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 1 7

To: CPUC
Prepared by: Paul McCabe
Job Title: Senior Advisor
Received Date: 1/6/2023

Response Date: 1/20/2023

Question 1/20/2023:
DG-MISC-80_FollowUp_1

ResourceAreas/Topic: N-0 and N-1 Conditions

SCE Data Submittal Item/Page:
Supplemental Data Request-011 Q.DG-MISC-80-First Supplemental Attachment 1 of 1.xlsx

Provide additional legend and footnotes to fully annotate the table provided in response to DG-MISC-80 (DG-MISC-80-First Supplemental Attachment 1 of 1.xlsx).

- In Row 3, identify the units for values including LAR, EENS, and period of flex deficit (e.g., MWh or hours).
- State the assumptions SCE used to define N-1 loss of transformer related to the values shown in Columns I (N-1 Transformer Outage - Period of Flexibility Deficit), J (N-1 Transformer Outage - LAR), and K (Meets N-1 Planning Criteria Yes/No).
  - o Define how SCE determined the period of flexibility deficit in Column I.
    - Having separated the N-1 Transformer Outage from the Flex 2-2 study case, please explain the reason(s) for larger LAR values being presented for the year 2031 in DG-MISC-80 for alternatives as compared to the corresponding alternative LAR values in later years presented for the Flex 2-2 study case in Exhibit G-2. For example, the VS-VN alternative is shown to have 2137 MWh of LAR in DG-MISC-80, whereas in Exhibit G-2, the worst scenario Spatial Base Forecast in Table 5-37, shows only 1710 MWh of LAR in 2033.
  - o Define how SCE determined the Load At Risk in Column J.
    - Having separated the N-1 Transformer Outage from the Flex 2-2 study case, please explain the reason(s) for larger PFD values being presented for the year 2031 in DG-MISC-80 for alternatives as compared to the corresponding alternative PFD values in later years presented for the Flex 2-2 study case in Exhibit G-2. For example, the VS-VN alternative is shown to have 38 hours of PFD in DG-MISC-80, whereas in Exhibit G-2, the worst scenario Spatial Base Forecast in Table 5-37, shows only 22 hours of PFD in 2033.
  - o Define the acceptance criteria used for declaring a project alternative received either a “Yes” or “No” for “Meets N-1 Planning Criteria” in Column K.
- Annotate in the box below the spreadsheet, how SCE determined the values reported for columns L (Resilience Flex-2-1 2031 LAR), M (Resilience Flex-2-1 2031 EENS), and Q (Period of Flexibility Deficit (# of hours between 672 and 896 MVA (after first hour and after spare transformer switched in)). As necessary, use footnotes to refer to reference paragraphs in Exhibit C-2 or Exhibit G-2 for SCE methodologies.

• Additional footnotes, as needed, for readers to understand the assumptions, methodology, accumulation, and units used for each item in the table.

SCE Response

Please see the attachment titled "DG-MISC-80-First Supplemental_A.09-09-022 CPUC-Supplemental Data Request-011 Q.DG-MISC-80-First Supplemental_Revised_20Jan2023.xlsx" which has been revised to include the units for values (updated in row 3 and in red font). Additionally, please see the notes section below the table of the attached file which has been revised (in red font) to state SCE's assumptions and methodology used to provide the data presented in columns I, J, K, L, M, and Q.

In response to the question requesting clarity around the values in column I (of the table provided in this data request response) being greater than those SCE provided in Exhibit G-2, the following explanation is provided.

The values provided in the two referenced documents (Exhibit G-2 and SCE's response to DG-MISC-80) cannot be directly compared because they were each provided to demonstrate comparisons of the relative performance of the various alternatives under different sets of assumptions. For example, in Exhibit G-2, the "Deficit Flex 2-2" values provided in the tables of Section 5.3 (examples include Tables 5-36, 5-37, and 5-38) represent a Flex 2-2 event that could occur anytime throughout the year (i.e., an average quantity). These values were derived by taking the total accumulated LAR (load at risk) across every hour of the year and dividing it by the number of hours in a year to arrive at an average LAR value per hour. This value was then multiplied by the number of hours in a two-week period (defined as the duration of a Flex 2-2 event) to arrive at an average LAR value for a Flex 2-2 event that could occur at any time within the year. This approach was taken since it cannot be known when, throughout the year, such an event would occur. By using an average value and consistently applying it to each alternative, these tables reflect the impacts and relative performance of each alternative for a Flex 2-2 event occurring at any point within the years studied. The event defined under this Flex-2-2 construct represents the impact of N-2 transformer outages (i.e., two transformers out of service and the Valley South System being served by a single transformer).

The data provided in response to question DG-MISC-80 was provided in response to interest from Energy Division in having visibility of the impacts of an N-1 transformer outage (single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) and the relative performance of each alternative. In the data provided in Exhibit G-2, performance during N-1 transformer events was not explicitly provided but rather was included in the performance values covered by the Flex 2-2 metric that represented both N-1 and N-2 transformer events. Energy Division and SCE discussed and agreed upon the study parameters to be used in providing the response to DG-MISC-80. These included separating an N-1 transformer outage from the Flex 2-2 metric and providing the total accrued LAR and EENS for the entire year. As two-week duration N-1 transformer events had not previously been studied independently, the values that were provided in response to DG-MISC-80 covered what was available from prior analyses and covered an entire year. For these reasons, the values provided in Exhibit G-2 and in data request question DG-MISC-80 are unable to be directly compared.

In response to why the LAR values of the Valley South-Valley North alternative are greater in the response to DG-MISC-80 than those presented in Exhibit G-2 (even though they occur two years earlier (2031 versus 2033)), the answer is simply that the assumptions of the study parameters are different as explained above. Though several parameters between Exhibit G-2 and DG-MISC-80 differ, the most significant are: 1) the Flex 2-2 values in Exhibit G-2 were not constrained to just N-1 transformer events, rather they reflect average values for a two-week event that could occur anytime throughout the year, and 2) the values in the response to DG-MISC-80 were constrained to just transformer N-1 events and the values provided indicate the total exposure to load at risk throughout the entire year.

In response to the question related to the comparison of the number of hours of flexibility deficit (PFD) between Exhibit G-2 and the response to DG-MISC-80, the following explanation is provided. The PFD values provided in the tables in Section 5.3 of Exhibit G-2 and those provided in columns I and Q of the response to DG-MISC-80 represent different information and are not comparable. In Exhibit G-2, the PFD values represent the number of hours where load exceeds capacity specifically for subtransmission lines[1] only and does not represent transformer loading. In the response to DG-MISC-80, the PFD values provided are specific to transformers only and are relevant to the specific parameters identified in the description of the columns (i.e., number of hours where loading is above 896 MVA and between 672 MVA and 896 MVA respectively). Because the PFD values between the two responses represent different information, a comparison of the two is not meaningful.

[1] Section 3.2.3 "Reliability Study Tools and Application" of Exhibit G-2 identifies that the N-1 contingency analysis performed (and performance of alternatives reported in the tables of Section 5.3) is limited to subtransmission lines. *"This tool generates single-circuit outages for all subtransmission lines within the system."*

A.09-09-022 CPUC-Supplemental Data Request-011 Q.DG-MISC-80-First Supplemental-Revised 20 Jan 2023

		Capacity N-0 (2031)		Meets N-0 Planning Criteria?	Reliability N-1 subtransmission lines (2031)		N-1 Transformer Outage (separated from Flex 2-2) (2031)		Meets N-1 Planning Criteria*	Resilience (Flex-2-1) (2031)		Meets all FEIR Project Objectives (2031)	Which FEIR Project Objectives are met?	Resilience Attributes	
Item No.	Project Alternative	LAR (MWh)	EENS (MWh)	Yes/No	LAR (MWh)	EENS (MWh)	Period of Flexibility Deficit (# of hours above 896 MVA) (hours)	LAR (MWh)	Yes/No	LAR (MWh)	EENS (MWh)	Yes/No	List each (1, 2, 3)	Provides improvement to Resilience (tied to FEIR Project Objective #2)	Period of Flexibility Deficit (# of hours between 672 and 896 MVA (after first hour and after spare transformer switched in)) (hours)
1	SCE Alberhill System Project	0	0	Yes	0	0	0	0	Yes	45,959	18	Yes	1,2,3	Yes	0
2	SDG&E	0	0	Yes	0	0	0	0	Yes	514,701	197	Yes	1,2,3	Yes	243
3	SCE Orange County	0	0	Yes	23	0.0013	0	0	Yes	483,013	185	Yes	1,2,3	Yes	224
4	Menifee	0	0	Yes	0	0	38	2,137	No	813,139	312	No	1,2	Yes**	268
5	Mira Loma	13.1	13.1	No	2	0.0003	4	58	No	2,368,206	908	No	2,3	Yes	283
6	VS-VN	0	0	Yes	0	0	38	2,137	No	3,577,448	1372	No	1	No	268
7	VS-VN-Vista	0	0	Yes	0	0	38	2,137	No	3,577,448	1372	No	1	No	268
8	CBESS in VS	0	0	Yes	0	0	94	8,757	No	3,577,448	1372	No	1	No	321
9	VS-VN+DBESS in VS	0	0	Yes	0	0	38	2,137	No	3,577,448	1372	No	1	No	268
10	SDG&E+CBESS in VS	0	0	Yes	0	0	0	0	Yes	514,701	197	Yes	1,2,3	Yes	243
11	Mira Loma+CBESS In VS	0	0	Yes	0	0	0	0	Yes	2,368,206	908	Yes	1,2,3	Yes	244
12	VS-VN+CBESS in VS & VN (original)	0	0	Yes	0	0	38	2,137	No	3,577,448	1372	No	1	No	268
13	VS-VN-Vista+CBESS in VS	0	0	Yes	0	0	38	2,137	No	3,577,448	1372	No	1	No	268
CPUC Energy Division versions of Alternative 12 with CBESS sized to meet appropriate operating threshold per SCE Planning Criteria*															
12a	VS-VN+CBESS in VS (with load transfer and right-sized)	0	0	Yes	0	0	0	0	Yes	TBD	TBD	No	1	No	TBD
12b	VS-VN+CBESS in VS (without load transfer and right-sized)	0	0	Yes	0	0	0	0	Yes	TBD	TBD	No	1,3	No	TBD

* With effective tie-lines, the system is planned for the 1,120 MVA limit under N-0 transformer conditions and 896 MVA limit under a transformer N-1 contingency. Without effective tie-lines, the system is planned to 896 MVA for both N-0 and N-1 conditions.

**While the Menifee alternative receives a "Yes" in this column, SCE notes it would be located essentially adjacent to Valley Substation (only 400 yards west) and only represents a marginal improvement to resilience.

Note 1: VS=Valley South, VN=Valley North, CBESS= Centralized BESS, DBESS=Distributed BESS

Note 2:

The FEIR includes the following Project Objectives:

1. Relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115-kV System 500/115-kV transformers
2. Construct a new 500/115-kV substation within the ENA that provides safe and reliable electrical service pursuant to North American Electric Reliability Corporation and Western Electricity Coordinating Council standards
3. Maintain system ties between a new 115-kV System and the Valley South 115-kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems

Note 3: All periods of flexibility deficit reflect the impact of load transfers during N-1 transformer contingency events

Note 4: Study methodology and assumptions:

1. All values of LAR (load at risk without probability weighting) and EENS (expected energy not served with probability weighting) values reflect analysis of the entire year 2031.
2. Columns D and E reflect LAR (load at risk without probability weighting) and EENS (expected energy not served with probability weighting) values respectively during normal (N-0) conditions of subtransmission lines and transformers for entire year 2031. Power flow studies were performed for each hour of the year to determine subtransmission line and transformer loading values. The loading value that exceeded normal condition operating limits was recorded and summed up to reflect the values in column D. Probability weighting was then applied to arrive at the values in column E. It is noted that for N-0 normal conditions (no contingency event) the probability is equal to 1.
3. Column F presents a "Yes" response if the value in column D is zero and a "No" response if the value in column D is non-zero. This reflects whether the alternative meets planning criteria of ensuring there is no unserved load during normal (N-0) conditions of subtransmission lines and transformers.
4. Columns G and H reflect LAR (load at risk without probability weighting) and EENS (expected energy not served with probability weighting) values respectively during abnormal (N-1) conditions of subtransmission lines only for entire year 2031. Power flow studies were performed for each hour of the year to determine subtransmission line loading values during single contingency (N-1) events. The loading values that exceeded emergency loading limits was recorded and summed up to reflect the values in column G. Probability weighting was then applied to arrive at the values in column H.
5. Column I reflects the PFD (number of hours where transformer loading is above the short-term emergency loading limit (STELL) of a single transformer (896 MVA)) for the entire year 2031. Column J reflects the LAR (load at risk without probability weighting) values during abnormal (N-1) conditions of a transformer outage for the entire year 2031. Power flow studies were performed for each hour of the year to determine transformer loading values. Each hour that exceeded 896 MVA was recorded and summed up to reflect the values in column I. The amount of load for each hour that exceeded 896 MVA was recorded and summed up to reflect the values in column J.
6. Column K presents a "Yes" response if the value in column I is zero and a "No" response if the value in column I is non-zero. This reflects whether the alternative meets planning criteria of ensuring there is no unserved load during abnormal (N-1) conditions of transformers.
7. Column L reflects LAR (load at risk without probability weighting) accumulated throughout the year of 2031 during a complete outage of Valley Substation. Column M reports the EENS of the LAR in Column L for a Flex 2-1 event lasting two weeks (using an average value of LAR per hour, applied to a two week duration, and probability weighted) that which could occur anytime within the year. Power flow studies were performed for each hour of the year to determine transformer loading values to record the total annual LAR.
8. Column N presents a "Yes" response if the value in column O is equal to "1,2,3" and therefore meets each of the FEIR project objectives and presents a "No" if the value in column O is anything but "1,2,3".
9. Column P presents a "Yes" response the if value in column O contains a value of "2" which represents whether the alternative improves resilience by creating a new 500/115 kV substation. In doing so, the alternative would reduce the loading in the Valley South System under normal conditions (through initial load transfers) and also allows for additional load transfers during abnormal conditions.
10. Column Q reflects, for each alternative, the PFD (number of hours where transformer loading in the Valley South System is above 672 MVA and below 896 MVA) for the entire year 2031 during a transformer outage and after use of system tie-lines to transfer load to an adjacent system. The values represent the duration of time after the 1-hour short-term emergency load limit (STELL) expires and before the 24-hour long-term emergency loading limit (LTELL) expires. For each alternative with a non-zero value, it is reflective of the number of hours across the year that there is exposure to load shedding (to ensure transformer loading limits are not exceeded) if the spare transformer is not available.
11. Alternatives 12a and 12b were not alternatives contemplated during the initial study phase and were included in the above table to demonstrate that with the appropriate "right sized" battery energy storage system (BESS), these two variations of the Alternative 12 could be made to meet the basic planning criteria requirements of having zero unserved load (LAR) during N-0 and N-1 conditions. Because they were not studied initially, no values for columns L, M, and Q are available, however because the Flex 2-1 and 2-2 metrics represent long-duration events, the values in columns L, M, and Q would be significant.