour duration each

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Appendix B: BTM Adoption Propensity Analysis Results

Table 12: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

Table 13: C&I 2-Hour Battery Adoption Propensity

2-Hour Battery BTM Adoption Propensity	Scenario		
	Low	**Medium**	**High**
Total C&I customers	520	520	520
Commercial customers	520	520	520
Total power (MW)	0.81	0.81	0.81
Total capacity (MWh)	1.45	1.45	1.45
Average payback period (yr)	1.41	0.93	0.70

Table 14: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery **BTM Adoption Propensity**	**Scenario**		
	Low	**Medium**	**High**
Total C&I customers	869	869	869
Commercial customers	869	869	869
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

Appendix F – Review of SCE's Electrical Engineering Analysis for the Alberhill System Project

Alberhill System Project

Review of SCE's Electrical Engineering Analysis for the Alberhill System Project

June 18, 2021

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Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP). This report builds upon Kevala's prior tie-line analysis, load forecast and performance metrics analysis, and distributed energy resource (DER) analysis to evaluate the reasonableness of the electrical engineering analysis performed for the ASP by SCE.

As part of the proposed Alberhill System Project, SCE identified an initial list of project alternatives that include minimal investment alternatives, conventional alternatives, Non-Wire Alternatives (NWAs), and hybrid alternatives. The proposed project and the alternatives were evaluated by SCE based on a load forecast which is expected to result in overloads that necessitate the proposed project. In this analysis, SCE's approach to the power flow study for the ASP is assessed relative to typical power flow study approaches used at similar electric utilities. SCE's study approach was found to be reasonable and consistent with widely used study approaches employed by similar utilities, such as Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E).

Kevala further expanded on the preliminary tie-line analysis documented in the report *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021) to identify the right sizing of battery energy storage systems (BESS). This report determines the need for a 143 MWh centralized BESS to cover the forecasted load peaks at the Valley South substation over the course of the year under single and double contingencies.

Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the Valley South system's two 560 MVA 500 kV transformers to become overloaded in 2023. This report documents a review of SCE's electrical engineering analysis of the ASP and the proposed alternatives, and assesses whether the electrical engineering analysis used by SCE to evaluate the ASP and the alternatives is reasonable.[21]

Findings from Kevala Analyses

Kevala has conducted several analyses as documented in the following reports:

- *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021)
- *Behind-the-Meter Adoption Propensity Analysis* (April 16, 2021)
- *DER Adoption and Impact on Load Forecast in Valley South System* (May 27, 2021)
- *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021)

An overview of the findings from each analysis are provided in Table 1 below.

Table 1: Summary of Findings from Kevala's Analyses

Report Title	Summary of Findings
Preliminary Results: Tie-Line Power Flow Analysis	• Proposed tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers. • Transferring service for two substations to the Valley North system and interconnecting distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements. • An assessment using both the worst single contingency and the worst double contingency showed that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads under ASP and all alternatives. • BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is

[21] A thorough review of the performance metrics used by SCE in assessing the results of their electrical engineering analysis is presented in Kevala's Report: *Evaluation of SCE's Load Forecast Methodology and Performance Metrics* (June 11, 2021)

	most effective when combined with tie-lines.
Behind-the-Meter Adoption Propensity Analysis	● Up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the highest adoption scenario that was modeled. ● Alberhill System Project is to increase system operational flexibility and maintain system reliability by creating system tie lines that establish the ability to transfer to substations from the current Valley South System. Due to this objective, adoption of BTM resources on their own could not meet all the project objectives. ● Evident that customers in the Valley South interconnecting solar + storage could alleviate capacity constraints on the Valley System.
DER Adoption and Impact on Load Forecast in Valley South System	● Results indicated that with the current configuration and no other projects, 188 MW of BTM BESS could eliminate the overloads on the Valley South transformers under normal system conditions. ● In the alternative case where service for Newcomb and Sun City substation loads were transferred to the Valley North substation, power flows over the Valley South transformers were sufficiently reduced such that they did not overload under normal or contingency conditions. ● Eleven buses were observed to experience voltages at 5 percent above their nominal voltage in scenario 4 when the peak load was reduced by 316 MW. Power flow results indicate that the BTM DER propensity that can be installed without causing negative impacts on the system is scenario 3 (DER is adopted to mitigate 3 outages for 1 hour duration each, totaling 188 MW of BESS and 261 MW of PV).
Evaluation of SCE's Load Forecast Methodologies and Performance Metrics	● The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and at SDG&E. ● This assessment also ascertained that SCE may have used a common performance metric, Loss of Load Expectation (LOLE), and adapted it to create a similar metric, Load at Risk (LAR), in order to suit their system. ● Consequently, project alternatives with tie-lines were weighted more heavily than alternatives without.

Assessment of Electrical Engineering Analysis

To perform this assessment, Kevala, Inc. (Kevala) reviewed the revised documents released by SCE in their refiling, including SCE's *Planning Study* (February 1, 2021) and Quanta Technology's (Quanta) reports, *Reliability Analysis of Alberhill System Project* (February 1, 2021) and *Benefit Cost Analysis of Alternatives* (February 1, 2021). This report is also informed by the Kevala analyses that are described in Table 1, above.

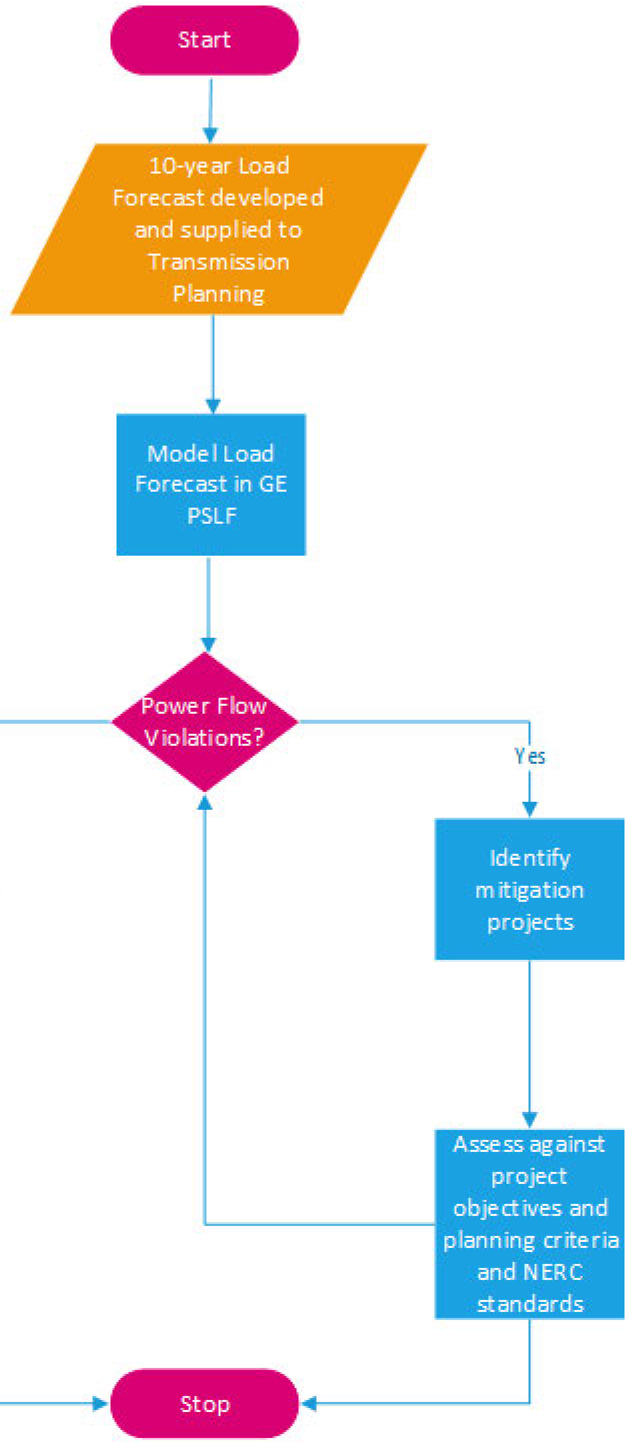
This report in particular expands on the preliminary findings of the tie-line power flow analysis by identifying the battery energy storage system (BESS) sizing that coincides with the forecasted peak loads at the Valley South substation over the course of the year. The battery capacity and duration of charge and discharge identified in the report, *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021), represents the minimum size BESS required for the Valley South system. In contrast, the *DER Adoption and Impact on Load Forecast in Valley South System* (May 27, 2021) report identified the maximum amount of distributed energy resources (DER) that can be interconnected in the Valley South system without causing system issues, such as voltage violations. This analysis finds the right-size BESS for the Valley South system.

Overview of SCE's Electrical Engineering Analysis

The ASP and each of the alternatives was evaluated by SCE by performing an electrical engineering analysis. To determine the reasonableness of the power flow study approach that was applied by SCE, Kevala reviewed the analysis as outlined in *SCE's Revised Planning Study* (Exhibit C-2, filed February 1, 2021), as well as Quanta Technology's (Quanta) report *Forecasted Impact on Service Reliability Performance* (Exhibit F-1, filed February 1, 2021).

SCE's power flow study approach consisted of modeling forecasted load in General Electric's Positive Sequence Load Flow (PSLF) cases. Power flow studies were then conducted on these cases to determine whether SCE's existing system as modeled could accommodate the forecasted load. These power flow studies assessed SCE's system under normal conditions, single contingency conditions, and double contingency conditions. Based on the results of these power flow studies, SCE identified potential projects to mitigate any line overloads, transformer overloads, or voltage criteria violations. When designing potential projects to mitigate overloads or voltage violations, particularly overloads on the Valley South transformer, SCE assessed the power flow results against project objectives as well as subtransmission planning criteria and guidelines. Figure 1 below illustrates the typical power flow study approach used by utilities and is consistent with SCE's power flow approach. The difference between a typical approach and SCE's approach is observed after the power flow analysis. Following the analysis, SCE developed metrics to evaluate the ASP and alternatives. This difference in approaches is described further in Kevala's *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics.*

Figure 1: Typical Transmission Planning Study Approach


Start
10-year Load Forecast developed and supplied to Transmission Planning
Model Load Forecast in GE PSLF
Power Flow Violations?
No
Yes
Identify mitigation projects
Existing system or identified mitigation project can adequately accommodate forecasted Load
Assess against project objectives and planning criteria and NERC standards
Stop

The results from these initial analyses demonstrate which alternatives are expected to perform best in relieving the Valley South transformer overloads while meeting the project objectives. The ranking of project alternatives from this analysis does not include the application of SCE developed metrics, such as Load at Risk, Flexibility-1, and Flexibility-2[22]. Moreover, this initial ranking is based on incremental improvement over a 30-year study period. Transmission planning studies are typically based on a 10-year load forecast. Mitigation projects, therefore, are also evaluated on their effectiveness in mitigating the violation under that same 10-year load forecast.

Kevala determined the power flow study approach used by SCE to be reasonable, though the 30-year study term is uncommon. Additionally, the electrical engineering analysis is consistent with the approach widely used by utilities in conducting transmission planning studies.

Once the power flow results were obtained from the electrical engineering analysis, as discussed above, SCE conducted additional analyses, including cost benefit analysis and risk assessments. The performance metrics developed by SCE that were discussed in Kevala's *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021) were then applied to establish a ranking of all the alternatives and the ASP.

As shown in Figure 1 above, the load forecast is the first important assumption made when building power flow base cases. The SCE load forecast, SCE load forecast trendline, Quanta load forecasts, historical load, and historical load trendline demonstrate that the SCE load forecast and Quanta load forecasts are relatively similar. This is visualized in Figure 2, below. The load forecasts could vary depending on the application of a linear trendline. Figure 2 demonstrates that the trendline based on SCE's load forecast is projected to be similar to the Quanta load forecasts. In contrast, the historical trendline shows a lower load growth rate than the SCE forecast and that the Valley South transformers would exceed their ratings a full two years later. This would result in power flow study results that suggest that a smaller project built two years later could mitigate the Valley South overloads.

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[22] A full evaluation of the performance metrics developed by SCE is available in *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021)

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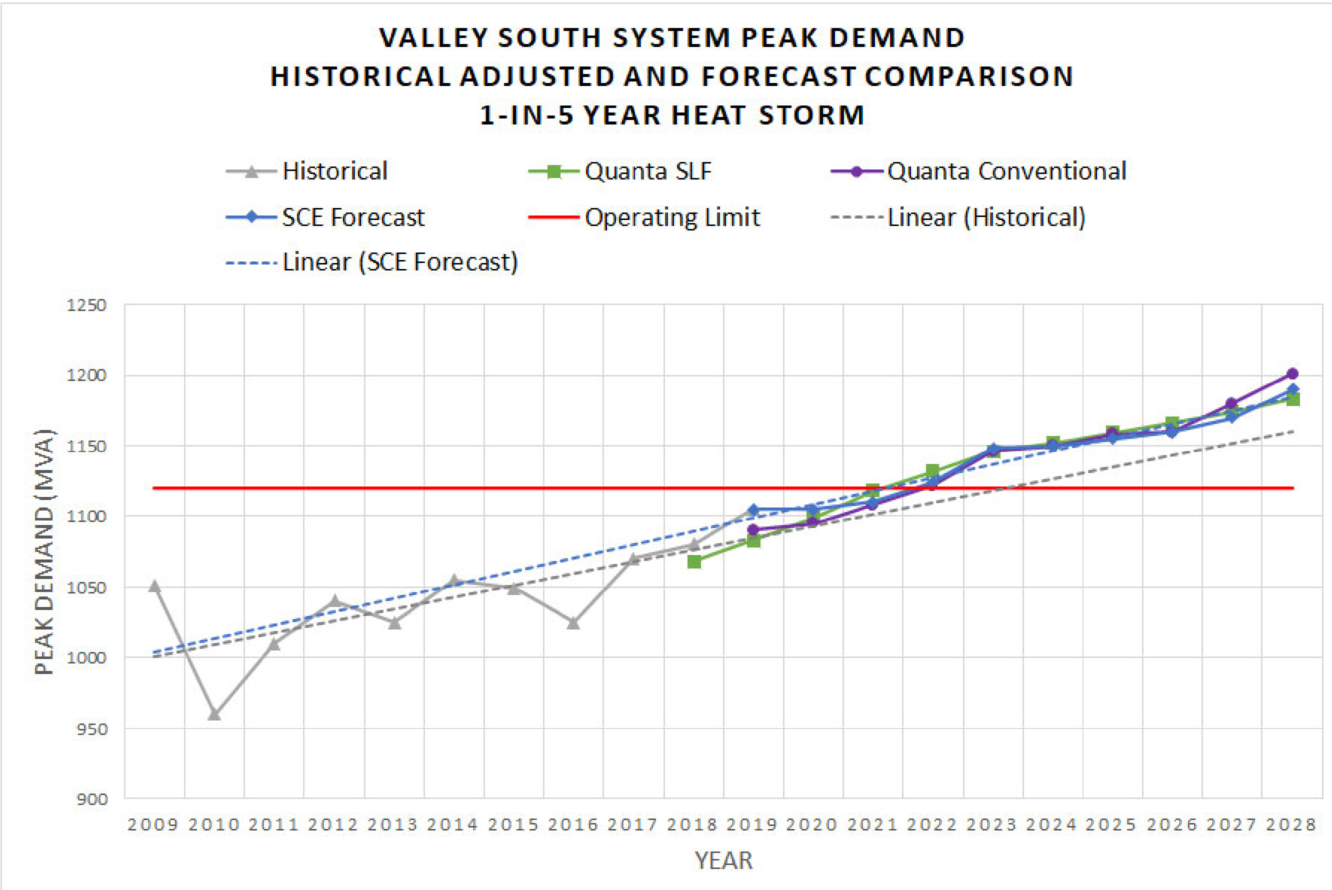
Figure2: Valley South system load forecast comparison



Supplement to the Tie-line Analysis

Kevala conducted a preliminary power flow analysis of the tie-lines. The findings of this preliminary analysis are summarized as follows:

- Proposed tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers.
- Transferring service for two substations to the Valley North system and interconnecting distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements.
- An assessment using both the worst single contingency and the worst double contingency showed that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads under ASP and all alternatives.
- BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is most effective when combined with tie-lines.

In SCE's planning study, a subset of the alternatives with tie-lines were deemed by SCE as inadequate in meeting the project objectives because the tie-lines were ineffective. As part of a data request (DATA REQUEST SET CPUC - Supplemental Data Request - 010), Kevala asked that SCE provide the contingency list which renders those tie-lines ineffective. SCE provided in their response (A.09-09-022 – Alberhill PTC & CPCN) a contingency list as well as an explanation and illustrations. The response shows that the example SCE used to illustrate effectiveness of tie-lines was the resulting overload on the Auld-Moraga 115 kV #2 line following a contingency on the Auld-Moraga 115 kV #1 line. In Figures 2 and 3, the Auld-Moraga 115 kV #2 overload is shown for the Valley South to Valley North alternative as well as for the ASP. This finding is consistent with the results Kevala found in the power flow results conducted for the Tie-line analysis. Moreover, Kevala found the magnitude of the overload to be consistent for both this alternative and the ASP.

Figure 2: Valley South to Valley North Alternative

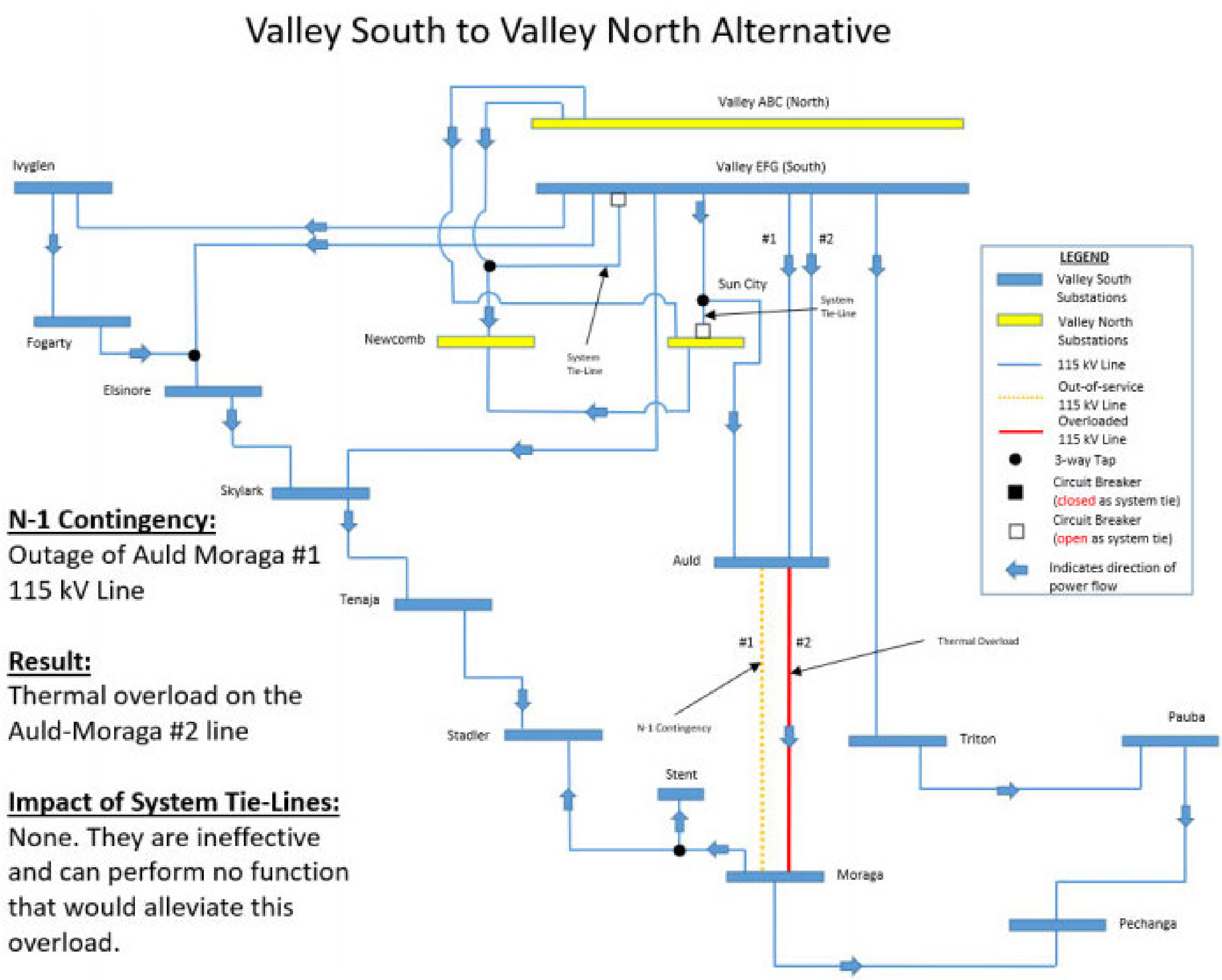
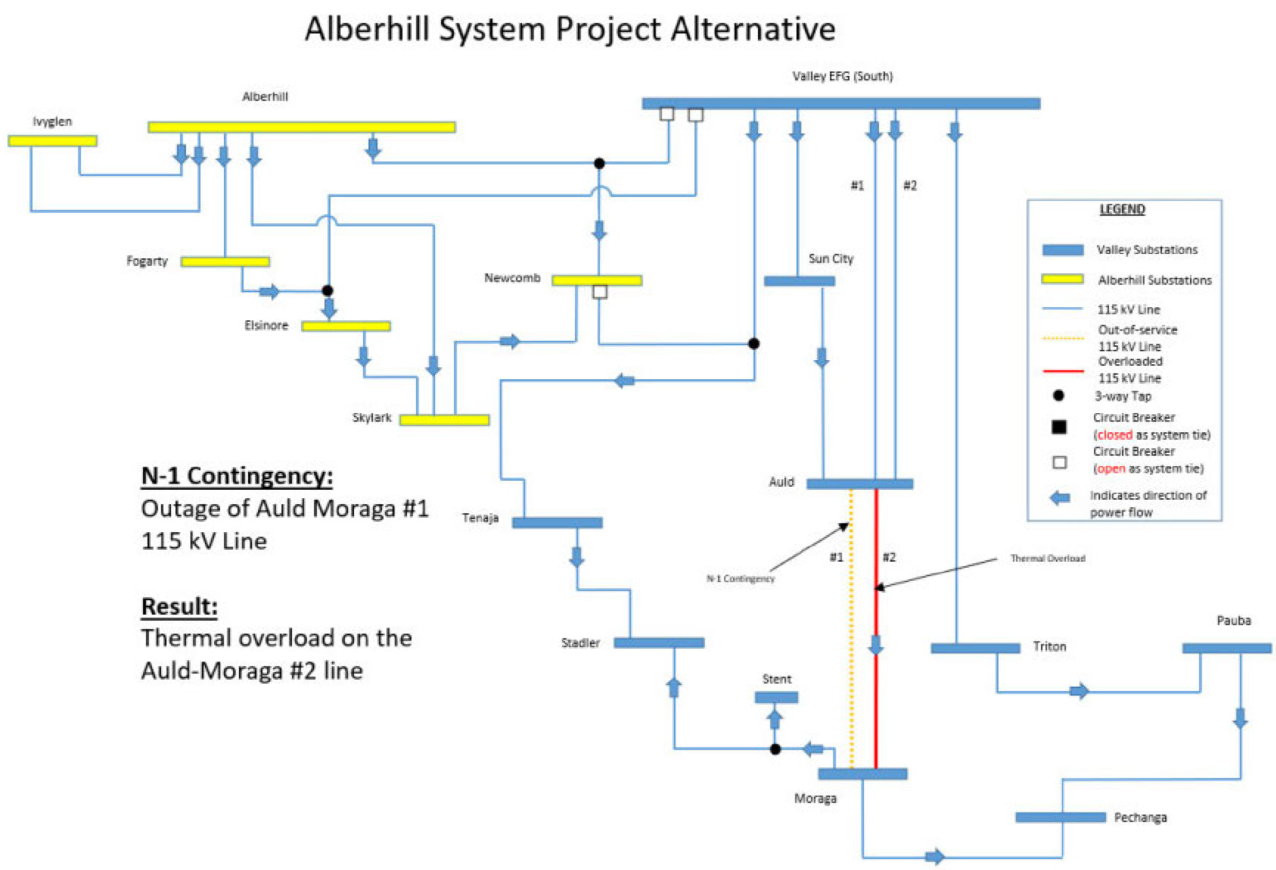
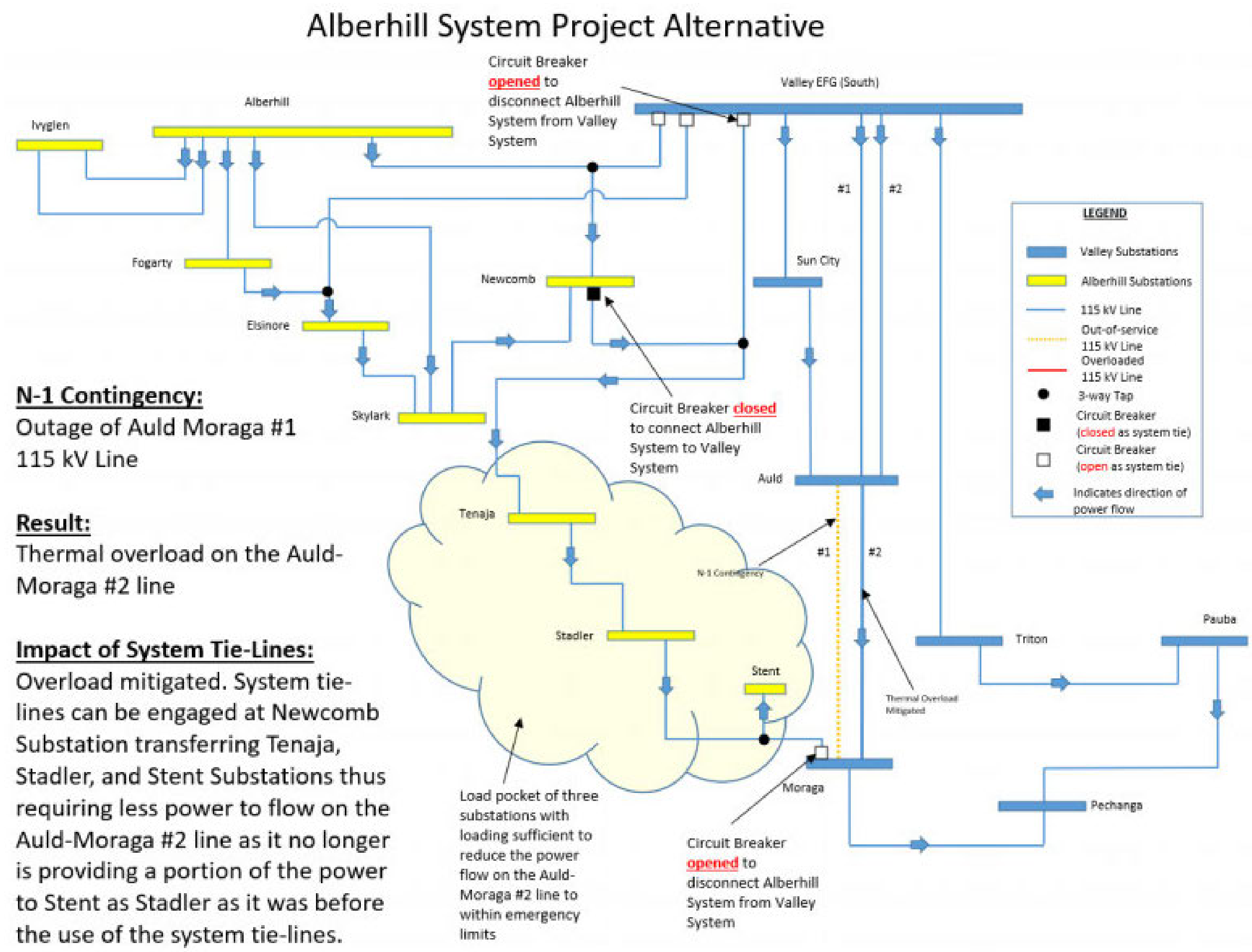


Figure 3: Alberhill System Project Alternative



The illustration in Figure 4 below, appears to show a special protection scheme (SPS) in use to alleviate the Auld-Moraga 115 kV #2 line overload. Without the deployment of this SPS, it would appear that the ASP does not relieve this overload. Kevala's power flow analyses showed that when one Auld-Moraga 115 kv line is out of service, the remaining Auld-Moraga 115 kV line experiences an overload. This result was consistent for all alternatives and ASP. Therefore, it appears that without the use of a SPS, the tie-lines in the Valley South to Valley North alternative are as effective as those in the ASP.

Figure 4: Alberhill System Project special protection scheme



Kevala performed an additional analysis to identify the appropriate sizing for centralized and distributed BESS to mitigate the Valley South transformer overload under normal system conditions. Kevala used their proprietary Network Assessor Battery Sizing Module to determine the required BESS capacity and duration capable of covering the Valley South substation forecasted peaks. The results of the analysis (shown in Table 2, below) identified the MWh required for centralized BESS located at the Valley South substation, and distributed BESS modeled at the Elsinore, Auld, and Moraga substations.

Table 2: Valley South System BESS capacity and duration

Substation	Under Single Contingency Conditions		Under Double Contingency Conditions	
	Size (MW)/ Duration (Hours)	Capacity (MWh)	Size (MW)/ Duration (Hours)	Capacity (MWh)
Valley South	39.0/2.8	107.4	39/3.7	143.2
Elsinore	9.8/4.6	45.0	9.8/6.1	60.0
Auld	15.8/4.8	75.9	15.8/6.4	101.2
Moraga	13.4/4.9	65.2	13.4/6.5	86.9

The BESS capacity values show that forecasted peak loads do not occur frequently during the year. Therefore, the duration of discharge in addition to the charge rate (MW) is important to ensure that the battery is appropriately sized. For example, a 143 MW BESS that operates for only 1 hour would be oversized in capacity and would not have sufficient duration to cover all the peak loads. A 39 MW BESS that has the capability to operate for up to 4 hours, in contrast, would adequately cover those peak hours. Similarly, the distributed BESS modeled at Elsinore, Auld, and Moraga substations, 9.8 MW, 15.8 MW, and 13.4 MW of BESS (respectively), can operate for up to 6.5 hours to cover the few hours during which the forecasted peak occurs. If any of these BESS systems were to operate for 4 hours, for example, the Valley South transformers would experience overloads during the remaining 2.5 hours when the BESS was not supplying capacity.

In Kevala's report, *DER Adoption and Impact on Load Forecast in Valley South System (May 27, 2021)*, power flow studies identified a 188 MW/362 MWh BESS as the maximum capacity of BESS or load reducing DER that could be installed in the Valley South system without causing voltage violations. By taking the results of the supplemental tie-line analysis in conjunction with this analysis, a BESS ranging from 143 MWh to 362 MWh would relieve the overload on the Valley South transformers without causing any other issues on the system.

Conclusions

In this report, SCE's electrical engineering analysis of the ASP is assessed relative to power flow study approaches used at similar electric utilities, such as PG&E and SDG&E. Kevala's review found SCE's analysis to be consistent with widely used study approaches. Once SCE obtained results from this analysis, SCE-developed performance metrics were applied to assess and rank the ASP and the alternatives.

Kevala conducted power flow analyses which found that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads following both the worst single contingency and the worst double contingency in the Valley South system. This overload is observed with all the power flow cases including the current configuration of the do-nothing case, the ASP, and the alternatives. This indicates that a mitigation project or a special protection scheme should be studied to address this overload, which appears unrelated to the ASP.

Kevala's previous tie-line analysis was supplemented in this report with a discussion of the right-sized BESS required to cover all hours of forecasted peak load at the Valley South substation. A 143 MWh BESS that is capable of operating for up to 6.5 hours was identified as the appropriate size to cover forecasted peak loads under double contingency conditions.

Appendix G – Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project

Memorandum

To: California Public Utilities Commission (CPUC)

From: WSP USA Inc. (formerly Ecology and Environment, Inc.)

Date: June 18, 2021

Subject: Integrated Time Series Benefit-Cost Analysis – Southern California Edison Alberhill System Project

Purpose

The purpose of this memo is to provide results of an integrated time series benefit-cost analysis (BCA). Previous Southern California Edison (SCE) BCAs (May 2020 and February 2021 BCAs and supporting spreadsheets, *Effective Photovoltaic [PV] Forecast*, *PV Watts Forecast*, and *Spatial Base Forecast*) were not appropriately developed over the actual project timeline, and the calculations of the Present Value Revenue Requirement (PVRR) total costs were not shown. While project benefits were treated appropriately in terms of traditional capital analysis net present valuation procedures, project costs were derived using an external program based on the PVRR process. Using this method to compute project costs externally made it unclear that total project costs and annual project costs were calculated appropriately. Further, there were no linkages to annual operations and maintenance (O&M) costs included in the project cost stream (O&M was found in the separate Excel project cost sheet, but not linked to the analysis). In addition, the year project construction was expected to start and the year benefits would begin accruing were not placed into the timeline correctly. For all alternatives, the project benefits and O&M costs designated within the model were accruing in years before the project was constructed (prior to the facility operational in-service date), thus yielding an erroneous BCA comparison among the alternatives under review.

Accordingly, the tasks described below were undertaken to gain a clear understanding of actual benefits and costs associated with the various alternatives.

Methodology

Using data from the SCE February 2021 BCA and the associated spreadsheets, three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. Each analysis described below employed integrated, appropriately timed benefit streams extending over the respective operational period(s). Total project costs were either based on SCE's PVRR cost or on an appropriately timed net present value (NPV) of cost streams with and without uncertainty and battery revenues. To evaluate the different cost effects (PVRR or NPV), the resulting net benefits and benefit-cost ratios (BCRs) were compared to those of the SCE February 2021 BCA and associated spreadsheets submission.

All BCAs involved an integrated time series (where the time series of the costs and benefits of each alternative were appropriately integrated with their construction and O&M timeline). This procedure adhered to a traditional capital improvement BCA.

BCA1

The first BCA model applied a constant 10 percent discount rate (NPV) to the costs, rather than employing the PVRR costs. Appropriately timed benefits were then compared to the appropriately timed NPV costs, arriving at an equitable assessment of net benefits (NPV benefits above NPV costs) and ensuing BCRs.

BCA2

The second BCA analysis took BCA1 and removed the uncertainty cost factors and battery revenues, deriving net present valuations of appropriately timed cost and benefit streams, their relative net benefits and BCRs. Appropriately timed benefits were then compared to the appropriately timed NPV reduced costs arriving at an equitable assessment of net benefits and resulting BCRs.

BCA3

The third BCA analysis also included appropriately timed benefits; however, with this analysis, the analyst used SCE's PVRR costs, which included both uncertainty and battery revenues. Appropriately timed benefits were then compared to the appropriately timed PVRR costs arriving at equitable net benefits and related BCRs.

References

WSP USA Inc. used or referred to the following spreadsheets:

1. *Project Costs: A.09-09-022 ED-Alberhill-SCE-Supplemental Data Request 003 Question DG-G-1 Revised Attachment 1 of 11*, received March 24, 2021.
2. *BCA: Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, received March 24, 2021.
3. *Exh G-2 Revised Cost Benefit Analysis Report A0909022-SCE ASP*.

4. *Exh C-2 Revised Planning Study A0909022-SCE ASP*.
5. *Exh I-1 Revised Best Solution and Rankings*.
6. *Exh F-1 Revised Forecasts A0909022-SCE ASP*.
7. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-55 Answer*.
8. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-55 Revised Answer*.
9. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-56 Answer*.
10. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-56 Revised Answer*.
11. *PVRR Model: A.09-09-022 TURN-SCE-Alberhill-007 Question 14_ Attachment 1 of 1\EPV RR Models*, received March 25, 2021.

Detailed Methodology and Results

The SCE BCAs' (as referenced above) stream of costs and benefits (for the 13 alternatives) show all project costs between 2022 and 2025, while the benefits begin in 2022, before any of the projects are complete. This lack of proper timing does not ensure a fair comparison of costs and benefits among the alternatives under review. Benefits were incorrectly entered/discounted in the first year of the time series, as if beginning before the project is constructed rather than after completion of construction (the year benefits would truly begin).

The stream of undiscounted costs and benefits have been properly entered into new time series spreadsheets for each alternative based on the accurate sequence of project-related events: (1) construction period (the year of construction start through the year of construction completion); (2) O&M spending; and (3) years of accrual of benefits.[1]

In the first model, BCA1, a constant 10 percent discount rate was applied across the board to the costs rather than applying the array of PVRR-based factors. A constant discount rate was used because the PVRR figures, which are used and added to the total project costs in the SCE BCAs, varied significantly among the alternatives. These factors influenced the final costs applied in the BCR because they were based on many factors (e.g., interest rates, applied taxes, depreciation, salvage values, revenues generated, etc.) and their derivation was difficult to track, reproduce, and verify.

Using the proposed stream of undiscounted capital costs, O&M costs, and benefits over the project life span, and discounting these expenditures using a 10 percent discount to the base year, allows for an equitable comparison of benefits and costs associated with each alternative. This method of calculation also allows for comparing efficiency effects among each alternative in terms of capital spending and benefit accrual over time.

The findings of this time series BCA were then compared to the BCA *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3.*

[1] The revised undiscounted costs and benefits, received March 24, 2021, were used as inputs.

In BCA2, two uncertainty factors ("to address uncertainties of load-reducing technologies and California's electrification goals," per page 216 of *Exh G-2 Revised Cost Benefit Analysis Report*, and "due to the lack of environmental analysis, licensing, and engineering design efforts," per page 18 of *Exh C-2 Revised Planning Study*) and the battery revenues were removed from the time series costs stream.

In BCA3, as a sensitivity analysis, SCE's PVRR costs, which include both uncertainty and battery revenues, were used.

The results of all three model runs were compared to the revised BCA *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, which found the BCRs listed in Figure 1.

Table 6-4. SCE Effective PV Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,648	11.02
F	Valley South to Valley North	$2,156	10.41
I	Valley South to Valley North and Distributed BESS in Valley South	$2,165	9.33
A	Alberhill System Project	$4,282	9.03
B	SDG&E	$4,001	8.84
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,468	8.54
G	Valley South to Valley North to Vista	$2,470	8.52
E	Mira Loma	$2,601	8.42
J	SDG&E and Centralized BESS in Valley South	$4,041	7.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542	6.93
K	Mira Loma and Centralized BESS in Valley South	$3,132	5.59
C	SCE Orange County	$4,021	5.38
H	Centralized BESS in Valley South	$2,535	4.83

Figure 1. SCE Effective PV Forecast – Benefit Cost Ratio

BCA1, a time series analysis, is a traditional capital improvement benefit cost analysis. It does not use SCE's PVRR computations, rather it uses the estimated stream of undiscounted capital costs, O&M costs, and benefits (as provided in SCE's spreadsheets), all timed correctly, over the project life span, including both uncertainty and battery revenues, then discounted these expenditures equitably using a 10 percent discount to a common point in time (the base year). This analysis resulted in the following BCR rankings. SCE BCRs and net benefits are consistently higher than the capital analysis (of BCA1) among all alternatives, which brings up the question *was the PVRR figure appropriately discounted*? In any event, conducting the capital analysis using the 10 percent discount rate reveals that the Alberhill System Project (Alberhill) is similarly ranked fifth with a BCR of 6.3; however, with the SCE analysis, Alberhill was ranked fourth with a BCR of 9.0. In terms of net benefits, BCA1 model shows a net benefits reduction from $4.3 million to $1.7 million, but Alberhill remains first in both evaluations.[2]

[2] The analyst did not change benefits, as calculated by SCE, except for adjusting them in time and how those benefits are discounted, (i.e., ensuring benefits begin after construction is completed).

Captial Improvement - Benefit Cost Analysis
(Includes Uncertainty and Battery Revenues)
Millions of ($2019 dollars)

	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	**Total Costs (NPV)**	**Benefits NPV**	**Net Benefits**	**BCR**	**BCR Ranking**	**PVRR COSTS**	**Net Benefits**	**BCR**	**BCR Ranking**
Valley S to Valley N to Vista	$192	$1,268	$1,076	6.6	1	$290	$2,470	8.5	7
Valley South to Valley North	$136	$1,106	$970	8.1	2	$207	$2,156	10.4	2
VS to VN & Distributed BESS VS	$144	$1,111	$967	7.7	3	$232	$2,165	9.3	3
Menifee	$222	$1,702	$1,480	7.7	4	$331	$3,648	11.0	1
Alberhill System Project	**$318**	**$1,996**	**$1,677**	**6.3**	**5**	**$474**	**$4,282**	**9.0**	**4**
VS to VN to VST & Cen BESS VS	$204	$1,266	$1,063	6.2	6	$289	$2,468	8.5	6
SDG&E	$301	$1,867	$1,566	6.2	7	$453	$4,001	8.8	5
Mira Loma	$204	$1,214	$1,009	5.9	8	$309	$2,601	8.4	8
SDG&E and Centralized BESS in VS	$354	$1,885	$1,532	5.3	9	$531	$4,041	7.6	9
VS to VN & Central BESS VS VN	$245	$1,304	$1,059	5.3	10	$367	$2,542	6.9	10
Mira Loma and Centralized BESS VS	$389	$1,461	$1,072	3.8	11	$560	$3,132	5.6	11
Centralized BESS in VS	$353	$1,301	$948	3.7	12	$525	$2,535	4.8	13
SCE Orange County	$504	$1,705	$1,201	3.4	13	$747	$4,021	5.4	12

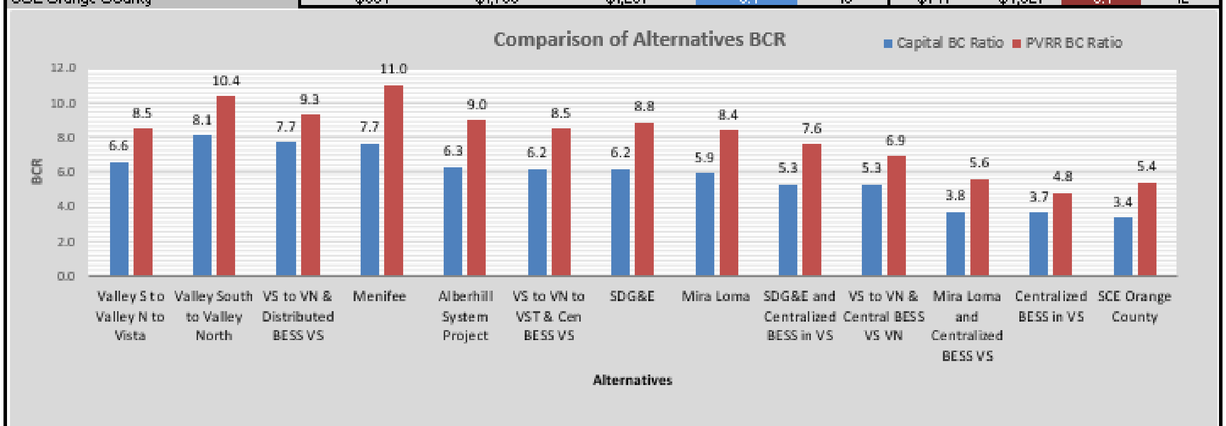


Figure 2. BCA 1: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (includes Uncertainty and Battery Revenues)

BCA2 is similar to BCA1 but excludes uncertainty and battery revenues from the costs streams, while all other time series factors remain the same. Although excluding uncertainty and battery revenues from the capital analysis has closed the BCR gap (between the capital and PVRR analyses), net benefits still are considerably divergent. This can be explained in part from the fact that the SCE benefits were not appropriately treated (discounted) in the year the projects become operational. The reason for the divergence in the costs is unknown. In any event, Alberhill moves to eighth in the BCR ranking compared to fourth with SCE evaluation. In terms of net benefits, as shown in Figure 3, several alternatives show similarly sized net benefits (in the range of $1.7 million to $1.9 million) when compared with Alberhill.

Captial Improvement - Benefit Cost Analysis
(Excludes Uncertainty and Battery Revenues)
Millions of ($2019 dollars)

Alternative	CAPITAL ANALYSIS Total Costs (NPV)	Benefits NPV	Net Benefits	BCR	BCR Ranking	PVRR ANALYSIS PVRR COSTS	Net Benefits	BCR	BCR Ranking
Valley S to Valley N to Vista	$151	$1,268	$1,117	8.4	1	$290	$2,470	8.5	7
Menifee	$167	$1,702	$1,535	10.2	2	$331	$3,648	11.0	1
Valley South to Valley North	$110	$1,106	$997	10.1	3	$207	$2,156	10.4	2
VS to VN & Distributed BESS VS	$118	$1,111	$994	9.5	4	$232	$2,165	9.3	3
SDG&E	$216	$1,867	$1,650	8.6	5	$453	$4,001	8.8	5
VS to VN to VST & Cen BESS VS	$150	$1,266	$1,117	8.5	6	$289	$2,468	8.5	6
Mira Loma	$152	$1,214	$1,062	8.0	7	$309	$2,601	8.4	8
Alberhill System Project	**$262**	**$1,996**	**$1,734**	**7.6**	**8**	**$474**	**$4,282**	**9.0**	**4**
VS to VN & Central BESS VS VN	$174	$1,304	$1,131	7.5	9	$367	$2,542	6.9	10
SDG&E and Centralized BESS in VS	$252	$1,885	$1,633	7.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$290	$1,461	$1,171	5.0	11	$560	$3,132	5.6	11
SCE Orange County	$358	$1,705	$1,347	4.8	12	$747	$4,021	5.4	12
Centralized BESS in VS	$322	$1,301	$978	4.0	13	$525	$2,535	4.8	13

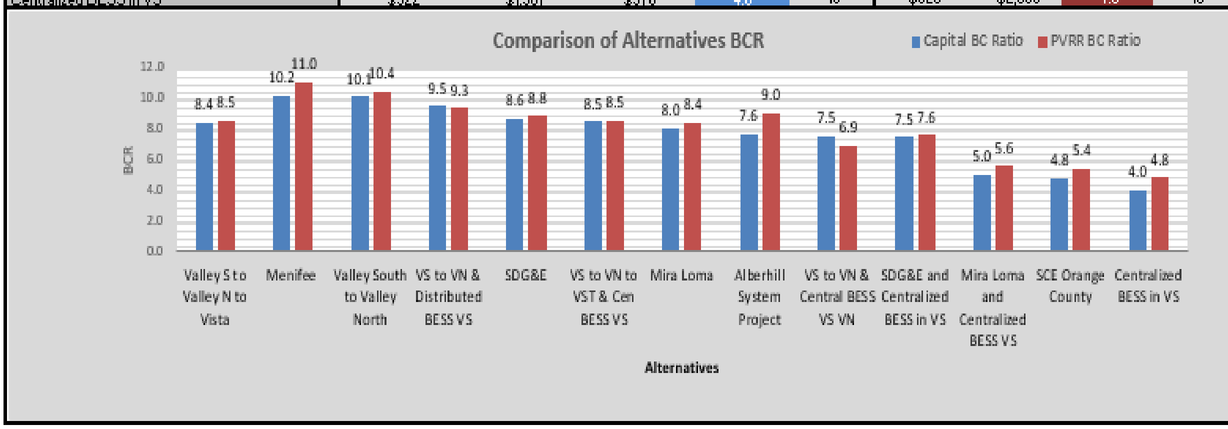


Figure 3. BCA 2: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (excludes Uncertainty and Battery Revenues)

Similar to BCA1, BCA3 is a hybrid capital improvement benefit cost analysis. Unlike BCA1, BCA3 uses SCE's PVRR computed costs and coupled with SCE's benefits timed correctly (including battery revenues and uncertainty). Under BCA3, Alberhill places sixth in the BCR ranking, and in terms of net benefits, as shown in Figure 4, several alternatives show similarly sized net benefits (in the range of $1.7 million to $1.9 million) when compared to Alberhill.

In terms of the Alberhill System Project, BCA1 (using a 10% discount rate) has a total project cost of $318 million (net present value) while BCA3 (using SCE's PVRR computed costs) has a much larger total project cost of $474 million (net present value). While BCA1 and BCA2 use different methods for computing total project costs, both BCA1 and BCA2 include uncertainty and battery revenues, times the accrual of benefits based on their actual occurrence (in-service, operational date), and all other factors are held constant.

MIXED BENEFIT COST ANALYSIS - USING "SCE" PVRR COSTS AND CAPITAL ANALYSIS BENEFITS Includes Uncertainty and Battery Revenues *Millions of ($2019 dollars)*									
	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	SCE PVRR COSTS	Capital Analysis Benefits NPV	Net Benefits	BCR	BCR RANK	PVRR COSTS	Net Benefits	BCR	BCR Rank
Valley South to Valley North	$207	$1,106	$899	5.3	1	$207	$2,156	10.4	2
Menifee	$331	$1,702	$1,371	5.1	2	$331	$3,648	11.0	1
VS to VN & Distributed BESS VS	$232	$1,111	$879	4.8	3	$232	$2,165	9.3	3
VS to VN to VST & Cen BESS VS	$289	$1,266	$977	4.4	4	$289	$2,468	**8.5**	6
Valley S to Valley N to Vista	$290	$1,268	$978	4.4	5	$290	$2,470	8.5	7
Alberhill System Project	**$474**	**$1,996**	**$1,521**	**4.2**	**6**	**$474**	**$4,282**	**9.0**	**4**
SDG&E	$453	$1,867	$1,414	4.1	7	$453	$4,001	8.8	5
Mira Loma	$309	$1,214	$905	3.9	8	$309	$2,601	8.4	8
VS to VN & Central BESS VS VN	$367	$1,304	$937	3.6	9	$367	$2,542	**6.9**	10
SDG&E and Centralized BESS in VS	$531	$1,885	$1,354	3.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$560	$1,461	$901	2.6	11	$560	$3,132	5.6	11
Centralized BESS in VS	$525	$1,301	$776	2.5	12	$525	$2,535	4.8	13
SCE Orange County	$747	$1,705	$958	2.3	13	$747	$4,021	5.4	12

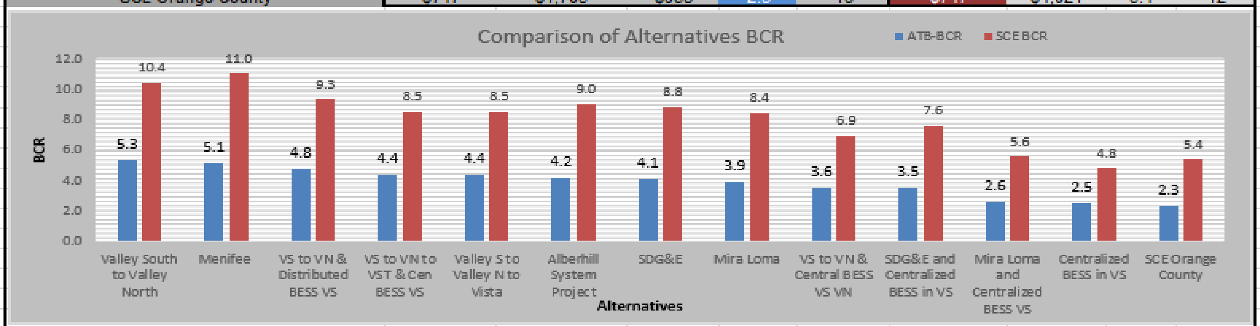


Figure 4. BCA 3: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (includes Uncertainty and Battery Revenues)

Summary

Regardless of which costs are used (NPV or PVRR), Alberhill is not the most cost-effective alternative.

Based on the above analysis, several alternatives were determined to yield a much lower project cost when compared to the proposed Alberhill System Project and to have a better BCR (a reflection of cost versus benefit efficiency). For example, Valley South to Valley North, at a cost of about $207 million, could be built twice and have lower life cycle project cost ($60 million less) compared to the Alberhill facility. Furthermore, the net benefits would outpace that of Alberhill by $277 million. The same generalized statement of net savings/benefits is attributable to Valley South to Valley North to Vista and Distributed BESS in Valley South (cost $289 million), in which SCE costs (including uncertainty and battery revenues) are used in conjunction with appropriately timed benefits. These two alternatives also appear to be economically viable based on the BCA2 analysis. Since there are alternatives that are smaller scaled and viable, two smaller projects could be implemented separately at different points in time in the future (one now and one later, based on needs) and possibly cost less than Alberhill and produce the best benefit to cost ratio with more overall benefits.

Memorandum

To: California Public Utilities Commission

From: WSP USA Inc. (WSP)(formerly Ecology and Environment Inc.)

Date: October 11, 2021

Subject: Benefit-Cost Analysis Review – Southern California Edison Alberhill System Project

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Purpose

Review of Southern California Edison (SCE) June 22, 2021, Second Amended Motion Benefit-Cost Analysis (BCA) materials (notice of clerical error corrections in *Planning Study and Benefit-Cost Analysis of Alternatives for SCE's Alberhill System Project*) to understand what changes were made in relation to previous versions and to see if the Second Amended Motion Cost-Benefit Analysis and supporting spreadsheets (indicated in the Second Amended Motion notice) changed the timing of costs and benefits (as suggested in WSP's previous review).

Methodology

This review was conducted in a two-step approach.

Step 1: Review Second Amended Motion document changes.
On June 23, 2021, WSP received the following documents (all dated June 22, 2021).

- A0909022-SCE Errata to Correct Amended Motion to Supplement.
- A0909022-SCE NOA Errata to Correct Amended Motion to Supplement.
- Exh C-2: *Planning Study Revision 2.1* A0909022-SCE Errata to Correct Amended Motion to Supplement.
- Exh G-2: Cost-Benefit Analysis report revision A0909022-SCE Errata to Correct Amended Motion to Supplement, revised *Cost-Benefit Analysis Report* by Quanta Technologies dated June 15, 2021, Version 2.1.

In Step 1, WSP reviewed the above documents. However, supporting revised BCA spreadsheets were not supplied to support the description of changes in the documents, as bulleted below. According to the Summary of Revisions in Exh C-2:

1. SCE found a variety of errors in the BCA ("with regard to spreadsheet tabular data," including that "some of the formulas were transferred incorrectly") and made corrections, but SCE says that the cumulative effects of all the changes only resulted in minor net effects.

   WSP findings: After reviewing the first (May 2020 Amended Application) and second versions (February 2021Amended Motion to Supplement the Record) of the BCA spreadsheets, WSP found a variety of minor errors in the tabular data (e.g., some formulas were found to be incorrectly placed or untraceable, along with a few mismatches in data entries). New changes to computed benefit data (as described in pages 2 and 3 of the June 2021 revised Planning Study Exh C-2), which includes changed calculations using Flex-1 metrics, changed assignment of Value of Service monetary values to unserved customer load, and changed monetization rate of commercial and industrial customers, would likely not have been found by WSP nor reflected in the integrated time-series BCA spreadsheets prepared by WSP in June 2021, prior to the filing of SCE's Second Amended Motion. However, if these corrections were minor, as stated by SCE, WSP agrees they would not have changed the overall outcome SCE presented, because the main issue with SCE's BCA (as described in the initial WSP June 2021 memo) remains with SCE's timing and streaming of benefits and operations and maintenance (O&M) spending occurring prior to project completion or in-service date (affecting the overall benefit-cost ratios and ranking of alternatives provided by SCE).

2. In Point #4 (page 4 of Summary of Revisions, Exh C-2), SCE states that the timing of the O&M costs is now applied beginning at the project in-service date.

   WSP findings: In WSP's integrated time-series BCA, WSP incorporated SCE's O&M costs as a separate line item to SCE's project costs or capital expenditures (CAPEX) (not embedded into the present value revenue requirement as done by SCE, for transparency) and correctly timed the O&M spending to begin at the project in-service date (or after the project was constructed). WSP also incorporated SCE's benefits for each alternative to begin at the project in-service date (or after the project was constructed). Since SCE stated that the timing of O&M spending had been corrected, WSP requested the new Second Amended Motion supporting BCA spreadsheets to verify that "O&M costs are now applied beginning at the project in-service date."

3. In Point #5 (page 4 of Summary of Revisions, Exh C-2) SCE states that, "now all alternatives have a common set of assumptions – consistently accruing benefits at the project need date (2022) and entering construction in 2023."

   WSP findings: It is unclear why SCE would continue to start accruing project benefits "at the project need date" and not on the "in-service date," when normal BCA practice is for benefits to begin only after the project is constructed and in-service.

4. In footnote 4 explaining Point #5 (page 4 of Summary of Revisions, Exh C-2) SCE states that "benefits are started on the need date rather than in-service date for all alternatives to maintain consistency among the alternatives, to simplify the analysis, and to ensure that the near-term load forecast has a more dominant impact on the relative performance of the alternatives."

   WSP findings: Claiming past impacts/benefits thought to occur prior to a project in-service operational date is not the proper method to calculate a BCA of alternatives, and SCE's footnote fails to explain its process. If SCE changed the timing of O&M spending from its previous spreadsheet timing (Point #4) to begin at the in-service date, it is unclear why SCE did not correct the timing of the benefits, since "timing of the accrual of benefits" was initially identified by WSP as a concern in a conference call on August 11, 2020. It is also unclear why "near-term load forecast" was needed to ensure a more dominant impact on the relative performance of the alternatives." This practice results in false performance results among alternatives under review. The computation of an alternative's benefits must be based on a realistic corresponding operational forecast moving forward and start on a project's in-service date and not before the facility is operational.

In summary, since revised BCA spreadsheets had not been provided to support the clerical changes in the BCA report (per SCE's Second Amended Motion), WSP requested to review SCE's (third version) spreadsheets to understand what changes were made in relation to the previous versions and to verify whether the third version of the Cost-Benefit Analysis changed the timing of O&M spending. WSP thought that if SCE's revisions were easily traceable, those revisions could quickly be incorporated into WSP's correctly timed BCA spreadsheet analyses from June 2021. However, the WSP analyst determined that if SCE was still attempting to accrue project benefits on a project need date and before the in-service date, minor changes to correct spreadsheet tabular data errors in the BCA would not correct a mistimed analysis.

Step 2: Review Third Revision BCAs.
On August 13, 2021, WSP received and reviewed the following documents (all dated June 22, 2021):

- Third Revision Cost-Benefit Analysis Spreadsheets: *Effective PV Spreadsheet-* A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Attachment 2 of 3_Effective PV (*Third Revision BCA spreadsheet*);
- A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Answer; and
- A.09-09-022 CPUC-JWS-4 Q.01i Revised Answer.

In Step 2, WSP reviewed the Second Amended Motion BCA spreadsheets (third version) in comparison with the February 2021 Amended Motion BCA spreadsheets (second version) alongside the variety of errors in the BCA noted in SCE's June 2021 Second Amended Motion.

Initially, the Alberhill and Valley South to Valley North Alternatives were reviewed for changes in the bottom-line benefit-cost ratio or net benefits. This review found minor adjustments. Most notably, changes found in earlier reviews were flat number inputs linked to database formulas in SCE's database modeling program. Also, certain underlying inputs (figures) were slightly changed, likely due to rounding errors, but they were not to an order of magnitude that would affect the results seen during the earlier reviews. With this being the case, a more in-depth review was undertaken on all the alternatives. In short, no major changes were detected that would affect the final benefit-cost ratios or other economic indicators derived in the analysis. WSP agrees with SCE's June 2021 Second Amended Motion that states "the cumulative effects of all the changes only resulted in minor net effects."

However, with this submission, SCE did not supply O&M cost data incorporated into the Second Amended Motion BCA showing O&M starting at the project in-service date, so WSP cannot verify "the timing of the O&M costs are now applied beginning at the project in-service date." The Second Amended Motion BCA spreadsheets were not much different to the February 2021 Amended Motion BCA spreadsheets. The benefits are still mistimed as they still begin accruing before the project in-service date and the Second Amended Motion BCA does not display the streaming of O&M costs. Therefore, incorporating the minor clerical changes into WSP's integrated time-series BCA (June 2021) would not be productive, and WSP's findings of the second review would not be significantly changed.

Step 3: Review Third Revision BCAs with Tracked Changes.
August 26, 2021: As an added measure of review and to verify that no key changes were missed in the review of third version spreadsheets that would warrant further investigation, on August 26, 2021, WSP submitted a request to SCE Regulatory Affairs for tracked changes versions of the spreadsheets (with highlighted locations to identify where changes, as cited in the Second Amended Motion, occurred in the spreadsheets).

September 10, 2021: SCE Regulatory Affairs sent tracked-version spreadsheets with green highlighted cells identifying changes.

September 16, 2021: WSP compared the spreadsheets, *Cost-Benefit SCE Effective PV Forecast_Tracked.xlsm*, received September 10, 2021 (tracked third version) with the *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, received March 24, 2021 (second version).

Although the highlighted tracked changes confirmed findings identified in Step 2 above, after review, WSP made the following observations:

1. The cells of the tracked third version spreadsheet are password protected, limiting disclosure and the scope of the review (note: the cells of the untracked third version spreadsheets [*A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Attachment 2 of 3_Effective PV*, received by email on August 13, 2021, and reviewed in Step 2] were also password protected).

2. In the second version spreadsheet, the computations of benefits were linked to a sheet titled *Cost Assumptions*. That sheet was included with the second version spreadsheet. However, in the tracked third version spreadsheet, the *Cost Assumptions* spreadsheet was renamed *Cost Data & Assumptions* (as referred to in cells), but a sheet was not included with the tracking spreadsheet, meaning that the computation of benefit cells is not linkable to the individual sources (these cells were also password protected). The purpose for excluding *Cost Data & Assumptions* during this latter round of revisions is unclear.

3. For most alternatives, certain underlying categorical benefit figures were slightly changed (e.g., benefits categories: EENS, FLEX-1, FLEX-2-1, FLEX-2-2, etc.); however the resulting total of aggregated benefits of those alternatives remained unchanged from the second version spreadsheets. Project costs among all alternatives remained unchanged.

4. However, for the Menifee Alternative, the changes resulted in benefits increasing by $234M ($3,882M – $3,648M = $234M) or a 6.4 percent increase. With Menifee's increase of benefits, WSP revisited the retimed *Capital Analysis BCA* (used for the second version spreadsheet, *Effective PV Forecast* review) to see how the benefits from the third version spreadsheet would affect the Menifee Alternative. WSP found that Menifee's benefit-cost ratio (BCR) changed. Applying the prorated increase (6.4 percent) to the WSP retimed *Capital Analysis BCA* caused the retimed benefits to increase from $1,702 to $1,881. Dividing these benefits by total project costs ($331M) yielded a BCR of 5.5 (up 0.4 from the original 5.1 BCR). This change results in Menifee moving up to first place, Valley South to Valley North moving to second place (switching places from WSP's previous analysis), and all other alternatives remaining in their previous positions (Alberhill remaining in sixth place).

Table 1. Adjusted BCR for Menifee per Tracked Changes

	(SCE 2nd REV) PVRR Costs and NPV Benefits	(SCE 3rd REV) PVRR Costs and NPV Benefits	Difference	Percent Change	Capital Analysis (Retimed 2nd REV)	Capital Analysis (Retimed 3rd REV)
Aggregate ($M)	3,648	3,882	234	1.064	1702	1811
Project Cost ($M)	331	331	0	N/A	331	331
BCR	11.22	11.73	0.7	N/A	5.1	5.5

Key:
BCR = benefit-cost ratio
NPV = net present value
PVRR = Present Value Revenue Requirement
REV = revision
SCE = Southern California Edison

In summary, while minor changes were made to interior cell numbers, because the spreadsheet is password protected, their computation cannot be verified. In any case, the final resulting benefits (and costs) among the two spreadsheets are the same (except Menifee). As noted previously, the timing of benefits in the third version spreadsheet is unchanged, and the timeframe of the analysis remains years 2022 to 2048.

No other changes (from third version spreadsheets) were applied to the retimed *Capital Analysis BCA* because the changes are minor and SCE hasn't changed the timing of accruing benefits before project is in service, making the changes primarily inconsequential.