Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-43:
Please provide the existing SAIDI, SAIFI, MAIFI, and CAIFI numbers from 2009-2019 for the following locations:

1. A-bank two transformers at Valley South substation
2. Entire Valley South substation
3. SCE system

Response to Question DG-MISC-43:

Please see SCE's response to the amended data request question *DG-MISC-43 Supplemental* in *CPUC-Supplemental Data Request Set – 006*, responded to on October 17, 2020.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 5

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-44:
For the base case, please tabulate the N-0, N-1, and N-1-1 contingency results in terms of number of customer outages served by at A bank substation for all scenarios that impact downtime.

Response to Question DG-MISC-44:

Please see SCE's response to the data request question *DG-MISC-54* in *CPUC-Supplemental Data Request Set – 006*, responded to on February 16, 2021.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-45:
For the case modeling the proposed Valley South project, please tabulate the N-0, N-1, and N-1-1 contingency results in terms of number of customer outages for all scenarios that impact downtime at A bank substation.

Response to Question DG-MISC-45:

Please see SCE's response to the data request question *DG-MISC-54* in *CPUC-Supplemental Data Request Set – 006*, responded to on February 16, 2021.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 5

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-46:
For each of the proposed alternatives, please tabulate the N-0, N-1, and N-1-1 contingency results in terms of number of customer outages for all scenarios that impact downtime at A-bank substation.

Response to Question DG-MISC-46:

Please see SCE's response to the data request question *DG-MISC-54* in *CPUC-Supplemental Data Request Set – 006*, responded to on February 16, 2021.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 5

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-47:
With the tie lines, there is opportunity to permanently shift load from Valley South to Valley North, which could alleviate the need for additional capacity at Valley South. What scenarios were studied to determine if a permanent load shift to Valley North would resolve the capacity issues at Valley South?

Response to Question DG-MISC-47:

Please see SCE's response to the amended data request question *DG-MISC-47 Supplemental* in *CPUC-Supplemental Data Request Set – 006*, responded to on September 30, 2020.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-48:
What studies were performed in assessing the change in capacity needs at Valley North that may enable the permanent shift of some of the Valley South load to Valley North?

Response to Question DG-MISC-48:

Please see SCE's response to the amended data request question *DG-MISC-48 Supplemental* in *CPUC-Supplemental Data Request Set – 006*, responded to on September 30, 2020.

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 5

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 3/4/2021

Question DG-MISC-49:
Please provide list of WDAT/R21 projects and DDOR at Valley North, interconnection status of each, and estimated interconnection application completion date.

Response to Question DG-MISC-49:

Please see the attachment titled "A.09-09-022 ED-Alberhill-SCE-Supplemental Data Request 005 Question DG-MISC-49.xlsx" which contains (as of 2/1/2021):

- All active and in-service WDAT and Rule 21 generation projects in the Valley North System (i.e., Valley 'ABC' 115 kV bus section)
- All active WDAT and Rule 21 applications for generation interconnection in the Valley North System (i.e., Valley 'ABC' 115 kV bus section)
- All SCE-proposed projects to address distribution services in the Valley North System (i.e., Valley 'ABC' 115 kV bus section) identified in SCE's 2020 DDOR filing

Note, SCE did not provide an "estimated interconnection application completion date" for each project as all projects are past the interconnection application phase with all but one either in construction or already in-service.

Attachment in response to CPUC Supplemental Data Request Set-005, Question DG-MISC-49 in A.09-09-022 Proceeding
Data current as of February 1, 2021

Line Item	Tariff Type	Project ID	Current Status	Technology Type (w/rated MW)	Net Facility Output (MW)	Max Facility Export (MW)*	Point of Receipt (circuit)	Electrical System
1	Rule 21 Non-Export	GFID2586	In-Service	Internal Combustion Engine (0.63)	0.630	0.000	Carbine 12 kV	Valley 'ABC' 115
2	Rule 21 Non-Export	GFID2645	In-Service	Combustion Turbine (1.434)	1.434	0.000	Gilman 12 kV	Valley 'ABC' 115
3	Rule 21 Non-Export	GFID7130	In-Service	Microturbine (0.057)	0.057	0.000	Napa 12 kV	Valley 'ABC' 115
4	Rule 21 Non-Export	GFID2704	In-Service	Internal Combustion Engine (1.5)	1.500	0.000	Landmark 12 kV	Valley 'ABC' 115
5	Rule 21 Non-Export	GFID2761	In-Service	Photovoltaic (0.45)	0.450	0.000	Elsworth 12 kV	Valley 'ABC' 115
6	Rule 21 Non-Export	GFID7149	In-Service	Photovoltaic (0.4)	0.400	0.000	Corsair 12 kV	Valley 'ABC' 115
7	Rule 21 Non-Export	GFID7184	In-Service	Fuel Cell ()/Gas Turbine ()	0.600	0.000	Trumble 12 kV	Valley 'ABC' 115
8	Rule 21 Non-Export	GFID8129	In-Service	Photovoltaic ()/Gas Turbine ()	1.090	0.000	Napa 12 kV	Valley 'ABC' 115
9	Rule 21 Non-Export	GFID8401	In-Service	Photovoltaic (1)	1.000	0.000	Oliver 33 kV	Valley 'ABC' 115
10	Rule 21 Non-Export	GFID8402	In-Service	Photovoltaic (1)	1.000	0.000	Trumble 12 kV	Valley 'ABC' 115
11	Rule 21 Non-Export	GFID10131	In-Service	Energy Storage (0.018)	0.018	0.000	Plummer 12 kV	Valley 'ABC' 115
12	Rule 21 Non-Export	GFID10161	In-Service	Energy Storage (0.054)	0.054	0.000	Playhouse 12 kV	Valley 'ABC' 115
13	Rule 21 Non-Export	GFID10202	Construction	Energy Storage (0.09)	0.090	0.000	Cambridge 12 kV	Valley 'ABC' 115
14	Rule 21 Non-Export	GFID10231	Construction	Energy Storage (0.12)	0.120	0.000	Aguanga 12 kV	Valley 'ABC' 115
15	Rule 21 Non-Export	GFID10234	Construction	Energy Storage (0.25)	0.250	0.000	Tudor 12 kV	Valley 'ABC' 115
16	Rule 21 Non-Export	GFID10235	Construction	Energy Storage (0.25)	0.250	0.000	Pachea 12 kV	Valley 'ABC' 115
17	Rule 21 Non-Export	GFID10203	Construction	Energy Storage (0.06)	0.060	0.000	Pachea 12 kV	Valley 'ABC' 115
18	Rule 21 Non-Export	GFID10270	Construction	Energy Storage (0.325)	0.325	0.000	Bazooka 12 kV	Valley 'ABC' 115
19	Rule 21 Export	GFID1225	In-Service	Microturbine (1.1)	1.100	1.100	Ginger 12 kV	Valley 'ABC' 115
20	WDAT	WDT786	In-Service	Photovoltaic (20)	20.000	20.000	Resort 33 kV	Valley 'ABC' 115
21	Rule 21 Export	GFID5637	In-Service	Photovoltaic (1.25)	1.250	1.250	Aviator 12 kV	Valley 'ABC' 115
22	Rule 21 Export	GFID5656	Construction	Photovoltaic (1.5)	1.500	1.500	Bonneville 12 kV	Valley 'ABC' 115
23	Rule 21 Export	GFID5657	Construction	Photovoltaic (1.5)	1.500	1.500	Bonneville 12 kV	Valley 'ABC' 115
24	WDAT	WDT462ISP	In-Service	Photovoltaic (8)	8.000	8.000	Chaney 12 kV	Valley 'ABC' 115
25	WDAT	WDT1051FT	In-Service	Photovoltaic (1.48)	1.480	1.480	Plummer 12 kV	Valley 'ABC' 115
26	Rule 21 Export	GFID8212	In-Service	Photovoltaic (0.985)	0.985	0.985	Massacre 12 kV	Valley 'ABC' 115
27	Rule 21 Export	GFID8218	In-Service (Conditional PTO)	Photovoltaic (0.976)	0.976	0.976	Plummer 12 kV	Valley 'ABC' 115
28	Rule 21 Export	GFID8218EXP	Construction	Photovoltaic (1.5)	1.500	1.500	Plummer 12 kV	Valley 'ABC' 115
29	Rule 21 Export	GFID8523	In-Service	Photovoltaic (0.366)	0.366	0.366	Girard 12 kV	Valley 'ABC' 115
30	Rule 21 Export	GFID8640	Construction	Photovoltaic (4.2)	4.080	4.080	Easter 12 kV	Valley 'ABC' 115
31	WDAT	WDT1559	QC 11, Study Phases Complete	Energy Storage (156.8)	150.000	150.000	Valley 'ABC' 115 kV Bus	Valley 'ABC' 115

* "Max Facility Export (MW)" is zero for those interconnections that are connected under the "Rule 21 Non-Export" tariff.

Attachment in response to CPUC Supplemental Data Request Set-005, Question DG-MISC-49 in A.09-09-022 Proceeding
Data current as of SCE's 2020 DDOR Submittal

										Deficiency (MW, MVAR or VPU)						Deficiency %												
GNA ID	DDOR ID	DDOR Project ID	Substation/Subtransmission line	Circuit	Distribution Service Required	Project Description	Project Description (Additional Information)	Type of Equipment To Be Installed	Operating Date	2020[A]	2021[A]	2022[A]	2023[A]	2024[A]	Units	2020[B]	2021[B]	2022[B]	2023[B]	2024[B]	DER Eligible Service	LNBA Values	Residential Customer	Commercial Customer	Industrial Customer	Agricultural Customer	Other Customer	Notes
GNA_2020_1	DDOR_2020_D237	DDOR_2020_977282	Alessandro 115/12 (D)	Benton	Capacity (UCT)	Underground Cable Temperature Mitigation	Replace Aluminum Cable with Copper Cable	Primary Feeder - Cable	6/1/2020	0.65	0.52	0.39	0.32	0.73	MW	6.23%	4.99%	3.74%	3.07%	7.15%	NO	5,326.36 $/MW-year	2121	227	0	0	162	
	DDOR_2020_D238	DDOR_2020_977282	Alessandro 115/12 (D)	Reagan	Capacity (UCT)	Underground Cable Temperature Mitigation	Replace Aluminum Cable with Copper Cable	Primary Feeder - Cable	6/1/2020	0.00	0.00	0.00	0.00	0.00	MW	0.00%	0.00%	0.00%	0.00%	0.00%	NO	5,326.36 $/MW-year	1218	113	1	0	111	
GNA_2020_24	DDOR_2020_D143	DDOR_2020_7290	Bunker 115/12 (D)	Corporal	Capacity (UCT)	Underground Cable Temperature Mitigation, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	4/30/2020	4.97	4.97	3.30	1.58	1.80	MW	65.39%	66.27%	35.33%	13.98%	15.93%	NO	23,012.02 $/MW-year	1463	45	0	0	65	
GNA_2020_25	DDOR_2020_D144	DDOR_2020_7290	Bunker 115/12 (D)	Harrier	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	4/30/2020	0.63	0.58	0.69	0.93	1.15	MW	5.29%	4.87%	5.80%	7.82%	9.66%	NO	23,012.02 $/MW-year	1558	36	0	0	126	
GNA_2020_26	DDOR_2020_D145	DDOR_2020_7290	Bunker 115/12 (D)	Helicopter	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	4/30/2020	0.22	0.13	0.06	0.00	0.00	MW	1.85%	1.09%	0.50%	0.00%	0.00%	NO	23,012.02 $/MW-year	1541	25	0	0	106	
	DDOR_2020_DV9	DDOR_2020_2020 DVAR Plan_11	Bunker 115/12 (D)	Carbine	Reactive Power	Project to Address Reactive Power Concern, New Capacitor Installation	(1) New Capacitor On Pole Line (Overhead)	Primary Feeder - Capacitor	12/31/2020	0.00	0.00	0.00	0.00	0.00	MVAR	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MVAR-year	636	205	2	0	134	
	DDOR_2020_DV10	DDOR_2020_2020 DVAR Plan_12	Bunker 115/12 (D)	Harrier	Reactive Power	Project to Address Reactive Power Concern, New Capacitor Installation	(1) New Capacitor On Pole Line (Overhead)	Primary Feeder - Capacitor	12/31/2020	0.00	0.00	0.00	0.00	0.00	MVAR	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MVAR-year	1558	36	0	0	126	
	DDOR_2020_DV11	DDOR_2020_2020 DVAR Plan_13	Bunker 115/12 (D)	Helicopter	Reactive Power	Project to Address Reactive Power Concern, New Capacitor Installation	(1) New Capacitor On Pole Line (Overhead)	Primary Feeder - Capacitor	12/31/2020	0.00	0.00	0.00	0.00	0.00	MVAR	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MVAR-year	1541	25	0	0	106	
GNA_2020_28	DDOR_2020_D138	DDOR_2020_6347_977275	Cajalco 115/12 (D)	Pinewood	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	6/1/2020	0.00	1.07	2.46	2.43	2.67	MW	[redacted]					NO	57,122.45 $/MW-year	1395	44	0	0	141	
GNA_2020_29	DDOR_2020_D139	DDOR_2020_6347_977275	Cajalco 115/12 (D)	Plummer	Capacity (UCT)	Underground Cable Temperature Mitigation, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	6/1/2020	4.65	2.93	2.89	2.97	3.52	MW	45.41%	28.01%	27.79%	28.50%	34.61%	NO	57,122.45 $/MW-year	621	492	3	0	219	
GNA_2020_97	DDOR_2020_DV109	DDOR_2020_2021 DVAR Plan_11	Gavilan 33/12 (D)	Blackfoot	Reactive Power	Project to Address Reactive Power Concern, New Capacitor Installation	(1) New Capacitor On Pole Line (Overhead)	Primary Feeder - Capacitor	12/31/2021	0.84	0.78	0.71	0.71	0.59	MVAR	[redacted]					NO	4,036.11 $/MVAR-year	1036	66	4	0	90	
	DDOR_2020_D155	DDOR_2020_7973_977270	Mayberry 115/12 (D)	Charlton	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	6/1/2021	0.00	0.00	0.00	0.00	0.00	MW	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MW-year	1946	71	0	0	139	
	DDOR_2020_D156	DDOR_2020_7973_977270	Mayberry 115/12 (D)	Dartmouth	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	6/1/2021	0.00	0.00	0.00	0.00	0.00	MW	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MW-year	1110	61	0	0	156	
	DDOR_2020_D157	DDOR_2020_7973_977270	Mayberry 115/12 (D)	Hemacinto	Capacity	Increase Circuit Capacity, New Circuit	Install (1) New 12 kV Circuit	Primary Feeder - New Distribution Line	6/1/2021	0.00	0.00	0.00	0.00	0.00	MW	0.00%	0.00%	0.00%	0.00%	0.00%	NO	0.00 $/MW-year	1675	57	0	0	75	
GNA_2020_148	DDOR_2020_D236	DDOR_2020_977279	Nelson 115/33 (D)	Resort	Reliability, Capacity	Circuit Outage Contingency Mitigation, Increase Circuit Capacity	Increase Conductor Size	Primary Feeder - Overhead Conductor	12/31/2020	7.00	7.00	7.00	7.00	7.00	MW	[redacted]					NO	85,796.21 $/MW-year	0	3	0	0	6	
GNA_2020_233	DDOR_2020_DV90	DDOR_2020_2020 DVAR Plan_84	Stetson 115/12 (D)	Corsair	Voltage	Project to Address Voltage Concern, New Capacitor Installation	(1) New Capacitor On Pole Line (Overhead)	Primary Feeder - Capacitor	12/31/2020	0.93	0.93	0.94	0.94	0.94	Vpu	93.33%	93.33%	93.83%	93.83%	94.33%	NO	177,414.31 $/Vpu-year	1556	97	1	4	221	

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DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 5

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 8/10/2020

Question DG-MISC-50:
Please clearly define the difference between DER growth forecast data at the busbar substation level and DER growth forecast data at the circuit level.

Response to Question DG-MISC-50:

A discussion of SCE's methodology for disaggregating and then reaggregating the CEC forecast is provided in SCE's 2019 Grid Needs Assessment (GNA) Report.[1] The impact of both load and DER growth on a distribution circuit is dependent upon the anticipated impact of the load or DER (using an 8,760 load shape) and the anticipated peak time of both the load and of the DER. After developing the forecast, and taking into consideration the load and DER load shape and growth rate at the distribution circuit level, the growth is then aggregated back up through the system (e.g., distribution substation level and then transmission substation level) and considers a coincidence factor between parent circuitry (e.g., substation) and child circuity (e.g., distribution circuit). This process occurs for all distribution circuit facilities across SCE's service territory including the Electrical Needs Area of the Alberhill System Project. Depending on the particular characteristics of each distribution circuit, its composition and profile of load and DERs, and the time of its peak, the sum of the non-coincident loading values for each distribution circuit do not necessarily reflect the loading values forecast at the substation busbar levels. However, a coincidence factor (parent-to-child relationship) is applied when doing substation busbar analyses and ensures the broader system-wide DER forecast is consistent with that developed from the CEC's forecasts.

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[1] http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F8F550647FB95BBE8825845F0063A27F/$FILE/R1408013-SCE%20Amended%202019%20GNA%20and%202019%20DDOR%20Reports%20(Public).pdf

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 8/10/2020

Question DG-MISC-51:
In SCE's analysis of the Alberhill project a Benefit/Cost analysis was performed wherein benefits were estimated by examining certain contingency events, their probabilities and associated customer financial impacts. Has such analysis been performed in support of SCE's statement that the interim battery project for near-term capacity needs is not cost justified? If so, please provide the analysis and if not please comment on the need to perform such analysis.

Response to Question DG-MISC-51:

SCE has stated that an interim battery project is not practical for reducing the reliance on the Valley Substation spare transformer as overload mitigation in the Valley South System (see attached document titled "A.09-09-022 CPUC-Supplemental Data Request-005 Question DG-MISC-51.pdf", which is SCE's revised response to A.09-09-022 CPUC-Supplemental Data Request – 001 Question DG-MISC-12). This statement was based on several factors, including costs relative to level of risk reduction, project implementation schedule relative to implementation of a long-term solution, and the ability of a BESS to meet project objectives. SCE did not conduct a full cost-benefit analysis of the BESS considered in the interim battery project evaluation (50 MW / 100 MWh) because it was not deemed to be necessary based on the clear results of the analysis that was done. However, the "Centralized BESS in Valley South" alternative in the Benefit/Cost analysis already analyzes the minimum required BESS that would meet N-0 capacity needs for the next five years (71 MW / 216 MWh per Table C-16 of SCE's Planning Study).[1] As SCE has noted in the planning study, the "Centralized BESS in Valley South" alternative does not include system tie-lines and was studied in order to compare system performance of other BESS alternatives that did include system tie-lines. A 50 MW / 100 MWh BESS does not meet the minimum N-0 capacity needs of the Valley South System through 5 years, does not provide system tie-lines or similar benefits that are offered by system tie-lines, and does not significantly reduce the use of the spare transformer as overload mitigation. An analysis of a 50 MW / 100 MWh BESS similar to that conducted in the Benefit/Cost analysis would show minimal benefits to SCE customers, since this size BESS cannot meet the minimum N-0 capacity needs through even five years and offers no flexibility for N-1

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[1] https://www.cpuc.ca.gov/Environment/info/ene/alberhill/Docs/A.09-09-022%20CPUC-JWS-4%20Q.01c%20Attachment%201%20of%201_A.09-09-022%20ED-Alberhill-SCE-JWS-4%20Q.01c.pdf

contingencies. Furthermore, relying on a relatively small-scale BESS estimated to cost $30M for capacity deferral in a system as large as the Valley South System is counter to prudent system planning. Year-over-year load volatility in the Valley South System has been shown to be as high as 50 MVA (see Section 9.2 of SCE's Planning Study), which demonstrates why the sufficient capacity margin that is offered by conventional system upgrades is beneficial for systems of this size. Incremental capacity projects such as BESS installations, that attempt to zero-in on (and track with near perfection) future load demands based on linear load forecasts, offer no flexibility should actual load demands exceed the forecast. Linear load forecasts rarely precisely represent actual projected loading values for any given year, rather they interpolate values expected to occur but which commonly oscillate about the linear trend (both above and below) and are intended to be directionally correct and to represent the appropriate slope over time. BESS installations are much more appropriate for addressing distribution level capacity issues where the volatility variances are not as extreme as it is for an area like the Valley South System that serves 600 square miles, over 1,000 MVA of load, and approximately 500,000 people.

INTRODUCTION

Southern California Edison's (SCE's) Valley South System currently serves over 187,000 metered customers, representing over 500,000 individuals and covering a service territory of approximately 600 square miles in southwestern Riverside County. The Valley South System is served by SCE's Valley Substation, which is unique within SCE's electric system in that it is the only substation that interfaces with the California Independent System Operator (CAISO)-controlled bulk electric system at 500/115 kilo-volts (kV) and then directly serves 115/12 kV distribution substation loads. The Valley Substation has been constructed to its ultimate load-serving design capacity of four 560 mega-volt amperes (MVA) 500/115 kV load-serving transformers totaling 2,240 MVA. Two transformers (or 1,120 MVA in total capacity) serve each of the Valley North and Valley South Systems.

The Valley South System has demonstrated peak loading in recent years that result in a 99.9% utilization.[1] Additionally, the Valley South System is the only subtransmission system within SCE's entire service territory that operates with zero system tie-lines to other systems. This lack of system tie-lines results in an isolated system which negatively impacts reliability and resiliency due to the inability to transfer load during both typically planned-for system contingency events (unplanned outages) and more extreme high-impact, low-probability events.[2] This lack of capacity margin and lack of system tie-lines is currently mitigated by aligning the Valley Substation spare transformer to the Valley South System during times of peak demand. The use of this mitigation measure is a temporary and short-term solution for addressing the transformer capacity needs of the Valley South System while awaiting approval to construct a project to comprehensively address the long-term capacity, reliability and resiliency needs of the Valley South System.

SCE has proposed the Alberhill System Project (ASP) as a comprehensive solution to address both the transformer capacity shortfall (expected to occur in 2022 when the system peak load is projected to exceed the ultimate system design capacity of 1,120 MVA), and the longstanding reliability and resiliency concerns (resulting from the system's current lack of system tie-lines) of the Valley South System. As part of the licensing proceeding for the ASP project, SCE submitted a Planning Study to the California Public Utilities Commission (CPUC) Energy Division (ED). The Planning Study provides a business case analysis to evaluate the performance and cost effectiveness of the ASP in addressing these project objectives. In light of the temporary mitigation measure described above and the expectation that ASP or another project would not be able to be implemented for several years (due to the required time to obtain a licensing decision and then construction), the ED has requested SCE to assess whether or not an interim project solution is needed to eliminate or otherwise reduce the use of the current mitigation and how it might be implemented.

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[1] The 2018 adjusted peak demand which includes weather adjustments to reflect expected loads during 1-in-5 year heat storm conditions, was 99.9% of the Valley South System's ultimate system design capacity (1,120 MVA).
[2] High-impact, low-probability events are credible contingencies but are outside of SCE's planning criteria. They may be considered for awareness and for use in further differentiating the relative performance between alternatives but are not used to determine the required scope of projects.

The purpose of this document is to:

- Further describe the planning and operating criteria that drive the use of the mitigation;
- Describe and quantify the mitigation's past use;
- Characterize the associated on-going risk associated with use of the mitigation;
- Describe a prospective interim Battery Energy Storage System (BESS) project to minimize the required use of the current mitigation;
- Describe opportunities and challenges to use existing SCE BESS-related programs and other regulatory options to implement such a project in a sufficiently timely manner in order to be effective in the interim period before a long-term permanent solution can be implemented to meet all of the project objectives; and
- Provide a recommendation for whether or not such an interim project would be cost effective.

SCE SYSTEM PLANNING AND OPERATING CRITERIA DRIVING EXISTING MITIGATION

SCE's Valley Substation serves both the Valley North and Valley South Systems via two 500/115 kV load-serving transformers for each system. The Valley South System is served by the 1AA and 2AA transformers, and the Valley North System is served by the 3AA and 4AA transformers. The Valley Substation also has a fifth 500/115 kV transformer (5AA), which is a shared spare transformer that can be aligned to either the Valley North System or the Valley South System to replace one of the four load-serving transformers that may be out-of-service due to either a planned or unplanned outage. Current mitigation plans align the 5AA spare transformer to the Valley South System when load approaches and is expected to exceed 896 MVA, which is the short-term emergency loading limit (STELL) of a single transformer.[3] SCE would allow loading up to the total nameplate rating of the two transformers (1,120 MVA) if there were a means to shed load and then restore service following an unplanned transformer outage (typically performed via load transfer with system tie-lines), but this is currently not implemented because of the lack of system tie-lines in the Valley South System. Therefore, the use of the 5AA spare transformer as mitigation is implemented at 896 MVA to avoid potential overloading (beyond the maximum allowable STELL rating) of either of the remaining transformers should there be an unplanned outage of either the 1AA or 2AA transformers.

In contrast, the Valley North System has an automated load shedding scheme and four system tie-lines to the Vista System, and therefore can transfer load away from the system during an outage of the 3AA or 4AA transformer. This capability to automatically shed load and then restore service by transferring it to an adjacent system allows for loading of the two transformers up to the combined nameplate rating of 1,120 MVA while preventing the remaining transformer from being overloaded (beyond its STELL rating) should there be an unplanned outage of one

[3] The Valley Substation transformers each have a nameplate rating of 560 MVA (continuous rating), a long-term emergency loading limit (LTELL) of 672 MVA (24-hour rating), and a short- term emergency loading limit (STELL) of 896 MVA (1-hour rating). With two transformers are operating together, SCE system operators do not permit loading to exceed 896 MVA without an automated instantaneous loss of transformer load-shedding scheme in place as well as a means to restore service to the shed load.

transformer. The Valley South System has no such automatic load shedding scheme in place. The scheme itself could be implemented but has not been previously considered because of the inability to restore service by transferring substations via system tie-lines. As such, the 896 MVA STELL rating is the maximum allowed loading level for the two load-serving transformers of the Valley South System to ensure preventing an overload condition during an unplanned transformer outage.

Due to a series of events detailed in the Planning Study, the Valley South System evolved to its current configuration having no system tie-lines to other nearby electrical systems. This has resulted in the Valley South System violating SCE's Subtransmission Planning Criteria and Guidelines, specifically the following clauses:

Table 1 – Subtransmission Guidelines Related to Valley South

Section	Guideline	Relevance to Valley South
2.3.2.1.B	Contingency Outages: Adequate transformer capacity and load rolling facilities shall be provided to prevent damage to equipment and to limit customer outages to Brief Interruptions…	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.
2.3.2.4	To avoid Protracted Interruption of Load, tie lines with normally open supervisory controlled circuit breakers will be provided to restore service to customers that have been dropped automatically to meet short-term Likely Contingency loading limits, and to reduce A-Bank load to the long-term Likely Contingency loading level.	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.

The Valley South System requires a comprehensive long-term solution to address forecasted transformation capacity shortfall and the lack of system tie-lines. Until a suitable solution can be constructed, the mitigation scheme is expected to remain in place to prevent a potential overload of the Valley South System transformers during periods of high electrical demand.

PAST USE OF MITIGATION

The mitigation plan was first used in 2017 and again in 2018 for a total of 14 distinct days in which load exceeded, or was projected to exceed, 896 MVA.[4] On seven of the 14 days, the load actually exceeded 896 MVA. The plan was not required to be used in 2019 due to a cooler than typical summer for this area. In 2017 and 2018 the duration of the individual time periods where the load exceeded 896 MVA ranged from approximately one to six hours. When the 5AA transformer is in-service as mitigation, it is not able to serve its intended function as a shared spare transformer immediately available to either the Valley North or Valley South Systems should there be an unplanned outage of one of the four load-serving AA-bank transformers.

There have been two incidents in which the spare transformer was required for its primary function coincident with a potential overload mitigation need in the Valley South System. In July 2018, the spare transformer was aligned to the Valley North System to address an unplanned transformer outage of one of the 3AA/4AA transformers. At the same time, load in Valley South approached 896 MVA, resulting in an acceleration of the repair activities for the Valley North System transformer, and a subsequent re-alignment of the spare transformer to the Valley South System for potential overload mitigation. In August 2018, while the spare transformer was aligned to the Valley South System operators discovered an oil leak on the spare transformer. Operators took the spare transformer out-of-service, repaired the cause of the minor leak and placed the transformer back in-service later that day.

ASSESSMENT OF RISK ASSOCIATED WITH CONTINUED USE OF MITIGATION

This mitigation plan is temporary and is considered acceptable only because there is a long-term comprehensive solution planned to address the loading and configuration issues in the Valley South System (e.g., the proposed Alberhill System Project). However, until a comprehensive solution is constructed and serving customers, the risk remains, in that the spare transformer is not capable of performing its primary function as a shared spare and serve as overload mitigation at the same time.

Normal System Conditions

Under normal system conditions (all facilities in-service), the Valley North and Valley South Systems are both capable of serving load demands through 2025 (with the use of the spare transformer as overload mitigation for the Valley South System). The forecast 1-in-5 year heat storm peak demand in 2025 for the Valley North and Valley South Systems is 823 MVA and

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[4] Note that each day does not necessarily indicate that the spare transformer was required to be used (i.e., load may not have exceeded 896 MVA on all days in which the spare was placed into service). Rather, system operators may place the spare in service as load approaches 896 MVA acknowledging that load changes can occur quickly and that on peak days there are commonly many other concurrent system issues being addressed. Additionally the transformer may not be taken immediately out-of-service when the threshold is no longer exceeded because in some cases, system operators may elect to keep the spare in service during multi-day heat storms to reduce the operational burden and number of circuit breaker operations associated with placing the spare in and out-of-service each day.

1,159 MVA,[5] respectively. In the case of the Valley South System, although the 1,159 MVA demand exceeds the nameplate rating of two transformers (1,120 MVA), with the spare transformer in-service as overload mitigation (in-service as load approaches 896 MVA and remaining in-service even as load exceeds 1,120 MVA) there would be three transformers serving the Valley South System.[6] This would provide a normal condition nameplate capacity of 1,680 MVA (3 x 560 MVA) which is in excess of the 1,159 MVA peak load value. In the case of the Valley North System, the 823 MVA projected peak demand is well within the normal condition nameplate rating of 1,120 MVA for two transformers (1,120 MVA).

Abnormal System Conditions
With the spare transformer aligned to the Valley South System as overload mitigation and under abnormal system conditions (N-1 transformer outage of one of the three transformers aligned to the Valley South System), there would still be two in-service transformers to serve load[7] and there would be no overload. The transformers would be capable of serving up to 1,792 MVA (2 x 896 MVA STELL rating) for one hour and then 1,344 MVA (2 x 672 MVA LTELL rating) for up to 24 hours while the situation was assessed and remedied. In this scenario, load would remain within the prescribed operating limits. The mitigation strategy would perform as intended under these abnormal system conditions until a comprehensive solution is constructed. It would prevent the instantaneous STELL overload of one remaining in-service transformer during an unplanned outage of the second transformer *and* allow load to be served in excess of the total 1,120 MVA nameplate rating of the two load-serving transformers during short periods of peak demand by applying the LTELL rating.

The following operator actions would be required if the spare transformer were aligned to the Valley South System as overload mitigation and an N-1 transformer outage of one of the two transformers aligned to the Valley North System were to occur. If the Valley North System load was above 896 MVA, the automatic shedding scheme would be triggered to bring loading below operating limits and then load would be transferred to the Vista System via system tie-lines. This would result in only a brief interruption in service. If load was below 896 MVA, the automatic load shedding scheme would not be triggered (avoiding the brief interruption of service) and system operators would assess which of the following two actions should be taken.

The first option is removing the spare transformer from the Valley South System and aligning it to the Valley North System, allowing for two transformers to again serve the Valley North System while leaving two transformers to serve the Valley South System. A second option is leaving the spare transformer aligned with the Valley South System and continuing to provide

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[5] Based on the Spatial Forecast APV SCE's Effective PV Scenario documented in Table 2-10 and Table 2-11 of Quanta Technology's report, "Deliverable 3: Benefit Cost Analysis of Alternatives".
[6] This configuration (three transformers operating together) increases the amount of energy (known as short-circuit duty) that would pass through the transformers should an electrical fault occur. Presently, this amount of energy does not exceed the ratings of select electrical equipment in the Valley South System; however, SCE notes that over time as additional resources come on-line (which contribute additional short-circuit duty), it may begin to exceed equipment ratings and would have to be addressed.
[7] If an automated load-shedding scheme is implemented in the Valley South System, which protects the system from transformer overloads due to a second transformer outage (N-1-1), the full capacity of the two remaining in-service transformers (nameplate and emergency ratings) could be credited to serve the system during N-1 contingencies.

service to the Valley North System with a single transformer. The two options have different risks and consequences that must be considered by system operators in the context of the specific heat storm, loading conditions, and anticipated transformer outage restoration period.

Should the spare transformer be shifted to serve the Valley North System, the Valley South System would again have only two transformers serving it. The 2025 projected peak load of the Valley South System is 1,159 MVA and while this value is below the STELL N-1 operating limits of the two in-service transformers (1,792 MVA) serving the Valley South System, it is above the STELL operating limit of a single in-service transformer (896 MVA) should there be a subsequent unplanned transformer outage. This would require the implementation of an automated load shedding scheme for the Valley South System (triggered to interrupt service to approximately 263 MVA of load (1,159 – 896 = 263 MVA)) in the event of a second transformer outage.

Alternatively, the spare transformer may be left in-service in the Valley South System. In this case the Valley North System would be served by a single transformer during this period, risking loss of service to the entire Valley North System should there be a subsequent outage to the remaining in-service transformer. If this subsequent loss of service to Valley North were to occur, operators would then realign the spare transformer from the Valley South System to the Valley North System to restore service to the Valley North System. This would leave two transformers remaining in the Valley South System, which is sufficient to serve load as described above. In this configuration, the Valley South System load shedding scheme described above would only be triggered in the event of a subsequent Valley South System transformer outage.

In summary, between now and 2025, in the context of assessing the risk of reliance on the spare transformer mitigation, there is one scenario within the Valley North and South Systems in which a significant amount of load could go unserved for greater than a momentary outage. This scenario would be in a case where two of the five combined (load-serving and spare) Valley North and Valley South transformers are simultaneously out-of-service (i.e., N-1-1 or N-2) and leave a single transformer to serve load in either system. This transformer outage scenario can be accommodated in the Valley North System with limited customer service interruption due to its current capacity margin and its tie-lines to an adjacent system. The occurrence of this level of contingency event is rare and not considered as planned-for contingencies when sponsoring new projects based on SCE's Subtransmission Planning Criteria and Guidelines. However, contingency events like this are considered by SCE's system operators in designing operational plans and also in system planning, as secondary resiliency attributes are useful in further differentiating various system alternatives designed to address primary project objectives.

POTENTIAL INTERIM BESS SOLUTION

SCE analyzed the effectiveness of using battery energy storage systems (BESS) to reduce reliance on the spare transformer during times of peak demand. Total spare transformer usage was evaluated for years 2020-2025, and various sizes of BESS installations were considered to determine how much spare transformer use could be reduced. The results of the study are summarized in Table 1 below.

Table 1. Reduction in Projected Spare Transformer Utilization for Various BESS Sizes

MW	MWh	Spare Transformer Utilization (Hours, 2020-2025)	Spare Transformer Utilization Reduction (Hours, 2020-2025)	Spare Transformer Utilization Reduction (%)
268	1520	167	433	72%
227	1178	183	417	69%
192	880	199	401	67%
168	670	213	387	64%
144	532	246	354	59%
120	430	288	312	52%
86	282	353	247	41%
61	167	406	194	32%
50	150	444	156	26%
50	100	**447**	153	**26%**
30	60	508	92	15%
0	0	600	0	0%

The BESS is assumed to go into service in 2022, at which point 167 hours of expected spare transformer utilization will have already accrued (this is why the reduction in spare transformer utilization is at most 72%). The results show that in order to mitigate the remainder of the expected spare transformer utilization (433 hours), a BESS of 268 MW / 1,520 MWh would be required. SCE did not perform a detailed cost estimate of a system of this particular size; thus, the cost of a similarly sized system (273 MW / 1666 MWh) is used as a surrogate, and this cost is greater than $500M.[8] Due to the surrogate project spreading out the cost of batteries over 30 years, the actual cost of a such a large project being installed in such a short amount of time is likely to be much higher than $500M.

The Planning Study conducted by SCE (which evaluated alternatives to the Alberhill Substation Project) determined that 50 MW / 100 MWh is the expected maximum size for BESS that can be installed at existing distribution substations in the Valley South System without significant substation modifications, and increased environmental impacts since these are previously disturbed sites. SCE previously performed a detailed cost estimate of a system of this size, and determined that the NPV cost of such a system is approximately $66M.[9]

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[8] This estimate is based on the Centralized BESS in Valley South alternative described in SCE's response to Item C (ED-Alberhill-SCE-JWS-4: Item C, or the Planning Study). This project was envisioned as a series of incremental BESS capacity additions that would be implemented over the course of 30 years, and was estimated as such. The figured reported in the Planning Study has been adjusted here to remove market participation cost offsets, and is presented on a net present value (NPV) basis. It is clear that the cost of a BESS of this magnitude is too large to be justified as a short term mitigation even if it were able to be implemented in a timely manner.

[9] This estimate was developed using the same methodology as the BESS components of the Valley South to Valley North and Distributed BESS in Valley South alternative of SCE's response to Item C (ED-Alberhill-SCE-JWS-4: Item C). However, the implementation date of the BESS is adjusted to 2022, and the estimate is presented here on a net present value basis (NPV) as opposed to a Present Value of Revenue Requirement (PVRR) basis.

In order to offset the cost, the 50 MW / 100 MWh BESS was considered as able to participate in CAISO real-time, day-ahead, and ancillary services markets. An analysis performed by Quanta Technology, under SCE's direction, found that providing a mix of frequency regulation ancillary services and participation in day-ahead markets through energy shifting/arbitrage would optimize the revenue for such a system, and that participation in these markets for the lifetime of a BESS without additional augmentation (assumed 10 years) would yield a NPV revenue of approximately $16M. The analysis assumes that participation in real-time and day-ahead markets is limited to non-summer months (October – May) until 2026, the year after the assumed 2025 in-servicing of the ASP, at which point the BESS is allowed to participate in energy markets year-round.

Additionally, the BESS could receive payments by offering its capacity for resource adequacy (RA), though the power output would have to be de-rated to 25 MW in order to meet the 4-hour duration requirement by the CPUC/CAISO. The CPUC-published 2018 RA Report contains weighted average, 85th percentile, and maximum prices paid for local RA in the LA basin. These values were used to estimate the additional revenue from payments for fulfilling local RA requirements for 8 months out of the year, at a power rating of 25 MW. A 3% escalation factor was used to account for inflation from year to year, and RA payments were assumed to be received 12 months out of the year starting in year 2026.

Table 2. Local RA Revenue, 25 MW, 8 months/year until 2026, then year-round

Local RA payments in the LA basin ($/kW-month)		NPV (thousands of $)
Weighted average	$3.66	$7,728
85th percentile	$4.25	$8,974
Max	$6.81	$14,379

Ultimately, considering the combination of potentially available market participation revenue of about $30M, a reasonably sized 50 MW / 100 MWh system would likely have a net cost to SCE ratepayers of $30M at a minimum (assuming market participation revenue would be maximized), and would reduce the use of the spare transformer in the Valley South System by only 26%. A 268 MW / 1,520 MWh system, to conceivably relieve all of the expected use of the spare transformer as capacity mitigation, is unreasonably large and costly considering the primary use-case time period, and is not considered a feasible option. Additionally, such a system would likely require a dedicated 115 kV substation and 115 kV source lines to accommodate that amount of capacity, and per GO131D would require a licensing and permitting proceeding for approval.

BESS PROJECT IMPLEMENTATION

In order to implement a BESS project, SCE requires a regulatory framework (program or process) through which to develop the project on its own, or to procure storage from a third-party. In the case where a BESS can be sited within an existing substation(s) and can interconnect at the 12 kV distribution level with limited additional environmental disturbance, an expedited project implementation could reasonably be expected. However, even in this case a BESS project would require a suitable regulatory framework to be implemented.

There are four existing programs that SCE currently uses to procure or develop energy storage:

- Energy Storage Integration Pilot (ESIP)
- Energy Storage Procurement and Investment Plan (ESP&IP)
- Reliability Utility Owned Energy Storage (RUOES)
- Distribution Investment Deferral Framework (DIDF)

The ESIP program is essentially closed to new procurement as energy storage projects procured under this program were already included as part of the 2021 General Rate Case proceedings. The ESP&IP program was set up to address AB2868, which allocated 166 MW of energy storage procurement to SCE. Since the general project size of ESP&IP is 2.5 MW / 4.5 MWh, a project of the magnitude in question is not a good fit for this program. The DIDF program most commonly considers DERs interconnected at the distribution level and is focused on projects that satisfy needs 4-5 years out, with corresponding implementation schedules.

Of these four programs, the RUOES program appears to be the best suited for a project of this size and this application. Unfortunately, the allocation for the RUOES program is complete and cannot accommodate additional energy storage procurement.

The timeline of such a project would be subject to the CAISO/SCE interconnection process, which typically takes a minimum of 2 years and can take as long as 5 years for complex projects. A potential way of expediting this process is to replace the usual queue cluster interconnection study with an independent study. However, performing an independent study would preclude the energy storage asset from participating in RA, thus increasing the total cost to SCE ratepayers by as much as $14M.

A final alternative is for SCE to propose a stand-alone project to the CPUC. The timeline for such a process is unclear and would not preclude any of the interconnection study and process requirements. Unless an expedited proceeding were undertaken, this would likely push project completion to some year beyond 2022, further diminishing the value of the project. However, this remains a suitable pathway to procurement so long as activities can be coordinated to optimize the timeline of the project.

RECOMMENDATION

SCE currently has in place an operating procedure that utilizes the Valley Substation spare transformer to mitigate potential overloads in the Valley South System during periods of peak electrical demand. Concurrently, peak electrical demand in the Valley South System is forecast to exceed the existing transformation capacity in 2022. Until a permanent solution is constructed to relieve the concentration of load in the Valley South System, such as the Alberhill System Project, the spare transformer overload mitigation procedure will be needed to maintain compliance with SCE planning and operating criteria and thereby ensure reliable service to customers.

The feasibility of an energy storage project to eliminate the need for the potential overload mitigation procedure was analyzed and such a project would not likely be constructed and placed in service any earlier than 2022. The size of a project that would eliminate the use of the spare transformer for the years 2022-2025 is too large to be implemented quickly and cost-effectively. The largest project identified that could be implemented within a reasonable time frame, i.e., by the year 2022, is on the order of 50 MW / 100 MWh. After accounting for potential revenue to offset the cost of such a project, it would cost SCE ratepayers approximately $30M over the expected 10-year life of the BESS. Also, the project is expected to only eliminate up to 26% of the potential hours the spare transformer would be needed.

SCE has concluded that developing a BESS or procuring energy storage to mitigate use of the spare transformer at Valley South is not a cost-effective solution in reducing the risk of service interruption to customers. Considering the low probability that the spare transformer would be needed to replace a main transformer while serving the Valley South System for potential overload mitigation, the cost of a system that would completely eliminate the risk is unreasonable (>$500M). Additionally, this risk would only be eliminated after the project is in service, which would, at best, be comparable to the current proposed schedule for a project like ASP. A reasonably sized system would still be a significant cost to SCE ratepayers, while eliminating only about a quarter of the risk of using the spare transformer to serve load for an additional few years. Note that, as discussed in the ASP Planning Study,[10] the use of the spare transformer to serve load is only one element of the overall unacceptable level of risk that exists in the Valley South System. SCE continues to recommend that SCE and the ED continue to focus attention on a permanent solution to address both the projected peak electrical demand and the lack of system tie-lines that threaten the reliability and resiliency in the Valley South System.

[10] See A.09-09-022 ED-Alberhill-SCE-JWS-2 Q.01c Response

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 8/10/2020

Question DG-MISC-52:
Please explicitly cite and share the CEC Forecast data that was given to Quanta for their study.

Response to Question DG-MISC-52:

Quanta's study is based on the CEC forecast found at the link provided below. The link includes a final report and three Microsoft Excel spreadsheets with scenario model results. The "PATHWAYS model: Electricity sector results" spreadsheet contains the "CEC 2050 - High Electrification Scenario" forecast data which was used as a basis for the Spatial Effective PV load forecast. Section 2.3 of Quanta Technology's "Benefit Cost Analysis of Alternatives Report" describes how the spreadsheet data was used to generate the Spatial Effective PV load forecast.

https://www.ethree.com/projects/deep-decarbonization-california-cec/

Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC-Supplemental Data Request-005

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 7/23/2020

Response Date: 8/10/2020

Question DG-MISC-53:
Please provide load allocation for Valley North substations similar to that provided for Valley South.

Response to Question DG-MISC-53:

Please see the attached file titled "A0909022-ED-Supplemental Data Request 005-Question DG-MISC-53.xlsx" which provides the data requested.

A0909022-ED-Supplemental Data Request 005-Question DG-MISC-53

				Non-coincident Peak Load - Normal Weather or 1-in-2 (MVA)									
				Projected									
System	Substation	Sub Type	Voltage	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Alessandro	SCE Distribution	115/12 kV	113.6	112.1	112.9	114.6	116.3	116.7	116.3	117.0	118.0	119.0
Valley North	Alessandro	SCE Distribution	115/33 kV	44.6	44.9	47.9	49.5	52.4	54.9	55.6	56.2	57.1	57.6
Valley North	Bunker	SCE Distribution	115/12 kV	82.3	82.3	81.8	81.6	80.6	79.6	78.7	78.0	76.8	76.1
Valley North	Cajalco	SCE Distribution	115/12 kV	61.4	63.8	63.3	62.5	62.9	63.0	64.6	64.6	64.7	64.6
Valley North	Karma	Customer	115/115 kV	27.8	23.1	25.3	25.5	26.0	27.0	30.0	33.0	36.0	36.0
Valley North	Lakeview	SCE Distribution	115/12 kV	19.7	19.5	19.4	20.0	20.9	21.4	22.0	22.5	22.9	23.5
Valley North	Mayberry	SCE Distribution	115/12 kV	98.0	97.1	96.9	98.3	97.7	97.0	94.2	93.6	93.1	92.6
Valley North	Moreno	SCE Distribution	115/12 kV	50.0	49.3	49.1	49.1	49.8	49.2	49.5	49.8	50.2	50.6
Valley North	Moval	Customer	115/115 kV	16.8	18.8	21.5	23.7	24.2	24.2	26.0	28.0	28.0	28.0
Valley North	MWD	Customer	115/115 kV	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Valley North	Nelson	SCE Distribution	115/12 kV	83.1	82.0	79.7	79.5	79.5	78.9	78.5	78.1	77.9	77.6
Valley North	Nelson	SCE Distribution	115/33 kV	52.0	52.4	56.0	56.3	56.7	56.8	56.7	56.7	56.8	56.7
Valley North	Stetson	SCE Distribution	115/12 kV	107.5	106.5	106.9	106.2	106.4	106.1	108.1	108.1	108.0	107.9
Valley North	Valley Jr	SCE Distribution	115/12 kV	70.3	75.0	79.6	79.9	80.5	80.6	80.8	80.8	81.0	81.1

A0909022-ED-Supplemental Data Request 005-Question DG-MISC-53

				Non-coincident Peak Load - Normal Weather or 1-in-10 (MVA)									
				Projected									
System	Substation	Sub Type	Voltage	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Alessandro	SCE Distribution	115/12 kV	123.6	121.9	122.8	124.7	126.5	126.9	126.5	127.3	128.3	129.4
Valley North	Alessandro	SCE Distribution	115/33 kV	47.8	48.1	51.4	53.1	56.2	58.9	59.6	60.3	61.2	61.8
Valley North	Bunker	SCE Distribution	115/12 kV	90.2	90.2	89.7	89.5	88.4	87.3	86.3	85.5	84.2	83.4
Valley North	Cajalco	SCE Distribution	115/12 kV	67.3	69.9	69.4	68.5	68.9	69.0	70.8	70.8	70.9	70.8
Valley North	Karma	Customer	115/115 kV	30.4	25.3	27.7	27.9	28.5	29.6	32.8	36.1	39.4	39.4
Valley North	Lakeview	SCE Distribution	115/12 kV	21.6	21.4	21.3	21.9	22.9	23.5	24.1	24.7	25.1	25.8
Valley North	Mayberry	SCE Distribution	115/12 kV	107.3	106.4	106.1	107.7	107.0	106.3	103.2	102.5	102.0	101.4
Valley North	Moreno	SCE Distribution	115/12 kV	54.8	54.1	53.8	53.8	54.6	53.9	54.3	54.6	55.0	55.5
Valley North	Moval	Customer	115/115 kV	18.4	20.6	23.5	25.9	26.5	26.5	28.5	30.7	30.7	30.7
Valley North	MWD	Customer	115/115 kV	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Valley North	Nelson	SCE Distribution	115/12 kV	91.0	89.8	87.3	87.1	87.1	86.4	86.0	85.6	85.3	85.0
Valley North	Nelson	SCE Distribution	115/33 kV	56.9	57.3	61.3	61.6	62.0	62.2	62.0	62.0	62.2	62.0
Valley North	Stetson	SCE Distribution	115/12 kV	116.5	115.4	115.9	115.1	115.3	115.0	117.2	117.2	117.1	116.9
Valley North	Valley Jr	SCE Distribution	115/12 kV	77.0	82.2	87.2	87.6	88.2	88.3	88.6	88.6	88.8	88.9