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

DATA REQUEST SET CPUC-Supplemental Data Request-016

To: CPUC
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Received Date: 12/23/2022

Response Date: 1/20/2023

Question DG-MISC-6:
ResourceAreas/Topic: May 2022 SCE/CPUC Technical Forum Sessions
SCE Data Submittal Item/Page:

The May 2022 SCE/CPUC technical forum sessions provided assumptions and methodology for treatment of the battery in the SCE analysis and the operating thresholds for the Valley South transformers. The sessions also examined N-1 loss of transformer under different durations shorter than the 2-week Flex 2-2 event. Provide a copy of the following May 2022 SCE/CPUC technical forum presentations and supporting documentation:
- May 4, 2022 presentation - Alberhill System Project: Benefit-Cost Analysis Workshop
- May 12, 2022 presentation (continuation of May 4, 2022 meeting) - Alberhill System Project: Benefit-Cost Analysis Workshop (supplemental slides to the presentation provided for the May 4, 2022 meeting). VS-VN + BESS Alternative Methodology and Assumptions submitted to the CPUC Energy Division on May 10, 2022 as supporting documentation to the May 12, 2022 presentation.

Response to Question DG-MISC-6:

Please find the requested presentations attached to this data request response.

Alberhill System Project: Benefit-Cost Analysis Workshop

Energy Division

May 4, 2022

Agenda

- Review Overall Analysis Framework and SCE Direction to Quanta for Implementation
- Discussion of Reliability Metrics, Industry Definitions and Applicability
- Discussion of Reliability Metrics used in Cost-benefit analysis
- Differences Between LAR and EENS
- Breakdown of Reliability Metrics, Events, Durations and Probabilities
- Treatment of Batteries in Cost-Benefit Framework
- Remote Spare Transformer In-Servicing
- 10-year vs 30-year horizon
- Pending Questions

Analysis Framework

- Purpose of analysis was to evaluate the overall relative performance and cost-effectiveness of ASP and alternatives in meeting the Project Objectives.
  - Item f: "forecasted impact of the proposed project on service reliability performance"
  - Item g: "cost/benefit analysis of several alternatives….including evaluation of energy storage, distributed energy resources…"
- SCE sought to develop a common set of metrics and application framework for both items

Analysis Framework (cont.)

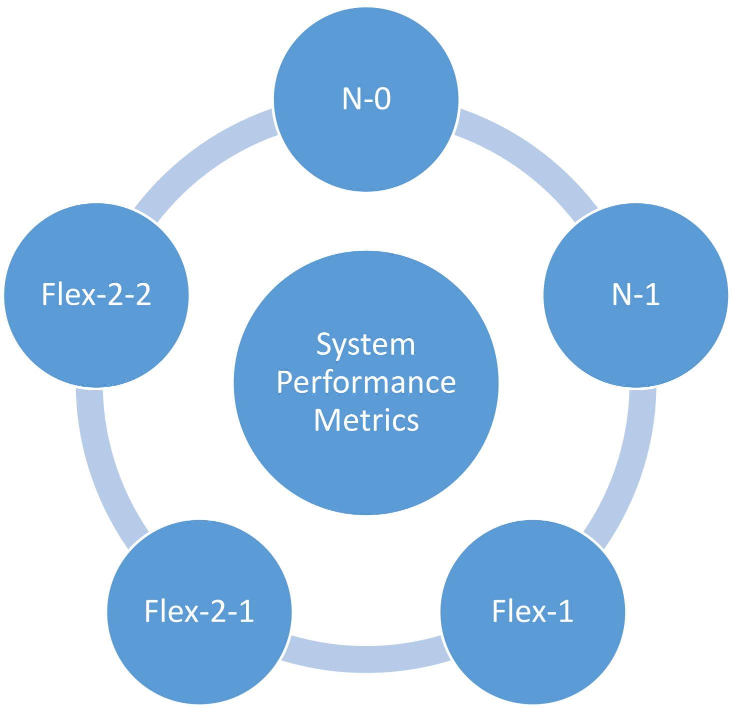
- Metrics
  - Forward-looking and reflect benefits and impact to customers
  - Able to be monetized
  - Sufficient granularity to reflect performance over 8760 hours/year to be consistent with move towards time-series based planning analysis
  - Reflect all project objectives in a transparent fashion (measure them independently where practical)
  - Consider both near-term and long-term performance in a transparent manner (10-year and 30-year forecast)
  - Contingency scenario assumptions based on standard industry and SCE planning criteria
    - Both what contingencies to consider in raw performance metrics and in the assumed probability of occurrence for monetization
    - Data-driven where data are available (and reasonable assumptions otherwise) to provide for relative performance comparison
- Alternatives
  - Practical to implement as projects/programs
  - Include wires-based, DER-based, and hybrid solutions
  - Exclude previously dismissed alternatives and those that do not clearly meet basic project objectives (except for some that were of stakeholder interest (e.g., VS-VN based alternatives and Centralized BESS)
  - Seek to minimize initial scope/cost to allow for incremental future scope additions as needed

Related to question: "Show how Edison uses the BCA to compare project alternatives."

System Performance Metrics – Approach

- SCE compared improvements of the ASP and alternatives to the No Project scenario by analyzing system performance under various operating scenarios
- All metrics included in the cost-benefit analysis are representative of normal and contingency operating scenarios that:
  - Form the basis for SCE Subtransmission Planning Criteria and Guidelines **or**
  - Reflect high-impact, low-probability events that have occurred in SCE's system or industry
- Planning Criteria definition of contingency events for planning purposes:
  - Likely: Any one generating unit offline and,
    - Outage of a single subtransmission system component
    - Unscheduled outage of single generating unit
    - Simultaneous outage of two subtransmission circuits on the same pole and exposed to vehicular traffic when the circuits are the sole supply for a substation
  - Unlikely: Any one generating unit offline and,
    - Simultaneous outage of two subtransmission circuits
    - Overlapping outage of any two generators or one generator and one line

System Performance Metric



- The following metrics are used to evaluate system performance improvements of the ASP and alternatives
  - N-0: Normal conditions with no contingency
  - N-1: Single line contingency
  - Flex-1: Common pole, double line contingency
  - Flex-2-1: Valley Substation Contingency
  - Flex-2-2: Valley South Transformer Contingency
- Likely Contingency: N-0, N-1, Flex-1, Flex-2-2 (partial –see below)
- Unlikely Contingency: Flex-1, Flex-2-1, Flex-2-2
- SCE Planning Criteria promotes study of Unlikely Contingency scenarios to evaluate how projects can minimize problems and risks associated with these operating scenarios
  - No scope was added to ASP or alternatives to specifically address the loss of load due to Unlikely Contingencies.
- The Flex-2-2 metric is inclusive of the LAR for the transformer N-1 scenario due to the lack of system tie-lines which limits the system loading to 896 MVA even with spare in service.
  - Accruing LAR above 896 MVA for loss of two transformers (N-2) and crediting the spare is equivalent to losing one transformer and proactively protecting the remaining transformers (consistent with N-1 planning criteria)
  - Thus, Flex-2-2 metric has elements of both reliability (N-1) and resiliency (N-2)

Related to questions:

- *"Explain the reliability metrics.*
- *Explain why Flex-1 was selected as the comparison for reliability metrics."*

System Performance Metrics – Approach

- Results of power system analysis are expressed in terms of power (in MW) required to curtail thermal or voltage violations
- Cost/benefit analysis required performance metrics (i.e., power system analysis results) to be:
  - Monetizable - To support a cost/benefit analysis
  - Forward-Looking – To study risks under 10-year and 30-year load forecasts
  - Scenario-Specific – Such that historical outage rates or probabilities can be applied
  - Reflective of Outage Magnitude (power) and Duration (energy) – To support monetization (energy) and benefits offered by BESS, which have power and energy components

Related to question: "Show how Edison uses the BCA to compare project alternatives."

Metrics Overview – Load at Risk

Metric	Definition	Satisfy Cost-Benefit Criteria
Load at Risk (LAR)	Total load required to be curtailed during periods of time in which subtransmission operating criteria were not met i.e., the amount of load vulnerable in the system.	Y
Energy Not Served (ENS)	Same construct as LAR. No standard definition and interpretation.	Y
Energy Not Supplied(ENS)	Same construct as LAR. No standard definition and interpretation. National Grid UK definition is the volume of energy to customers (MWh) that is lost as a result of faults or failures on the network	Y

- The Load at Risk metrics measure the total MWh or average MWh of unserved energy during events in the system
- The Load at Risk metric assumes that contingencies are present in order to measure the total load at risk should the contingency occur (i.e., the metric is <u>not</u> probability-weighted)

Metrics Overview – Energy Not Served

Metric	Definition	Satisfy Cost-Benefit Criteria
Expected Energy Not Served (EENS)	LAR that is probability-weighted for specific events and scenarios, reflecting the actual expected unserved energy need for customers.	Y
Expected Unserved Energy (EUE)	Similar construct as EENS, summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours.	Y
Value at Risk (VaR)	A measure of the risk for a chosen probability. Similar to EENS.	Y
Conditional Value at Risk (CVaR)	Measures the expected (weighted average) outcome of tail-end events. Conditional Value at Risk (CVaRα), is the probability-weighted average value of the lowest surplus (capacity minus load) over the (100 – α) percentile of possible outcomes (where α typically ranges from 90 to 99).	N

- The Expected Energy Not Served metrics measure the probability-weighted amount of unserved energy during events in the system
- Outage rates or probability of event occurrence is incorporated into these metrics
- EUE may also be used as a Resource Adequacy metric

Metrics Overview – Resource Adequacy

Metric	Definition	Satisfy Cost-Benefit Criteria
Loss of Load Expectation (LOLE)	Expected number of days per time period (usually a year) for which the available generation capacity is insufficient to serve the demand at least once per day. LOLE counts the days having loss of load events, regardless of the number of consecutive or nonconsecutive loss of load hours in the day.	N
Loss of Load Hours (LOLH)	Expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity.	N
Loss of Load Probability (LOLP)	Probability that the load will exceed the available generation; it is often limited to the ability to meet annual, weekly peak load.	N

- These resource adequacy metrics reflect if the system has sufficient generation capacity and reserves to meet peak demand. The Valley South System is not constrained by generation capacity limitations.
- Not applicable to 8,760 hour time-series analysis
- They are not reflective of the transmission systems' ability to serve load under normal or contingency events
- Cannot be used to study duration-limited resources such as batteries

Reliability Metric - Summary

Historical SAIDI/SAIFI/CAIDI Metrics

- Most applicable to distribution system reliability and are not easily translated into sub-transmission networks.
  - These metrics would be calculated directly from LAR values, so they do not provide unique insight into the relative performance of system alternatives.
  - The use of SAIDI/SAIFI/CAIDI requires extrapolation of historic customer interruption on the distribution system to the sub-transmission system.
  - No evidence of forecasted SAIDI/SAIFI/CAIDI being used to compare alternatives at the sub-transmission level in national or international literature reviews.
  - IEEE Standard 1366 identifies metrics as "Electric **Distribution** Reliability Indices".

Resource Adequacy Based Metrics

- Traditional reliability metrics of LOLE (defined by NERC, FERC, ISOs, etc.) are applicable to generation system reliability and capacity planning.
  - LOLE is most commonly expressed in days/year
  - Only measures the number of mismatches between generation and load and does not characterize magnitude or duration.
  - Most applicable towards generation capacity expansion planning i.e., – CPUC Integrated Resource Planning (IRP) proceedings.
  - There is increasing interest in the industry to move towards EUE since it considers the magnitude of the loss of load events and changing generation mix.

Transmission System Reliability Metrics

- EENS is most applicable to Transmission System Reliability and is expressed in energy/year.
  - Monetizable because it is expressed in energy
  - Reflective of customer impacts

Related to question: " Is it standard planning practice to consider SAIDI/SAIFI/CAIDI or LOLE, ENS and EENS as a group? As a single metric, how does LAR capture the full scope of impact (e.g., customer count, hour count of vulnerability, etc.) when it normally requires three of more metrics to understand?"

Implementation of System Performance Metrics

Metric	Description	Duration Assumptions	Outage Probability Assumptions
N-0	Calculates EENS during normal system conditions	Time of overload	N/A
N-1	Calculates EENS with one line out of service	2.8 hours	3.4 Outages/100 Mile-Years
Flex-1	Calculates EENS with two lines out of service	3.0 hours	0.8 Outages/100 Mile-Years
Flex-2-1	Calculates EENS with no Valley South Transformers in service	2 weeks (expected restoration duration)	1-in-100 Year Event (0.01), adopted from NERC for similar events
Flex-2-2	Calculated EENS with one Valley South Transformer in service (Due to 896 MVA Limit under transformer N-1 or N-2 conditions)	Time of overload during 2 week restoration time	Based on CIGRE Transformer Outage Survey (0.0015)*

**Probability of peak condition (spare in service N-1 outages) is underestimated for alternatives with ineffective tie-lines because shorter duration peak load transformer outages were not considered.*

Related to questions:

- *"Explain the reliability metrics.*
- *For both of the Flex 2 cases, how was the 2-week outage duration used across the 8,760 hours to accumulate the energy unserved to produce the LAR value? It is stated in both cases that it is "assumed to occur randomly throughout the year".*
- *Are the probabilities used for Flex-2-1 and Flex-2-2 appropriate given the significant difference?"*

LAR -> EENS -> Monetized Benefits Process

- Derive LAR for the five metrics.
- Derive EENS
  - N-0 Metric: Sum of discrete, hourly LAR dictated solely by system load
  - Contingency Metrics: EENS = LAR/8760 x Average Duration x Outage Rate
    - LAR/8760 x Average Duration represents average LAR over the course of event duration
    - Outage Rate incorporates likelihood of contingency to occur
- EENS is monetized using SCE's Value of Service studies that provide a $/unserved kWh for events of different durations and customer classes

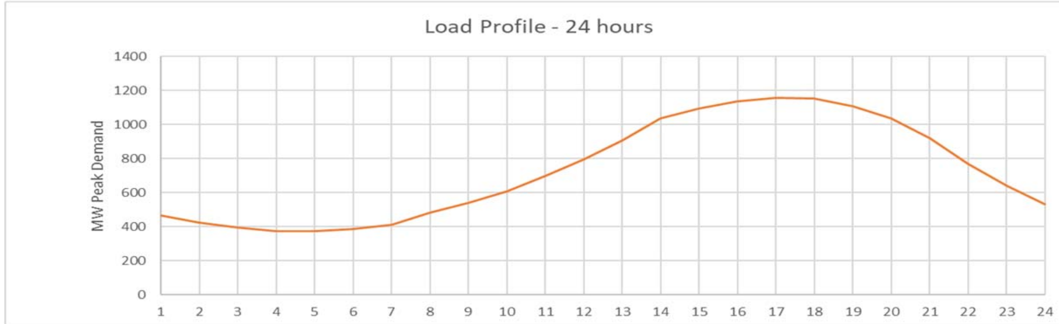
Customer Class	Load %	$/kWh (1 hour)	$/kWh (FLex-2-1)
Residential	33%	$9.47	$5.68
Small/Medium Business	36%	$431.60	$238.41
Commercial & Industrial	31%	$78.28	$52.11

Related to questions:

- *"What required Edison to develop and apply LAR when EENS can be quantified and monetized in all cases, which includes the Valley South System being isolated?*
- *Is it correct to refer to the monetized value of LAR as EENS, given the difference between the methodology taken to arrive at the value (LAR vs. ENS) before applying the probability factor?"*

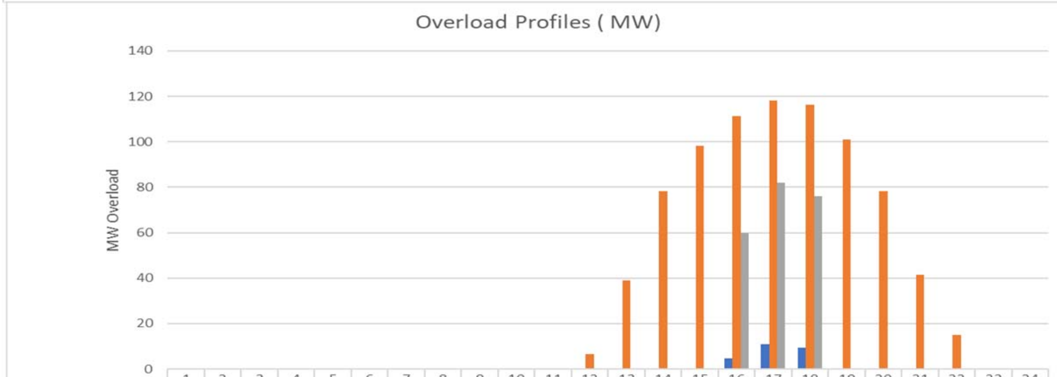
Example of Reliability Metrics (LAR to EENS)

Metric	Load at Risk	EENS
N-0	218	218
N-1	24.9	0.0032
N-2	803	0.007414



EENS = LAR x (Ave. Duration/8760) x Outage Rate

N-0 = 218
N-1 = 24.9 x (2.8/8760) x 0.40664
N-2 = 803 x (3.0/8760) x 0.02696



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N-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	11	9	0	0	0	0	0	0
Flex-1 (N-2)	0	0	0	0	0	0	0	0	0	0	0	6.6	38.9	78.1	98.1	111	118	116	101	78.1	41.5	15	0	0
N-0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60	82	76	0	0	0	0	0	0

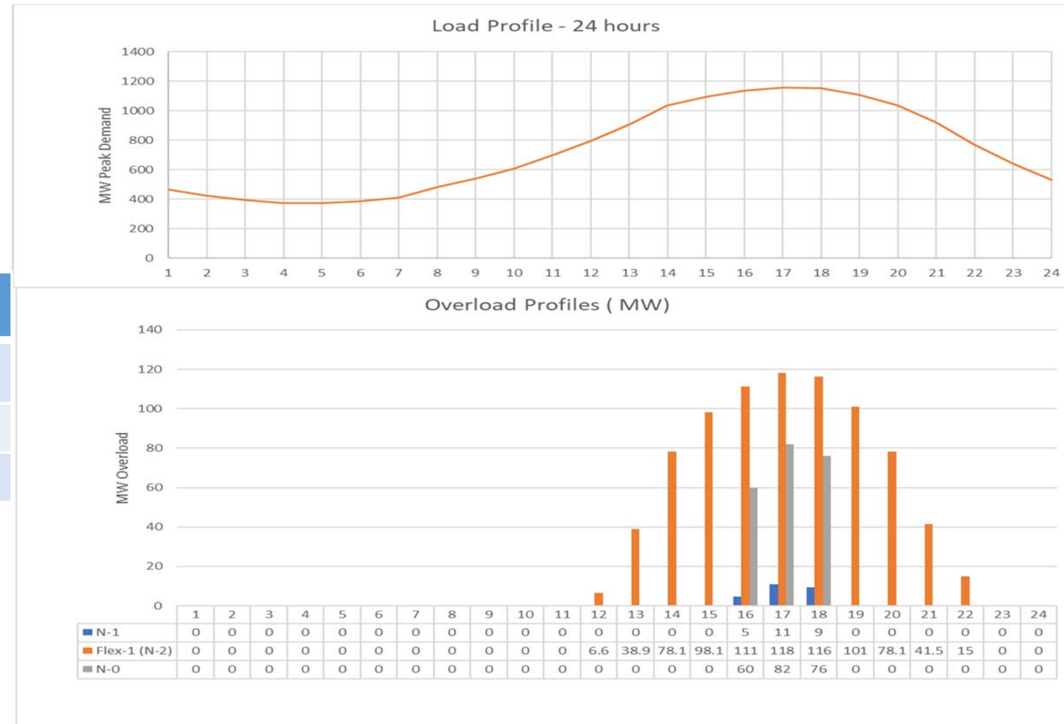
Related to questions:

- *"Provide more intermediate analysis of contingency events, durations, probabilities and customer impacts.*
- *Show how Edison uses the BCA to compare project alternatives."*

Example of Reliability Metrics (Monetization)

Metric	Load at Risk	EENS
N-0	218	218
N-1	24.9	0.0032
N-2	803	0.007414

Customer Class	$/kWh (1 hour)	Load %
Residential	9.47	33%
SMB	431.60	36%
C&I	78.28	31%



N-1 =[(0.0032 *9.47 * 33%) + (0.0032 *431.6 * 36%) + (0.0032 *78.28 * 31%)]*1000 = $584.90

Same approach for all performance metrics across all alternatives
Difference between Alternative and No project = $ Benefits

Related to questions:
- *"Provide more intermediate analysis of contingency events, durations, probabilities and customer impacts.*
- *Show how Edison uses the BCA to compare project alternatives."*

Breakdown of Performance Metrics

- In the next few slides, the performance metrics are broken down into five primary categories. These represent the building blocks or intermediate steps in translating LAR to EENS to Monetization.

  - **Contingency events –** Define the type of event under study
  - **LAR Calculation –** Approach to calculate Load at Risk. All LAR was calculated using 8760 profiles and power flows.
  - **Probabilities –** Assumed Probability for the event
  - **Duration –** Assumed duration for the event used to calculate average LAR
  - **Customer impacts –** Monetization basis

Related to question: "Explain the reliability metrics."

N-0 LAR/EENS

Contingency events – No contingency (N-0 or system normal conditions)

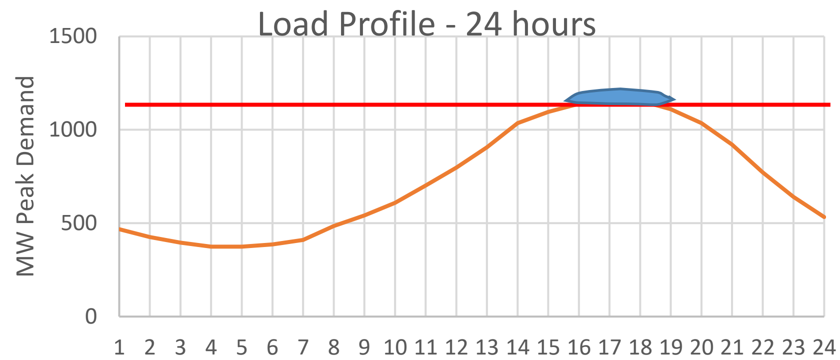
LAR Calculation – Load curtailment required to reduce loading in excess of transmission line or transformer normal rating (Rate A) or voltages within 5% criteria.

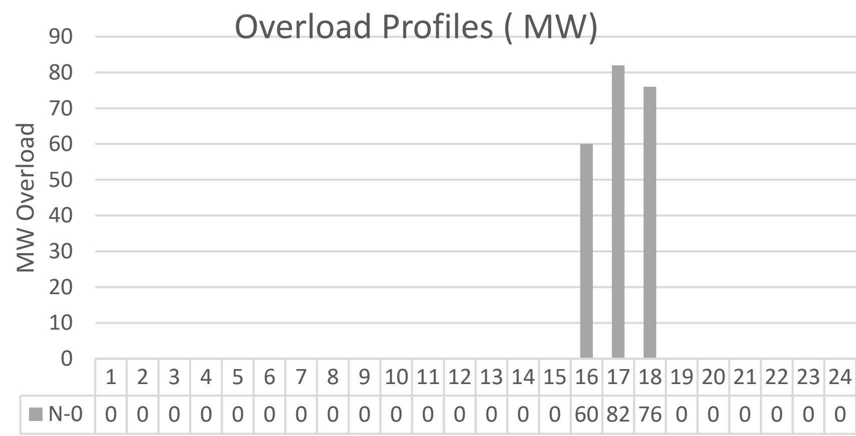
Probabilities – No probabilities associated with N-0 events. LAR is same as EENS.

Duration – The duration varies depending on number of hours load is in excess of transformer rating. LAR is accumulated for area under the curve (alongside)

Customer impacts –

LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.





Related to question: "Explain the reliability metrics."

N-1 LAR/EENS

Contingency events – N-1 outage of subtransmission lines in the Valley South system

LAR Calculation – Load curtailment required to reduce loading in excess of transmission line or transformer emergency rating (Rate B) or voltages within 5% criteria, for each event. Calculated as a rolling average across the year for event duration of 2.8 hours.

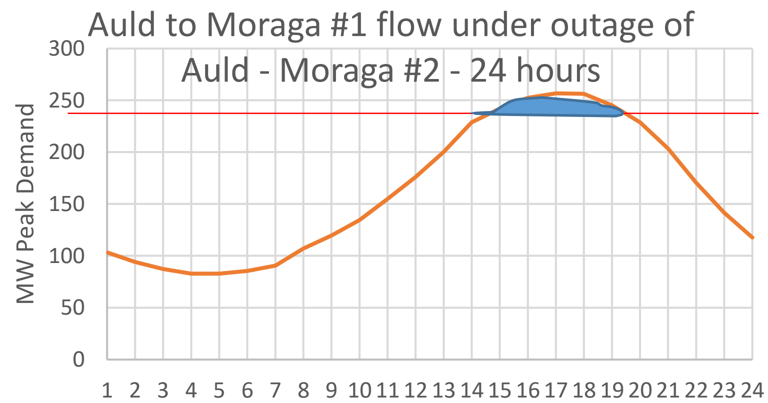
Probabilities – Failure rate of 3.4 outages per 100-mile years, based on historic event data. Event specific probabilities can be found in Table 3-3 of Quanta Report.

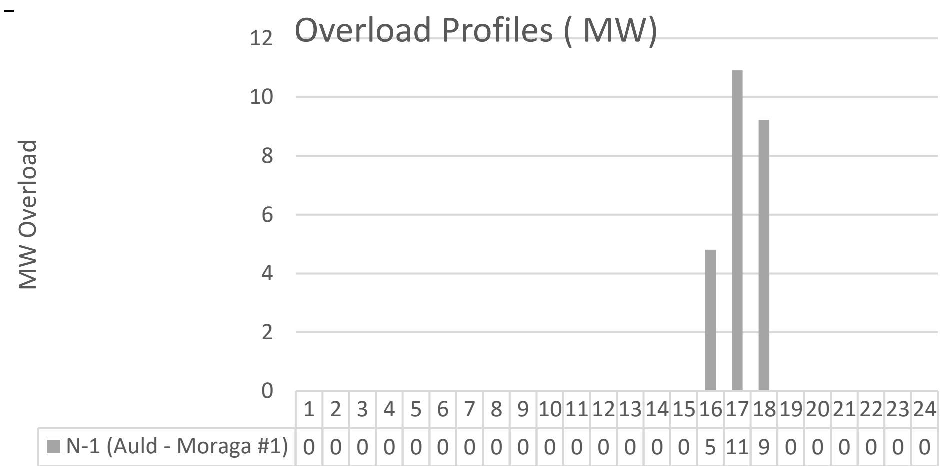
Duration – Mean duration of 2.8 hours, based on historic event data

EENS Calculation = LAR x (Ave. Duration/8760) x Outage Rate

Customer impacts –

EENS (MWh) for the year across each event multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.





Related to question: "Explain the reliability metrics."

Flex-1 LAR/EENS

Contingency events – N-2 outage of subtransmission lines in the Valley South system that share common poles.

LAR Calculation – Load curtailment required to reduce loading in excess of transmission line or transformer emergency rating (Rate B) or voltages within 5% criteria, for each event. Calculated as a rolling average across the year for event duration of 3.0 hours.

Probabilities – Failure rate of 0.8 outages per 100-mile years, based on historic event data. Event specific probabilities can be found in Appendix of Quanta Report

Duration – Mean duration of 3 hours, based on historic event data

EENS Calculation = LAR x (Ave. Duration/8760) x Outage Rate

Customer impacts –

EENS (MWh) for the year across each event multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.

Related to questions:

- *"Explain the reliability metrics.*
- *Explain why Flex-1 was selected as a comparison for reliability metrics."*

Flex-2-1 LAR/EENS

Contingency events – Loss of Valley Substation (all source of power flowing through Valley Substation)

LAR Calculation – Load loss due to loss of service transformers. Calculated as a rolling average across the year for event duration of 2 weeks.

Probabilities – Failure rate of 0.01 (NERC treatment of High Impact Low Probability events – 1 in 100-year occurrence)

Duration – Mean duration of 2 weeks, reflective of the minimum restoration duration for an event of this magnitude.

EENS Calculation = LAR x (Ave. Duration/8760) x Outage Rate

Customer impacts –

EENS (MWh) for the year across each event multiplied by the cost of lost load ($/MWh) derived as the average cost of lost load using hour 1 and hour 24.

Considering the uncertainties and shortage of publicly available data sources to support the quantification of customer interruption costs due to events of this magnitude, the average of hour 1 and hour 24 cost data would prevent bias towards to a higher or lower monetary impact.

Related to question: "Explain the reliability metrics."

Flex-2-2 LAR/EENS

Contingency events – Loss of two Valley South transformers*

The utilization of spare transformer is the *temporary* mitigation strategy.

LAR Calculation – Load curtailment required to reduce loading in excess of transformer emergency ratings (up to STELL (896 MVA) for one hour, then below LTELL (672 MVA)). Calculated as a rolling average across the year for event duration of 2 weeks.

Probabilities – Failure rate of 0.00075/transformer (data for major transformer events (fire or explosion))**

Duration – Mean duration of 2 weeks, reflective of the minimum restoration duration for an event of this magnitude**

EENS Calculation = LAR x (Ave. Duration/8760) x Outage Rate

Customer impacts –

EENS (MWh) for the year across each event multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.

**Accruing LAR above 896 MVA for loss of two transformers (N-2) and crediting the spare is equivalent to losing one transformer and proactively protecting the remaining transformers (consistent with N-1 planning criteria)*

****Cost-benefit simplification due to complexity of occurring of LAR and calculating EENS for multiple short duration outages at peak conditions for the range of alternatives*

Related to question: "Explain the reliability metrics."

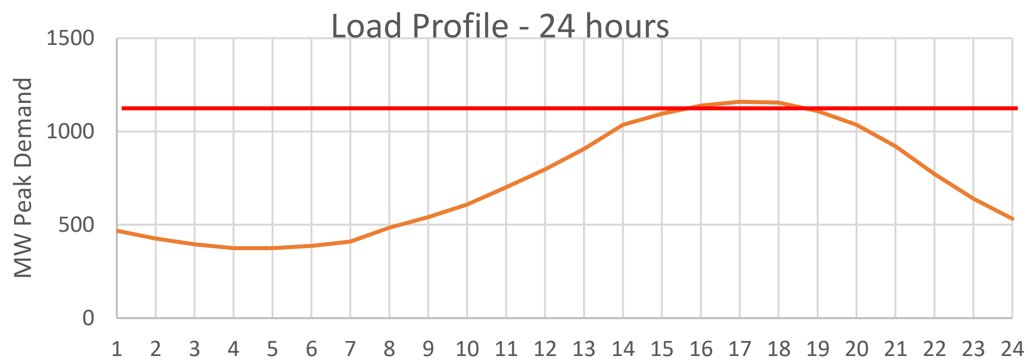
Treatment of Batteries/Energy Storage Solutions

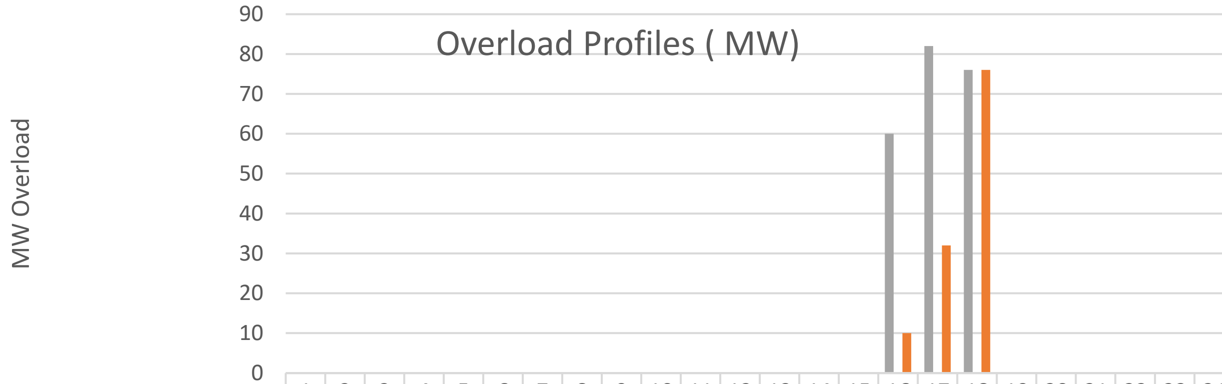
- Battery Dispatch
  - For each hour of the 8760 simulation, the batteries are discharged based on its size (MW/MWh) to mitigate overload. The batteries were sized to mitigate <u>transformer</u> N-0 overloads*.
  - Use of the battery resources results in the overload being eliminated or reducing it – so for that hour the batteries are fully credited for the amount of load at risk they have effectively addressed.
  - If the battery runs out of its full discharge capability prior to the overload being mitigated or reduced, Load at Risk is accumulated
  - In all analyses, the battery is assumed to be fully available for discharge under any event – irrespective of any potential charging constraints. In other words, the battery is always full charged and available for dispatch.
- Upcoming slides demonstrate how batteries are being credited across different metrics.

*N-1 transformer overloads were expected to be addressed with alternatives that included effective tie-lines (consistent with meeting SCE's Planning Criteria and the FEIR's Project Objectives) and those without tie-lines would accrue load at risk in contrast. SCE recommends a subsequent workshop session to review parameters for this analysis.

LAR N-0 with BESS

- N-0 is indicative of the load at risk in excess of transformer thermal loading limits without any projects in service. Total <u>218 MWh of load at risk</u>.
- N-0 82 MW/218 MWh BESS results in <u>zero load at risk</u> because it is sized to address the transformer overload.
- N-0 50 MW/100 MWh (2 hour) BESS results in <u>118 MWh of load at risk</u>.
  - In hour 16, the peak overload is 60 MW. BESS can only supply 50 MW –> 10 MW load at risk.
  - In hour 17, peak overload is 82 MW. BESS can only supply 50 MW –> 32 MW load at risk.
  - In hour 18, the BESS has run out of capacity ->76 MW load at risk
  - Total 10+32+76 = 118 MWh of load at risk.



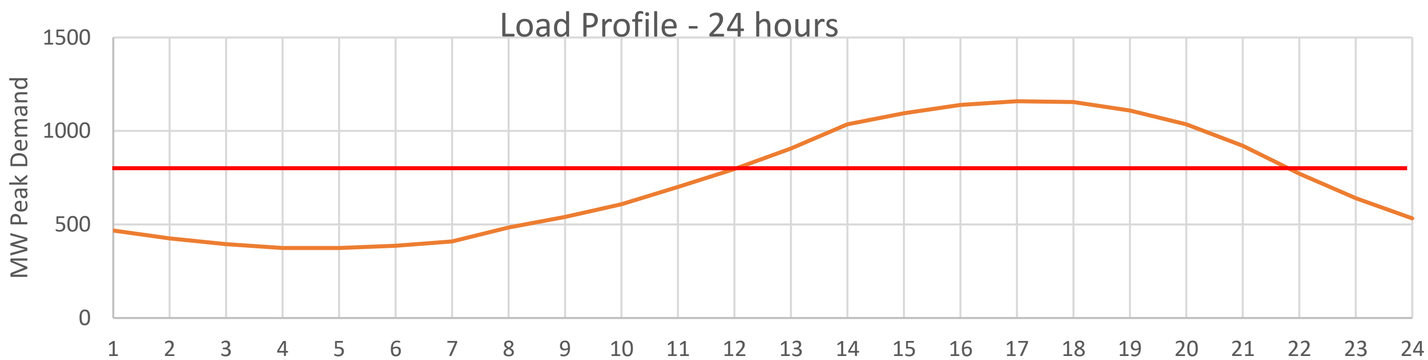


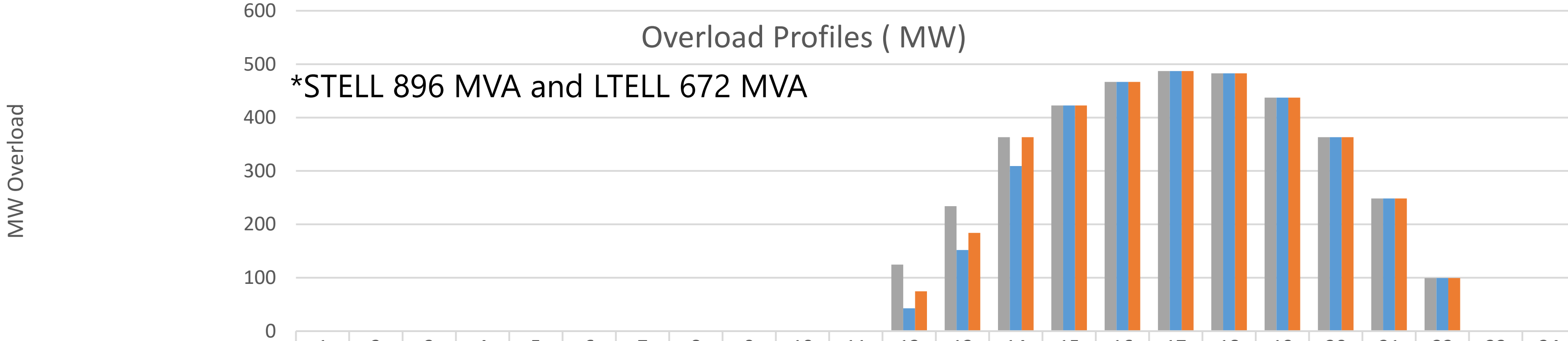
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
N-0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60	82	76	0	0	0	0	0	0
N-0 82MW/218 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N-0 50MW/100 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	32	76	0	0	0	0	0	0

Related to question: "Show how and when batteries are accredited for load relief in this model."

Flex-2-2 with BESS

- Figures below compare the load at risk under Flex-2-2 (loss of transformers) for a combination of solutions
- Flex-2-2 is indicative of the load at risk in excess of 896 MVA/672 MVA transformer emergency loading limits*. Total 3,729 MWh of load at risk.
- Flex-1 82 MW/218 MWh BESS results in 3,511 MWh (3,729-218=3,511) load at risk because it has insufficient capacity to discharge and address the duration of N-2 violation.
- N-0 50 MW/100 MWh (2 hour) BESS results in 3,629 MWh (3,729-100=3,629) of load at risk because it has insufficient capacity to discharge and address the duration of N-2 violation.





	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Flex-2-2	0	0	0	0	0	0	0	0	0	0	0	125	234	363	423	467	487	483	437	363	248	99	0	0
Flex-2-2 82MW/218 MWH	0	0	0	0	0	0	0	0	0	0	0	43	152	309	423	467	487	483	437	363	248	99	0	0
Flex-2-2 50MW/100 MWH	0	0	0	0	0	0	0	0	0	0	0	75	184	363	423	467	487	483	437	363	248	99	0	0

Related to question: "Show how and when batteries are accredited for load relief in this model."

Comparison of Metrics: N-0

- The N-0 metric measures transformer and line overloads with all facilities in service

  No Project:
  6,310 MWh
  Valley South to Valley North:
  2,680 MWh
  Valley South to Valley North and Distributed BESS:
  2,564 MWh

- No Project N-0 overloads total 6,310 MWh in 2048 for the current Valley South System.

- Transfer of Newcomb and Sun City Substations in the Valley South to Valley North alternative reduce LAR to 2,680 MWh

- 50MW of Distributed BESS further reduce Valley South System loading and provide an additional reduction of LAR (2,564 MWh)

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
SCE Orange County	232	578	417,292	777,797	44,419	91%	74%
Menifee	114	1,040	163,090	1,207,691	61,787	87%	70%
Mira Loma	1,905	1,151	300,643	2,811,049	68,008	67%	33%
Valley South to Valley North[2]	2,680	1,041	163,090	4,060,195	61,787	59%	10%
Valley South to Valley North to Vista[2]	852	1,041	163,090	4,060,195	61,787	79%	10%
Centralized BESS in Valley South	0	0	248,058	4,060,195	149,603	100%	6%
Valley South to Valley North and Distributed BESS in Valley South[2]	2,564	614	134,586	4,060,195	61,787	65%	10%
SDG&E and Centralized BESS in Valley South	0	0	128,102	827,505	51,564	100%	79%
Mira Loma and Centralized BESS in Valley South	0	15	262,902	2,811,049	67,834	100%	34%
Valley South to Valley North and Centralized BESS in Valley South and Valley North[2]	0	506	194,760	4,060,195	61,697	94%	9%
Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	735	506	194,760	4,060,195	61,697	86%	9%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Related to question: "Show how and when batteries are accredited for load relief in this model."

Comparison of Metrics: N-1

- The N-1 metric measures line overloads for each line contingency in the Valley South System
  - Tie-lines and BESS are used to alleviate overloads when helpful

No Project:
2,823 MWh
Valley South to Valley North:
1,041 MWh
Valley South to Valley North and Distributed BESS:
614 MWh

- No Project N-1 overloads total 2,823 MWh in 2048 for the current Valley South System.
- Transfer of Newcomb and Sun City Substations in the Valley South to Valley North alternative reduce LAR to 1,041 MWh
  - Reduced system peak loading generally reduces all line overloads
- 50 MW of Distributed BESS further reduce Valley South System loading and provide an additional reduction of LAR during most N-1 contingencies (614 MWh)

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
SCE Orange County	232	578	417,292	777,797	44,419	91%	74%
Menifee	114	1,040	163,090	1,207,691	61,787	87%	70%
Mira Loma	1,905	1,151	300,643	2,811,049	68,008	67%	33%
Valley South to Valley North[2]	2,680	1,041	163,090	4,060,195	61,787	59%	10%
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SDG&E and Centralized BESS in Valley South	0	0	128,102	827,505	51,564	100%	79%
Mira Loma and Centralized BESS in Valley South	0	15	262,902	2,811,049	67,834	100%	34%
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Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	735	506	194,760	4,060,195	61,697	86%	9%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Related to question: "Show how and when batteries are accredited for load relief in this model."

Comparison of Metrics: Flex-1

- The Flex-1 metric measures line overloads for each possible double-circuit (common pole) contingency in the Valley South System
  - Tie-lines and BESS are used to alleviate overloads when helpful

No Project:
526,314 MWh
Valley South to Valley North:
163,090 MWh
Valley South to Valley North and Distributed BESS:
134,586 MWh

- No Project Flex-1 overloads total 526,314 MWh in 2048 for the current Valley South System.
- Transfer of Newcomb and Sun City Substations in the Valley South to Valley North alternative reduce LAR to 163,090 MWh
- 50MW of Distributed BESS further reduce Valley South System loading and provide an additional reduction of LAR during most Flex-1 contingencies (134,586 MWh)

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
SCE Orange County	232	578	417,292	777,797	44,419	91%	74%
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Centralized BESS in Valley South	0	0	248,058	4,060,195	149,603	100%	6%
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Valley South to Valley North to Vista and Centralized BESS in Valley South[2]	735	506	194,760	4,060,195	61,697	86%	9%

Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Related to question: "Show how and when batteries are accredited for load relief in this model."

Comparison of Metrics: Flex-2-1

- The Flex-2-1 metric measures the amount of load at risk when the Valley Substation is out of service (i.e., supply through Valley Substation from is interrupted).
  - Valley South to Valley North alternative transfers provide no benefit because Valley North would simultaneously lose a source of supply.
  - BESS does not provide any Flex-2-1 benefits due to lack of grid-synchronization capability (i.e., the BESS would be isolated under this condition). The BESS model does not assume grid-forming capability or the ability to operate as a microgrid.
  - Tie-lines provide benefits by transferring load to adjacent systems.

No Project:
4,060 GWh
Valley South to Valley North:
4,060 GWh
Valley South to Valley North and Distributed BESS:
4,060 GWh

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
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Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Related to questions:

- *"Is there a full description of the BESS charge and discharge logic that was applied during the two-week outage duration, as well as the shorter 24-hour duration associated with the N-2 study? Was it more than a single discharge at the onset of each planning case?*
- *Show how and when batteries are accredited for load relief in this model."*

Comparison of Metrics: Flex-2-2

- The Flex-2-2 metric measures the amount of load at risk under loss of two Valley South transformers (but with spare transformer in service) (i.e., N-1 outage of Valley South 500/115 kV in-service transformer)
  - Tie-lines and BESS are used to alleviate overloads when helpful

    No Project:
    0.155 GWh
    Valley South to Valley North:
    0.06 GWh
    Valley South to Valley North and Distributed BESS:
    0.06 GWh
- No Project Flex-2-2 results in 0.155 GWh of LAR
- Transfer of Newcomb and Sun City Substations in the Valley South to Valley North alternative reduce LAR to 0.061 GWh
  - Reduced system peak loading generally reduces transformer overload under N-1
- 50 MW of Distributed BESS provided negligible relief to address the N-1 transformer overload relative to initial Valley South to Valley North transfers.
  - Relatively small size compared to need (Peak demand – 896 MW (STELL) or 672 MW (LTELL)

Table 6-2 – Quantitative Capacity, Reliability and Resiliency Metrics for All Alternatives in 2048

Alternative	Capacity		Reliability/Resiliency			Capacity Improvement[1]	Reliability/ Resiliency Improvement[1]
	LAR N-0 (MWh)	LAR N-1 (MWh)	Flex-1 (MWh)	Flex 2-1 (MWh)	Flex 2-2 (MWh)		
No Project	6,310	2,823	526,314	4,060,195	155,780	-	-
Alberhill System Project	3	202	136,664	87,217	100	99%	95%
SDG&E	244	0	159,201	827,505	51,564	97%	78%
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Note 1: Improvement in Reliability/Resiliency was calculated by comparing the sum of Flex-1, Flex-2-1, and Flex-2-2 metrics for each project to the sum of those metrics for the No Project scenario. Capacity Improvement was calculated by comparing the sum of EENS N-0 and EENS N-1 metrics for each project to the sum of those metrics for the No Project scenario.

Note 2: Improvements for alternatives with a Valley South to Valley North transfer are conservative due to a modeling simplification. A complete contingency analysis was not performed for these alternatives. The improvements therefore do not consider any potential line overloads in the Valley North System.

Related to questions:

- *"Is there a full description of the BESS charge and discharge logic that was applied during the two-week outage duration, as well as the shorter 24-hour duration associated with the N-2 study? Was it more than a single discharge at the onset of each planning case?*
- *Show how and when batteries are accredited for load relief in this model."*

Remote Spare Transformer In-Servicing

- The two-week outage duration for the Flex-2 metrics is based on the assumed time required to in-service (at Valley Substation) the remote spare transformer (some of these activities can occur concurrently)
  - Transporting the spare includes:
    - Validate route, obtain emergency heavy-haul permits and escorts
    - Coordinate pre-contracted heavy-haul transport (limited resource)
    - Load and haul transformer (~15 miles)
  - Remote site pre-transport activities*
    - Mobilize tanker truck for oil removal
    - Remove radiator fins, bushings, and other ancillary equipment
  - Valley Substation pre-arrival activities**
    - Mobilize tanker truck for oil removal
    - Undress and remove failed transformer
    - Inspect and ensure concrete pad adequacy
  - Install, dress, and in-service spare transformer at Valley Substation

**Spare must be maintained in a fully dressed condition to ensure its readiness for service and to comply with manufacturer warranty*

***Assumes transformer failure only with no collateral damage other equipment*

Related to question: "The 2-week outage duration of the Flex-2-2 case is based on the time required to place the remotely stored spare transformer into operation. What is the breakdown of action items to perform this work? Is there any preparation work that can be done to reduce this time requirement?"

Use of 10-Year and 30-Year Horizons

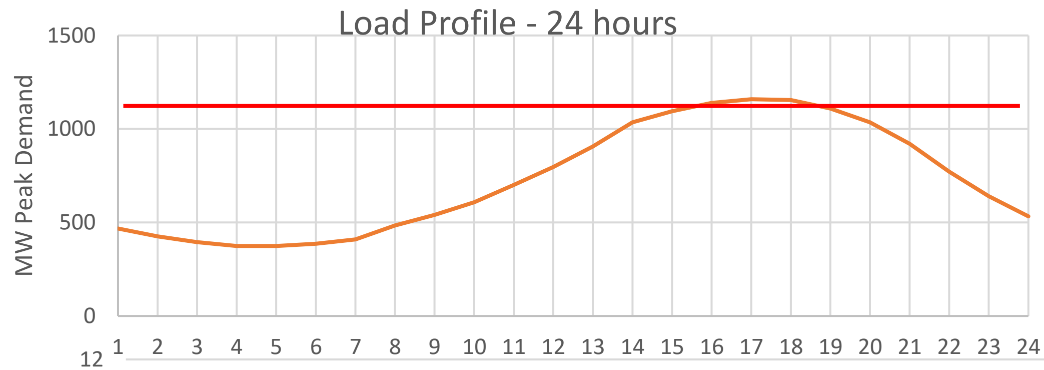
- Decision 18-08-026, issued August 31, 2018, directed SCE to supplement the record with additional analyses of alternatives which may satisfy the needs of the Valley South System.
  - f) The forecasted impact of the proposed project on service reliability performance, using electric service reliability metrics where applicable;
  - g) Cost/benefit analysis of several alternatives for: enhancing reliability providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart-grid solutions;
- 30 years is the average life of a transmission or substation asset.
- Storage assets typically have a lifetime of 15 years while accounting for degradation upfront and inverter replacement.
- 10 years is traditional planning window but need to recognize that there are benefits of long-lived assets
- Was recognized that the earliest likely operating date of a project would be only ~4-5 years before the end of the 10-year planning horizon which would inadequately reflect the system needs just beyond the 10th year

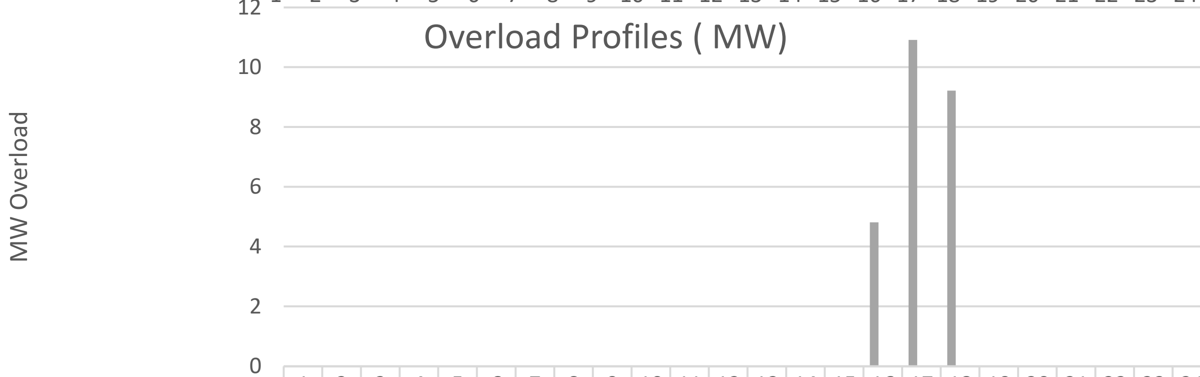
Related to question: "Discuss why 10-year and 30-year horizons are both used."

Backup

LAR N-1 with Batteries

- N-1 is indicative of the load at risk in excess of subtransmission line overload. Total <u>25 MWh of load at risk</u>.
- N-1 82 MW/218 MWh BESS results in <u>zero load at risk</u> because it has sufficient capacity to discharge and address the N-1 violation.
- N-1 50 MW/100 MWh (2 hour) BESS results in <u>zero load at risk</u> because it has sufficient capacity to discharge and address the N-1 violation.

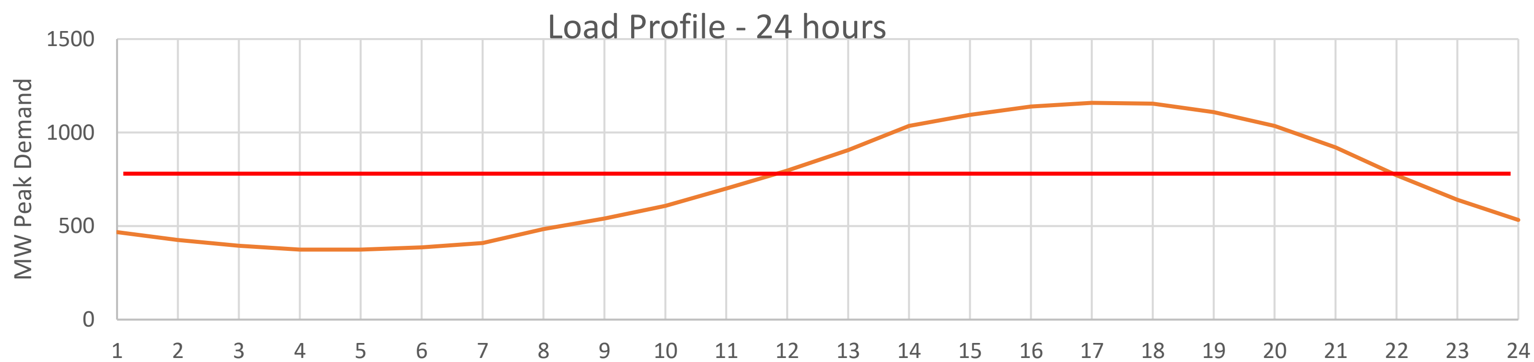


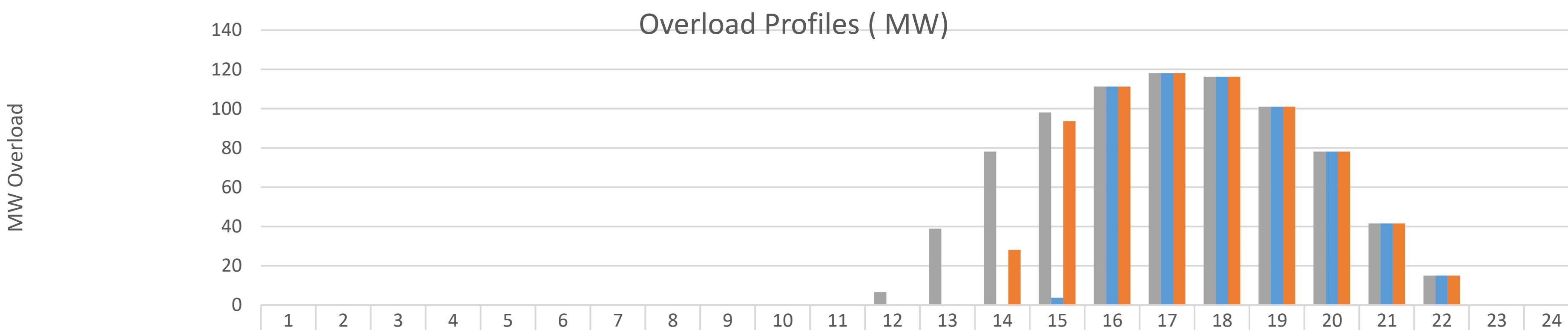


	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
N-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	11	9	0	0	0	0	0	0
N-1 82MW/218 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N-1 50MW/100 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

LAR N-2 with batteries

- Flex-1(N-2) is indicative of the load at risk in excess of subtransmission line overload. Total 803 MWh of load at risk under the "no project" alternative.
- Flex-1 82 MW/218 MWh BESS results in 585 MWh (803-218=535) load at risk because it has insufficient capacity to discharge and address the duration of N-2 violation.
- N-0 50 MW/100 MWh (2 hour) BESS results in 703 MWh (803-100=703) of load at risk because it has insufficient capacity to discharge and address the duration of N-2 violation.





	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Flex-1 (N-2)	0	0	0	0	0	0	0	0	0	0	0	6.6	38.9	78.1	98.1	111.3	118.1	116.3	101	78.1	41.5	15	0	0
Flex-1 82MW/218 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	111	118	116	101	78.1	41.5	15	0	0
Flex-1 50MW/100 MWH	0	0	0	0	0	0	0	0	0	0	0	0	0	28.1	93.6	111.3	118.1	116.3	101	78.1	41.5	15	0	0

Alberhill System Project: Benefit-Cost Analysis Workshop

(supplemental slides to the presentation provided for the May 4, 2022 meeting)

Energy Division

May 12, 2022 (continuation of May 4, 2022 meeting)

Background

- Following the May 4, 2022 workshop, SCE was asked to elaborate on the performance of BESS resources for Flex 2-2 events that may be shorter in duration than a full 2-week outage. These slides provide an example of an 6-hour duration event as the other “bookend” to the 2-week outage event.
- The relevant background to support discussions on upcoming slides has been detailed within a separate document, shared with ED on 5/10/2022.
- In particular, the document covers the following items:
  - Scope of Alternative under evaluation
  - System Operating Thresholds (896 MVA and 672 MVA)
  - BESS Sizing Factors
  - Cost/Benefit Analysis Assumptions

BESS Sizing for 896 MVA limit

- BESS has been sized consistent with criteria described on previous slide under the following system configuration
  - Valley South to Valley North transfers
    - Newcomb and Sun City transferred to Valley North
  - Batteries have been sized to minimize loading on Valley South transformers under normal (N-0) conditions to 896 MVA (Short-term Emergency Rating).
- To ensure consistency with prior analysis and enable comparative Cost/Benefit analysis –
  - First year of installation is 2022, with a five-year deployment and augmentation cycle to address needs in the year 2027.

Deployment Year	Addresses need through	Battery MW	Battery Capacity MWH	
2022	2027	104	410	
2027	2032	147	696	
2032	2037	194	1,018	
2037	2042	239	1,326	
2042	2048	277	1,641	

- *BESS sizes reflect the total capacity needed to address the N-0 system needs i.e., not incremental capacity*
- *BESS sizes do not account for Generator N-1 contingency.*
- *BESS sizes do not account for battery degradation*

ID#			Value	Units
A	Peak Demand (Valley South) - Year 2027		1174	MW
B	Combined Peak Demand for Newcomb & Suncity - Year 2027		198	MW
C	Peak Demand (Valley South) - Year 2027 after Valley South - Valley North transfers	A-B	976	MW
D	MVA Losses		2.50%	%
E	Peak Demand (Valley South) - Year 2027 after Valley South - Valley North transfers (with losses)	C * D	1000	MW
F	Transformer Short Term Emergency Loading limit		896	MW
G	BESS Size to Cover Peak	E-F	104	MW

BESS performance under Flex-2-2 events

- The performance of BESS has been evaluated under a short-duration transformer N-1 outage event
- Examples of shorter-duration events (than that of a 2-week outage)
  - Bushing failure
    - 500 kV – 4 day outage
    - 115 kV – 3 day outage
  - Load-tap-changer (LTC) failure (diverter switch) – 3 day outage
  - Gasket leak – 1 to 2 day outage
  - System alarm (requiring investigation but no repair) – ~6 hours

- Transformers have a Short-term (1-hour) emergency rating of 896 MVA and a long-term emergency rating of 672 MVA (24-hour).
- A six-hour duration is considered around the peak demand profile for the study year 2025.
  - For comparison with a 2-week restoration duration event in SCE planning study
  - Performance of 104 MW, 410 MWh battery evaluated

- 6-hour outage duration that lasts from hour 15 to hour 20
- Without batteries
  - Hour 15, Load at risk is 14 MW (910 MW – 896 MW)
  - Hour 16, Load at risk is 274 MW (946 MW – 672 MW)
  - Hour 19, Load at risk is 250 MW (922 MW – 672 MW)
  - Hour 20, Load at risk is 188 MW (860 MW – 672 MW)
- With 104 MW/410 MWh batteries
  - Hour 15, Load at risk is 0 MW
  - Hour 16, Load at risk is 170 MW (946 MW – 672 MW– 104 MW)
  - Hour 19, Load at risk is 250 MW (922 MW – 672 MW - 84 MW) – **Battery max SOC**
  - Hour 20, Load at risk is 188 MW (860 MW – 672 MW – 0 MW) – **Battery max SOC**