EXHIBIT F-1 (SECOND AMENDED)

Item F:

The forecasted impact of the proposed project on **service reliability performance**, using electric service reliability metrics where applicable.

Response to Item F:

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: February 2, 2021

Summary of Revisions:

- Modifies the terminology for the primary metric (previously Expected Energy Not Served (EENS) and now Load at Risk (LAR)) to clarify that the metrics are cumulative values of the potential amount of unserved load and are not probability weighted to associate the frequency and timing of events that would prompt loss of service to customers.
- Deletes the SAIFI, SAIDI and CAIFI metrics to avoid confusion with similar data reported in Supplemental Data Response Items B and C[1] which are calculated on the basis of a different customer base and thus cannot be compared directly. Because these SAIFI, SAIDI and CAIDI values previously provided here were derived from the LAR values they did not provide any additional insight on the effectiveness of the Alberhill System Project in meeting system reliability/resiliency needs.
- Modifies the description of the Flex-1 and Flex-2 metrics to reflect more realistic operation scenarios.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item C and DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

1.0 Executive Summary

SCE interprets this data request as inquiring about the service reliability performance of the proposed Alberhill System Project (ASP)[2].

The proposed ASP was designed to mitigate the transformer capacity shortfall currently anticipated to occur in the Valley South System as early as 2022, while also addressing the long-standing need for system tie-lines to improve reliability and resiliency by providing the ability to transfer load to adjacent systems for maintenance and other activities (planned outages), and under abnormal system operating conditions (unplanned outages). To evaluate the impact of the proposed project on service reliability performance, the response to this data request uses forward-looking service reliability performance metrics, related to customers and energy at risk due to service interruption, to demonstrate that the ASP meets the identified project needs for capacity, reliability, and resiliency over both short-term (10 year) and long-term (30 year) horizons. These metrics demonstrate that the ASP reduces the customer risk of loss of service due to outages related to capacity, reliability, and resiliency issues by 99% through 2028, and by 97% through 2048[3]. These reductions sufficiently improve system performance to comply with SCE's planning standards[4] through 2038, with only one line reconductoring project needed to satisfy these criteria through 2048.

2.0 Introduction

As discussed throughout the ASP Certificate of Convenience and Necessity (CPCN) proceeding (A.09-09-022) and specifically highlighted in an earlier supplemental data request response[5], the reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity[6] margin, configuration, and size that make the Valley South subtransmission system[7] much more vulnerable to future reliability[8] problems than any other Southern California Edison (SCE) subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections

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[2] Service reliability results for alternatives to the Alberhill System Project, which were studied in the cost benefit analysis described in DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C, can be found in Quanta Technology Report, *Benefit Cost Analysis of Alternatives.*

[3] These percentages capture the projected cumulative percent reduction in unserved customer energy needs for various line and transformer outage contingency conditions (through 2028 and 2048 respectively) that are achieved as a result of ASP being in service.

[4] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[5] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

[6] *"Capacity"* is defined as the availability of electric power to serve load and is primarily comprised of two elements in a *radial transmission system*; a lack of capacity of either type will lead to reliability challenges in a radial subtransmission system: (1) "*transformation capacity"* – the ability to deliver power from the transmission system (through substation transformers); and (2) "*subtransmission system line capacity"* – the ability to deliver power to substations which directly serve the customer load in an area. Subtransmission system line capacity also includes "*system tie-line capacity*," which is the ability to transfer load to an adjacent subtransmission system to avoid, and reduce the number of customer's affected by, planned and unplanned outages in the system. Note, a *radial subtransmission system* is one that is provided power from a single source on the transmission system. This is in contrast to a networked system which has multiple transmission and subtransmission source connections. Almost all of SCE's subtransmission systems are of a radial design.

[7] While Southern California Edison typically considers a planning area to be at the substation level, for the purpose of this data request, the discussion herein focuses on the Valley South System, as it is most relevant to the Alberhill System Project proceedings. Certain characteristics discussed here may have broader impacts (on the Valley North System specifically, given the split nature of these systems), but the focus of this response remains on the Valley South System.

[8] *"Reliability"* is defined as a utility's ability to meet service requirements under normal and N-1 contingency conditions, both on a short-term and long-term basis. The ability to meet long-term capacity needs of a given system is an important aspect of reliability. This definition is consistent with IEEE 1366*, "IEEE Guide for Electric Power Distribution Reliability Indices"* which excludes extraordinary events from reliability data reporting.

(system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under normal and abnormal conditions.

Also discussed in this proceeding, in the case of a catastrophic event (such as a major fire, earthquake, or incident at Valley Substation), SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation[9]. This characteristic, in combination with others described in this submittal, results in specific concerns for the Valley South System from a resiliency[10] perspective.

In an earlier supplemental data request response[11], SCE provided an analysis of several years of electric reliability performance for the Valley Systems to demonstrate existing customer service metrics. SCE provided data for Valley South (and Valley North) historical reliability metrics (SAIDI and SAIFI) compared to other SCE subtransmission systems. These data show that, to date, the capacity of the Valley South System has been sufficient to serve all system customers under commonly planned for normal and extreme weather conditions. SCE noted that while SAIDI and SAIFI data are the principal metrics used to report on historical system reliability, they are primarily influenced by events at the distribution system level and thus are less informative for planning at the subtransmission system level. This is because when an electric power system has sufficient substation transformer capacity and/or sufficient system tie-line capacity, and is properly maintained and operated, reliability performance is driven largely by random, distribution-level events. Importantly, as SCE stated, the past reliability performance of the Valley Systems is not a driver for the proposed ASP project. Given the limited remaining transformer capacity serving the Valley South System and its lack of system tie-lines, the future reliability performance of the Valley South System will be driven less by random, distribution level events, and more by subtransmission level events that cannot be mitigated due to the lack of capacity margin and/or system tie-lines. These events would otherwise be mitigated by operational flexibility enabled by available transformer and system tie-line capacity to allow for short-term line and transformer overloads (per standards) to be addressed through the transfer of distribution substations to an adjacent system.

This data request response evaluates the Valley South System with and without the ASP and compares the reliability performance of the two system configurations using a set of *forward-looking* reliability and resiliency metrics related directly to SCE's ability to serve customer load throughout this specific electrical needs area. The analysis presented herein was developed and implemented collaboratively between SCE and a contractor, Quanta Technology[12], and documented in the attached report by Quanta Technology (see Appendix A).

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[9] The source of power to the Valley South System passes through a single point of delivery at Valley Substation, which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level.

[10] *"Resiliency"* is defined as how well a utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events (such as wildfires, earthquakes, cyberattacks, and other potential high impact, low probability (HILP) events) which can have widespread impact on its ability to serve customers. This definition is consistent with IEEE PES-TR65 "*The Definition of Quantification of Resilience*" (April 2018).

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

[12] Quanta Technology is an expertise-based, independent technical consulting and advisory services company specializing in the electric power and energy industries.

3.0 Methodology

In order to compare the impact of the ASP to the current Valley South System configuration[13] on a technical basis, a time-series power flow analysis was performed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is commonly used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance.

Models for the existing Valley South System and the proposed ASP[14], were developed in the PSLF software tool. An 8,760-hour load profile was used to simulate the annual forecasted load and power flows in each of the models, and identified thermal overload and voltage violations based on the following analysis criteria, which are consistent with SCE standards[15].

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the simulation for each year, for base (N-0) and (N-1, or N-2) contingencies[16]. The calculated unserved load is then used to calculate the specific metrics described below. Results for both 10-year and 30-year horizons[17] are presented in this response to assess both near-term and long-term reliability impacts of the proposed ASP.

4.0 Definition of Metrics

The performance of each system configuration was evaluated using the following reliability and resiliency metrics:

- <u>Load at Risk (LAR)</u>
    - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.
    - Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- <u>Maximum Interrupted Power (IP)</u>

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[13] For purposes of this comparison, the current configuration of the Valley South System includes the Valley-Ivyglen 115 kV Line Project (VIG) and the Valley South 115 kV Subtransmission Line Project (VSSP), both of which are in construction and anticipated to be completed in 2022 and 2021 respectively. See Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018) and Valley South 115 kV Subtransmission Project ("VSSP") CPUC Decision 16-12-001 (issued December 1, 2016).

[14] The ASP PSLF model includes both the new Alberhill System, and the Valley South System with the required modifications to implement the ASP. This allows the PSLF model to evaluate the performance of the <u>entire</u> Valley South System Electrical Needs Area with and without the ASP.

[15] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[16] N-0 refers to operating conditions when all facilities are in-service. N-1 refers to operating conditions when a single subtransmission system component is out-of-service. N-2 refers to operating conditions when two subtransmission system components are simultaneously out-of-service.

[17] These horizons correspond to the 10-year and 30-year load forecasts which project future load in the Valley South System in 2028 and 2048, respectively. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A for the 10-year forecast, and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C for the 30-year load forecast.

  - Maximum power that would be required to be curtailed during thermal overload and voltage violation periods.
  - Calculated for N-0 and N-1 contingencies.
- Flexibility 1 (Flex-1)
  - Accumulation of LAR for all possible N-2 line contingencies.
  - Credits the available system tie-line capacity that can be used to reduce LAR.
  - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- Flexibility 2 (Flex-2)
  - Flex-2-1
    - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability event.
    - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
  - Flex-2-2
    - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
    - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.
    - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated time to deliver, install, and in-service the remotely stored spare Valley transformers to restore full transformation capacity to Valley South.
    - Observe 1 hour (Short-Term Emergency Load Limit) of 896 megavolt-amperes (MVA)[18] (160% of the 560 MVA transformer nameplate rating). Following this, 24-hour rating (Long-Term Emergency Loading Limit) rating of 672 MVA (120%).
    - Credits the available system tie-line capacity that can be used to reduce EENS.
- Period of Flexibility Deficit (PFD)
  - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
  - Calculated for N-0 and N-1 contingencies.

Note that these metrics represent future projections of system performance, and the results of each system configuration should be reviewed relative to the other.

5.0 Results

The attached Quanta Technology report demonstrates that the ASP provides substantial benefit relative to the current Valley South System configuration. The study compares the performance of the Valley South System in its current configuration to the performance of the system after implementing the ASP using forward-looking, quantitative, and customer-benefit driven metrics.

[18] For simplicity, within this document it is assumed that MW = MVA.

Table 1 shows the results for each of the metrics described above for the years 2028 and 2048[19] with and without the ASP and demonstrates the positive impact the ASP has on service reliability performance.

Table 1. Service Reliability Performance of the Valley South System with and without the ASP, 2028 and 2048

Metric	Unit	2028		2048	
		Without ASP	With ASP	Without ASP	With ASP
LAR N-0	MWh	250	0	6,310	3[20]
LAR N-1	MWh	67	0	2,823	202
Flex-1	MWh	163,415	30,438	526,314	136,664
Flex-2-1	MWh	3,485,449	39,532	4,060,195	87,217
Flex-2-2	MWh	72,331	0	155,780	100
IP N-0	MW	65	0	288	2
IP N-1	MW	11	0	68	24
PFD N-0	Hours	7	0	77	2
PFD N-1	Hours	32	0	153	14

While the ASP results in substantial improvement in all metrics, the most significant from the perspective of customer impact are the metrics that directly address potential dropped load due to capacity, reliability, and resiliency concerns (i.e., LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 calculated in units of potential lost MW-hours of service). Table 2 provides comparative results of the cumulative dropped load from the LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 metrics from 2022[21] through the years 2028 and 2048.

Table 2 – Total Cumulative Load at Risk of Being Dropped with and without the ASP, 2028 and 2048

Metric Category	Metric	2022 – 2028			2022 - 2048		
		Without ASP (MWh)	With ASP (MWh)	*% Reduction*	Without ASP (MWh)	With ASP (MWh)	*% Reduction*
Capacity	LAR N-0	971	0	*100.0%*	56,581	6	*99.9%*
	LAR N-1	274	0	*100.0%*	21,373	1,047	*95.1%*
Reliability & Resiliency	Flex-1	762,859	103,783	*86.4%*	7,841,596	1,817,470	*76.8%*
	Flex-2-1	23,907,934	245,766	*99.0%*	100,091,707	1,545,650	*98.5%*
	Flex-2-2	450,142	0	*100.0%*	2,788,436	432	*99.9%*

Through 2048, the ASP effectively eliminates the capacity (99.9% reduction in LAR N-0) concerns and substantially addresses the reliability concerns associated with line failures (76.8% reduction in Flex-1), and substantially mitigates the resiliency concerns associated with loss of transformers serving the Valley South System (98.5% and 99.9% reductions in Flex-2-1 and Flex-2-2, respectively).

Other key highlights of the projected service reliability performance for the area served by the

[19] These dates represent the end of the 10 year and 30 year horizon starting in 2018, respectively, which are consistent with the load forecast addressed in other data responses. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item G.

[20] The 3 MWh of LAR N-0 in 2048 is caused by an overload on the Alberhill-Fogarty 115 kV Line (the line is first overloaded in 2046), which is correctable by reconductoring. At no time through 2048 are the ASP transformers overloaded under N-0 conditions.

[21] These metrics begin to accrue coincident with the project need year of 2022, and continue to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

current Valley South System with ASP in service are as follows:

- The ASP eliminates transformer capacity shortfalls under N-0 conditions on the Valley South System transformers over the entire 30-year study horizon.
- The ASP eliminates subtransmission line capacity shortfalls under N-0 conditions until 2046, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded.
- The ASP eliminates subtransmission line capacity shortfalls under N-1 conditions until 2038, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded. Additional 115 kV lines are overloaded under N-1 conditions in 2043 (Alberhill-Skylark) and 2048 (Auld-Moraga #1). As such, requirements for system planning consistent with SCE's Subtransmission Planning Criteria and Guidelines are met until 2038. These shortfalls could be corrected by reconductoring each of the three lines to restore the subtransmission line loading to within capacity limits.
- The ASP creates system tie-line capacity which significantly improves the reliability and resiliency performance during N-1 and N-2 conditions in the area served by the current Valley South System. As demonstrated by the Flex-1 and Flex-2 metrics, the ASP provides the ability to transfer load between the Valley South System and the Alberhill System during these contingency conditions.

Important notes regarding the projected service reliability performance for the current Valley South System *without* any project in service include:

- The Valley South System transformers are projected to overload by year 2022.
- By 2028, over 250 MWh of LAR are observable in the system under N-0 conditions. This extends to 6,310 MWh by 2048 with no project in service.
- Between 2028 and 2048, the flexibility deficit duration in the system increases from 7 hours to 77 hours under N-0 conditions.

A Appendix: Quanta Reliability Analysis

The Quanta Technology *Reliability Analysis of Alberhill System Project, Version 2.1 (Second Amended Motion)* is attached as Appendix A to this data submittal.

QUANTA
TECHNOLOGY

Report

Reliability Analysis of Alberhill System Project

PREPARED FOR

Southern California Edison (SCE)

DATE

June 15, 2021
Version 2.1 (Errata)

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VERSION HISTORY:

Version	Date	Description
0.1	11/8/2019	Initial draft
0.2	12/5/2019	Final draft
1	12/20/2019	Final
2	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only.
2.1 (Second Amended Motion)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power-flow studies that evaluate the impact of the load forecast on the Valley South system both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of the project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South System by the year 2022 as the load exceeds the Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within the Valley South System is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates the benefits of the ASP project in meeting the overall needs in the Valley South System. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are as follows:
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more sub-transmission circuits in the Valley South system, the availability of tie-lines with the ASP reduces the expected energy unserved by greater than 70%.
  - The ASP provides measurable operational flexibility improvement to address system needs under high impact low probability (HILP) events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.

- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

The findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

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1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses of the capacity and reliability needs in the Valley South 500/115 kV system. The objective of this analysis is to evaluate the forecasted impacts of the ASP on service reliability performance utilizing a combination of power flow simulations and service reliability metrics where applicable.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South system is not supplied by any alternative means or tie-line. In other words, this portion of the system is radially served by a single point of interconnection from the bulk electric system (BES) which is under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility, and resiliency needs of the Valley South system.

The Valley South 115 kV system electrical needs area (ENA) consists of 15 distribution level 115/12 kV substations.

During the most recent forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0). This forecast was developed for extreme weather conditions (1-in-5-year heat storm).[1] SCE has additionally identified the need to provide system ties to improve reliability, resiliency, and operational flexibility.[2] To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area. Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.

[1] 1-in-5-year peak demand adjusted for extreme weather conditions are typically utilized for system planning involving the sub-transmission system.

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resiliency needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected. customers. System tie-lines can effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

- Construction of approximately 20 miles of 115 kV sub-transmission lines to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

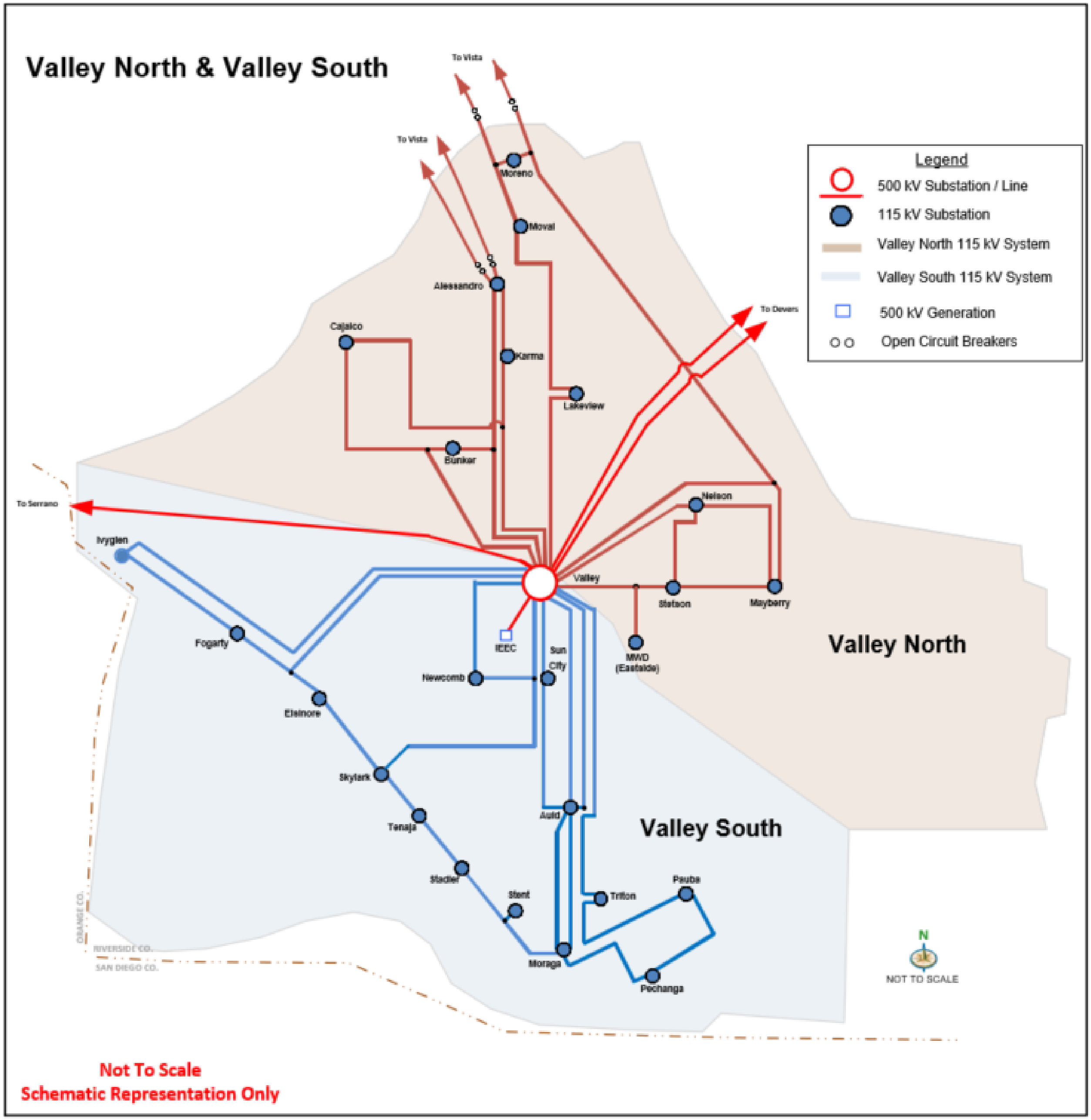

Figure 1-1. Valley Service Areas[3]

[3] Valley-Ivyglen and VSSP 115 kV line projects included.

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the proceedings for the ASP, the CPUC requested additional analyses to justify the peak demand forecasts and reliability cases for the project. The CPUC also requested a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; the alternatives include but are not limited to energy storage, demand response, and distributed energy resources (DERs).

Quanta Technology supported SCE's intent to supplement the existing record in the CPUC proceeding for the ASP utilizing a comprehensive reliability assessment framework. The scope of this assessment included the following:

1. Quantifying the needs in the Valley South 500/115 kV System using the applicable load forecast.
2. Using power flow simulations and quantitative review of project data to evaluate the forecasted impact of proposed ASP on the Valley South System needs.
3. Applying the load forecast to analyze service reliability performance benefits provided by the ASP in the Valley South System.

1.2 Report Organization

In order to provide a comprehensive view of the study methodology, findings, and conclusions, this report has been separated into three sections.

Section 2 of this report introduces the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Section 2.4 presents the forecasted performance of the ASP using the metrics. Section 3 serves as the conclusion.

2 RELIABILITY ASSESSMENT FRAMEWORK AND RESULTS

2.1 Introduction

The objective of this analysis is to evaluate the performance and benefits of the ASP in comparison to the baseline scenario (i.e., no project in service). The performance of the baseline system is initially presented, followed by the ASP. Within the framework of this analysis, reliability, capacity, operational flexibility, and resiliency benefits have been quantified.

In order to successfully evaluate the benefits of a potential project in the Valley South System, its performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to the baseline scenario (no project in service),
3. To establish a basis to value the performance of the ASP against overall project objectives,
4. To take into consideration the benefits or impacts of flexibility and resiliency (high-impact, low-probability events), and
5. To guide comparison of the projects against the alternatives.

Within the scope of the developed metrics, the following key project objectives are addressed:

Capacity

- Serve current and long-term projected electrical demand requirements in the SCE ENA.
- Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

Reliability

- 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 ENA (i.e., the area served by the existing Valley South system).

Operational Flexibility and Resiliency

- Increase system operational flexibility and maintain system reliability (e.g., by creating system ties that establish the ability to transfer substations from the current Valley South system and to address both normal condition capacity and N-1 capacity needs).

2.2 Study Methodology

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance.
2. Quantify the project performance using commercial power flow software.

Each of the above areas is further detailed throughout this chapter. Since the focus of this analysis is the Valley South system, all discussions are pertinent to this study area.

2.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and ASP systems. This information encompassed the following data:

1. GE PSLF[4] power flow models for Valley South and Valley North Systems.
   a. 2018 system configuration (current system).
   b. 2021 system configuration (Valley-Ivyglen[5] and VSSP[6] projects modeled and included).
   c. 2022 system configuration (with the ASP in service).
2. Substation layout diagrams representing the Valley Substation.
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations.
4. Single-line diagram of the Valley South and Valley North Systems.
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System.
7. Metered customer information per substation (customer count).

The reliability assessment utilizes the spatial load forecast developed for Valley South and Valley North service territories to evaluate the performance of the system for future planning horizons. The developed forecast includes the effects of future developments on photovoltaic projects or installations, electric vehicles, energy efficiency, energy storage, and load modifying demand response as defined in the IEPR 2018 forecast.[7] The representative load forecast is presented in Figure 2-1, which demonstrates system deficiency in the year 2022, where the loading on the Valley South system transformers exceeds maximum operating limits (1,120 MVA).

[4] General Electric's Positive Sequence Load Flow (PSLF) program.

[5] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).

[6] VSSP (Valley South 115 kV Sub-transmission Project) CPUC Decision 16-12-001 (issued December 1, 2016).

[7] California Energy Commission, "2018 Integrated Energy Policy Report," 2018.

Benefits begin to accrue coincident with the project need year of 2022. For this assessment, it is assumed that the ASP will be in service by this year and that benefits accrue from 2022 to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

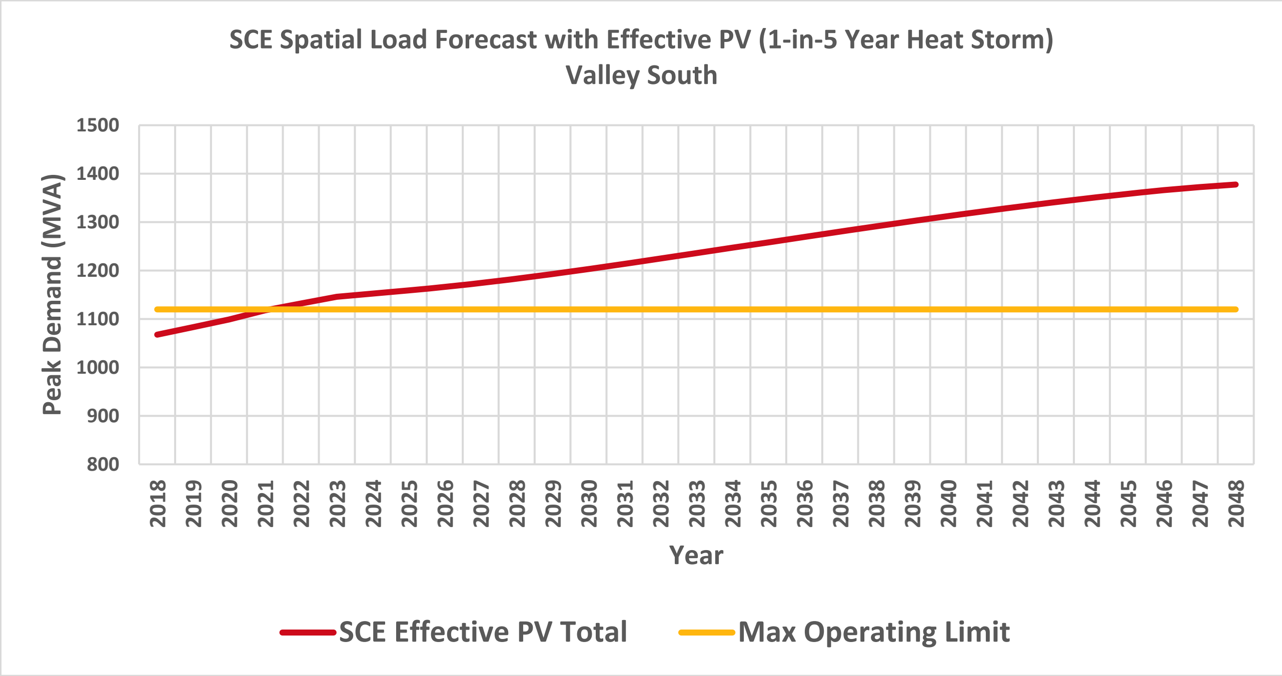

Figure 2-1. Valley South Load Forecast (Peak MVA)

System configuration for the years 2018, 2021, and 2022 are depicted in Figure 2-2 through Figure 2-4.

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrates the largest variability among available records.[8] This load shape is presented in Figure 2-5.

[8] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

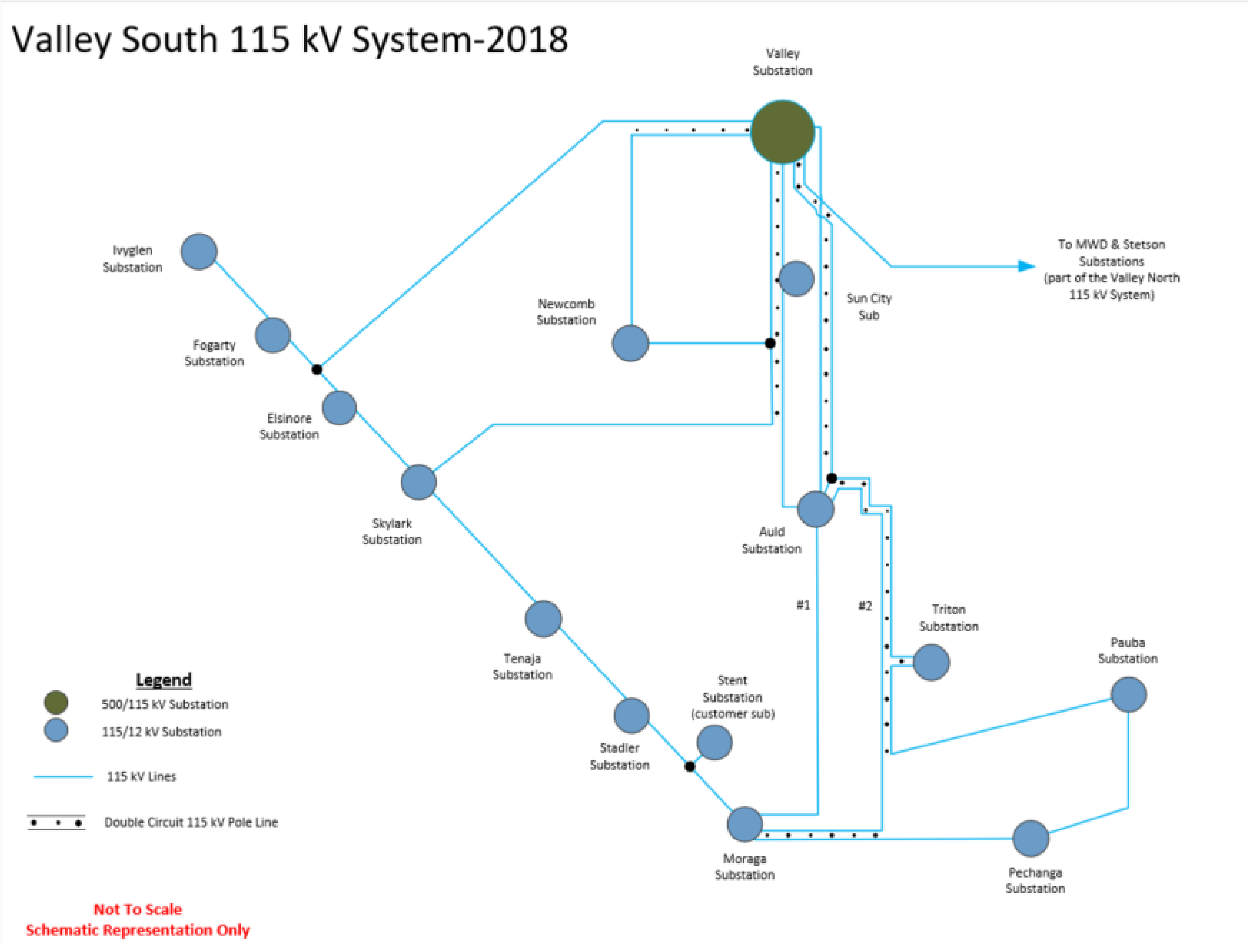

Figure 2-2. Valley South System Configuration (2018)

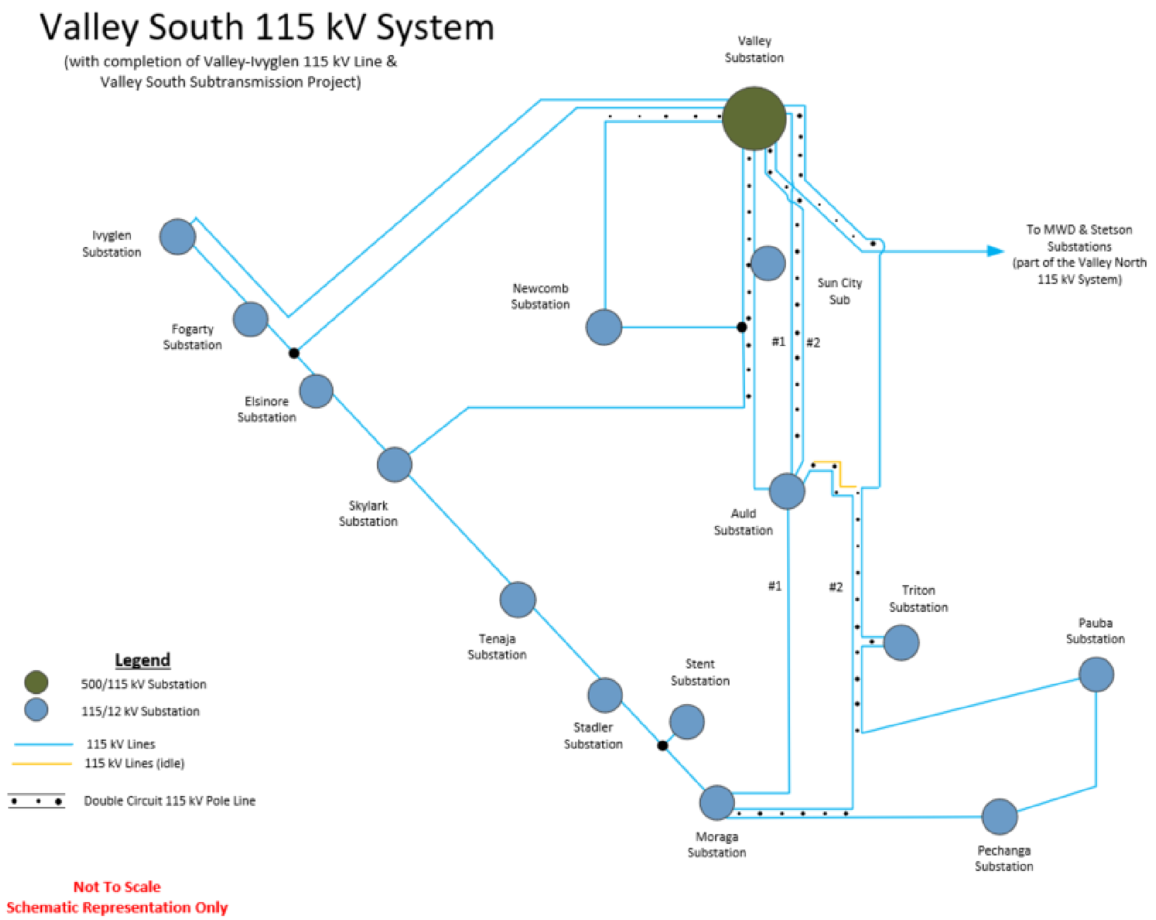

Figure 2-3. Valley South System Configuration (2021)

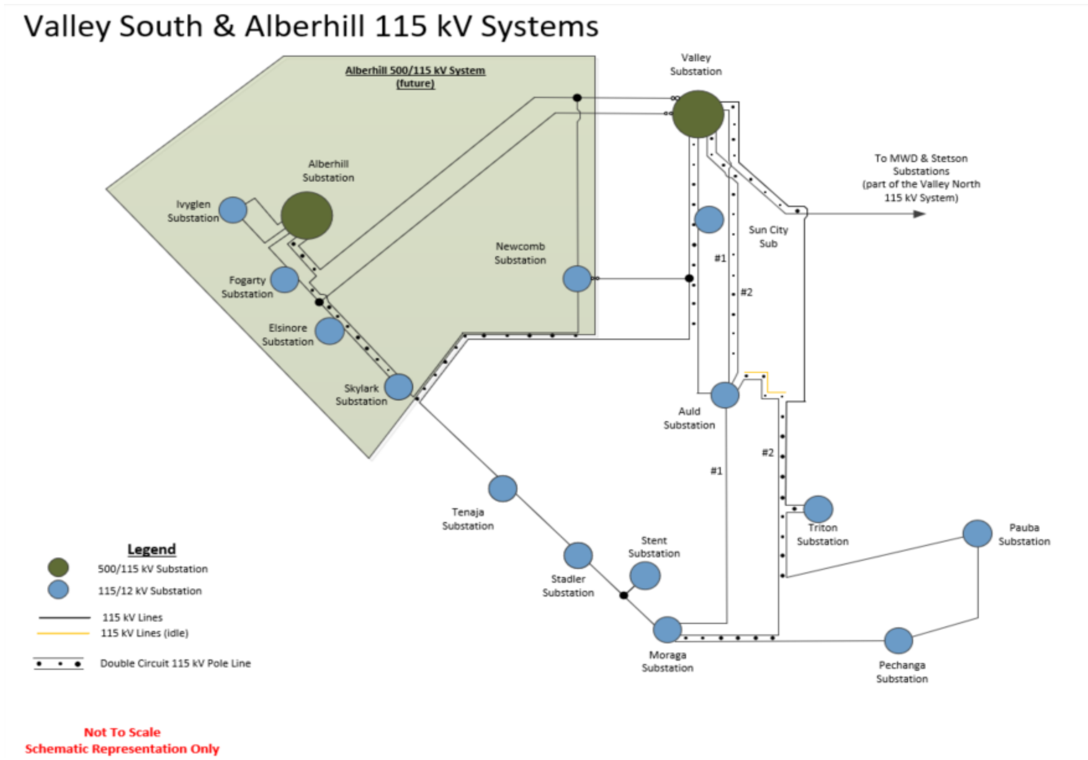

Figure 2-4. Valley South System Configuration (2022 with the ASP in service)

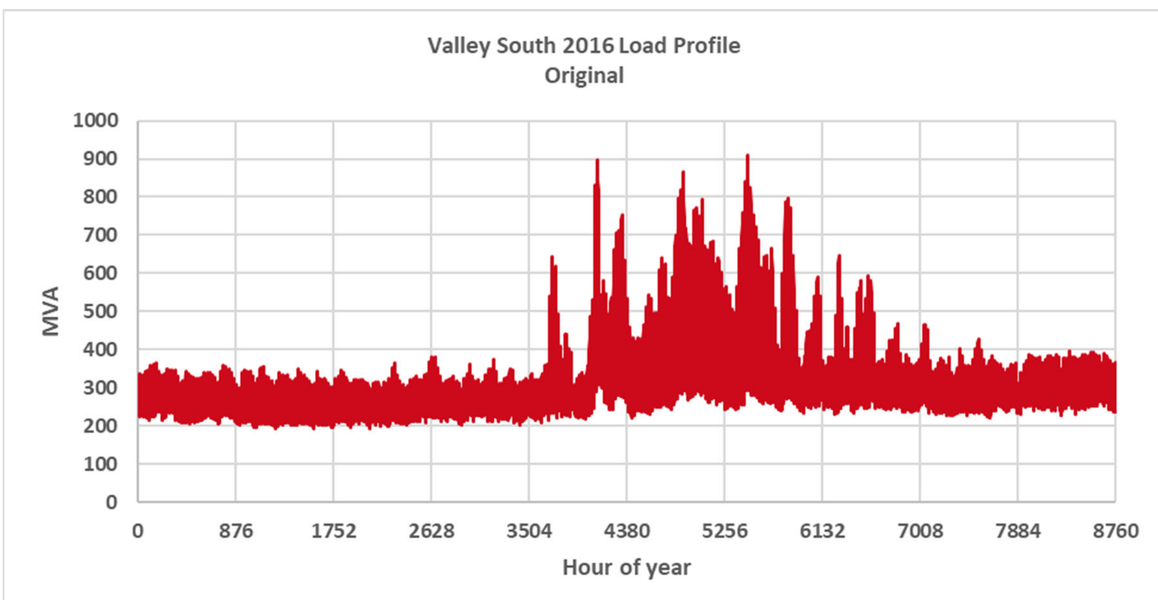

Figure 2-5. Load Shape of the Valley South Substation

2.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability (NERC) and Western Electricity Coordinating Council (WECC) standards have been used, especially while taking into consideration the impact on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 (normal) and N-1 (emergency) operating conditions.
- Voltage limits of 0.95–1.05 per unit (pu) under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

2.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been used for this analysis (i.e., GE PSLF and PowerGem TARA). GE PSLF has been used for base-case model development, conditioning, contingency development, and drawing capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is traditionally used in distribution system analysis to assess variation of various quantities over time with changes in load, generation, transmission-line status, etc. It is now finding common application even in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 2-6 for the Valley South System as an example. The MW peak load is then distributed amongst the various load models in the Valley Substation in proportion to their MW-to-peak-load ratio in the base case. Load centers under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 2-1.

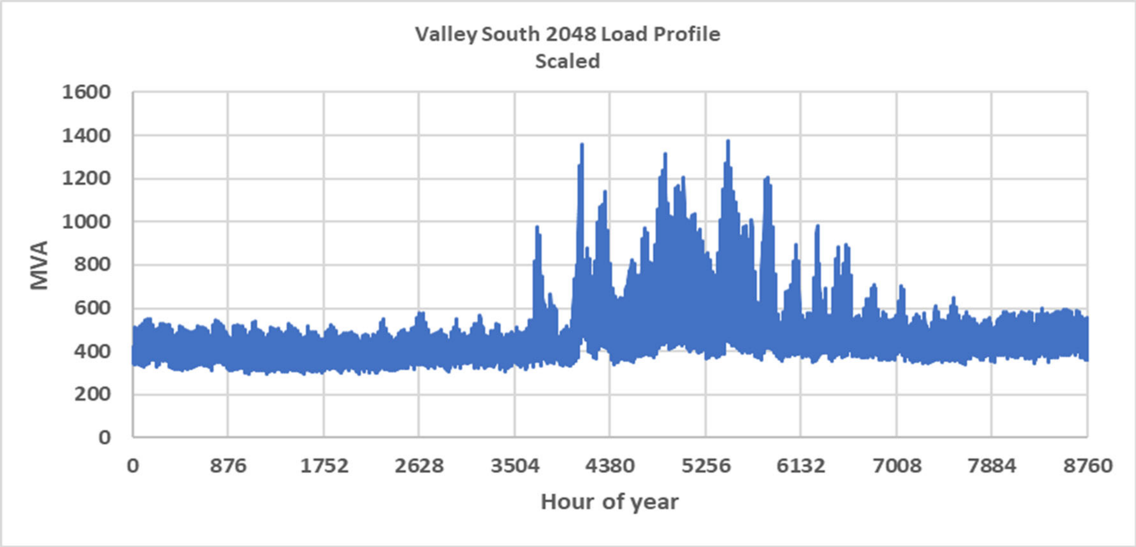

Figure 2-6. Scaled Valley South Load Shape Representative of Study Years

Table 2-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

The hourly study (i.e., 8,760 simulations per year) was conducted in selected years (5-year periods from 2022 including 2027, 2032, 2037, 2042, and 2048). The results for years in between were interpolated.

For each simulation, the AC power-flow solution is solved, relevant equipment is monitored under N-0 conditions (normal) and N-1 analysis (emergency), potential reliability violations are recorded, and performance reliability metrics (as described in Section 2.2.4) are calculated. A flowchart of the overall study process is presented in Figure 2-7.

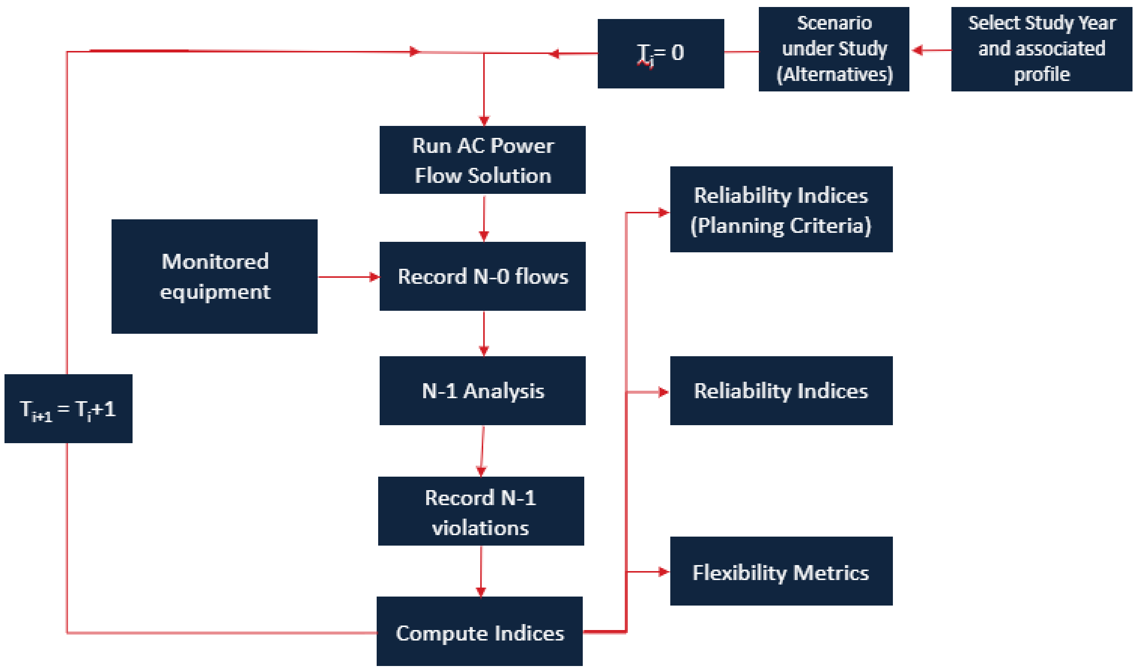

Figure 2-7. Flowchart of Reliability Assessment Process

Unless otherwise specified, all calculations performed under the reliability analysis compute the load at risk, which is not a probability-weighted metric.

In the reliability analysis, the N-1 contingency has been evaluated for every hour of the 8,760 simulations, and all outages are considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single circuit outages for all sub-transmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to the computation of the relevant reliability metric. When the project under evaluation has system tie-lines that can be leveraged, they are engaged to minimize system impacts.

Several flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency or planned/unplanned outages and high-impact, low-probability (HILP) events in the Valley South System.

The Flexibility-1 metric evaluates the system under N-2 (double line outage) conditions, which is representative of combinations of lines switched out for service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common structure. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 2-8 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk. The results were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. When the project under evaluation has tie-lines, they are considered to minimize system impacts.

The Flexibility-2 metric evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting the Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of load at risk:

- The Flexibility 2-1 metric evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of load at risk is determined. Utilizing power flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- The Flexibility 2-2 metric evaluates a condition wherein Valley South System is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g., fire or explosion) of one of the two normally load-serving transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Using the 8,760-load shape and the transformer short-term/long-term emergency loading limits (STELL/LTELL), the average amount of MWh load at risk is estimated and aggregated considering a 2-week duration (mean time to repair under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

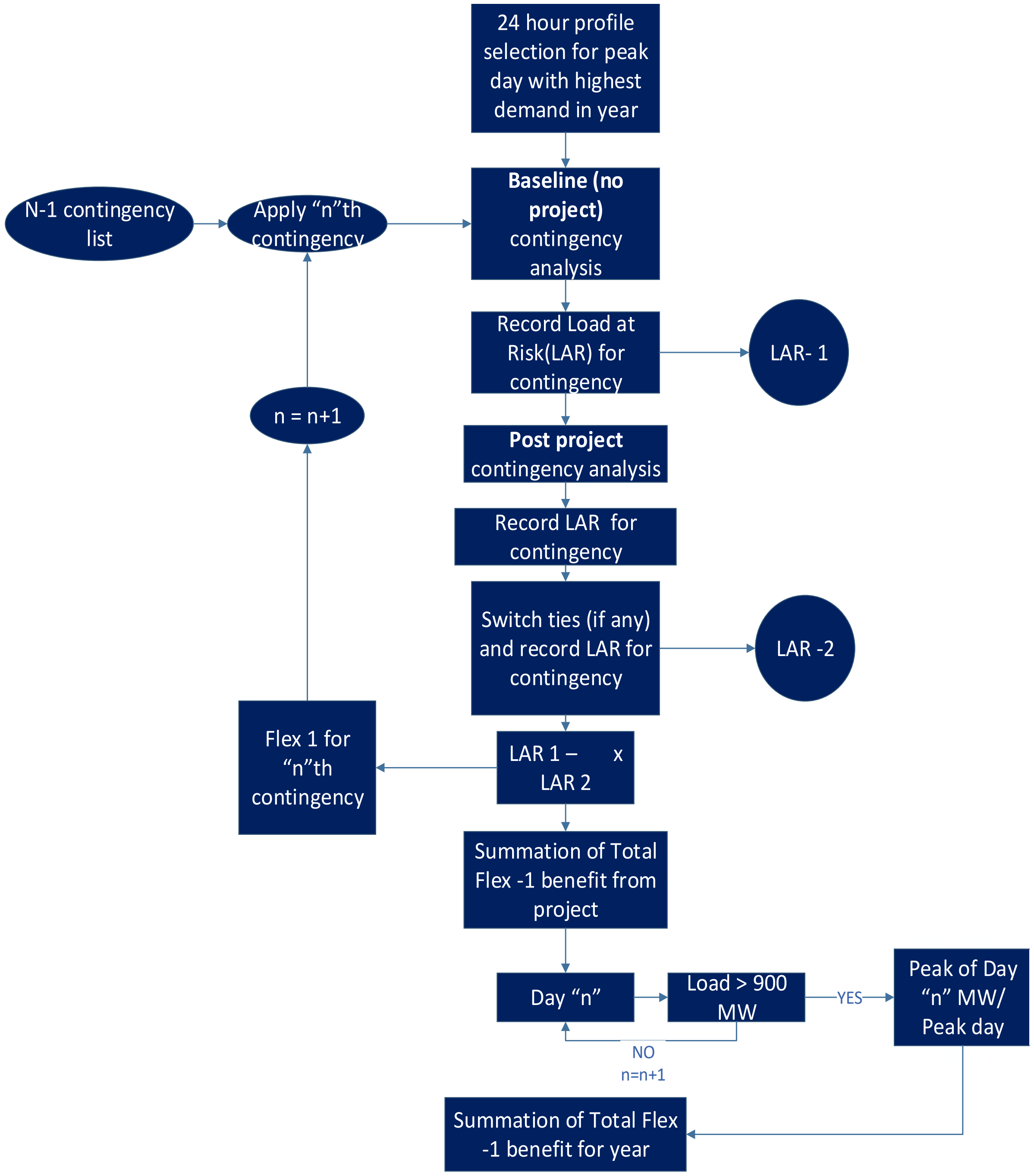

Figure 2-8. Flowchart of Flexibility Metric 1 (Flex 1) Calculation Process

2.2.4 Reliability Metrics

Before introducing reliability metrics, the key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The treatment of the following is consistent with applicable NERC guidelines and standards for the BES:

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions, and normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, and planned outage conditions. Therefore, it is expected to operate the system radially and accommodate flexibility by employing normally open tie(s) and connection(s).
- Resiliency has been viewed as an extension of the flexibility benefits, wherein ties and connections are leveraged to recover load under HILP events in the system.

Building on the overall project objectives, the reliability metrics described in the following subsections have been established.

2.2.4.1 Quantitative Metrics

The following quantitative metrics have been proposed to address the reliability, capacity, flexibility, and resiliency needs of the system:

- **Load at Risk**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below ratings. This includes transformers and lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on voltage sensitivity of the bus to bring voltage within limits. The sensitivity study established ranges of load shed associated with varying levels of post-contingency voltage. For the deviation of 1 pu of voltage from the 0.95 pu limit, 0.5 MW of load shed was identified.
  b. Computed for N-0 events and N-1 events and aggregated over the course of the year.
  c. For N-1 events, tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. Computed for N-0 events and N-1 events.

- **Losses**: Losses are treated as the active power losses in the Valley South system. New lines introduced by the scope of a project have also been included in the loss computation.

- **Availability of Flexibility in the System**: The measure of the availability of the flexible resource (tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of additional/incremental flexibility (MWh) the alternative solution provides to the system for maintenance operations, emergency events, or the need to relieve other operational issues. Two flexibility metrics are considered:
    a. Flexibility 1: Capability to recover load for maintenance and outage conditions.
        i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served utilizing the flexibility attributes of the project.
        ii. Considering the large combination of N-2-line outages that potentially impact the Valley South System, the analysis is limited to only circuits that share a common double circuit pole.

    b. Flexibility 2: Recover load for the emergency condition: Single point of failure Valley South substation and transformer banks.
        i. Flex 2-1: Calculated as the energy unserved when the system is impacted by low probability high consequence events such as the loss of the entire Valley Substation. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events. This event is calculated over an average 2-week period (average restoration duration for events of this magnitude) in the Valley system.

           Flex 2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (both transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley System. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was less than required, resulting in energy being unserved for a given time horizon and direction.

The above list has been iteratively developed to successfully translate the objectives into quantifiable metrics that provide a basis for project performance evaluation.

2.3 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study without any project in service to address the shortfalls in transformer rated capacity. This scenario forms the primary basis for comparison against the ASP performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the study years 2022 (project need year), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.3.1 System Performance under Normal Conditions (N-0)

Table 2-2 presents the findings from system analysis under N-0 conditions in the system.

Table 2-2. Baseline N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	22	13	2
	2028	250	65	7
	2033	905	120	18
	2038	2212	190	37
	2043	4184	246	53
	2048	6310	288	77

2.3.2 System Performance under Normal Conditions (N-1)

Table 2-3 presents the findings from system analysis under N-1 conditions.

Table 2-3. Baseline N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	10	2	14
	2028	67	11	32
	2033	249	21	54
	2038	679	35	88
	2043	1596	45	120
	2048	2823	68	153

In the baseline system analysis, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond). In Table 2-4, only the thermal violations associated with each constraint are reported.

Table 2-4. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Valley South Transformer	N-0	Base case	2022
Auld to Moraga #1	N-0	Base case	2047
Auld to Moraga #2	N-1	Auld-Moraga #1	2038
Auld to Moraga #1	N-1	Auld-Moraga #2	2022
Valley EFG to Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043
Tap 39 to Elsinore	N-1	Valley EFG-Newcomb-Skylark	2038
Auld to Moraga #1	N-1	Skylark-Tenaja	2048
Skylark to Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033
Valley EFG to Sun City	N-1	Valley EFG-Auld #1	2043
Valley EFG to Auld #1	N-1	Valley EFG-Sun City	2048
Valley EFG to Tap 22	N-1	Valley EFG-Newcomb	2043
Valley EFG to Auld #1	N-1	Valley EFG-Auld #2	2048
Valley EFG to Sun City	N-1	Valley EFG-Auld #2	2043
Auld to Moraga #1	N-1	Valley EFG - Triton	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2038

2.3.3 Flexibility Metrics

Table 2-5 presents the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-5. Flexibility and Resiliency Metrics for the Baseline System

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
No Project	**2022**	54,545	127,935	2,138
	2028	163,415	133,688	2,774
	2033	254,140	139,702	3,514
	2038	344,864	145,991	4,421
	2043	435,589	151,619	5,294
	2048	526,314	155,733	5,975

2.3.4 System Losses

Table 2-6 presents the aggregated losses from the 8,760 assessment of the Valley South system.

Table 2-6. Losses in the Baseline System

	Year	Losses (MWh)
No Project	**2022**	49,667
	2028	52,288
	2033	54,472
	2038	56,656
	2043	58,840
	2048	61,024

2.3.5 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South transformers are overload by the year 2022 (above maximum transformer ratings).
2. By the year 2028, 250 MWh of the load is observed to be at risk in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service.
3. Between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain the system N-1 secure.

2.4 Reliability Analysis of the Alberhill System Project

The ASP has been evaluated under the study years 2022, 2028, 2033, 2038, 2043, and 2048 consistent with the baseline system. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.4.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area presently served by the Valley South 115 kV system.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line. The total length is 3.3 miles.
3. Construction of a new 115 kV subtransmission line and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV substations (Ivyglen, Fogarty, Elsinore,

Skylark, and Newcomb) presently served by the Valley South 115 kV system to the new 500/115 kV substation. The total length is approximately 20.4 miles.

4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network. The total length is approximately 8.7 miles.

Figure 2-9 presents an overview of the project layout and schematic.

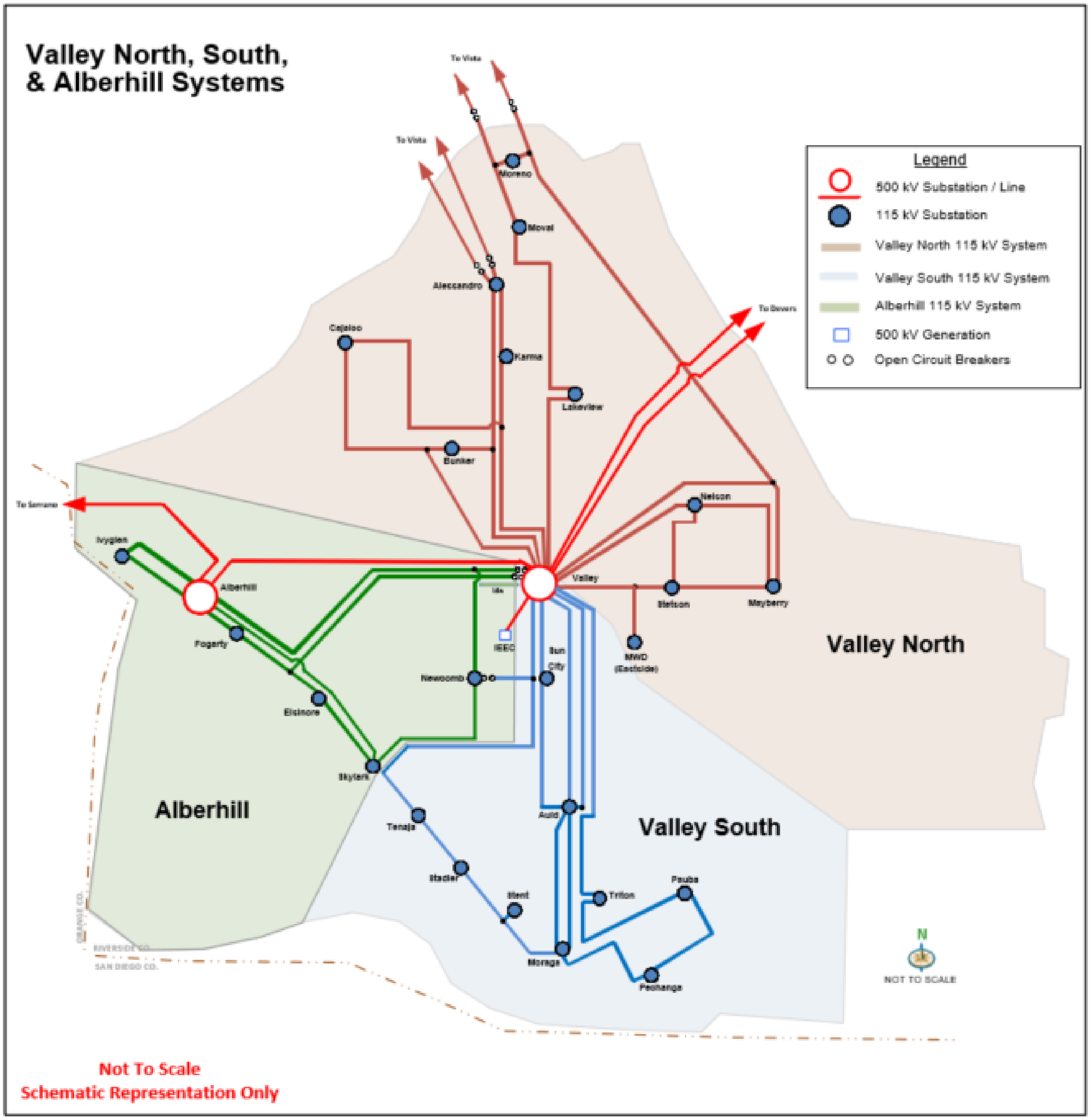

Figure 2-9. Service Territory Configuration after Proposed Alberhill System Project

2.4.2 System Performance under Normal Conditions (N-0)

Table 2-7 presents the findings from system analysis under N-0 conditions.

Table 2-7. Alberhill N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	**2022**	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	0	0	0
	2043	0	0	0
	2048	3	2	2

2.4.3 System Performance under Normal Conditions (N-1)

Table 2-8 presents the findings from system analysis under N-1 conditions.

Table 2-8. Alberhill N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	2022	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	21	8	4
	2043	84	17	8
	2048	202	24	14

In analyzing the ASP, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond).

In Table 2-9 below, only the thermal violations associated with each constraint are reported.

Table 2-9. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Alberhill to Fogarty	N-0	Base case	2046
Alberhill to Fogarty	N-1	Alberhill–Skylark	2038
Alberhill to Skylark	N-1	Alberhill–Fogarty	2043
Auld to Moraga #1	N-1	Valley EFG–Newcomb–Tenaja	2048

2.4.4 Flexibility Metrics

Table 2-10 present the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-10. Flexibility and Resiliency Metrics for the ASP

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
ASP	2022	0	1,163	0
	2028	30,438	1,516	0
	2033	56,720	1,947	0
	2038	83,001	2,452	0
	2043	109,282	2,954	1
	2048	136,664	3,345	4

2.4.5 System Losses

Table 2-11 presents the aggregated losses from the 8760 assessment of the Valley South and ASP systems.

Table 2-11. Losses in the ASP

	Year	Losses (MWh)
ASP	2022	40,621
	2028	42,671
	2033	44,380
	2038	46,089
	2043	47,797
	2048	49,506

2.4.6 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. 3 MWh of load at risk is recorded under N-0 condition in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line.
2. By the year 2038, overloads due to N-1 events will be observable on the Alberhill–Fogarty 115 kV circuit, Alberhill–Skylark 115 kV, and Auld–Moraga 115 kV circuits, which cannot be resolved by potential transfer flexibility.
3. The project provides significant flexibility to address N-1 and N-2 events in the system while also providing significant benefits to address needs under HILP events that occur in the Valley System.

2.5 Evaluation of Quantitative Metrics

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over the 10-year and 30-year study horizons calculated at the start of the need year 2022 (i.e., end of 2021). The benefits are quantified as the difference between the baseline and the ASP for each of the metrics and discounted at SCE's weighted aggregate cost of capital (WACC) of 10%. As an example, Figure 2-10 exhibits N-0 load at risk values over the study horizon and its present worth using discount rate of WACC. A similar process was applied to other metrics.

The present worth of *benefits* for reliability metrics over 10-year and 30-year horizons are presented in Table 2-13. The cumulative *benefits* over a 10-year and 30-year horizon are presented in Table 2-12.

The cumulative and present worth of benefits are presented in Appendix C: Reliability Performance Additional Details for both the baseline and the ASP to provide a relative comparison of performance in each reliability category.

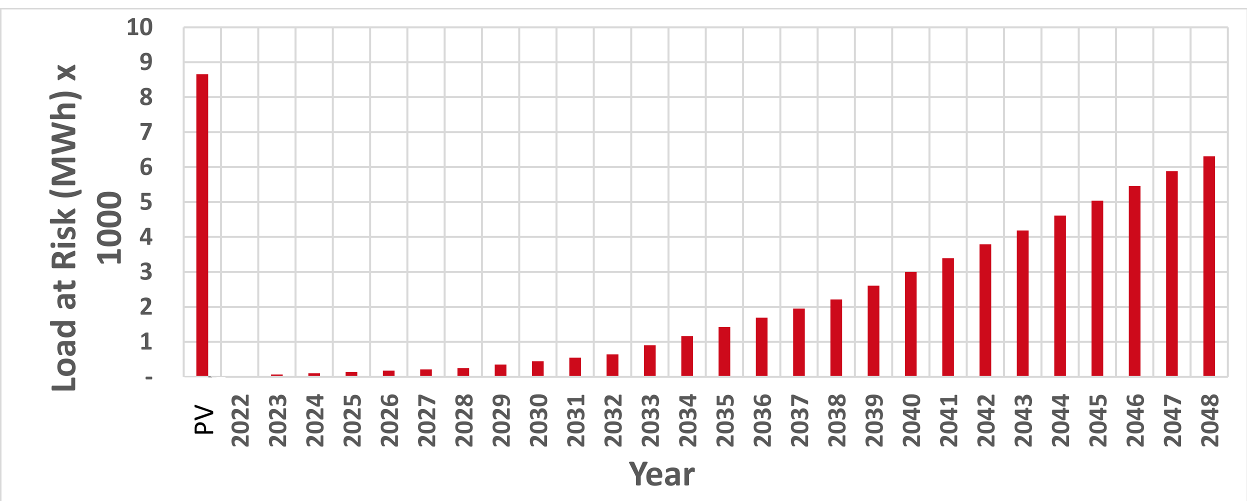

Figure 2-10. N-0 Load at Risk over the Study Horizon and Its PV

Appendix C provides comparative metrics over the 10-year and 30-year horizon between the baseline (no project) and the ASP. These are used to derive the benefits presented in Table 2-12 and (later in Table C-1).

Table 2-12. Cumulative Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Cumulative Value of Benefits over 10-year horizon (until 2028)	Cumulative Value of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	65,319	277,608
N-1	Load at Risk (MWh)	274	20,326
N-1	IP (MW)	45	601
N-1	PFD (hr)	173	1,907
N-1	Flex 1 Load at Risk (MWh)	659,076	6,024,126
N-1	Flex 2-1 Average Load at Risk (MWh)	907,590	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	106,937
N-0	Load at Risk (MWh)	971	56,575
N-0	IP (MW)	288	4,053
N-0	PFD (hr)	35	811

Table 2-13. Present Worth of Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Present Worth of Benefits over 10-year horizon (until 2028)	Present Worth of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	45,254	90,384
N-1	Load at Risk (MWh)	173	2,896
N-1	IP (MW)	28	133
N-1	PFD (hr)	115	420
N-1	Flex 1 Load at Risk (MWh)	434,402	1,438,932
N-1	Flex 2-1 Average Load at Risk (MWh)	629,646	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	29,195
N-0	Load at Risk (MWh)	606	8,657
N-0	IP (MW)	185	853
N-0	PFD (hr)	23	146

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resiliency needs in the Valley South service area.

3 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for the ASP with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power flow studies that evaluate the impact of the load forecast on the Valley South System both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South system by the year 2022, as the load exceeds Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within Valley South service territory is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates significant benefits of the ASP project in meeting overall needs in the Valley South service area. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are discussed.
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more subtransmission circuits in the Valley South System, the availability of tie-lines with the ASP reduces load at risk by greater than 70%.

- The ASP provides measurable operational flexibility improvement to address system needs under the HILP events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.
- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

Findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

APPENDIX A: GLOSSARY

ASP: Alberhill System Project

BES: Bulk Electric System

CAIDI: Customer Average Interruption Duration Index

CAISO: California Independent System Operator

CPUC: California Public Utility Commission

DER: Distributed Energy Resources

LAR: Load at Risk

NERC: North American Electric Reliability Corporation

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

WECC: Western Electricity Coordinating Council

APPENDIX B: REFERENCES

1. Sub-transmission Planning Criteria and Guidelines, SCE 9/24/2015.
2. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project, CPUC 8/31/2018.

APPENDIX C: RELIABILITY PERFORMANCE ADDITIONAL DETAILS

The cumulative benefits over a 10-year and 30-year horizon are presented in Table C-1 and Table C-2, respectively.

The present worth of benefits over a 10-year and 30-year horizon are presented in Table C-3 and Table C-4, respectively.

Table C-1. Cumulative Reliability Performance and Benefits with and without the ASP (10-year)

Category	Component	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Benefit over 10-year Horizon
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	356,842	291,522	65,319
N-1	Load at Risk (MWh)	274	0	274
N-1	IP (MW)	45	0	45
N-1	PFD (hr)	173	0	173
N-1	Flex 1 Load at Risk (MWh)	762,858	103,783	659,076
N-1	Flex 2-1 Average Load at Risk (MWh)	917,017	9,427	907,590
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	0	17,266
N-0	Load at Risk (MWh)	971	0	971
N-0	IP (MW)	288	0	288
N-0	PFD (hr)	35	0	35

Table C-2. Cumulative Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Benefit over 10-year horizon (until 2048)
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	1,494,322	1,216,714	277,608
N-1	Load at Risk (MWh)	21,684	1,047	20,327
N-1	IP (MW)	780	179	601
N-1	PFD (hr)	1,999	92	1,907
N-1	Flex 1 Load at Risk (MWh)	7,841,596	1,817,470	6,024,127
N-1	Flex 2-1 Average Load at Risk (MWh)	3,839,134	59,285	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	106,954	17	106,937
N-0	Load at Risk (MWh)	56,581	6	56,575
N-0	IP (MW)	4,056	4	4,053
N-0	PFD (hr)	815	4	811

Table C-3. Present Worth of Benefits with and without the ASP (10-year)

Category	Component	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Benefits over 10-year horizon (till 2028)
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	247,375	202,121	45,254
N-1	Load at Risk (MWh)	173	0	173
N-1	IP (MW)	28	0	28
N-1	PFD (hr)	115	0	115
N-1	Flex 1 Load at Risk	497,134	262,732	434,402
N-1	Flex 2-1 Average Load at Risk (MWh)	636,100	6,453	629,646
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	0	11,822
N-0	Load at Risk (MWh)	606	0	606
N-0	IP (MW)	185	0	185
N-0	PFD (hr)	23	0	23

Table C-4. Present Worth Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Benefits over 30-year horizon (until 2048)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	490,137	399,753	90,384
N-1	Load at Risk (MWh)	3,054	112	2,896
N-1	IP (MW)	154	21	133
N-1	PFD (hr)	431	11	420
N-1	Flex 1 Load at Risk	1,806,240	368,207	1,438,032
N-1	Flex 2-1 Average Load at Risk (MWh)	1,259,315	16,083	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	29,196	2	29,195
N-0	Load at Risk (MWh)	8,658	0	8,657
N-0	IP (MW)	853	0	853
N-0	PFD (hr)	147	0	147

EXHIBIT F-1 (SECOND AMENDED) REDLINE

Item F:

The forecasted impact of the proposed project on **service reliability performance**, using electric service reliability metrics where applicable.

Response to Item F:

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: February 2, 2021

Summary of Revisions:

- Modifies the terminology for the primary metric (previously Expected Energy Not Served (EENS) and now Load at Risk (LAR)) to clarify that the metrics are cumulative values of the potential amount of unserved load and are not probability weighted to associate the frequency and timing of events that would prompt loss of service to customers.
- Deletes the SAIFI, SAIDI and CAIFI metrics to avoid confusion with similar data reported in Supplemental Data Response Items B and C[1] which are calculated on the basis of a different customer base and thus cannot be compared directly. Because these SAIFI, SAIDI and CAIDI values previously provided here were derived from the LAR values they did not provide any additional insight on the effectiveness of the Alberhill System Project in meeting system reliability/resiliency needs.
- Modifies the description of the Flex-1 and Flex-2 metrics to reflect more realistic operation scenarios.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item C and DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

1.0 Executive Summary

SCE interprets this data request as inquiring about the service reliability performance of the proposed Alberhill System Project (ASP)[2].

The proposed ASP was designed to mitigate the transformer capacity shortfall currently anticipated to occur in the Valley South System as early as 2022, while also addressing the long-standing need for system tie-lines to improve reliability and resiliency by providing the ability to transfer load to adjacent systems for maintenance and other activities (planned outages), and under abnormal system operating conditions (unplanned outages). To evaluate the impact of the proposed project on service reliability performance, the response to this data request uses forward-looking service reliability performance metrics, related to customers and energy at risk due to service interruption, to demonstrate that the ASP meets the identified project needs for capacity, reliability, and resiliency over both short-term (10 year) and long-term (30 year) horizons. These metrics demonstrate that the ASP reduces the customer risk of loss of service due to outages related to capacity, reliability, and resiliency issues by ~~98~~99% through 2028, and by 97% through 2048[3]. These reductions sufficiently improve system performance to comply with SCE's planning standards[4] through 2038, with only one line reconductoring project needed to satisfy these criteria through 2048.

2.0 Introduction

As discussed throughout the ASP Certificate of Convenience and Necessity (CPCN) proceeding (A.09-09-022) and specifically highlighted in an earlier supplemental data request response[5], the reliability issues in the Valley South System are associated with a combination of characteristics related to its limited capacity[6] margin, configuration, and size that make the Valley South subtransmission system[7] much more vulnerable to future reliability[8] problems than any other Southern California Edison (SCE) subtransmission system. Specifically, in its current status, the Valley South System operates at or very close to its maximum operating limits, has no connections

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[2] Service reliability results for alternatives to the Alberhill System Project, which were studied in the cost benefit analysis described in DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C, can be found in Quanta Technology Report, *Benefit Cost Analysis of Alternatives.*

[3] These percentages capture the projected cumulative percent reduction in unserved customer energy needs for various line and transformer outage contingency conditions (through 2028 and 2048 respectively) that are achieved as a result of ASP being in service.

[4] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[5] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item B.

[6] *"Capacity"* is defined as the availability of electric power to serve load and is primarily comprised of two elements in a *radial transmission system*; a lack of capacity of either type will lead to reliability challenges in a radial subtransmission system: (1) "*transformation capacity"* – the ability to deliver power from the transmission system (through substation transformers); and (2) "*subtransmission system line capacity"* – the ability to deliver power to substations which directly serve the customer load in an area. Subtransmission system line capacity also includes "*system tie-line capacity*," which is the ability to transfer load to an adjacent subtransmission system to avoid, and reduce the number of customer's affected by, planned and unplanned outages in the system. Note, a *radial subtransmission system* is one that is provided power from a single source on the transmission system. This is in contrast to a networked system which has multiple transmission and subtransmission source connections. Almost all of SCE's subtransmission systems are of a radial design.

[7] While Southern California Edison typically considers a planning area to be at the substation level, for the purpose of this data request, the discussion herein focuses on the Valley South System, as it is most relevant to the Alberhill System Project proceedings. Certain characteristics discussed here may have broader impacts (on the Valley North System specifically, given the split nature of these systems), but the focus of this response remains on the Valley South System.

[8] *"Reliability*" is defined as a utility's ability to meet service requirements under normal and N-1 contingency conditions, both on a short-term and long-term basis. The ability to meet long-term capacity needs of a given system is an important aspect of reliability. This definition is consistent with IEEE 1366*, "IEEE Guide for Electric Power Distribution Reliability Indices"* which excludes extraordinary events from reliability data reporting.

(system tie-lines) to other systems, and represents the largest concentration of customers on a single substation in SCE's entire system. These characteristics threaten the future ability of the Valley South System to serve load under normal and abnormal conditions.

Also discussed in this proceeding, in the case of a catastrophic event (such as a major fire, earthquake, or incident at Valley Substation), SCE's ability to maintain service or to restore power in the event of an outage is significantly limited by the concentration of source power in a single location at Valley Substation[9]. This characteristic, in combination with others described in this submittal, results in specific concerns for the Valley South System from a resiliency[10] perspective.

In an earlier supplemental data request response[11], SCE provided an analysis of several years of electric reliability performance for the Valley Systems to demonstrate existing customer service metrics. SCE provided data for Valley South (and Valley North) historical reliability metrics (SAIDI and SAIFI) compared to other SCE subtransmission systems. These data show that, to date, the capacity of the Valley South System has been sufficient to serve all system customers under commonly planned for normal and extreme weather conditions. SCE noted that while SAIDI and SAIFI data are the principal metrics used to report on historical system reliability, they are primarily influenced by events at the distribution system level and thus are less informative for planning at the subtransmission system level. This is because when an electric power system has sufficient substation transformer capacity and/or sufficient system tie-line capacity, and is properly maintained and operated, reliability performance is driven largely by random, distribution-level events. Importantly, as SCE stated, the past reliability performance of the Valley Systems is not a driver for the proposed ASP project. Given the limited remaining transformer capacity serving the Valley South System and its lack of system tie-lines, the future reliability performance of the Valley South System will be driven less by random, distribution level events, and more by subtransmission level events that cannot be mitigated due to the lack of capacity margin and/or system tie-lines. These events would otherwise be mitigated by operational flexibility enabled by available transformer and system tie-line capacity to allow for short-term line and transformer overloads (per standards) to be addressed through the transfer of distribution substations to an adjacent system.

This data request response evaluates the Valley South System with and without the ASP and compares the reliability performance of the two system configurations using a set of *forward-looking* reliability and resiliency metrics related directly to SCE's ability to serve customer load throughout this specific electrical needs area. The analysis presented herein was developed and implemented collaboratively between SCE and a contractor, Quanta Technology[12], and documented in the attached report by Quanta Technology (see Appendix A).

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[9] The source of power to the Valley South System passes through a single point of delivery at Valley Substation, which is connected to the CAISO-controlled Bulk Electric System at the 500 kV voltage level.

[10] *"Resiliency"* is defined as how well a utility anticipates, prepares for, mitigates, and recovers from effects of extraordinary events (such as wildfires, earthquakes, cyberattacks, and other potential high impact, low probability (HILP) events) which can have widespread impact on its ability to serve customers. This definition is consistent with IEEE PES-TR65 "*The Definition of Quantification of Resilience*" (April 2018).

[11] See DATA REQUEST SET ED-Alberhill-SCE-JWS-2 Item D.

[12] Quanta Technology is an expertise-based, independent technical consulting and advisory services company specializing in the electric power and energy industries.

3.0 Methodology

In order to compare the impact of the ASP to the current Valley South System configuration[13] on a technical basis, a time-series power flow analysis was performed using the GE-PSLF (Positive Sequence Load Flow) analysis software. PSLF is commonly used by power system engineers throughout the utility power systems industry, including many of the California utilities and the CAISO, to simulate electrical power transmission networks and evaluate system performance.

Models for the existing Valley South System and the proposed ASP[14], were developed in the PSLF software tool. An 8,760-hour load profile was used to simulate the annual forecasted load and power flows in each of the models, and identified thermal overload and voltage violations based on the following analysis criteria, which are consistent with SCE standards[15].

- No potential for N-0 transformer overloads in the system.
- Voltage remains within 95%-105% of nominal system voltage under N-0 and N-1 operating configurations.
- Voltage deviations remain within established limits of +/-5% post contingency.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.

For each hour analyzed, the model determines how much, if any, load is required to be transferred to an adjacent system (if system tie-line capacity is available) or dropped (if system tie-line capacity is not available) to maintain the system within the specified operating limits. The dropped (or unserved) load is summed over the 8,760 hours of the simulation for each year, for base (N-0) and (N-1, or N-2) contingencies[16]. The calculated unserved load is then used to calculate the specific metrics described below. Results for both 10-year and 30-year horizons[17] are presented in this response to assess both near-term and long-term reliability impacts of the proposed ASP.

4.0 Definition of Metrics

The performance of each system configuration was evaluated using the following reliability and resiliency metrics:

- Load at Risk (LAR)
    - Quantified by the number of megawatt-hours (MWh) at risk during thermal overload and voltage violation periods.
    - Calculated for N-0 and all possible N-1 contingencies.
    - For N-1 contingencies, credits the available system tie-line capacity that can be used to reduce LAR.
- Maximum Interrupted Power (IP)

[13] For purposes of this comparison, the current configuration of the Valley South System includes the Valley-Ivyglen 115 kV Line Project (VIG) and the Valley South 115 kV Subtransmission Line Project (VSSP), both of which are in construction and anticipated to be completed in 2022 and 2021 respectively. See Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018) and Valley South 115 kV Subtransmission Project ("VSSP") CPUC Decision 16-12-001 (issued December 1, 2016).

[14] The ASP PSLF model includes both the new Alberhill System, and the Valley South System with the required modifications to implement the ASP. This allows the PSLF model to evaluate the performance of the entire Valley South System Electrical Needs Area with and without the ASP.

[15] See Southern California Edison Subtransmission Planning Criteria and Guidelines, September 24, 2015.

[16] N-0 refers to operating conditions when all facilities are in-service. N-1 refers to operating conditions when a single subtransmission system component is out-of-service. N-2 refers to operating conditions when two subtransmission system components are simultaneously out-of-service.

[17] These horizons correspond to the 10-year and 30-year load forecasts which project future load in the Valley South System in 2028 and 2048, respectively. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A for the 10-year forecast, and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C for the 30-year load forecast.

    - Maximum power that would be required to be curtailed during thermal overload and voltage violation periods.
    - Calculated for N-0 and N-1 contingencies.
- Flexibility 1 (Flex-1)
    - Accumulation of LAR for all possible N-2 line contingencies.
    - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Results for each N-2 contingency simulation are probabilistically weighted to reflect the actual frequency of occurrence of N-2 contingencies.
- Flexibility 2 (Flex-2)
    - Flex-2-1
        - Amount of LAR in the Valley South System under a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability event.
        - LAR accumulated over a two-week period that is assumed to occur randomly throughout the year. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
        - Credits the available system tie-line capacity that can be used to reduce LAR.
    - Flex-2-2
        - Amount of LAR under a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other.
        - The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System.
        - The coincident transformer outages are assumed to occur randomly throughout the year and to have a two-week duration – the estimated time to deliver, install, and in-service the remotely stored spare Valley transformers to restore full transformation capacity to Valley South.
        - Observe 1 hour (Short-Term Emergency Load Limit) of 896 megavolt-amperes (MVA)[18] (160% of the 560 MVA transformer nameplate rating). Following this, 24-hour rating (Long-Term Emergency Loading Limit) rating of 672 MVA (120%).
        - Credits the available system tie-line capacity that can be used to reduce EENS.
- Period of Flexibility Deficit (PFD)
    - Maximum number of hours when the available flexibility capacity offered by system tie-lines was less than the required, resulting in LAR.
    - Calculated for N-0 and N-1 contingencies.

Note that these metrics represent future projections of system performance, and the results of each system configuration should be reviewed relative to the other.

5.0 Results

The attached Quanta Technology report demonstrates that the ASP provides substantial benefit relative to the current Valley South System configuration. The study compares the performance of the Valley South System in its current configuration to the performance of the system after implementing the ASP using forward-looking, quantitative, and customer-benefit driven metrics.

[18] For simplicity, within this document it is assumed that MW = MVA.

Table 1 shows the results for each of the metrics described above for the years 2028 and 2048[19] with and without the ASP and demonstrates the positive impact the ASP has on service reliability performance.

Table 1. Service Reliability Performance of the Valley South System with and without the ASP, 2028 and 2048

Metric	Unit	2028		2048	
		Without ASP	With ASP	Without ASP	With ASP
LAR N-0	MWh	250	0	6,310	3[20]
LAR N-1	MWh	67	0	2,823	202
Flex-1	MWh	163,415	~~49,088~~30,438	526,314	136,664
Flex-2-1	MWh	3,485,449	39,532	4,060,195	87,217
Flex-2-2	MWh	72,331	0	155,780	~~2,161~~100
IP N-0	MW	65	0	288	2
IP N-1	MW	11	0	68	24
PFD N-0	Hours	7	0	77	2
PFD N-1	Hours	32	0	153	14

While the ASP results in substantial improvement in all metrics, the most significant from the perspective of customer impact are the metrics that directly address potential dropped load due to capacity, reliability, and resiliency concerns (i.e., LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 calculated in units of potential lost MW-hours of service). Table 2 provides comparative results of the cumulative dropped load from the LAR N-0, LAR N-1, Flex-1, Flex-2-1 and Flex-2-2 metrics from 2022[21] through the years 2028 and 2048.

Table 2 – Total Cumulative Load at Risk of Being Dropped with and without the ASP, 2028 and 2048

Metric Category	Metric	2022 – 2028			2022 - 2048		
		Without ASP (MWh)	With ASP (MWh)	*% Reduction*	Without ASP (MWh)	With ASP (MWh)	*% Reduction*
Capacity	LAR N-0	971	0	*100.0%*	56,581	6	*99.9%*
	LAR N-1	274	0	*100.0%*	21,373	~~1,035~~1,047	*95.~~2~~1%*
Reliability & Resiliency	Flex-1	762,859	~~251,663~~103,783	*~~67~~86.4~~.0~~%*	7,841,596	~~2,152,978~~1,817,470	*~~72.5~~76.8%*
	Flex-2-1	23,907,934	245,766	*99.0%*	100,091,707	1,545,650	*98.5%*
	Flex-2-2	450,142	0	*100.0%*	2,788,436	~~8,832~~432	*99.~~7~~9%*

Through 2048, the ASP effectively eliminates the capacity (99.9% reduction in LAR N-0) concerns and substantially addresses the reliability concerns associated with line failures (~~72.5~~76.8% reduction in Flex-1), and substantially mitigates the resiliency concerns associated with loss of transformers serving the Valley South System (98.5% and 99.~~7~~9% reductions in Flex-2-1 and Flex-2-2, respectively).

Other key highlights of the projected service reliability performance for the area served by the

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[19] These dates represent the end of the 10 year and 30 year horizon starting in 2018, respectively, which are consistent with the load forecast addressed in other data responses. See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item A and DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item G.

[20] The 3 MWh of LAR N-0 in 2048 is caused by an overload on the Alberhill-Fogarty 115 kV Line (the line is first overloaded in 2046), which is correctable by reconductoring. At no time through 2048 are the ASP transformers overloaded under N-0 conditions.

[21] These metrics begin to accrue coincident with the project need year of 2022, and continue to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

current Valley South System with ASP in service are as follows:

- The ASP eliminates transformer capacity shortfalls under N-0 conditions on the Valley South System transformers over the entire 30-year study horizon.
- The ASP eliminates subtransmission line capacity shortfalls under N-0 conditions until 2046, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded.
- The ASP eliminates subtransmission line capacity shortfalls under N-1 conditions until 2038, when the Alberhill-Fogarty 115 kV Line is forecasted to become overloaded. Additional 115 kV lines are overloaded under N-1 conditions in 2043 (Alberhill-Skylark) and 2048 (Auld-Moraga #1). As such, requirements for system planning consistent with SCE's Subtransmission Planning Criteria and Guidelines are met until 2038. These shortfalls could be corrected by reconductoring each of the three lines to restore the subtransmission line loading to within capacity limits.
- The ASP creates system tie-line capacity which significantly improves the reliability and resiliency performance during N-1 and N-2 conditions in the area served by the current Valley South System. As demonstrated by the Flex-1 and Flex-2 metrics, the ASP provides the ability to transfer load between the Valley South System and the Alberhill System during these contingency conditions.

Important notes regarding the projected service reliability performance for the current Valley South System *without* any project in service include:

- The Valley South System transformers are projected to overload by year 2022.
- By 2028, over 250 MWh of LAR are observable in the system under N-0 conditions. This extends to 6,310 MWh by 2048 with no project in service.
- Between 2028 and 2048, the flexibility deficit duration in the system increases from 7 hours to 77 hours under N-0 conditions.

A Appendix: Quanta ~~Load Forecast~~Reliability Analysis

The Quanta Technology *Reliability Analysis of Alberhill System Project, Version 2.1 (Second Amended Motion)* is attached as Appendix A to this data submittal.

QUANTA TECHNOLOGY

Report

Reliability Analysis of Alberhill System Project

PREPARED FOR

Southern California Edison (SCE)

DATE

~~January 27~~June 15, 2021
~~(~~Version 2.1 (Errata)

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VERSION HISTORY:

Version	Date	Description
0.1	11/8/2019	Initial draft
0.2	12/5/2019	Final draft
1	12/20/2019	Final
2	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only.
2.1 (Errata)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power-flow studies that evaluate the impact of the load forecast on the Valley South system both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of the project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South System by the year 2022 as the load exceeds the Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within the Valley South System is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates the benefits of the ASP project in meeting the overall needs in the Valley South System. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are as follows:
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more sub-transmission circuits in the Valley South system, the availability of tie-lines with the ASP reduces the expected energy unserved by greater than 70%.
  - The ASP provides measurable operational flexibility improvement to address system needs under high impact low probability (HILP) events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.

- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

The findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

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1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses of the capacity and reliability needs in the Valley South 500/115 kV system. The objective of this analysis is to evaluate the forecasted impacts of the ASP on service reliability performance utilizing a combination of power flow simulations and service reliability metrics where applicable.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South system is not supplied by any alternative means or tie-line. In other words, this portion of the system is radially served by a single point of interconnection from the bulk electric system (BES) which is under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility, and resiliency needs of the Valley South system.

The Valley South 115 kV system electrical needs area (ENA) consists of 15 distribution level 115/12 kV substations.

During the most recent forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0). This forecast was developed for extreme weather conditions (1-in-5-year heat storm).[1] SCE has additionally identified the need to provide system ties to improve reliability, resiliency, and operational flexibility.[2] To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area. Key features of this project are as follows:

- Construction of a 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano–Valley 500 kV transmission line.

[1] 1-in-5-year peak demand adjusted for extreme weather conditions are typically utilized for system planning involving the sub-transmission system.

[2] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resiliency needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected. customers. System tie-lines can effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

- Construction of approximately 20 miles of 115 kV sub-transmission lines to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations from the Valley South System to the new Alberhill System and to create 115 kV system tie-lines between the two systems.

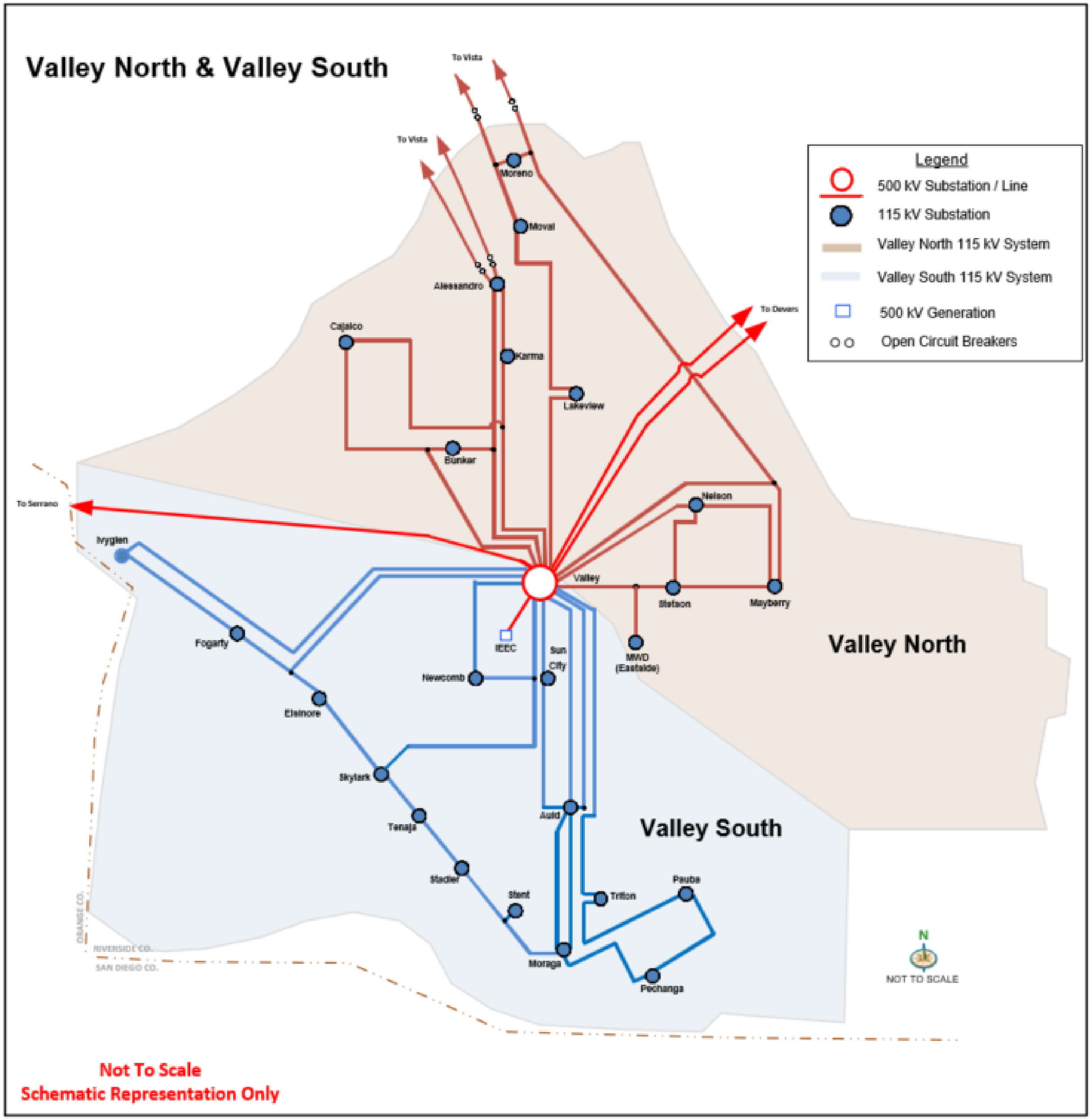

Figure 1-1. Valley Service Areas[3]

[3] Valley-Ivyglen and VSSP 115 kV line projects included.

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the proceedings for the ASP, the CPUC requested additional analyses to justify the peak demand forecasts and reliability cases for the project. The CPUC also requested a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; the alternatives include but are not limited to energy storage, demand response, and distributed energy resources (DERs).

Quanta Technology supported SCE's intent to supplement the existing record in the CPUC proceeding for the ASP utilizing a comprehensive reliability assessment framework. The scope of this assessment included the following:

1. Quantifying the needs in the Valley South 500/115 kV System using the applicable load forecast.
2. Using power flow simulations and quantitative review of project data to evaluate the forecasted impact of proposed ASP on the Valley South System needs.
3. Applying the load forecast to analyze service reliability performance benefits provided by the ASP in the Valley South System.

1.2 Report Organization

In order to provide a comprehensive view of the study methodology, findings, and conclusions, this report has been separated into three sections.

Section 2 of this report introduces the reliability assessment framework while describing the tools, formulation, and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Section 2.4 presents the forecasted performance of the ASP using the metrics. Section 3 serves as the conclusion.

2 RELIABILITY ASSESSMENT FRAMEWORK AND RESULTS

2.1 Introduction

The objective of this analysis is to evaluate the performance and benefits of the ASP in comparison to the baseline scenario (i.e., no project in service). The performance of the baseline system is initially presented, followed by the ASP. Within the framework of this analysis, reliability, capacity, operational flexibility, and resiliency benefits have been quantified.

In order to successfully evaluate the benefits of a potential project in the Valley South System, its performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to the baseline scenario (no project in service),
3. To establish a basis to value the performance of the ASP against overall project objectives,
4. To take into consideration the benefits or impacts of flexibility and resiliency (high-impact, low-probability events), and
5. To guide comparison of the projects against the alternatives.

Within the scope of the developed metrics, the following key project objectives are addressed:

Capacity

- Serve current and long-term projected electrical demand requirements in the SCE ENA.
- Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

Reliability

- 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 ENA (i.e., the area served by the existing Valley South system).

Operational Flexibility and Resiliency

- Increase system operational flexibility and maintain system reliability (e.g., by creating system ties that establish the ability to transfer substations from the current Valley South system and to address both normal condition capacity and N-1 capacity needs).

2.2 Study Methodology

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance.
2. Quantify the project performance using commercial power flow software.

Each of the above areas is further detailed throughout this chapter. Since the focus of this analysis is the Valley South system, all discussions are pertinent to this study area.

2.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and ASP systems. This information encompassed the following data:

1. GE PSLF[4] power flow models for Valley South and Valley North Systems.
   a. 2018 system configuration (current system).
   b. 2021 system configuration (Valley-Ivyglen[5] and VSSP[6] projects modeled and included).
   c. 2022 system configuration (with the ASP in service).
2. Substation layout diagrams representing the Valley Substation.
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations.
4. Single-line diagram of the Valley South and Valley North Systems.
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System.
7. Metered customer information per substation (customer count).

The reliability assessment utilizes the spatial load forecast developed for Valley South and Valley North service territories to evaluate the performance of the system for future planning horizons. The developed forecast includes the effects of future developments on photovoltaic projects or installations, electric vehicles, energy efficiency, energy storage, and load modifying demand response as defined in the IEPR 2018 forecast.[7] The representative load forecast is presented in Figure 2-1, which demonstrates system deficiency in the year 2022, where the loading on the Valley South system transformers exceeds maximum operating limits (1,120 MVA).

[4] General Electric's Positive Sequence Load Flow (PSLF) program.

[5] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).

[6] VSSP (Valley South 115 kV Sub-transmission Project) CPUC Decision 16-12-001 (issued December 1, 2016).

[7] California Energy Commission, "2018 Integrated Energy Policy Report," 2018.

Benefits begin to accrue coincident with the project need year of 2022. For this assessment, it is assumed that the ASP will be in service by this year and that benefits accrue from 2022 to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

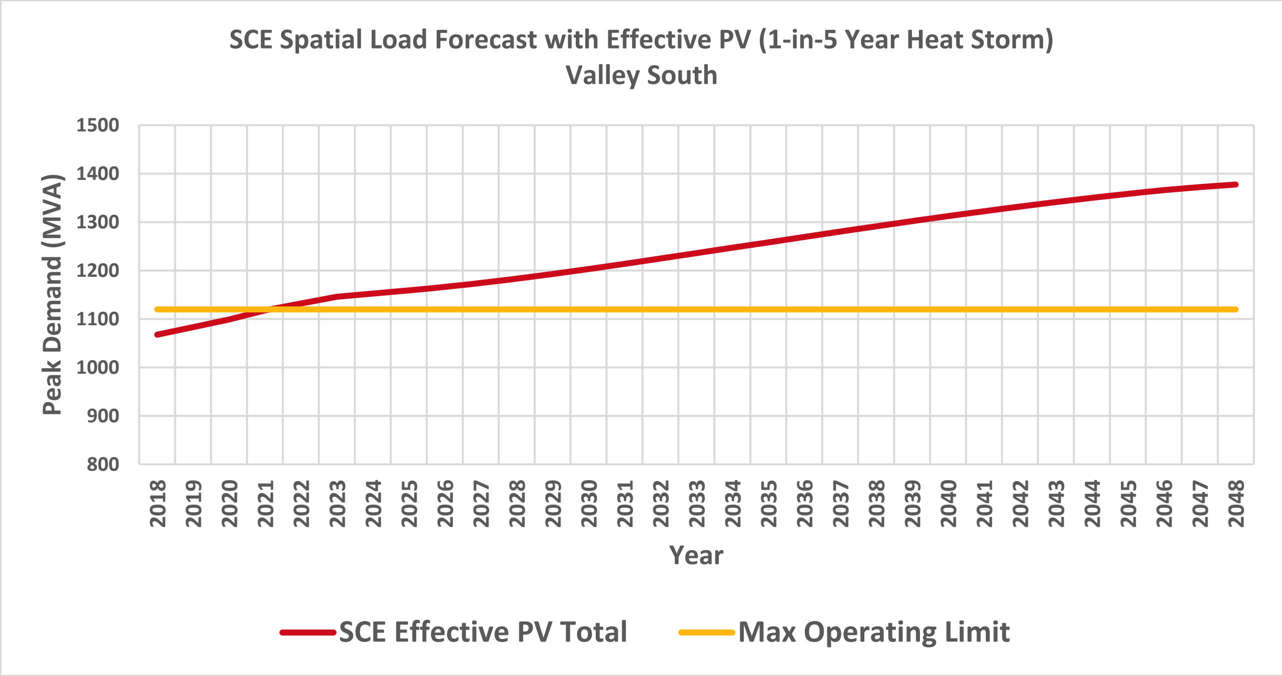

Figure 2-1. Valley South Load Forecast (Peak MVA)

System configuration for the years 2018, 2021, and 2022 are depicted in Figure 2-2 through Figure 2-4.

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrates the largest variability among available records.[8] This load shape is presented in Figure 2-5.

[8] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

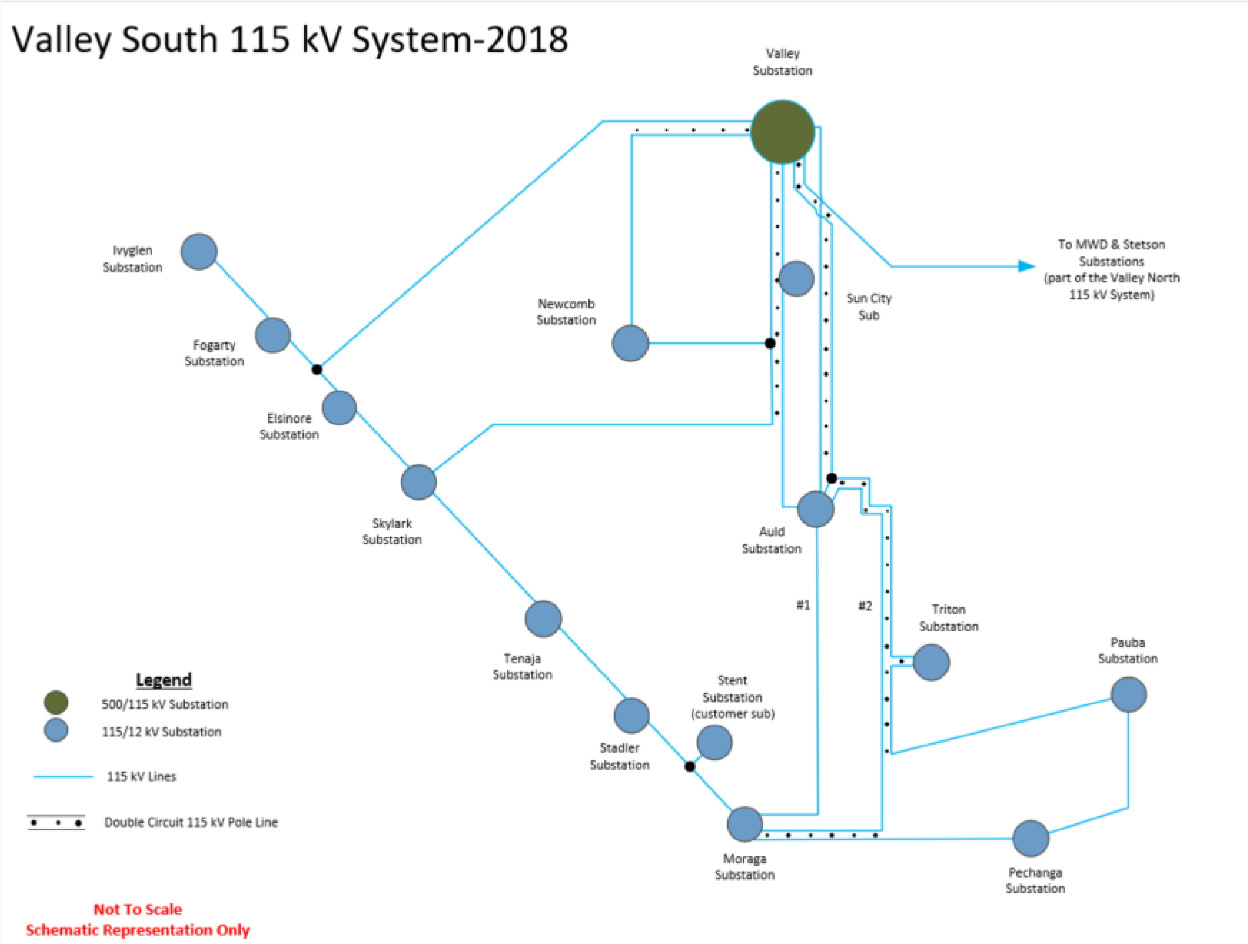

Figure 2-2. Valley South System Configuration (2018)

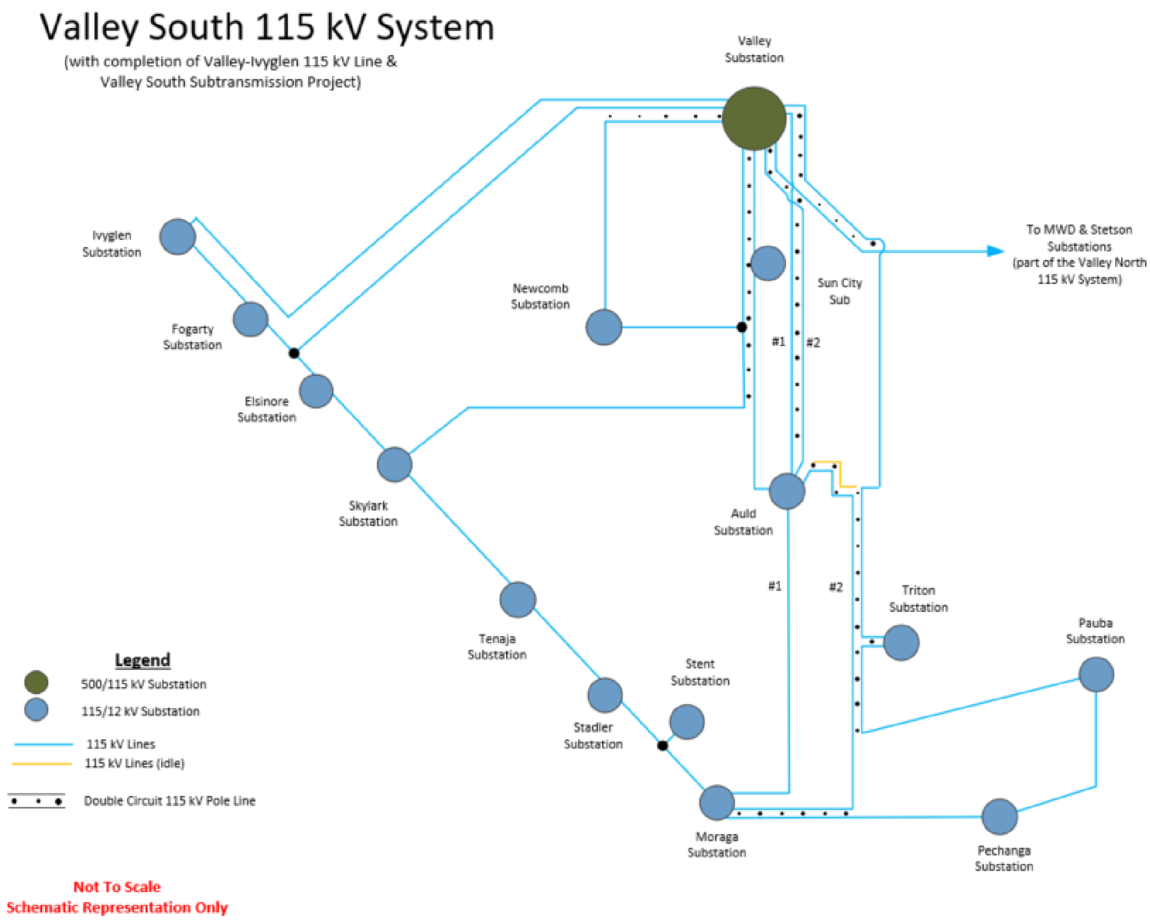

Figure 2-3. Valley South System Configuration (2021)

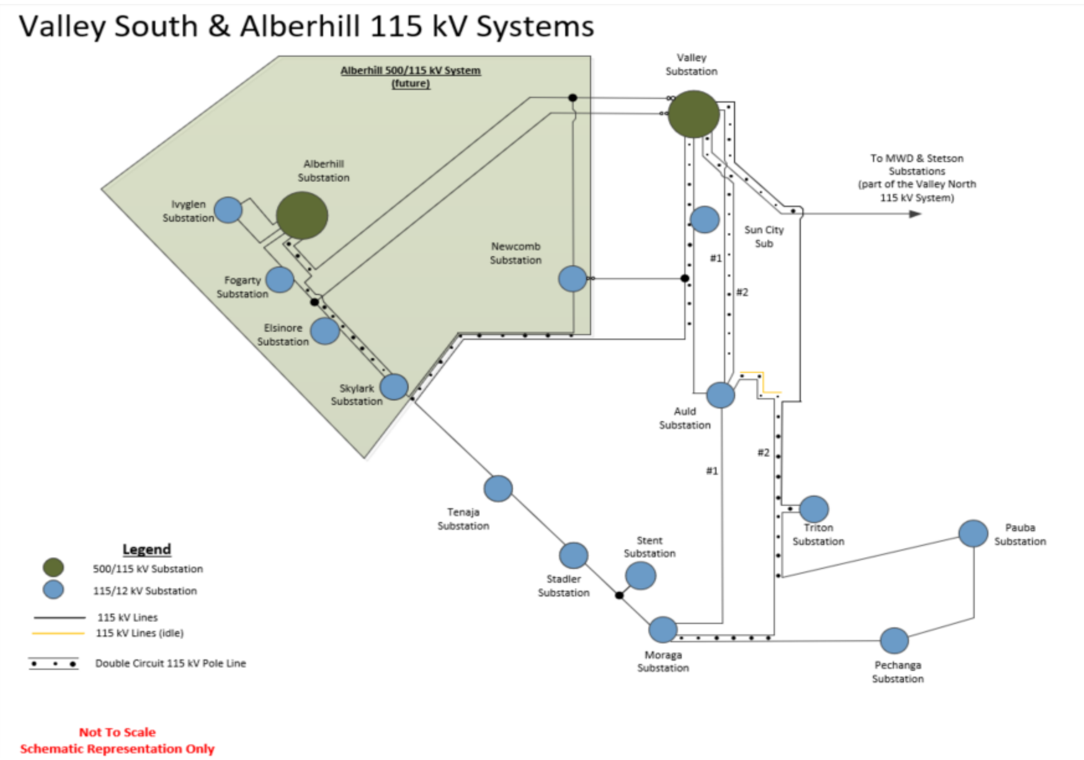

Figure 2-4. Valley South System Configuration (2022 with the ASP in service)

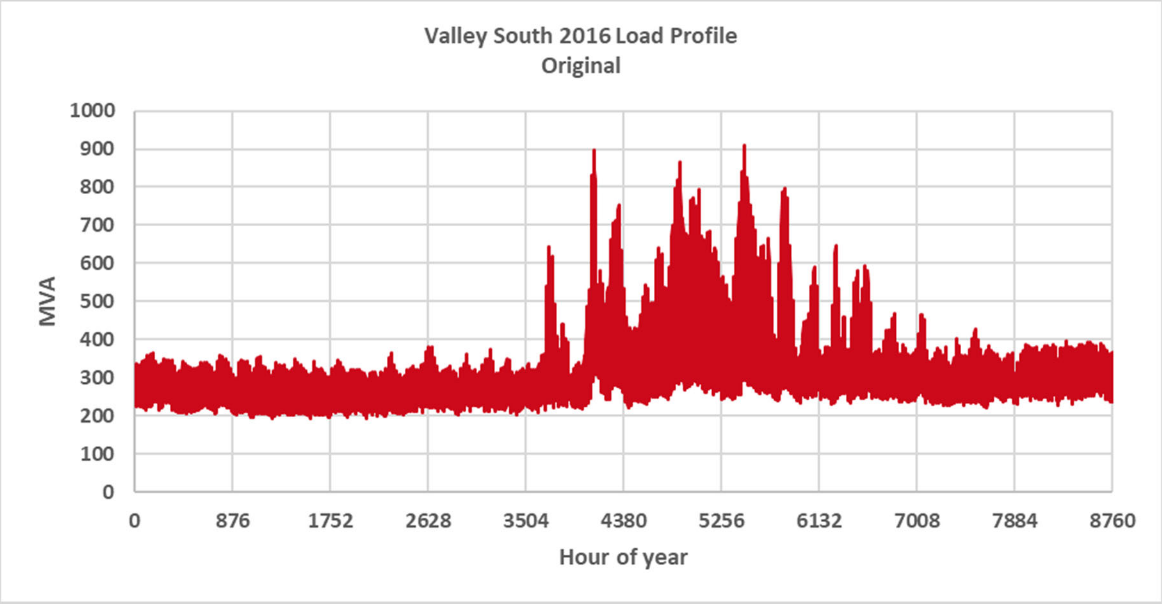

Figure 2-5. Load Shape of the Valley South Substation

2.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability (NERC) and Western Electricity Coordinating Council (WECC) standards have been used, especially while taking into consideration the impact on the BES and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 (normal) and N-1 (emergency) operating conditions.
- Voltage limits of 0.95–1.05 per unit (pu) under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

2.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been used for this analysis (i.e., GE PSLF and PowerGem TARA). GE PSLF has been used for base-case model development, conditioning, contingency development, and drawing capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is traditionally used in distribution system analysis to assess variation of various quantities over time with changes in load, generation, transmission-line status, etc. It is now finding common application even in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 2-6 for the Valley South System as an example. The MW peak load is then distributed amongst the various load models in the Valley Substation in proportion to their MW-to-peak-load ratio in the base case. Load centers under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 2-1.

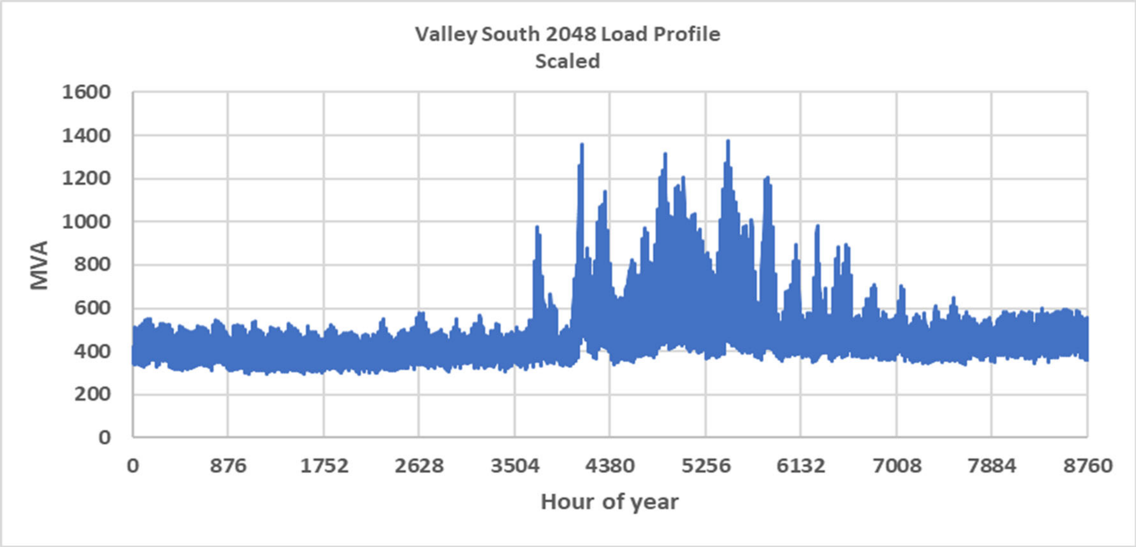

Figure 2-6. Scaled Valley South Load Shape Representative of Study Years

Table 2-1. Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

The hourly study (i.e., 8,760 simulations per year) was conducted in selected years (5-year periods from 2022 including 2027, 2032, 2037, 2042, and 2048). The results for years in between were interpolated.

For each simulation, the AC power-flow solution is solved, relevant equipment is monitored under N-0 conditions (normal) and N-1 analysis (emergency), potential reliability violations are recorded, and performance reliability metrics (as described in Section 2.2.4) are calculated. A flowchart of the overall study process is presented in Figure 2-7.

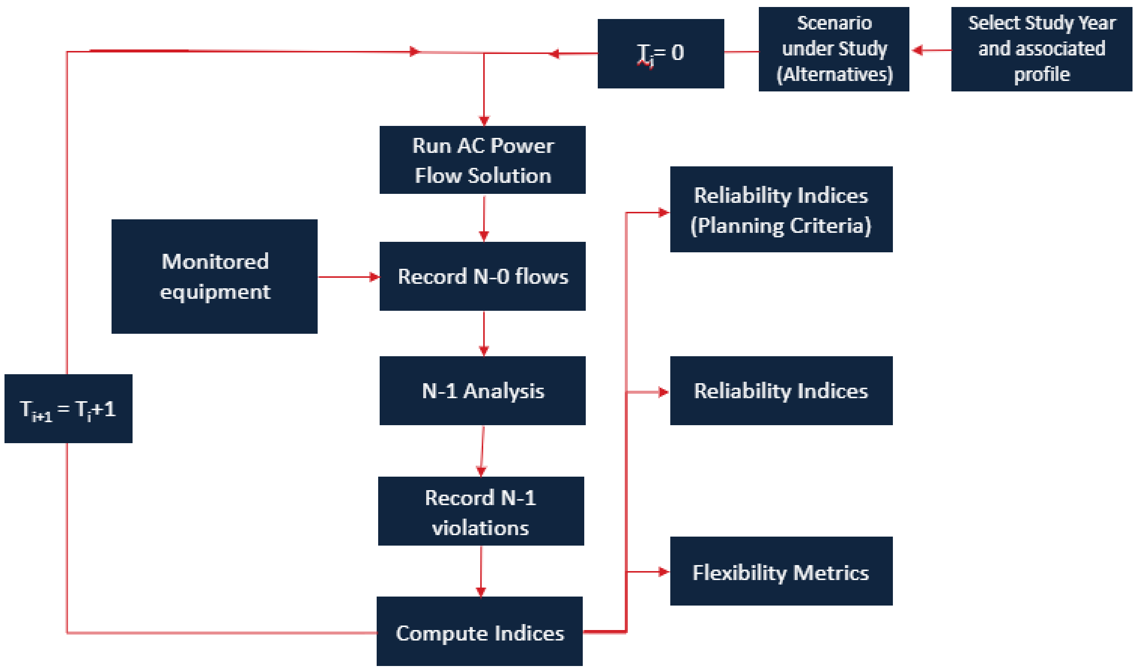

Figure 2-7. Flowchart of Reliability Assessment Process

Unless otherwise specified, all calculations performed under the reliability analysis compute the load at risk, which is not a probability-weighted metric.

In the reliability analysis, the N-1 contingency has been evaluated for every hour of the 8,760 simulations, and all outages are considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates single circuit outages for all sub-transmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to the computation of the relevant reliability metric. When the project under evaluation has system tie-lines that can be leveraged, they are engaged to minimize system impacts.

Several flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency or planned/unplanned outages and high-impact, low-probability (HILP) events in the Valley South System.

The Flexibility-1 metric evaluates the system under N-2 (double line outage) conditions, which is representative of combinations of lines switched out for service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common structure. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 2-8 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk. The results were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. When the project under evaluation has tie-lines, they are considered to minimize system impacts.

The Flexibility-2 metric evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting the Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of load at risk:

- The Flexibility 2-1 metric evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of load at risk is determined. Utilizing power flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- The Flexibility 2-2 metric evaluates a condition wherein Valley South System is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g., fire or explosion) of one of the two normally load-serving transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Using the 8,760-load shape and the transformer short-term/long-term emergency loading limits (STELL/LTELL), the average amount of MWh load at risk is estimated and aggregated considering a 2-week duration (mean time to repair under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

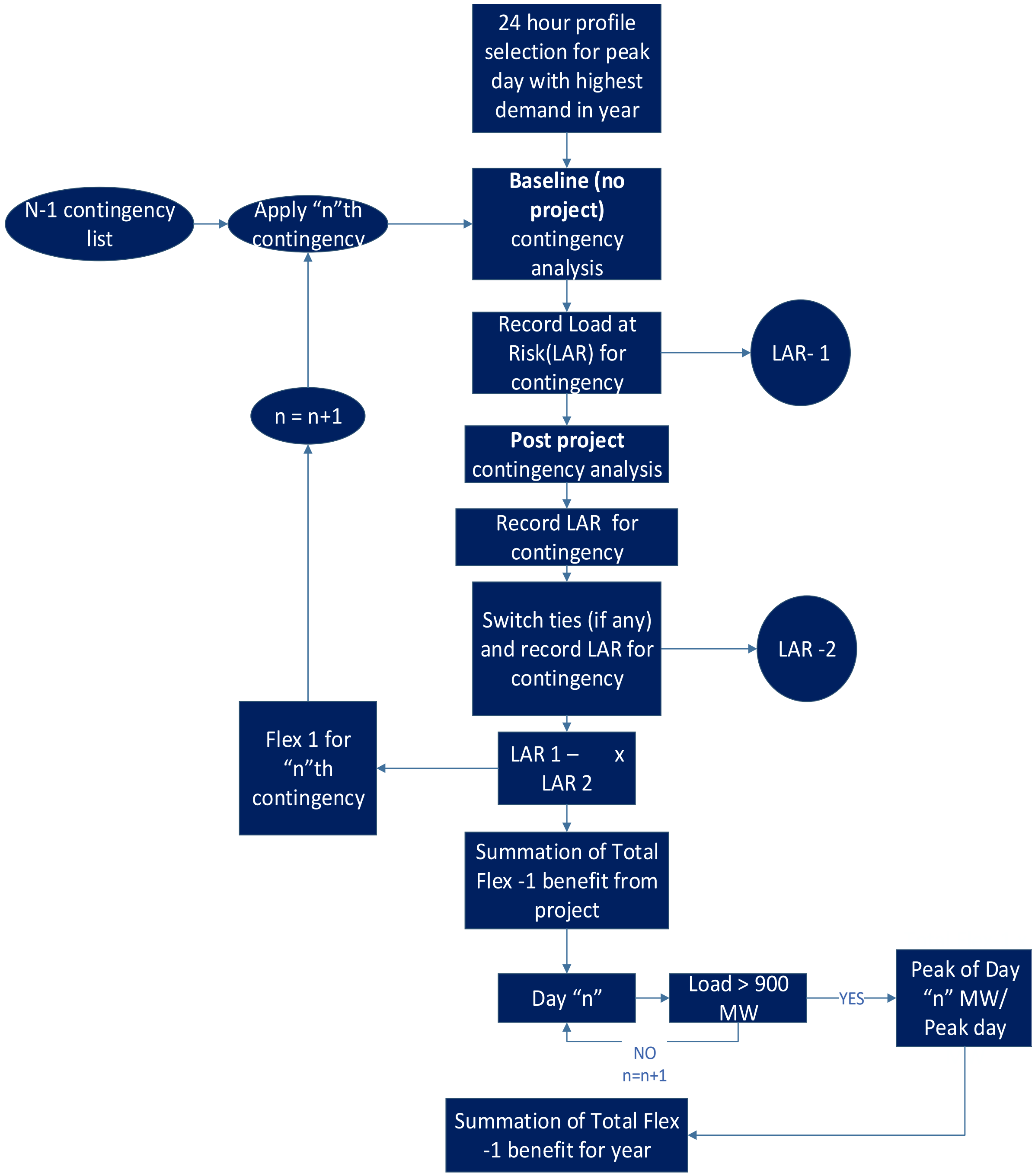

Figure 2-8. Flowchart of Flexibility Metric 1 (Flex 1) Calculation Process

2.2.4 Reliability Metrics

Before introducing reliability metrics, the key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The treatment of the following is consistent with applicable NERC guidelines and standards for the BES:

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions, and normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, and planned outage conditions. Therefore, it is expected to operate the system radially and accommodate flexibility by employing normally open tie(s) and connection(s).
- Resiliency has been viewed as an extension of the flexibility benefits, wherein ties and connections are leveraged to recover load under HILP events in the system.

Building on the overall project objectives, the reliability metrics described in the following subsections have been established.

2.2.4.1 Quantitative Metrics

The following quantitative metrics have been proposed to address the reliability, capacity, flexibility, and resiliency needs of the system:

- **Load at Risk**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below ratings. This includes transformers and lines serving the Valley South system.
     ii. For voltage violations, the MW amount of load to be dropped based on voltage sensitivity of the bus to bring voltage within limits. The sensitivity study established ranges of load shed associated with varying levels of post-contingency voltage. For the deviation of 1 pu of voltage from the 0.95 pu limit, 0.5 MW of load shed was identified.
  b. Computed for N-0 events and N-1 events and aggregated over the course of the year.
  c. For N-1 events, tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
  a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
  b. Computed for N-0 events and N-1 events.

- **Losses**: Losses are treated as the active power losses in the Valley South system. New lines introduced by the scope of a project have also been included in the loss computation.

- **Availability of Flexibility in the System**: The measure of the availability of the flexible resource (tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of additional/incremental flexibility (MWh) the alternative solution provides to the system for maintenance operations, emergency events, or the need to relieve other operational issues. Two flexibility metrics are considered:
  a. Flexibility 1: Capability to recover load for maintenance and outage conditions.
     i. Calculated as the amount of energy not served for N-2 events. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served utilizing the flexibility attributes of the project.
     ii. Considering the large combination of N-2-line outages that potentially impact the Valley South System, the analysis is limited to only circuits that share a common double circuit pole.

  b. Flexibility 2: Recover load for the emergency condition: Single point of failure Valley South substation and transformer banks.
     i. Flex 2-1: Calculated as the energy unserved when the system is impacted by low probability high consequence events such as the loss of the entire Valley Substation. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events. This event is calculated over an average 2-week period (average restoration duration for events of this magnitude) in the Valley system.

        Flex 2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (both transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley System. Projects that establish ties or connections to an adjacent network can support the recovery of load during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was less than required, resulting in energy being unserved for a given time horizon and direction.

The above list has been iteratively developed to successfully translate the objectives into quantifiable metrics that provide a basis for project performance evaluation.

2.3 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under the study without any project in service to address the shortfalls in transformer rated capacity. This scenario forms the primary basis for comparison against the ASP performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under the study years 2022 (project need year), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.3.1 System Performance under Normal Conditions (N-0)

Table 2-2 presents the findings from system analysis under N-0 conditions in the system.

Table 2-2. Baseline N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	22	13	2
	2028	250	65	7
	2033	905	120	18
	2038	2212	190	37
	2043	4184	246	53
	2048	6310	288	77

2.3.2 System Performance under Normal Conditions (N-1)

Table 2-3 presents the findings from system analysis under N-1 conditions.

Table 2-3. Baseline N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
No Project	**2022**	10	2	14
	2028	67	11	32
	2033	249	21	54
	2038	679	35	88
	2043	1596	45	120
	2048	2823	68	153

In the baseline system analysis, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond). In Table 2-4, only the thermal violations associated with each constraint are reported.

Table 2-4. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Valley South Transformer	N-0	Base case	2022
Auld to Moraga #1	N-0	Base case	2047
Auld to Moraga #2	N-1	Auld-Moraga #1	2038
Auld to Moraga #1	N-1	Auld-Moraga #2	2022
Valley EFG to Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043
Tap 39 to Elsinore	N-1	Valley EFG-Newcomb-Skylark	2038
Auld to Moraga #1	N-1	Skylark-Tenaja	2048
Skylark to Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033
Valley EFG to Sun City	N-1	Valley EFG-Auld #1	2043
Valley EFG to Auld #1	N-1	Valley EFG-Sun City	2048
Valley EFG to Tap 22	N-1	Valley EFG-Newcomb	2043
Valley EFG to Auld #1	N-1	Valley EFG-Auld #2	2048
Valley EFG to Sun City	N-1	Valley EFG-Auld #2	2043
Auld to Moraga #1	N-1	Valley EFG - Triton	2043
Moraga-Pechanga	N-1	Valley EFG - Triton	2038

2.3.3 Flexibility Metrics

Table 2-5 presents the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-5. Flexibility and Resiliency Metrics for the Baseline System

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
No Project	**2022**	54,545	127,935	2,138
	2028	163,415	133,688	2,774
	2033	254,140	139,702	3,514
	2038	344,864	145,991	4,421
	2043	435,589	151,619	5,294
	2048	526,314	155,733	5,975

2.3.4 System Losses

Table 2-6 presents the aggregated losses from the 8,760 assessment of the Valley South system.

Table 2-6. Losses in the Baseline System

	Year	Losses (MWh)
No Project	**2022**	49,667
	2028	52,288
	2033	54,472
	2038	56,656
	2043	58,840
	2048	61,024

2.3.5 Key Highlights of System Performance

The key highlights of system performance for the baseline system are as follows:

1. Without any project in service, the Valley South transformers are overload by the year 2022 (above maximum transformer ratings).
2. By the year 2028, 250 MWh of the load is observed to be at risk in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service.
3. Between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under the N-0 condition.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain the system N-1 secure.

2.4 Reliability Analysis of the Alberhill System Project

The ASP has been evaluated under the study years 2022, 2028, 2033, 2038, 2043, and 2048 consistent with the baseline system. Each of the reliability metrics established in Section 2.2.4 has been calculated using the study methodology outlined in Section 2.2.3.

2.4.1 Description of Project Solution

The ASP would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area presently served by the Valley South 115 kV system.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano–Valley 500 kV transmission line. The total length is 3.3 miles.
3. Construction of a new 115 kV subtransmission line and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV substations (Ivyglen, Fogarty, Elsinore,

Skylark, and Newcomb) presently served by the Valley South 115 kV system to the new 500/115 kV substation. The total length is approximately 20.4 miles.

4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network. The total length is approximately 8.7 miles.

Figure 2-9 presents an overview of the project layout and schematic.

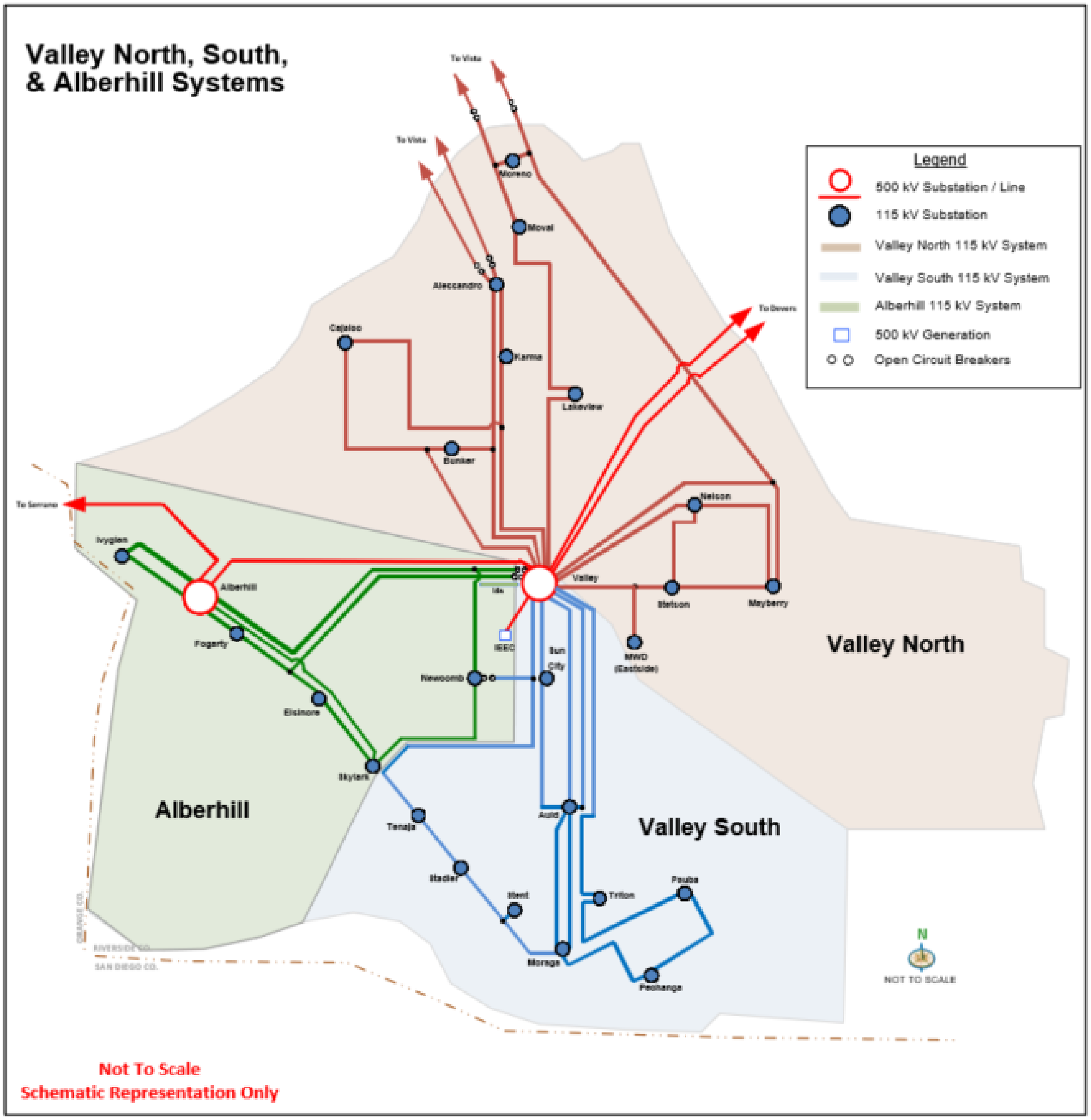

Figure 2-9. Service Territory Configuration after Proposed Alberhill System Project

2.4.2 System Performance under Normal Conditions (N-0)

Table 2-7 presents the findings from system analysis under N-0 conditions.

Table 2-7. Alberhill N-0 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	**2022**	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	0	0	0
	2043	0	0	0
	2048	3	2	2

2.4.3 System Performance under Normal Conditions (N-1)

Table 2-8 presents the findings from system analysis under N-1 conditions.

Table 2-8. Alberhill N-1 System Performance

	Year	Load at Risk (MWh)	IP (MW)	PFD (hr)
ASP	2022	**0**	**0**	**0**
	2028	0	0	0
	2033	0	0	0
	2038	21	8	4
	2043	84	17	8
	2048	202	24	14

In analyzing the ASP, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the load at risk among other reliability metrics under study (reported for 2022 and beyond).

In Table 2-9 below, only the thermal violations associated with each constraint are reported.

Table 2-9. List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Year of Overload
Alberhill to Fogarty	N-0	Base case	2046
Alberhill to Fogarty	N-1	Alberhill–Skylark	2038
Alberhill to Skylark	N-1	Alberhill–Fogarty	2043
Auld to Moraga #1	N-1	Valley EFG–Newcomb–Tenaja	2048

2.4.4 Flexibility Metrics

Table 2-10 present the findings from system analysis for Flex 1 and Flex 2 metrics. The Flex 2 metric results represent the average load at risk during the 2-week recovery period for the defined scenario.

Table 2-10. Flexibility and Resiliency Metrics for the ASP

	Year	Flex 1 Load at Risk (MWh)	Flex 2-1 Average Load at Risk (MWh)	Flex 2-2 Average Load at Risk (MWh)
ASP	2022	~~22,815~~0	1,163	0
	2028	~~49,088~~30,438	1,516	0
	2033	56,720~~70,982~~	1,947	0
	2038	~~92,876~~83,001	2,452	0
	2043	109,282~~114,770~~	2,954	1
	2048	136,664	3,345	4

2.4.5 System Losses

Table 2-11 presents the aggregated losses from the 8760 assessment of the Valley South and ASP systems.

Table 2-11. Losses in the ASP

	Year	Losses (MWh)
ASP	2022	40,621
	2028	42,671
	2033	44,380
	2038	46,089
	2043	47,797
	2048	49,506

2.4.6 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. 3 MWh of load at risk is recorded under N-0 condition in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line.
2. By the year 2038, overloads due to N-1 events will be observable on the Alberhill–Fogarty 115 kV circuit, Alberhill–Skylark 115 kV, and Auld–Moraga 115 kV circuits, which cannot be resolved by potential transfer flexibility.
3. The project provides significant flexibility to address N-1 and N-2 events in the system while also providing significant benefits to address needs under HILP events that occur in the Valley System.

2.5 Evaluation of Quantitative Metrics

The established performance metrics were compared between the baseline and the ASP to quantify the overall benefits accrued over the 10-year and 30-year study horizons calculated at the start of the need year 2022 (i.e., end of 2021). The benefits are quantified as the difference between the baseline and the ASP for each of the metrics and discounted at SCE's weighted aggregate cost of capital (WACC) of 10%. As an example, Figure 2-10 exhibits N-0 load at risk values over the study horizon and its present worth using discount rate of WACC. A similar process was applied to other metrics.

The present worth of *benefits* for reliability metrics over 10-year and 30-year horizons are presented in Table 2-13. The cumulative *benefits* over a 10-year and 30-year horizon are presented in Table 2-12.

The cumulative and present worth of benefits are presented in Appendix C: Reliability Performance Additional Details for both the baseline and the ASP to provide a relative comparison of performance in each reliability category.

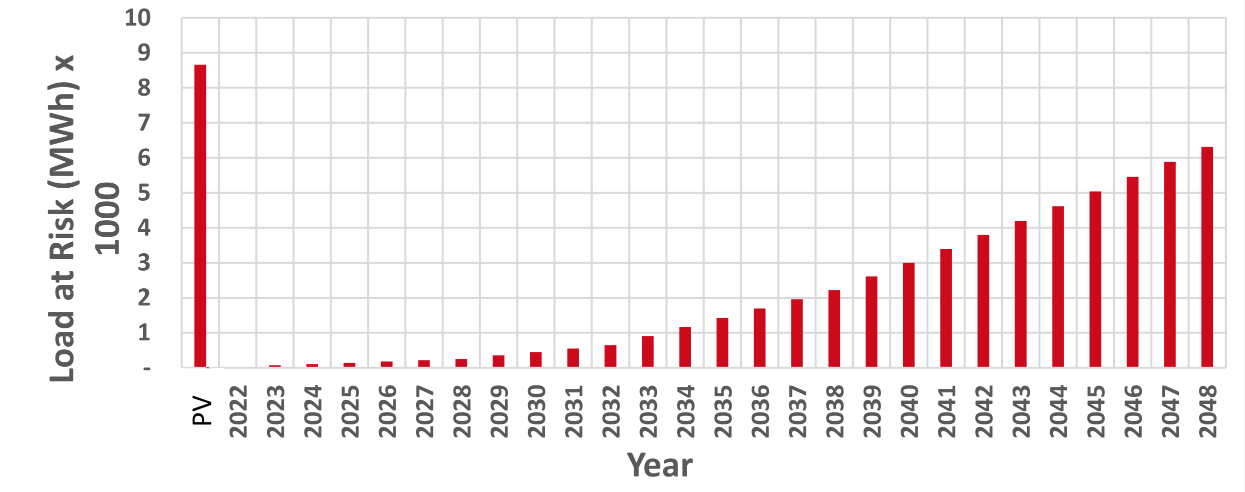

Figure 2-10. N-0 Load at Risk over the Study Horizon and Its PV

Appendix C provides comparative metrics over the 10-year and 30-year horizon between the baseline (no project) and the ASP. These are used to derive the benefits presented in Table 2-12 and (later in Table C-1).

Table 2-12. Cumulative Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Cumulative Value of Benefits over 10-year horizon (until 2028)	Cumulative Value of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	65,319	277,608
N-1	Load at Risk (MWh)	274	20,~~339~~326
N-1	IP (MW)	45	601
N-1	PFD (hr)	173	1,907
N-1	Flex 1 Load at Risk (MWh)	~~511,196~~659,076	~~5,688,618~~6,024,126
N-1	Flex 2-1 Average Load at Risk (MWh)	907,590	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	106,937
N-0	Load at Risk (MWh)	971	56,575
N-0	IP (MW)	288	4,053
N-0	PFD (hr)	35	811

Table 2-13. Present Worth of Benefits between Baseline and ASP (10-year and 30-year)

Category	Component	Present Worth of Benefits over 10-year horizon (until 2028)	Present Worth of Benefits over 30-year horizon (until 2048)
N-0	Losses (MWh)	45,254	90,384
N-1	Load at Risk (MWh)	173	2,896
N-1	IP (MW)	28	133
N-1	PFD (hr)	115	420
N-1	Flex 1 Load at Risk (MWh)	434,402~~330,171~~	1,438,932~~1,281,190~~
N-1	Flex 2-1 Average Load at Risk (MWh)	629,646	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	29,195
N-0	Load at Risk (MWh)	606	8,657
N-0	IP (MW)	185	853
N-0	PFD (hr)	23	146

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the ASP. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resiliency needs in the Valley South service area.

3 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for the ASP with additional analyses to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this report is to quantitatively assess the reliability benefits of the ASP.

A comprehensive framework was developed in coordination with SCE to evaluate the performance of the ASP. This evaluation is complemented by the development of load forecasts for the Valley North and Valley South system planning areas. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until the year 2048).

The benefits were calculated using power flow studies that evaluate the impact of the load forecast on the Valley South System both without and with the ASP in service. Each of the reliability, capacity, flexibility, and resiliency objectives of project performance is quantified by service reliability metrics over a 10-year and 30-year planning horizon. Benefits are quantified as the relative performance of the ASP to the baseline for each of the metrics.

The key findings of this study are summarized as follows:

- The peak load forecast identifies a transformer capacity need in the Valley South system by the year 2022, as the load exceeds Valley South 500/115 kV transformer capacity of 1,120 MVA. The peak demand within Valley South service territory is projected to grow from 1,132 MVA in the year 2022 to 1,378 MVA in the year 2048.
- An evaluation of the quantitative metrics demonstrates significant benefits of the ASP project in meeting overall needs in the Valley South service area. Key highlights from the ASP project performance across the 10-year (2028) and 30-year (2048) horizons are discussed.
  - Without the ASP in service and under normal operating conditions (N-0 or all facilities in service), the load at risk increases from 250 MWh to 6,300 MWh between the years 2028 and 2048. With the ASP in service, the amount of load at risk is reduced to 3 MWh in 2048.
  - The periods wherein the system observes a shortage in capacity increases from 7 hours by the year 2028 to 77 hours by the year 2048 under normal operating conditions (N-0). With the ASP in service, this is reduced to 2 hours in the year 2048.
  - Without the ASP in service, maintaining adequate N-1 capacity becomes increasingly challenging at higher load levels. The ASP reduces the N-1 capacity risk from 2,800 MWh to 200 MWh by the year 2048.
  - For emergency, unplanned, or planned maintenance events involving the simultaneous outage of two or more subtransmission circuits in the Valley South System, the availability of tie-lines with the ASP reduces load at risk by greater than 70%.

- The ASP provides measurable operational flexibility improvement to address system needs under the HILP events in the Valley System. The current system configuration does not provide any benefit in this regard due to unavailable system ties.
- The ASP reduces the losses in the system from 52 GWh to 42 GWh in the year 2028 and from 61 GWh to 49 GWh in the year 2048.

Overall, the ASP demonstrated the robustness necessary to address the needs identified in the Valley service territory. By design, the project provides an alternative source of supply into the original Valley South service territory while effectively separating the system with tie-lines. This offers several advantages that can also help overcome the variability and uncertainty associated with the forecast peak load. The available flexibility through system tie-lines provides relief to system operations under both normal system conditions (increasing flexibility for planned maintenance outages) and for abnormal system conditions (unplanned outages) such as N-1, N-2, and HILP events that affect the region.

Findings and results reported in this document are based on publicly available information and the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

APPENDIX A: GLOSSARY

ASP: Alberhill System Project

BES: Bulk Electric System

CAIDI: Customer Average Interruption Duration Index

CAISO: California Independent System Operator

CPUC: California Public Utility Commission

DER: Distributed Energy Resources

LAR: Load at Risk

NERC: North American Electric Reliability Corporation

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

WECC: Western Electricity Coordinating Council

APPENDIX B: REFERENCES

1. Sub-transmission Planning Criteria and Guidelines, SCE 9/24/2015.
2. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project, CPUC 8/31/2018.

APPENDIX C: RELIABILITY PERFORMANCE ADDITIONAL DETAILS

The cumulative benefits over a 10-year and 30-year horizon are presented in Table C-1 and Table C-2, respectively.

The present worth of benefits over a 10-year and 30-year horizon are presented in Table C-3 and Table C-4, respectively.

Table C-1. Cumulative Reliability Performance and Benefits with and without the ASP (10-year)

Category	Component	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Service Reliability Performance over 10-year Horizon	Cumulative Benefit over 10-year Horizon
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	356,842	291,522	65,319
N-1	Load at Risk (MWh)	274	0	274
N-1	IP (MW)	45	0	45
N-1	PFD (hr)	173	0	173
N-1	Flex 1 Load at Risk (MWh)	762,858	~~251,662~~103,783	659,076~~511,196~~
N-1	Flex 2-1 Average Load at Risk (MWh)	917,017	9,427	907,590
N-1	Flex 2-2 Average Load at Risk (MWh)	17,266	0	17,266
N-0	Load at Risk (MWh)	971	0	971
N-0	IP (MW)	288	0	288
N-0	PFD (hr)	35	0	35

Table C-2. Cumulative Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Service Reliability Performance over 30-year horizon (until 2048)	Cumulative Benefit over 10-year horizon (until 2048)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	1,494,322	1,216,714	277,608
N-1	Load at Risk (MWh)	21,684	1,047~~35~~	20,327~~649~~
N-1	IP (MW)	780	179	601
N-1	PFD (hr)	1,999	92	1,907
N-1	Flex 1 Load at Risk (MWh)	7,841,596	~~2,152,978~~1,817,470	~~5,688,618~~6,024,127
N-1	Flex 2-1 Average Load at Risk (MWh)	3,839,134	59,285	3,779,849
N-1	Flex 2-2 Average Load at Risk (MWh)	106,954	17	106,937
N-0	Load at Risk (MWh)	56,581	6	56,575
N-0	IP (MW)	4,056	4	4,053
N-0	PFD (hr)	815	4	811

Table C-3. Present Worth of Benefits with and without the ASP (10-year)

Category	Component	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Service Reliability Performance over 10-year horizon (until 2028)	Present Worth of Benefits over 10-year horizon (till 2028)
		Baseline	***ASP***	***Baseline – ASP***
N-0	Losses (MWh)	247,375	202,121	45,254
N-1	Load at Risk (MWh)	173	0	173
N-1	IP (MW)	28	0	28
N-1	PFD (hr)	115	0	115
N-1	Flex 1 Load at Risk	497,134	~~166,962~~262,732	~~330,172~~434,402
N-1	Flex 2-1 Average Load at Risk (MWh)	636,100	6,453	629,646
N-1	Flex 2-2 Average Load at Risk (MWh)	11,822	0	11,822
N-0	Load at Risk (MWh)	606	0	606
N-0	IP (MW)	185	0	185
N-0	PFD (hr)	23	0	23

Table C-4. Present Worth Reliability Performance and Benefits with and without the ASP (30-year)

Category	Component	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Service Reliability Performance over 30-year horizon (until 2048)	Present Worth of Benefits over 30-year horizon (until 2048)
		Baseline	*ASP*	*Baseline – ASP*
N-0	Losses (MWh)	490,137	399,753	90,384
N-1	Load at Risk (MWh)	3,054	112~~1~~	2,896~~943~~
N-1	IP (MW)	154	21	133
N-1	PFD (hr)	431	11	420
N-1	Flex 1 Load at Risk	1,806,240	~~525,050~~368,207	~~1,281,190~~1,438,032
N-1	Flex 2-1 Average Load at Risk (MWh)	1,259,315	16,083	1,243,232
N-1	Flex 2-2 Average Load at Risk (MWh)	29,196	2	29,195
N-0	Load at Risk (MWh)	8,658	0	8,657
N-0	IP (MW)	853	0	853
N-0	PFD (hr)	147	0	147