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Data Request Response No. 2

Prairie Song Reliability Project

OCTOBER 2025

Prepared for:

CALIFORNIA ENERGY COMMISSION

Prepared by:

PRAIRIE SONG RELIABILITY PROJECT, LLC

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ATTACHMENTS

1	Section 3.1, Air Quality - Redline Version
2	Appendix 3.1A - Updated Modeling and Calculations
3	Appendix 3.1D - Antelope Valley AQMD - Application Notice of Completeness
4	Appendix 3.1E - CAISO Charging and Renewables Analysis
5	Section 4, Alternatives - Redline Version
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1 Introduction

On August 1, 2025, Prairie Song Reliability Project, LLC (Applicant) received a Determination of Incomplete Application and Request for Information from California Energy Commission (CEC) Staff for the Prairie Song Reliability Project (Project; Docket Number 25-OPT-02) in response to the Applicant's application filed on July 2, 2025.

Table 1 lists the data requests responded to in a previous response No. 1. (TN:265873 and 265874). Table 2 lists the data responses provided in this submission. This submission completes the responses to all requests for information in TN: 265211.

Table 1. Data Responses Previously Provided

Data Request Resources Area	Data Request Number
Mandatory Opt-in Requirements	MAND-1
Cultural and Tribal Cultural Resources	CUL/TRI-1 through CUL/TRI-4
Geological Hazards and Resources	GEO-1 through GEO-4
Land Use	LAND-1 through LAND-5
Paleontological Resources	PAL-1 and PAL-2
Public Health	PH-1 through PH-4
Socioeconomics	SOCIO-1 and SOCIO-2
Soils	SOILS-1 and SOILS-2
Traffic and Transportation	TRANS-1 through TRANS-4
Transmission System Design	TSD-1 through TSD-5
Waste Management	WASTE-1 and WASTE-2
Wildfire	WF-1

Table 2. Data Responses Provided Herein

Data Request Resources Area	Data Request Number
Air Quality	DR AQ-1 through DR AQ-4
Alternatives	DR ALT-1
Biological Resources	DR BIO-1 through DR BIO-34
Greenhouse Gas Emissions	DR GHG-1 through DR GHG-12
Hazardous Materials Handling	DR HAZ-1 through DR HAZ-4
Project Description	DR PD-1
Socioeconomics	SOCIO-3
Water Resources	DR WATER-1 through DR WATER-11
Worker Safety and Fire Protection	DR WS-1 through DR WS-25

2 Air Quality

Public Resources Code, section 25545.1(b)(1) provides that the issuance of a certificate by the CEC is in lieu of any local air quality permit that would have been issued from the Antelope Valley Air Quality Management District (AVAQMD or District) and such permit requirements are incorporated into the CEC's Opt-In application requirements in California Code of Regulations, title 20, section 1877(d), Appendix B, and CEC's certification. Per California Code of Regulations, title 20, Appendix B (g) (8) (A), to assist CEC staff and the District in reviewing the project, the applicant should submit the necessary information to the District to complete an evaluation of the proposed emergency generators. To ensure the District's requirements are contained in the CEC's

Staff Assessment (including an Environmental Impact Report (EIR)) and certification, staff needs copies of all correspondence between the applicant and the District in a timely manner to stay up to date on any issues that arise prior to completion of the environmental document.

DR AQ-1. Since three emergency generators would be used, please provide a completeness determination letter from the AVAQMD confirming that the application for the proposed emergency generators submitted to the District has been deemed complete.

DR AQ-1 Response. The AVAQMD provided a Notice of Complete (NOC) Application on August 14, 2025. Please see Appendix 3.1D, AVAQMD Notice of Receipt of Complete Application.

In Section 3.1.3 of the application, the applicant lists estimated emission rates of criteria pollutants for construction and operation of the project. To validate the applicant's work, staff requests the spreadsheets that the applicant used to estimate emissions.

DR AQ-2. Please provide a copy of the spreadsheet file of the emissions calculations with live, embedded calculations used for estimated emission rates of criteria pollutants in Table 3.1-6, Table 3.1-7 and Table 3.1-11.

DR AQ-2 Response. A copy of the spreadsheet file of the emissions calculations used for Table 3.1-6, Table 3.1-7, and Table 3.1-11 was provided to CEC staff via Kiteworks on October 9, 2025.

In Table 3.1-12. Level 1 Operational Ambient Air Quality Assessment Results – Unmitigated, the maximum project contribution for 24-hours PM_{2.5} and PM₁₀ are shown as 4.41 µg/m³. However, Table 4 in Appendix 3.1B shows that the project contribution for 24-hour PM_{2.5} and PM₁₀ are 0.29 µg/m³. In addition, Table 4 in Appendix 3.1B shows that the background concentration as 36 µg/m³. But the cumulative concentration is shown as 35.99 µg/m³, which is lower than the background concentration.

DR AQ-3. Please clarify the maximum project contribution for 24-hour PM_{2.5} and PM₁₀ during project operation.

DR AQ-3 Response: The maximum Project contributions during Project operation identified in Appendix 3.1B are the correct values at 0.29 µg/m³ for 24-hour PM_{2.5} and 24-hour PM₁₀ (TN: 264408). The incorrect reference to 4.41 µg/m³ is a result of a prior model run when the use of Tier 4 Final emergency generators was not assumed. During application preparation, the decision was made to pivot to using Tier 4 Final emergency generators, and the Project contribution for 24-hour PM_{2.5} and PM₁₀ in Table 3.1-12 was inadvertently not

updated. Table 3.1-12 has been updated to show the correct value of $0.29 \mu\text{g}/\text{m}^3$ for 24-hour $\text{PM}_{2.5}$ and 24-hour PM_{10} .

DR AQ-4. Please clarify the background concentration for 24-hour $\text{PM}_{2.5}$.

DR AQ-4 Response: The reported background concentration in Appendix 3.1B of $36 \mu\text{g}/\text{m}^3$ for 24-hour $\text{PM}_{2.5}$ is correct. The background concentration was rounded up from $35.70 \mu\text{g}/\text{m}^3$ to $36 \mu\text{g}/\text{m}^3$. The cumulative Project contribution uses the more accurate number for the background concentration because the Project contribution is below the single digit rounding error. The background concentration of $35.70 \mu\text{g}/\text{m}^3$ + the Project contribution of $0.29 \mu\text{g}/\text{m}^3$ results in a total concentration of $35.99 \mu\text{g}/\text{m}^3$.

3 Alternatives

California Code of Regulations, title 20, Appendix B (f) (1) requires that in accordance with Public Resources Code section 25540.6(b), the application shall include a discussion of the applicant's site selection criteria, any alternative sites considered for the project, and the reasons why the applicant chose the proposed site. California Code of Regulations, title 20, Appendix B (f) (2) also requires the application to evaluate the comparative engineering, economic, and environmental merits of the alternatives discussed in (f) (1).

Section 4 Alternatives, subsection 4.5.1 of the application (TN 264414) states that "...[a] total of 60 contiguous acres was used to identify the minimum viable project size." Subsection 4.5.1 states that "...[s]everal alternative site locations were considered but subsequently rejected from further analysis because they would result in greater impacts than the Project, primarily due to the construction of a longer gen-tie line from the alternative site to the Vincent Substation and sloped terrain." The application provides the site locations for two alternative sites (Mountain Springs Alternative Site and Peaceful Valley Alternative Site), but does not identify the locations of other sites that were initially considered by the applicant but subsequently rejected from further analysis. CEC staff would like to review these alternative site locations and reasons for their rejection. In addition, application subsection 4.5.1 explains that a two-mile radius was used as a criterion to screen alternative site locations to avoid a lengthy gen-tie line. However, staff do not consider generation-intertie lines (gen-tie) greater than two miles as infeasible, particularly if the longer gen-tie line allows for development of a site that has fewer impacts to sensitive resources such as residences, schools, recreation areas, biological resources, and cultural resources. Subsection 4.8 discusses a reduced project alternative that would only require a 45-acre footprint within the proposed project site. No alternative 45-acre sites were considered for the reduced project alternative outside of the proposed project site. To satisfy the requirements of Public Resources Code, section 25540.6(b), staff request the location of all alternative sites considered for the project, including sites that are located outside of the two-mile radius of the Vincent Substation and sites that may accommodate a 45-acre reduced project alternative.

Section 3.2 Biological Resources explains that the project's gen-tie line would be sited in the Santa Clara River Significant Ecological Area (SEA), which is a Los Angeles County land use designation containing sensitive biological resources. Per the California Environmental Quality Act (CEQA), to avoid or substantially lessen any of the significant biological resources effects of the project, the alternatives analysis should include an alternative gen-tie line route that would avoid the County SEA. However, no alternative gen-tie line routes are discussed in application subsections 4.1 through 4.10 (TN 264414). Staff have reviewed maps of the project site and have noted that a gen-tie line could avoid the County SEA if it was sited northeast from the project along Carson Mesa Road or Soledad Canyon Road, and then continued east towards Vincent Substation along the northern side of the parcels located along Foreston Drive. Staff request that the applicant identify an alternative gen-tie line route that avoids the Santa Clara River SEA.

Section 2 Project Description, subsection 2.3.2 explains that the project's 500-kV gen-tie would be constructed as an overhead transmission line. As noted in application subsection 3.6.2.3, Los Angeles County policies applicable to the project site include Antelope Valley Area Plan Policy COS 14.1, which requires new transmission lines to be placed underground. CEQA requires a discussion of any inconsistencies between the proposed project and applicable general plans, specific plans, and regional plans.

Therefore, the alternatives analysis should include an underground construction alternative for the project's gen-tie line.

DR ALT-1. Per California Code of Regulations, title 20, Appendix B (f) (1) and Appendix B (f) (2), please provide the following:

- a. Provide a map (preferably with a KMZ file provided) and description (i.e., location, parcel number, size, etc.) of all alternative site locations initially considered for the project, including sites that are located outside of the two-mile radius of the Vincent Substation and smaller sites that could accommodate a 45-acre reduced project alternative; and
- b. Provide a map (preferably with a KMZ file provided) and description of an alternative gen-tie line route that avoids the Santa Clara River SEA (e.g., possibly extending northeast from the project site). In the description of the alternative gen-tie route, please provide information on right-of-way width, land use and zoning designations, parcel ownership, and adjacent land uses. If no such route was found to be feasible, please provide details on the justifications for the infeasibility conclusion (e.g., major highway crossings, geologic hazards, sensitive biological or cultural resources, etc.).
- c. Provide a map (preferably with a KMZ file provided) and description for an underground gen-tie line alternative. While staff encourages the applicant to evaluate more than one route for an underground gen-tie line, staff requests that the applicant provide information for at least one underground gen-tie line route that is located entirely outside of the Santa Clara SEA. For each underground gen-tie alternative, provide alternative data on major transmission components, estimated temporary and permanent disturbance acreages, and estimated construction activity duration.

DR ALT-1(a) Response. In response to Data Request ALT-1(a), an expanded alternative site location analysis was completed. The expanded alternative site analysis is two-pronged as it looks at (1) alternative locations that are within a larger radius of the Vincent Substation (6 miles as opposed to 2 miles) and (2) alternative locations that could support a smaller 45-acre reduced project alternative. Please refer to the redline version of Section 4, Alternatives, specifically Section 4.5.2 and Sections 4.9 through 4.13 for the expanded alternatives analysis. A KMZ file was provided to CEC staff via Kiteworks on October 9, 2025.

DR ALT-1(b) and (c) Response. Due to constraints imposed by Southern California Edison (SCE) on where the Project must enter the substation (see Appendix 4A, SCE email 08/08/2025), the location of the SEA, and constructability requirements for tensioning and pulling conductors between towers, an alternative gen-tie route (underground or overhead) that avoids the SEA is not feasible. The information below and included in redline version of Section 4, Alternatives, specifically Section 4.5.3, provides an analysis of each constraint to entering the Vincent Substation. A KMZ file was provided to CEC staff via Kiteworks on October 9, 2025.

Discussion of Entry into the Vincent Substation and the Significant Ecological Area

An alternative gen-tie route (underground or overhead) that avoids the SEA is not feasible due to constraints imposed by SCE on where the Project must enter the substation (see Appendix 4.A, SCE email 08/08/2025). As background, it is important to understand SCE requirements relating to interconnection facilities. Per Section 4.15 of the SCE Interconnection Handbook, “Currently there is no equipment that allows a below ground POCO for interconnections at 66 kV [kilovolts] and above. Any POCO [Point of Change of Ownership] at these voltage levels will need to be installed above ground to ensure clear distinction between SCE’s equipment and the Interconnection Customer’s equipment” (Appendix 4.A, The Interconnection Handbook Southern California Edison Company Rev. 15, January 31, 2024). This means that SCE requires that the Project install an aboveground pole outside of SCE property to accommodate a

change of ownership facilities. This is true for both underground and overhead gen-tie options. The installation of an aboveground POCO is a limiting factor in the Project's ability to identify an alternative gen-tie route that avoids the SEA. The following discussion reviews each border (east, north, west, south) of the Vincent Substation and describes constraints specific to each border relative to the SEA.

East: The SEA directly borders an existing road (Angeles Forest Highway) and the Vincent substation to the east. SCE owns the parcels within the SEA along the eastern border of the Vincent Substation (Assessor's Parcel Numbers [APNs] 3056015803, 3056014813). These parcels, and the SEA, extend north and south beyond the eastern boundary of the substation, effectively blocking any entry to the substation from the east that does not impact the SEA. Because SCE owns the parcels within the SEA along the eastern boundary of the Vincent Substation, the pole cannot be placed east of the substation without being constructed on SCE land or impacting the SEA. As stated above, SCE requires that the pole be constructed on non-SCE owned land. Therefore, the pole cannot be placed east of the substation without violating SCE's requirements regarding construction of the pole on SCE-owned land or impacting the SEA.

North: The Vincent Substation is bordered on the north by parcels owned primarily by SCE (APNs 3056014814, 3056014813, 3056014810, 3056014812). These parcels contain eight (8) high-voltage transmission lines, as well as two (2) low-voltage lines. These lines fully encumber the southern portion of the parcels that are closest to the Vincent Substation, making it technically impossible to enter the Vincent Substation from the north near the substation. If the Project attempted to cross farther north (approximately 2,300 feet), near Carson Mesa Road, the lines disperse and it would only need to cross five (5) high-voltage lines before heading back south into the substation. It is extremely difficult to build a line over or under the group of five (5) aligned high-voltage lines on the western edge of APN 3056014810. If the Project could build towers tall enough to span the approximately 1,000-foot right-of-way created by the existing transmission corridor, it would be stuck outside the Vincent Substation as it approached from the north. It would then have to cross back over six (6) high-voltage transmission lines in a constrained area to get to an open bay position on the western side of the substation. Therefore, while a gen-tie route that entered the Vincent Substation on the north could avoid the SEA, it is infeasible because the gen-tie could not reach the northern portion of the substation from the Project's eastern location. There is one potential route onto SCE property in the northwestern corner of the substation that is discussed below.

West: The Vincent Substation is bordered on the west by a residential neighborhood. The residential neighborhood consists of two (2) rows of 14 parcels. Purchasing 14 residential parcels to enter directly from the west of the Vincent Substation is unlikely. The residential neighborhood effectively blocks the proposed gen-tie line from entering the substation from a western route.

South: Similar to the eastern side of the substation, the southern side of the substation is surrounded by the SEA. The SEA boundary is located between approximately 115 feet and 160 feet from the southern border of the substation. An alternative path that enters the substation from the south would need to be located within the 115-to-160-foot space between the SEA and the substation, which has the potential to cause permanent and/or temporary impacts to the SEA due to the required right-of-way width and temporary laydown and workspace needed to construct and operate the line. There is no alternative path that can enter the substation from the south that extends farther than 160 feet south of the substation because of the location of the SEA.

Due to the proximity of the SEA boundary to the east and south, existing infrastructure to the north, restrictions on construction of the interconnection facilities on SCE-owned property to the east and north, and the neighboring community to the west, there is only one potential route to connect the Project to the Vincent Substation that avoids permanent impacts the SEA. This route would utilize two (2) privately owned parcels (APNs 3056014046, 3056014042) along the northwestern border of the SCE-owned parcels surrounding the Vincent Substation that would allow for potential access. In this alternative gen-tie scenario, starting from the Vincent Substation, SCE would place the first tower (Conceptual Pole [CP] 3) outside the southern border of the Vincent Substation in a similar location to the routes proposed by the Project. The route would then head west to just outside the southwestern corner of the Vincent Substation where a tower (CP-2) would be placed to turn the route 90 degrees to the north. The route would then run north between the Vincent Substation to the east and the residential community to the west. Due to the presence of an existing 230 kV monopole outside the southwestern corner of the Vincent Substation, the CP-2 tower would need to be placed closer to the residential community than as currently proposed (approximately 150 feet away from the property line). The route would then run north and place a third tower (CP-1) outside the northeastern corner of the Vincent Substation, where it would exit the SCE property into privately owned APN 3056014046.

While conceptually possible, this route has two fatal flaws that render it infeasible. One, the route would effectively ring fence the Vincent Substation to the south and west and eliminate the potential for future projects to access the substation from these directions. SCE has stated that the Project cannot change its entry point into the substation (see SCE email 08/08/2025) and does not allow projects to block future access to the substation. Two, it is not feasible to string and tension the conductors between the towers south of the Vincent Substation (CP-2 and CP-3). The steep terrain south of the towers and constraints imposed by existing structures do not provide adequate space to string and tension the conductors. In addition, if it were possible to overcome terrain restrictions to the south, the stringing and tensioning area would generate temporary impacts in the SEA.

Finally, the applicant also does not have site control or rights-of-way over the parcels between the site and the substation for a route that avoids the SEA. Obtaining the additional site control necessary to construct this line (seven [7] landowners over nine [9] unique parcels) would be an additional feasibility concern.

Alternative Gen-Tie Constraints

Direction	Limitation(s)	SEA Impact
East	- SEA boundary - SCE requirement for POCO on private property	POCO must be aboveground. Permanent impacts to the SEA would be necessary.
North	- Existing high-voltage transmission lines - SCE requirement to maintain current Point of Interconnection location	No impact, but not technically possible to enter from the north due to multiple high-voltage line crossings in a constrained space.
West	Residential development containing 28 parcels	No impact, but impact to residential neighborhood is like and site control is unlikely.
South	SEA borders substation to the south	Permanent impacts to the SEA for any line extending more than 160 feet to the south.

Alternative Gen-Tie Constraints

Direction	Limitation(s)	SEA Impact
Northwestern Corner	- SEA borders substation to the south - Residential neighborhood to the west - Topography does not allow for tensioning and pulling lines	If possible, there would be temporary impacts to the SEA from tensioning and pulling requirements.

Note: gen-tie = generation interconnection; SEA = Significant Ecological Area; SCE = Southern California Edison; POCO = Point of Change of Ownership.

4 Biological Resources

DR BIO-1. Pursuant to California Code of Regulations, title 20, section 1704, (a) (3) (A), please provide representative photographs of the site, as available, particularly overview photos of large portions of the site, photos of portions that would be developed, and photos of features that may include state or federal waters or other potentially jurisdictional features such as intermittent and ephemeral streams. Very few photographs of the project site were provided in the Section 3.2 Biological Resources of the Application. Please provide any Biological Technical Reports as available, or as specifically further requested below.

DR BIO-1 Response. A photo exhibit has been prepared and is provided as Appendix 3.2I. The photo exhibit includes representative photographs of the on-site vegetation communities, jurisdictional waters, and sensitive resources. There are only ephemeral streams in the Study Area. Survey reports for rare plants, California Desert Native Plant Act, and Crotch's bumble bee, as well as a biota report are included in Appendices 3.2D, 3.2E, 3.2F, and 3.2G, respectively.

Survey reports for rare plants and Crotch's bumble bee (*Bombus crotchii*) have not been provided for the southern gen-tie route option. Staff notes that the application indicates that fiber-optic telecommunications lines would be installed on the southern gen-tie route regardless of which gen-tie option is chosen to be built.

DR BIO-2. Provide a complete survey report for results of special-status plant surveys conducted for the southern gen-tie route, describing methodology and results, and also provide the names and resumes of staff completing the surveys. These surveys should be conducted following the Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Sensitive Natural Communities (CDFW 2021). As staff has not received all survey data for special status plant species, staff may provide additional data requests upon receipt of the requested information.

DR BIO-2 Response. A rare plant survey report has been prepared and is provided as Appendix 3.2D. The report documents the methodology that was used, which included California Department of Fish and Wildlife (CDFW) protocols. The names of the staff that conducted the surveys can be found in the report and in Table 3.2-1, Schedule of Surveys, in Section 3.2. Resumes of the staff that conducted the surveys are included in Appendix 3.2C. The additional rare plant geographic information system (GIS) data was provided to CEC staff via Kiteworks on October 9, 2025, along with the other GIS data requested.

DR BIO-3. Please provide a complete survey report describing Crotch's bumble bee (*Bombus crotchii*) surveys conducted along the southern gen-tie route, describing methodology and results, and also provide the names and resumes of staff completing the surveys. Surveys should be conducted following the California Department of Fish and Wildlife (CDFW) Survey Considerations for California Endangered Species Act (CESA) Candidate Bumble Bee Species (CDFW 2023). This information should be submitted as part of a comprehensive survey report covering all Crotch's bumble bee surveys conducted for the project. As staff has not received all survey data for this species, staff may provide additional data requests upon receipt of the requested information.

DR BIO-3 Response. A Crotch's bumble bee survey report has been prepared and is provided as Appendix 3.2F. The report documents the methodology that was used, which is based upon CDFW's 2023 guidelines.

The surveys conducted by the applicant for Crotch's bumble bee may not be adequate to determine presence. Based on a review of survey Table 3.2-1 in the application (TN 264413) it appears that early season surveys (April to May), when botanical resources would have been present, were not conducted.

DR BIO-4. Please provide justification for why surveys for Crotch's bumble bee across the entire project area did not include early season surveys. Please explain why the surveys did not conform to the CDFW guidelines for bumble bee surveys (CDFW 2023), which recommend conducting surveys throughout the flight season.

DR BIO-4 Response. The surveys were split across 2 years because the Project owner did not have access to the entire Project gen-tie area during the 2024 surveys. Separate site surveys were conducted according to CDFW 2023 guidelines. "Survey efforts should include multiple on-site surveys and should be developed to detect foraging bumble bees and potential nesting sites (nesting surveys). Survey timing should be determined on a project-by-project basis based on seasonality and when activity or foraging will most likely occur each year 3. Timing of the surveys may vary depending on the location, elevation, seasonal rainfall, average ambient air temperatures, and local seasonal weather conditions. To increase probability of detection, bumble bee survey efforts should be conducted during the Colony Active Period and when floral resources are present, ideally during peak bloom."

The three (3) 2024 surveys (June 12, 2024; July 1, 2024; and July 2, 23, and 24, 2024) were conducted from June through July, during the Colony Active Period of April through August, which according to CDFW guidelines had the highest detection period, and were spaced between 2 and 4 weeks apart. The three (3) 2025 surveys, which covered the remainder of the Project site, were conducted between April and June, which is during the Colony Active Period. The 2025 surveys were spaced 4 weeks apart to cover a wider period during the Colony Active Period while also meeting recommended guidelines.

For more detailed information, please see Appendix 3.2F.

Subsection 3.2.1.2.1 of the Application references the Upper Santa Clara River Integrated Regional Water Management Plan prepared by Kennedy/Jenks Consultants in 2014. However, the link to this plan provided in the references listed in Subsection 3.2.8 is broken.

DR BIO-5. Please provide an accessible link for the Upper Santa Clara River Integrated Regional Water Management Plan, prepared by Kennedy/Jenks Consultants, 2014.

DR BIO-5 Response. An accessible link for the Upper Santa Clara River Integrated Regional Water Management Plan, prepared by Kennedy/Jenks Consultants, 2014, is included here: <https://pw.lacounty.gov/core-service-areas/water-resources/upper-santa-clara-irwm/>. The link has also been updated in subsection 3.2.8 of the redline Biological Resources application section attached.

The applicant is currently not seeking take authorization for Crotch's bumble bee, a candidate for listing pursuant to the California Endangered Species Act (CESA). Protocol surveys along the southern gen-tie route are ongoing, and results are outstanding at the time of staff's initial review of the Application. Should the survey results indicate potential for take, the applicant should consider submitting a take authorization application for Crotch's bumble bee.

DR BIO-6. Please provide survey results (performed pursuant to DR BIO-3) to demonstrate that no take is expected to result from project activities. Please also refer to DR BIO-4 and explain the rationale for not

conducting surveys during appropriate period when floristic resources would have been available to Crotch's bumble bee.

If the applicant is requesting incidental take authorization, please provide all information that would be required in an ITP application for CESA-listed or candidate species, specifically Crotch's bumble bee, including an impacts analysis and proposed mitigation measures (Cal. Code of Regs., tit. 20, § 1877(a) (referencing Cal. Code of Regs., tit. 14, § 783.2(a)(1) through (a)(10)).

DR BIO-6 Response. A Crotch's bumble bee survey report has been prepared and is provided as Appendix 3.2F. See the response to DR BIO-4 for the seasonality of the surveys. As documented in the report, no Crotch's bumble bee were observed during the surveys, which occurred over two (2) survey seasons. No bumble bees of any kind were observed during that period. Floral resources for the species are present but in limited numbers, with the Study Area being dominated by California juniper woodland, fourwing saltbush scrub, and Mormon tea scrub, as shown in Table 3.2-3, Vegetation Communities and Land Covers in the Study Area. Additionally, there are few records for the occurrence of the species or any other bumble bee from the Acton region.^{[1][2][3]} Due to the limited foraging opportunities and the few records of bumble bees as a whole in the region, the Project is not expected to involve take of Crotch's bumble bee. However, MM-BIO-4, Crotch's Bumble Bee Avoidance and Minimization Measures, requires avoidance and minimization measures for the species and provides for consultation with CDFW for an Incidental Take Permit should the species be found.

- ^[1] CDFW (California Department of Fish and Wildlife). 2025a. California Natural Diversity Database (CNDDB). RareFind 5.0 (Commercial Subscription). Sacramento, California: CDFW, Biogeographic Data Branch. Accessed September 2025. <https://nrmsecure.dfg.ca.gov/cnddb/Default.aspx>.
- ^[2] The Xerces Society. 2025. Bumble Bee Atlas [online database]. Accessed September 2025. <https://www.bumblebeeatlas.org/>
- ^[3] iNaturalist. 2025. Observations of burrowing owl from Los Angeles County. Accessed September 2025. <https://www.inaturalist.org>.

Several culverts or stream crossings are not included in Appendix 3.2-D. These include a culvert conveying water from NWW-1a under Soledad Canyon Road at 34.48392, - 118.14375 and several areas where a stream intersects Foreston Drive at 34.48384, - 118.13718. It is not clear if increased use of roads during construction and operation would result in siltation, need for culvert repair, or other impacts to streams, including downstream impacts. This information is needed for staff to prepare an adequate impact assessment pursuant to CEQA (see also DR BIO-1, Cal. Code Regs. Tit. 20 § 1704, (a) (3) (A)), in addition to potentially forming part of a lake and streambed alteration application (Appendix B (g) (13) (D) (ii)), if necessary.

DR BIO-7. Describe and map any culverts or other potential jurisdictional features that would be in the work area, including those affected by project-related traffic. Describe how they would be affected by project construction and operation, and if any work, such as regrading or culvert repair, would be required to accommodate project-related traffic.

DR BIO-7 Response. There is a 36-inch culvert that conveys flows from NWW-1a across Soledad Canyon Road. The culvert is reinforced with concrete, will be maintained throughout construction, and will not be affected by Project-related traffic. The culvert will not be affected by construction and operation and is not expected to need repair (see note 4 on Updated Appendix 2A, drawing PSR-CS-004 S010). The downstream end of the culvert will be connected to a new manhole to provide continuation of the stormwater conveyance downstream of the BESS facility.

The feature NWW-1a is described in Appendix 3.2-D as entering the review area from a culvert beneath Soledad Canyon Road, however the area north of the culvert, which is located within the battery energy storage system (BESS) facility's footprint, is not mapped. This information is needed for staff to prepare an adequate impact assessment pursuant to CEQA (See also DR BIO-1, Cal. Code Regs. Tit. 20 § 1704, (a)

(3) (A)), in addition to potentially forming part of a lake and streambed alteration application (Appendix B (g) (13) (D) (ii)), if necessary.

DR BIO-8. Please provide updated maps and waters delineations that include the portion of NWW-1a north of the culvert. Please update GIS shapefiles accordingly.

DR BIO-8 Response. The feature in question was delineated by Dudek on August 22, 2025, and it was added to the dataset and used in the impact-mitigation analysis, as well as the Streambed Alteration Agreement notification package, which is included as Appendix 3.2K. Several other features were revisited after discussions with Aspen, and some additions to the jurisdictional water dataset were made. The GIS information for these additions was provided to CEC staff via Kiteworks on October 9, 2025.

The Lake and Streambed Alteration (LSA) Notification included in Appendix 3.2-D (TN 264472) states that the "proposed substation and BESS will be constructed on a raised pad and runoff from this area will drain southwest into catch basins located across the site", but it does not discuss how the flow of existing streams on the site would be rerouted. In addition, the LSA Notification states that "In the event stormwater basins reach capacity, stormwater will be discharged from the detention basins via storm drainpipes and sheet flow at rates no greater than pre-development conditions following natural drainage patterns." However, it is not clear where stormwater would be discharged or what method would be used to ensure that flow rates would not exceed pre-development patterns. This information is needed for staff to prepare an adequate impact assessment pursuant to CEQA (See also DR BIO-1, Cal. Code Regs.

Tit. 20 § 1704, (a) (3) (A))), in addition to potentially forming part of a lake and streambed alteration application (Appendix B (g) (13) (D) (ii)), if necessary.

DR BIO-9. Please provide further details about drainage design of the BESS facility during operation. Discuss how the flow of any streams which would be filled, including but not limited to NWW-1a, NWW-1b, and NWW-1c, would be diverted. Provide clarification whether the drainages would be culverted under the developed area, routed around it, diverted to join the stormwater control system, or addressed via another option. Provide the location and method of discharge in the event that stormwater basins reach capacity.

DR BIO-9 Response. Streams NWW-1a, NWW-1b, and NWW-1c will be filled in within the BESS area. Culverts will manage upstream off-site stormwater runoff throughout the overall Project site and will be used to manage flows previously routed through existing streams. Various culverts running beneath site access driveways will be used to bypass flows from upstream of the site. One existing 36-inch culvert allows runoff to flow south underneath Soledad Canyon Road towards the southern BESS yard. A manhole with an open grate will collect stormwater runoff at the downstream point of the existing 36-inch culvert. A new 60-inch storm sewer will be placed from the manhole to the downstream end of the site to convey upstream stormwater runoff from the BESS facilities. A hydraulic dissipator with riprap will be placed at the downstream site of the BESS facility. This can be seen on drawings PSR-CS-004 S011 and PSR-CS-004 S012 (TN 264472). A 72-inch culvert will also be placed to route stormwater runoff under the site. A manhole with an open grate will collect stormwater runoff, which will be conveyed, underground, downstream to the south of the substation site. A hydraulic dissipator

with riprap will be placed at the downstream site of the substation. Sizing of the culverts, calculations, and figures with the locations of the structures can be seen in the Stormwater Management Report found in Appendix K of Appendix 3.15A, Water Quality Management Plan (TN264386).

The Application (TN 264413) is unclear regarding whether the project applicant is seeking a Lake and Streambed Alteration Agreement from the California Department of Fish and Wildlife (CDFW), or if it is seeking lake and streambed alteration authorization under Fish and Game Code section 1602 from the CEC under its in-lieu permitting authority. Section 3.2.6 of the Application (TN 264413) states that the “project is expected to require a Lake or Streambed Alteration Agreement from CDFW” and proposes MM-BIO-7, which references “wildlife handling and relocation methodology from the CDFW-issued Streambed Alteration Agreement”. However, a list of required permits in Section 1 Executive Summary, subsection 1.6.4 does not include a Lake and Streambed Alteration Agreement from CDFW, and Subsection 3.2.5.2 (TN 264413) discusses using the Assembly Bill 205 opt-in process to obtain in-lieu permitting from the California Energy Commission (CEC). Under Opt-In, the CEC serves as the exclusive permitting authority for covered state permits, including those under Fish and Game Code, section 1602. This information is needed for staff to prepare an adequate impact assessment pursuant to CEQA (See also DR BIO-1, Cal. Code Regs. Tit. 20 § 1704, (a) (3) (A)), in addition to potentially forming part of a lake and streambed alteration application (Appendix B (g) (13) (D) (ii)), if necessary.

DR BIO-10. Please confirm that the applicant is seeking in-lieu permitting coverage from the CEC. If a Lake and Streambed Alteration Notification has been submitted to CDFW, the applicant should withdraw the online Environmental Permit Information Management System (EPIMS) Notification to CDFW to avoid duplicative permitting.

DR BIO-10 Response. The Project is seeking in-lieu permitting coverage from the CEC, and no notification to CDFW via EPIMS has been made. The Streambed Alteration Agreement notification is included as part of Appendix 3.2K, and a reference has been added to Section 3.2 regarding it.

DR BIO-11. Please prepare and submit the information that would be included in an LSAA notification for project activities in redline and strikeout format. Include all information as required in Fish and Game Code, section 1602(a)(1)(A) through (F) in a standalone document and incorporate responses to DR BIO-7 through DR BIO-10. Please submit a clean and redline and strikethrough version of the revised information that would be included in an LSAA notification.

DR BIO-11 Response. Appendix 3.2K, Completed 1602 Lake and Streambed Alteration Agreement Application Package, contains the requested information.

The new access roads proposed to be built during project construction are not included in impact maps (e.g., Figures 3.2-1, 3.2-5a, 3.2-7, 3.2-8, and 3.2-9, impact shapefiles, or in the impact analysis (Subsection 3.2.2) and proposed Mitigation Measures (Subsection 3.2.4). These roads extend due west from Tower 10, due south from Tower 9, and approximately northwest from Tower 4 (if the southern gen-tie route alternative is chosen), as shown in Section 1 Executive Summary, Figure 1-3 of the Application (TN 264413). If impacts in these areas (i.e. access roads associated with Towers 10, 9, and 4 as previously described) were not addressed in maps, shapefiles, analysis, or proposed Mitigation Measures, the project is required to update the calculations of project impacts and compensatory mitigation acreage for jurisdictional waters including waters of the state and waters subject to Section 1600 of the California Fish and Game Code, native vegetation communities, special-status species habitat, and numbers of plants (e.g. cacti), subject to the California Desert Native Plants Act. This information is needed for staff to prepare an adequate impact assessment pursuant to CEQA (See also DR BIO-1, Cal. Code Regs. Tit. 20

§ 1704, (a) (3) (A))), in addition to potentially forming part of a lake and streambed alteration application (Appendix B (g) (13) (D) (ii)), if necessary.

DR BIO-12. Please submit updated figures and GIS shapefiles that include all project access roads and any other project-related disturbances, as part of the defined project area (see Fish and Game Code, section 1602).

DR BIO-12 Response. The previously submitted Section 3.2 did include the access roads for the impact and mitigation analysis, but the previous GIS submittal to the CEC accidentally clipped the roads to the gen-tie line work areas. The full GIS data regarding the roads was provided via Kiteworks on October 9, 2025.

The Application does not provide descriptions of species, associated impacts, and project feature or location, and severity or duration of impact, as required by California Code of Regulations, title 20, Appendix B (g) (1) for all special-status species. For example, in Section 3.2.1.10 of the Application (TN 264413), no specific information is provided regarding the location, duration, or type of impact within the Study Area for Blainville's horned lizard (*Phrynosoma blainvillii*). In addition, Section 3.2.1.10 only provides general species accounts and does not provide details for onsite habitat conditions.

DR BIO-13. Provide a table detailing temporary and permanent acres of impact by project component and habitat type within the Study Area.

DR BIO-13 Response. Please see the attached redline version of Section 3.2, Biological Resources. Table 3.2-9, Potential Impacts to Vegetation Communities and Land Covers in the Study Area, provides a breakdown of the impacts, and text has been added to Section 3.2.2.2.1 to provide additional details on how species would be affected by the Project.

DR BIO-14. Clearly depict temporary and permanent impacts throughout the document and include a description of the specific location(s), habitat types being impacted and acreage amounts, and other relevant information. This should include any area added to the project's impacts per DR BIO-12. Please submit a clean and redline and strikethrough version of Section 3.2.5.

DR BIO-14 Response. Please see the attached redline version of Section 3.2, Biological Resources. Additional language has been added throughout Section 2.2.2, CEQA Appendix G Assessment Criteria, to clarify the nature of the temporary and permanent impacts to sensitive resources.

Figure 3.2-2 in the Application (TN 264413) depicts Mountains Recreation and Conservation Authority (MRCA) lands outside a 10-mile buffer distance from the project site. However, page 3.2-4 of states that the northern gen-tie option would span parcels managed by the MRCA that are deed restricted for open space use.

DR BIO-15. Please provide an updated map and/or written description that clarifies the location of MRCA lands in relation to the project components and resolves the apparent inconsistency between Figure 3.2-2 and the text on page 3.2-4.

DR BIO-15 Response. Please see the attached redline version of Section 3.2, Biological Resources. Additional language has been added throughout Section 2.2.2, CEQA Appendix G Assessment Criteria, to clarify the nature of the temporary and permanent impacts to sensitive resources. Please see updated Figures 3.2-2, Protected Areas, and 3.2-3, Local Protected Areas, for a representation of the protected areas surrounding the Project.

The description of which species are included in the “Potential to Occur” table in Appendix 3.2-B (TN 264407) is inconsistent. Further, the methodology used may exclude species found within 10 miles of the project as required by California Code of Regulations, title 20, Appendix B (g) (13) (A).

Page 3.2-7 of the Application (TN 264413) states that “Appendix 3.2B provides a list of special-status species with records within the two (2) USGS 7.5-minute topographic quadrangles (Acton and Pacifico Mountain) and the surrounding 10 quadrangles Study Area during the literature review”, while page 3.2-17 states that a “A list of all special- status plant species known to occur in the vicinity of the Study Area (and the surrounding nine (9) topographic quadrangles) including their habitat requirements, potential to occur onsite, and survey observations, is provided in Appendix 3.2B”. In addition, page 3.2-18 states that “the two [2] USGS 7.5-inch quadrangles that the Study Area is in and the surrounding 10 quadrangles” was used to generate the special- status wildlife list. Therefore, animal species included in the potential to occur table were based on a 12-quadrangle search, while plant species included were based on a 9- quadrangle search.

As the project site is near the eastern edge of the Acton quadrangle, the 9-quadrangle search used for plants excludes areas of the Littlerock and Juniper Hills quadrangles, which are located within 10 miles of the project site. Additionally, as the project site is near the northern edge of the Acton quadrangle, both the 9-quadrangle search used for plants and the 12-quadrangle search used for animals exclude a small portion of the Lancaster West and Lancaster East quadrangles, which are located within 10 miles of the project site.

DR BIO-16. Please revise the methodology used for conducting the special-status species database search to include, at minimum, all areas within 10 miles of the project site per the requirements California Code of Regulations, title 20, Appendix B (g) (13) (A). Include the updated description of methodology, the revised potential to occur table in Appendix 3.2-B, and any relevant species discussion or protective measures accordingly. Please use consistent methods for all species, not separate methods for plants and animals. Please submit a clean and redline and strikethrough version of Section 3.2.5 and Appendix 3.2-B. See also DR BIO-12 and DR BIO 14.

DR BIO-16 Response. Please see the attached redline and clean version of Section 3.2, Biological Resources. Sections 3.2.1.9 and 3.2.1.10 have been updated, and a 14-quadrangle query was used that includes the ones the Study Area is in and the quadrangles that the 10-mile buffer intersects. This was done because the California Native Plant Society’s Rare Plant Inventory only uses quadrangles so a 10-mile query is not feasible. The few additional species were added to the now Appendix 3.2B, Potential to Occur Tables and Compendia.

The list of species observed and the potential to occur tables in Appendix 3.2-B (TN 264407) lack titles or descriptions in the appendix, so it is not clear from Appendix 3.2-B alone what these items are intended to represent.

DR BIO-17. For clarity, please resubmit Appendix 3.2-B and add a title and a brief description of what species are included to both the list of species observed and the potential to occur table in Appendix 3.2-B. Please submit a clean and redline and strikethrough version of the appendix.

DR BIO-17 Response. Appendix 3.2B has been updated and revised to include a title and brief description. The revised Potential to Occur Tables and Compendia are referenced in the attached redline version of Section 3.2, Biological Resources, and updated appendices.

Short-joint beavertail (*Opuntia basilaris* var. *brachyclada*) and other cacti are covered under the California Desert Native Plants Act. However, this state law was omitted from Section 3.2.5. The removal of cacti requires a permit

as well as a fee per plant removed in accordance with the California Desert Native Plants Act (Cal. Food and Ag. Code, division 23, ch. 3 §§ 80071–80075; and ch. 4 §§ 80101–80108). The California Desert Native Plants Act requires that a fee be paid to the County Commissioner for issuance of permits, wood receipts, tags, or seals required for lawful harvest or transport protected species. However, the CEC holds in-lieu authority over any county permits that would otherwise be required for the project and would incorporate permitting requirements into staff's conditions of certification. In order to identify where these species occur, all cacti must be counted and mapped.

DR BIO-18. Please include the California Desert Native Plants Act in the LORS table and include a discussion in Section 3.2.5 of the Application. Please submit a clean and redline and strikethrough version of Subsection 3.2.5 of the Application. See also DR BIO-12, DR BIO-14, and DR BIO-16.

DR BIO-18 Response. Please see the attached redline and clean version of Section 3.2, Biological Resources. The California Desert Native Plants Act was added to Table 3.2-18, LORS Applicable to Biological Resources, and a discussion was added in Section 3.2.5.2.4, California Native Desert Plant Act.

DR BIO-19. Please provide a complete census report of short-joint beavertail, and any other cactus species such as Wiggins' cholla (*Cylindropuntia echinocarpa*), beavertail pricklypear (*Opuntia basilaris* var. *basilaris*), coast prickly pear (*Opuntia littoralis*) on the site, or within 500 feet offsite, including linear features. Please also include maps at an appropriate scale and provide GIS shapefiles with pertinent metadata. See also DR BIO-12.

DR BIO-19 Response. A California Native Desert Plant Act survey report has been prepared and is provided as Appendix 3.2E. The report and Figure 3.2-11, California Desert Native Plant Act Covered Species in the Survey Area, of the redline Section 3.2 provide an exhibit of the mapped individuals. The GIS data of the mapped individuals covered by the act was provided via Kiteworks on October 9, 2025.

California Code of Regulations, title 20, Appendix B (g) (13) (A) (vi) requires the Opt-In application include a discussion of locally significant species that are rare or uncommon in a local context, such as county or region, or is so designated in local or regional plans, policies, or ordinances. Significant Ecological Areas (SEAs) are officially designated areas within Los Angeles County that contain irreplaceable biological resources.

As defined in subsection 22.102 (HH) of the SEA Ordinance, "Sensitive Local Native Resources" include species identified by the Los Angeles (LA) County Department of Regional Planning to be rare or uncommon in the county or within a specific SEA, due to, but not limited to, being at the outer limits of their known range, having declining populations in the region, occurring in naturally small populations, being dependent on habitat that is declining in size and quality, having few records within the region, or having historically been abundant in the region, but for which there are no recent records.

Subsection 22.102 (FF) (3) identifies Sensitive Local Native Resources as a SEA Resource Category 3 classification. As stated in the SEA Implementation Guide (Los Angeles County Planning 2020; Appendix B, pg. 112), the county-wide list for native plant species that meet the definition of "Sensitive Local Native Resources" is currently in development; however, staff is aware that the list has been developed to a degree that currently allows the County to identify certain SEA areas that currently support or potentially support these resources.

Additionally, the SEA Implementation Guide (Los Angeles County Planning 2020; Appendix B. pg. 112) describes that avian species on the Audubon Society's "Los Angeles County Sensitive Bird List" should be considered as "Sensitive Local Native Resources" in all SEAs. The list of species defined as sensitive in Los Angeles County can be found at: <https://planning.lacounty.gov/wp-content/uploads/2022/11/LA-Countys-Sensitive-Bird-Species.pdf>.

DR BIO-20. Please provide documentation, including copies of any correspondence, of whether the applicant coordinated with the LA County biologist at the LA County Department of Regional Planning to determine if there are any known native plant species occurrences that meet the definition of “Sensitive Local Native Resource” within survey area for the generation tie-line.

DR BIO-20 Response. The applicant contacted LA County Planning regarding any special Sensitive Local Native Resources on September 4, 2025 (see Appendix 3.2L). The LA County representative responded on September 8, 2025. In the email response, the applicant was directed to take note of big sagebrush shrubland, juniper woodland, pinyon-juniper woodland, *Petalonyx thurberi*, and *Cylindropuntia echinocarpa*. The applicant was also directed to be on the lookout for anything that seems unusual and to consult Steve Boyd’s flora of the Liebre Mountains to look for anything identified as “scarce” or “local” (see Appendix 3.2C, Resumes of Applicant’s Biologists). The Audubon Society’s Los Angeles County Sensitive Bird List was also checked and greater roadrunner was added to the analysis. If it is determined that native plant species are known to be present, that were not previously addressed, please update the potential for the species to occur accordingly in the “Special-Status Plants” table in Appendix 3.2B of the application.

Additionally, if it is determined that any avian species meeting the definition of “Sensitive Local Native Resource” are not already listed in the table and have the potential to occur within 10 miles of the project area, please resubmit the “Special- Status Wildlife” table in Appendix 3.2B to reflect with the potential to occur within 10 miles of the project area. Please submit a clean and redline and strikethrough version of both tables.

As required by California Code of Regulations, title 20, Appendix B (i) (1) (A), Table 3.2.11 in the Application (TN 264413) states that the project would conform with the LA County Department of Regional Planning requirements under the SEA Ordinance (LA County Code, title 22, division 5, sections 22.102 et seq.) through mitigation in accordance with the ordinance and CEQA guidelines. The ordinance requires the submittal of application materials (see DR BIO-21) that would be necessary for the issuance of a Conditional Use Permit (CUP) or its equivalent under the CEC’s in-lieu permitting authority and in compliance with the currently adopted SEA Ordinance.

It should be noted that Senate Bill (SB) 1425 (passed in 2022; adding Section 65565.5 to the Government Code), and AB 1889 (passed in 2024; amending Section 65302 of the Government Code), mandate updates to open space plans and general plans, focusing on equitable access, climate resilience, rewilding, and wildlife and habitat connectivity. SB 1425 requires cities and counties to update their open-space plan elements by January 1, 2026, while AB 1889 requires updates to general plan conservation elements on or after January 1, 2028. Subsequently, staff is aware that LA County is currently addressing mandated updates to their 2035 General Plan and the SEA Ordinance, which is a component of the Conservation and Natural Resources Element of the general plan.

DR BIO-21. Please provide the following materials to allow CEC to determine whether the project would conform with the SEA Ordinance under the SEA Ordinance:

1. Biological Constraints Map (BCM). The BCM should be consistent with the requirements defined under Section 22.14.190 (D) of the SEA Ordinance and Chapter 6 (pp. 64-65) of the SEA Implementation Guide. Please provide documentation that the BCM has been prepared by a consulting biologist that is on the SEATAC Certified Consultants List at the time of preparation.
2. Conceptual Project Design. A Conceptual Project Design (CPD), required under section 22.102.050 (A) (3) of the SEA Ordinance and consistent with Chapter 5, no. 3 (p. 54) of the SEA Implementation Guide. The CPD can be shown directly on the BCM or separately as a Conceptual Site Plan.

3. **Biota Report.** The SEA Ordinance requires the submittal of a Biological Constraints Report and/or a Biota Report. A Biota Report that includes a thorough discussion of the baseline conditions in the project area will be sufficient for submittal to the CEC and should be a standalone document. The Biota Report, required under section 22.102.080 (B) (1) (b) of the SEA Ordinance should be consistent with the requirements defined in Chapter 6 (pp. 67-68) of the SEA Implementation Guide. Please provide documentation that the Biota Report has been prepared by a consulting biologist that is on the SEATAC Certified Consultants List at the time of preparation.
4. **Protected Tree Report.** A Protected Tree Report is required under section 22.102.070 (C) (2) of the SEA Ordinance. Please submit a standalone report that includes all details defined in number (a) through (e) of that section of the SEA Ordinance. For further guidance, please refer to Chapter 3 of the SEA Implementation Guide. Please provide documentation that the Protected Tree Report has been prepared by a Qualified Arborist or resource specialist as required under the SEA Ordinance.

Please provide any GIS shapefiles used for the development of maps and figures associated with the submittals requested under Items 1 through 4.

DR BIO-21 Response. A biota report has been prepared and is included as Appendix 3.2G. The protected tree report is included as Appendix A of the biota report. The biological constraints map is included as Appendix B of the biota report. The SEA portion of the redline Section 3.2.2.2.5 provides the context of the impact mitigation analysis that has been used in the biota report.

Per California Code of Regulations, title 20, Appendix B (g) (13) (B) regulations the Opt- In Application is required to include a list of species observed within 1,000 feet of the linear facility corridors. However, page 3.2-3 of the Application (TN 264413) describes the Study Area as consisting of the project site and a 100-foot buffer. The Study Area should extend to 1,000 feet for the liner facility corridors. In addition, maps showing areas surveyed were not provided.

DR BIO-22. Please provide a description of species expected to occur, as well as those observed, within 1,000 feet of the linear facility corridors.

DR BIO-22 Response. Please see the attached redline version of Section 3.2, Biological Resources. Statements regarding the observed and expected species and habitats within 1,000 feet of the gen-tie were added to Sections 3.2.1, 3.2.1.9, and 3.2.1.10. It is expected that the species and habitat would be similar to the Study Area because there are no significant changes in topography, geology, or hydrology within that distance.

DR BIO-23. Please provide detailed maps indicating where biological surveys were conducted, including transects, surveys routes, and/or polygons of surveyed area.

DR BIO-23 Response. Please see the attached redline version of Section 3.2, Biological Resources. Figure 3.2-7, Biological Surveys, provides an exhibit of where the surveys occurred.

California Code of Regulations, title 20, Appendix B (g) (13) (B) (iii) requires maps showing “showing any potential jurisdictional features delineated out to 250 feet from the edge of disturbance”. The Aquatic Resources Delineation Report, included as Appendix 3.2-D (TN 264472, TN 264477, and TN 264476) does not meet this requirement. For example, the feature NWW-1c is not mapped as it crosses under the railroad tracks and in addition as it continues to the southwest of the disturbance area.

DR BIO-24. Provide an aquatic delineation that extends 250 feet from the edge of disturbance. Areas where access is not available and disturbance would not occur may be mapped using aerial imagery or similar methods, if distinguished from ground-truthed delineation in maps and narratives.

DR BIO-24 Response. Please see the attached redline version of Section 3.2, Biological Resources. The jurisdictional waters delineation was extended 250 feet from the Project impact limit, as shown in Figure 3.2-1, Hydrologic Features.

California Code of Regulations, title 20, Appendix B (g) (13) (B) (iv) requires GIS data for all data mapped for biological resources.

DR BIO-25. Please provide GIS shapefiles for the biological survey coverage map, juniper map, California Desert Native Plants Act, changes to the waters maps, and any other maps described in the data requests.

DR BIO-25 Response. All requested GIS files were uploaded to Kiteworks on October 9, 2025, as part of this submittal.

Page 3.2-3 of the Application (TN 264413) states that Crotch's bumble bee "survey passes were led by Callie Amoaku, who holds a Memorandum of Understanding (MOU) and Scientific Collecting Permit (SCP) to capture Crotch's bumble bee. Dudek conducted three protocol level surveys for Crotch's bumble bee spaced in June and July 2024 (June 11, July 1 and July 17). The surveys were conducted by qualified biologists with experience in surveying for Crotch's bumble bee." Table 3.2-1 in the Application only lists Callie Amoaku as conducting surveys on June 12, 2024 and May 21, 2025. Callie Amoaku is not listed as conducting surveys on July 1, July 24 or July 25, 2024.

According to CDFW's survey guidance, surveyors must be qualified to conduct surveys for candidate bumble bee species. Qualifications may include coursework, bumble bee- specific workshops, or focused survey experience. Additionally, detailed survey methodology was not included.

DR BIO-26. Please provide an updated resume that demonstrates the qualifications and relevant experience of Josh Elson in conducting surveys for Crotch's bumble bee or other applicable bumble bee survey qualifications. Please provide a detailed description of the survey methodology used for the protocol-level surveys, consistent with CDFW's survey guidance for candidate bumble bee species.

DR BIO-26 Response. An updated resume for Josh Elson is included in an updated Appendix 3.2C, Resumes of Applicant's Biologists. Mr. Elson's and others' inclusion in the surveys was at the discretion of Ms. Amoaku after her assessment of the site's potential to support the species being very low and the lack of any bumble bees being observed.

MM-BIO-5 in Subsection 3.2.4.1 of the Application (TN 264413) proposes the establishment of a conservation easement area that would preserve up to approximately 162 acres of native vegetation communities within the Study Area parcels associated with the gen-tie routes, however this is alternately reported on page 3.2-38 of the application as requiring "the establishment of a conservation area that will preserve up to 648 California juniper acres of Water Resources in the Study Area parcels". In addition, no figures or GIS shapefiles of the proposed compensatory mitigation land are provided, so it is unclear where these lands are located.

DR BIO-27. Clarify the total amount of compensatory mitigation land proposed under MM-BIO-5 and ensure consistency between references to MM-BIO-5 in the application.

DR BIO-27 Response. Please see the attached redline version of Section 3.2, Biological Resources. The total amount of compensatory mitigation land proposed under MM-BIO-5 has been reanalyzed and updated. The applicant shall demonstrate recordation of a conservation easement, as defined by California Civil Code Section 815.1, that permanently preserves up to approximately 136 acres of non-impacted vegetation communities and up to approximately 26 acres of temporary impacted areas that will be restored within the Project boundaries for long-term conservation and management as a natural conservation area (“Conservation Area”). The Conservation Area will be up to approximately 162 acres and located within portions of the Study Area within the Santa Clara River SEA. Table 3.2-17, Unimpacted Vegetation Communities and Land Cover Types in the Santa Clara River Significant Ecological Area Portion of the Study Area That Could Be Conserved, summarizes the potential vegetation communities and land cover that could be preserved.

DR BIO-28. Provide figures and GIS shapefiles showing the proposed mitigation land to be protected under a Conservation Easement.

DR BIO-28 Response. All requested GIS files have been uploaded to Kiteworks on October 9, 2025, as part of this submittal.

The suitability of proposed compensatory mitigation land for each species is not discussed. Additionally, is it unclear which species and habitats (eg. special-status species, habitat types, waters of the state, and individual plants subject to the California Desert Native Plants Act) the proposed compensatory mitigation land is designated as mitigation for.

DR BIO-29. Clarify if compensatory mitigation land for each species and habitat will overlap. Discuss the suitability of the proposed compensatory mitigation land for each species based on information in the requested Biological Technical Report (see DR BIO-1). Identify the aquatic resources and where the aquatic resources would be within the mitigation lands. Clearly identify the exact areas, and provide the number of acres, within the mitigation site where habitat would be provided for species proposed to be covered for take or other compensatory mitigation proposed by the applicant. Identify each area by habitat type (e.g. native vegetation communities).

DR BIO-29 Response. Please see the attached redline version of Section 3.2, Biological Resources. Figure 3.2-13, Conservation Area, was created, and additional clarifying text was added in Section 3.2.2.2.1. The species that would have habitat impacted have the potential to occur in similar habitats to the proposed mitigation land, with the exception of California legless lizard, which would only occur in communities with California juniper.

There is no title report for proposed compensatory mitigation land, and there is no discussion of easements or encumbrances on proposed compensatory mitigation land. It is unclear if there are conflicting easements or encumbrances that would preclude the use of this land for habitat mitigation, such as severed mineral rights, Williamson Act contracts, or subdivision prohibitions. It is also unclear if the land is already conserved, in which case using the land as mitigation would likely not be appropriate. Further, any potential environmental hazards from the proposed mitigation lands’ historic or current uses should be fully investigated and disclosed to determine the feasibility of the proposed mitigation lands.

DR BIO-30. Please provide a title report or similar documentation demonstrating that there are no conflicting easements or encumbrances on the proposed mitigation land, and that the land is not already conserved under a conservation easement or similar mechanisms. Please provide a Phase I Environmental Site Assessment for the proposed mitigation land.

DR BIO-30 Response. The proposed mitigation parcels are located in the SEA and are made up of the same habitat as the land where the potential impacts would occur and thus make them ideal parcels for mitigation. The proposed mitigation land is made up of the following parcels and gross acreages.

APN	Gross Acreage
3056-019-040 (south of railroad tracks)	12.85
3056-017-022	9.25
3056-017-016	5.07
3056-027-007	40.31
3056-015-008	40.06
3056-017-028	9.93
3056-017-027	9.90
3056-017-026	9.39
3056-017-023	40.04
Total Gross Acreage	173.36*

Notes: APN = Assessor's Parcel Number.

* Excludes areas where permanent impacts would occur. There will be up to approximately 3.44 acres of permanent impacts. The gross acreage of the parcels above totals 176.80 acres. Therefore, the total gross acreage when excluding the 3.44 acres of permanent impact is approximately 173.36 acres.

As noted in Table 2-4 in the Project description, the Project gen-tie line will generate less than 5 acres of permanent impacts to the parcels listed above. This leaves over 170 acres of land for potential mitigation needs.

Redacted Preliminary ALTA Surveys have been provided in Appendix 3.2A. The ALTA survey information has been redacted to remove landowner names, non-mitigation land information, and any financial information that may be present in the title reports associated with the ALTA surveys, consistent with applicable privacy concerns. As demonstrated in the ALTA, the parcels being considered for mitigation land are not already conserved, nor do they contain any conflicting easements or encumbrances that would limit or preclude the use of this land for habitat mitigation, such as severed mineral rights, Williamson Act contracts, or subdivision prohibitions. Please note that title report in the Redacted Preliminary ALTA Survey for APN 3056-015-023 includes exception 3 for an oil and gas lease on the APN. That exception has been removed from the title and is no longer applicable to the parcel. Please see the updated title report for APN 3056-15-023 included at the end of the Redacted Preliminary ALTA Survey document.

Phase I Environmental Site Assessment information for the mitigation lands has already been provided in Appendix 3.5A, Hazardous Materials Handling Appendices Part 1 (TN264399 and TN264340), and no current or historical recognized environmental conditions were found.

California Code of Regulations, title 20, Appendix B (i) (1) (B) requires a table of agencies with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies that would have permit approval or enforcement authority,

but for the exclusive authority of the Commission to certify sites and related facilities etc. This table was not provided.

DR BIO-31. Please provide a table of agencies with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies that would have permit approval or enforcement authority, but for the exclusive authority of the Commission to certify sites and related facilities, as required by California Code of Regulations, title 20, Appendix B (i) (1) (B).

DR BIO-31 Response. Please see the attached redline version of Section 3.2, Biological Resources. A table has been added to Section 3.2.6, Permits and Permit Schedule.

The table of agency contacts (Table 3.2-13) in the application (TN 264413) is mislabeled and is missing information. The table is required by Code of Regulations, title 20, Appendix B (i) (2). The email provided for CDFW is to a regional shared email mailbox.

DR BIO-32. Please update Table 3.2-13 to include addresses of agencies as well as names, titles, phone numbers, and correct email addresses, as publicly available, of the person contacted at each agency.

DR BIO-32 Response. Please see the attached redline version of Section 3.2, Biological Resources. Table 3.2-21, Summary of the Agency Contacts, was updated to include only the agency that was directly contacted, County of Los Angeles Regional Planning. CDFW's input on the biological resources for the Project was during a meeting on January 16, 2025, which resulted in the raptor nest surveys. The U.S. Fish and Wildlife Service was not contacted since no species listed under the federal Endangered Species Act or Bald and Golden Eagle Protection Act was expected to occur as a resident or during breeding.

DR BIO-33. Verify that CDFW and the U.S. Fish and Wildlife Service were the only agencies contacted. Alternatively, update the table to add other agency contacts.

DR BIO-33 Response. Please see response to DR BIO-32.

Subsection 3.2 of the Application does not include a schedule of when the applicant expects to receive a 401 water quality certification from the Regional Water Quality Control Board or any other required permit, as required per California Code of Regulations, title 20, Appendix B (i) (3).

DR BIO-34. Please update Section 3.2.6 of the Application to include the estimated timeline for receiving a 401 water quality certification or Waste Discharge Requirement (WDR) from the Regional Water Quality Control Board. If additional state permits are required, please provide similar estimated timelines for each.

DR BIO-34 Response. Please see the attached redline version of Section 3.2, Biological Resources. The expected timeline for the WDR was added to Section 3.2.6, Permit and Permit Schedule.

5 Greenhouse Gases

Battery performance degrades over time, gradually decreasing the round-trip efficiency. Staff expects battery augmentation would be performed to offset battery degradation and maintain Project performance commitments, increasing auxiliary loads. Staff needs to determine the total number of battery enclosures by year 20 which would be the midpoint of the Project's life cycle.

Staff will also need the annual indirect GHG emissions calculations with estimated transmission and charging/discharging cycle losses and auxiliary loads for both the beginning (year-1) and midpoint of the Project life (20-year assuming a 40-year project life, as stated in the application). Staff needs the spreadsheet file of the emissions calculations with live, embedded calculations to complete the analysis.

DR GHG-1. Please estimate the annual indirect GHG emissions (metric tons) from transmission and charging/discharging cycle losses. Please include assumptions that account for the degradation of round-trip efficiency over the project lifetime in the calculation of indirect GHG emissions.

DR GHG-1 Response. Indirect greenhouse gas (GHG) emissions during operations may result from system round-trip efficiency (RTE) losses. The system is expected to start with an RTE close to 88.9% and degrade at rate of approximately 0.2% a year until year 20 (representing the Project life mid-point or average) when it is expected to be approximately 85% (84% RTE including auxiliary loads). In year 20, the Project will require 10,777 megawatt-hours (MWh) to deliver 9,200 MWh of energy to the grid. It is anticipated that the Project would have maximum site buildout in year 20. This RTE results in a loss of 1,577 MWh per charge. The Project will cycle once per day or approximately 365 times per year, which would equate to total annual RTE losses of 575,605 MWh.

An analysis of the California Independent System Operator (CAISO) Service Path 15 prices (where the Project will be injecting energy) and energy mix over the last 5 years was conducted to understand the estimated carbon intensity of the energy that may be used to charge the Project (see Appendix 3.1E in Section 3.1). The analysis assumed the Project would charge during the lowest priced 8 hours of the day and discharge during the most expensive 8 hours of the day.

The analysis showed that the estimated carbon intensity of energy during charging is between 30% and 40%, or 60% and 70% carbon free. If the 5-year average charging carbon intensity is separated by year, the percentage of carbon free energy during charging increases from 44% in 2020 to 88% in 2025.

Year	Average Percent of Carbon Free Energy During Charging
2020	43.94
2021	54.22
2022	55.99
2023	64.86
2024	77.76
2025	88.14*

Note:
* It should be noted that the 2025 average is likely to be artificially high because the year is not complete. The average is skewed towards the higher carbon-free charging numbers found during the summer months.

To provide a conservative annual indirect GHG analysis, the analysis assumed a 40% carbon intensity (i.e., 60% of charging energy was carbon free, similar to the 2023 charging year) of energy during charging for the Project.

GHG emissions associated with RTE losses were estimated in a spreadsheet model to account for the 60% renewables during charging. This is a conservative estimate because it does not account for the offset in high carbon intensity energy that the Project is offsetting when discharging low carbon intensity energy (see Appendix 3.1E subsection 8-Hour Analysis in Section 3.1). Conservatively estimated annual indirect GHG emissions from RTE losses would be approximately 105,077.49 metric tons of carbon dioxide equivalent (MT CO_{2e}) per year. These GHG emissions are also provided in Table 3.1-17 of the redline application section provided herein.

It should be noted that the data in the analysis shows an increasing trend of carbon-free energy in the CAISO energy mix over the last 5 years. The 100 Percent Clean Energy Act of 2018 (Senate Bill 100 [2018]) established state policy for eligible renewable energy resources and zero-carbon resources to supply 100% of retail sales of electricity to California end-use customers by December 31, 2045, with milestone percentages of 50% by December 31, 2026, and 60% by December 31, 2030. Under the Clean Energy, Jobs, and Affordability Act of 2022 (Senate Bill 1020), the state provided additional milestones of 90% by December 31, 2035, 95% by December 31, 2040, and 100% of all retail sales of electricity to California end-use customers by December 31, 2045, and 100% of electricity procured to serve all state agencies by December 31, 2035. Implementation of regulatory actions to implement these policies would further reduce the carbon intensity of energy used for charging, which would result in further decreases to indirect GHG emissions from RTE losses.

DR GHG-2. Please estimate the annual indirect GHG emissions from auxiliary loads. Please include assumptions that account for the BESS efficiency degradation over the project lifetime in the calculation of indirect GHG emissions.

DR GHG-2 Response. In addition to the indirect GHG emissions from system RTE losses, the Project will also generate indirect GHG emissions from energy used to power auxiliary systems, including but not limited to, thermal management systems (TMS), supervisory control and data acquisition system (SCADA), and other energy-consuming equipment. In year 20, the system RTE, including auxiliary losses, is expected to be 84%. The system auxiliary load in year 20 is expected to be 23.17 megawatts (MW). For the purposes of this analysis, auxiliary loads are counted in hours when the Project is not charging or discharging. Auxiliary loads accrue for approximately 8 hours a day for a total expected auxiliary load of 185.4 MWh a day and an annual auxiliary load of 67,664 MWh per year. In CalEEMod, auxiliary loads were summed with the electricity demand for the operations and maintenance (O&M) buildings and parking lot. The CalEEMod default energy intensity factors for SCE for year 2029 were applied to these components.

Conservatively estimated annual indirect GHG emissions from the auxiliary loads for the battery energy storage system (BESS), as well as the O&M buildings and lighting for the parking lot, would be approximately 10,696 MT CO_{2e} per year. These GHG emissions are also provided in Table 3.1-17 of the redline application section provided herein.

DR GHG-3. Please provide a copy of the spreadsheet file of the emissions calculations with live, embedded calculations.

DR GHG-3 Response. A copy of the spreadsheet file of the emissions calculations was provided to CEC staff via Kiteworks on 10/9/2025.

In Appendix 3.1A of the Air Quality and Greenhouse Gas Emissions Modeling and Calculations (page 110/119), the applicant proposes to use R-410A as the refrigerant for “other commercial A/C and heat pumps”. However, the application does not demonstrate how the use of R-410A would comply with the Prohibitions on Use of Certain Hydrofluorocarbons (HFCs) in Stationary Refrigeration, Stationary Air-conditioning and Other End-Uses (California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 on Climate Change, Article 4, Subarticle 5, Section 95374).

In addition, on page 3.1-26 of the Application, it states that during operations and maintenance, one of the sources of GHG emissions could potentially be fugitive emissions from batteries containing difluoromethane (R-32) gas. R-32 has a global warming potential (GWP) of 771 using CO₂ at a reference value of 1 (IPCC 2024). However, according to the HFC prohibitions, new air conditioning units/chillers that use refrigerants with a GWP of 750 or greater have been prohibited. Staff needs analysis to demonstrate that the project would not conflict with regulations adopted for the purpose of reducing the emissions of greenhouse gases. In addition, staff needs clarification on whether R-32 or another refrigerant would be used for the BESS cooling system.

DR GHG-4. Please demonstrate how the use of R-410A, R-32, or any other refrigerant proposed for BESS cooling would comply with the Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Stationary Air-conditioning and Other End-Uses. If not, please propose an alternative refrigerant, and provide updated greenhouse gas emission estimates associated with the newly proposed refrigerant.

DR GHG-4 Response. To ensure compliance with the California Air Resources Board’s Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Stationary Air-conditioning, and Other End-Uses, R-32 is proposed as the refrigerant for both the BESS cooling and the heating, ventilation, and air conditioning (HVAC) systems in the O&M buildings. As of July 2025, R-32 is the standard refrigerant shipped with Sungrow’s Power Titan II. R-32 is also one of the preferred refrigerants of the California Air Resources Board (CARB). With a global warming potential (GWP) of 675, R-32 falls below the regulatory threshold of 750 and is therefore compliant. R-32 is the only refrigerant that is contemplated being used on the Project. The R-410A is a CalEEMod default for commercial A/C and heat pumps for O&M buildings. R-410A has a GWP of 2,088 and does not meet the prohibition requirements. R-32 is a common alternative to R-410A. Less R-32 is needed than R-410A to achieve the same cooling level. In our updated model, we have conservatively assumed the same amount of R-32 for the O&M buildings as we did for R-410A. The CalEEMod default is 0.3 kilograms (kg) per kilopound-force per square foot, which would equate to a total of 0.72 kg of R-32, or 1.6 pounds of R-32. BESS cooling would utilize an estimated 16,151 pounds of R-32, and HVAC in the O&M buildings would utilize an estimated 1.6 pounds of R-32.

GHG emissions associated with R-32 were calculated using standard leak rates and have been incorporated into Table 3.1-17 of the redline application section provided herein.

DR GHG-5. Please explain how the proposed refrigerant(s) would comply with the sale and distribution prohibition timelines established in SB 1206 (Skinner, Chapter 884, Statutes of 2022) (Health and Safety Code, section 39735).

DR GHG-5 Response. The proposed use of R-32 for BESS cooling complies with the sale and distribution restrictions established under Senate Bill (SB) 1206 (Skinner, Chapter 884, Statutes of 2022), codified in

Health and Safety Code Section 39735. This legislation prohibits the sale, distribution, or entry into commerce of bulk HFCs exceeding specific GWP thresholds—2,200 beginning in 2025, 1,500 in 2030, and 750 in 2033. R-32 has a GWP of 675, which is below all current and future thresholds outlined in the statute. It also complies with Section 39735(e) because any leak replenishment with R-32 would be below the 750 GWP threshold. Furthermore, the refrigerant is not being sold or distributed as bulk product but rather used within a closed-loop cooling system. As such, its use does not fall under the scope of the prohibition and remains compliant with SB 1206.

DR GHG-6. Please confirm whether R-32 would be used for BESS cooling. If another refrigerant would be used, please provide the specifications of the refrigerant to be used and provide GHG emissions calculation due to refrigerant leakage.

DR GHG-6 Response. R-32 will be used for BESS cooling and has a GWP of 675. The GHG emissions calculations associated with this refrigerant leakage were provided to the CEC via Kiteworks on October 9, 2025.

In the Application Part 1, TN 264413 Table 3.1-17, under the emission source Energy, the value for total CO₂e emissions is 105,576 MTCO₂e. Please explain all assumptions that went into this calculation. This value seems a bit high for estimated annual operational GHG emissions. Staff needs confirmation whether this value is due to an input error.

DR GHG-7. Please confirm the value for the Energy operations use is 105,576 MTCO₂e, and if not, please revise this value.

DR GHG-7 Response. The value for energy operations use has been revised to 116,340 MTCO₂e per year. This value includes emissions associated with RTE losses, auxiliary loads, building energy, and parking lot lighting. Refer to the responses in DR GHG-1 and DR GHG-2 for additional context and a detailed explanation of how this value was derived.

According to Appendix G of the CEQA Guidelines (Cal. Code Regs. tit. 14, § Div. 6 Ch. 3 App. G) a project cannot conflict with an applicable plan, policy, or regulation adopted for the purpose of reducing the emissions of greenhouse gases (GHGs). In addition, according to Pub. Resources Code § 21183.6(a)(2), the applicant needs to demonstrate mitigation of the impacts resulting from GHG emissions. Staff needs more details on how the project would reduce GHG emissions, especially as it relates to the diesel-fueled emergency backup generators (backup generators) proposed as part of the project.

DR GHG-8. Explain how the proposed installation of the backup generators at the project site is consistent with the State of California's goal of achieving carbon neutrality no later than 2045.

DR GHG-8 Response. The proposed diesel backup generators are intended solely for emergency use to support the reliability of the Project during power outages. Their limited operation (less than 50 hours per year) ensures minimal contribution to overall Project emissions. The generators will comply with applicable CARB standards, CEC, and AVAQMD permitting requirements. As part of a broader clean energy infrastructure, their inclusion enhances grid resilience and supports the integration of renewable energy, aligning with California's long-term carbon neutrality goals. Furthermore, the applicant has committed to using renewable diesel for the Project's emergency generators. However, default carbon intensity for non-renewable diesel was conservatively assumed in the analysis.

DR GHG-9. What other technologies or fuel alternatives to diesel for the backup generators have you explored and why were they not pursued?

DR GHG-9 Response. Backup generators are proposed for emergency backup power due to their proven reliability, scalability, and ability to deliver high-capacity power over extended durations. The applicant will employ renewable diesel to power the backup generators. The facility requires 24 hours of backup at full load—an amount that cannot be feasibly supported by alternative technologies. The applicant discussed utilizing battery power or natural gas, but due to the critical nature of the backup generators, those technologies were not selected. Battery power was not a good solution to provide the 24 hours of back-up desired by the applicant to meet Project reliability needs. Natural gas was investigated but eliminated from consideration due to equipment and fuel supply uncertainty and additional maintenance requirements. Hydrogen fuel cells are not yet commercially viable at this scale.

DR GHG-10. Has the project applicant explored the procurement of renewable diesel and/or carbon offsets as a means of demonstrating consistency with the State of California’s goal of carbon neutrality? If not, why not?

DR GHG-10 Response. The Project will procure renewable diesel to power the backup generators.

In Section 3.1 Air Quality page 4.1-24, under refrigerants, states that the proposed circuit breakers and gas-insulated switchgear would contain sulfur hexafluoride (SF6). However, according to the Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear, which became effective on January 1, 2022, starting on the applicable phase-out dates, no person may acquire SF6 gas-insulated equipment (GIE) for use in California unless one of following provisions apply:

1. An SF6 phase-out exemption was approved by the Executive Officer of the California Air Resources Board (CARB), or SF6 GIE were acquired in response to a failure, pursuant to section 95357.
2. The SF6 GIE device was present in California and reported to CARB pursuant to section 95355(a) for a data year prior to the applicable phase-out date listed in Table 1 or Table 2.
3. The SF6 GIE device was purchased by the GIE owner prior to the applicable phase-out date listed in Table 1 or Table 2 for the relevant GIE characteristics and enters California no later than 24 months after the purchase date.
4. The SF6 GIE manufacturer replaces a defective SF6 GIE device under the terms of the manufacturer's warranty.

Staff needs to confirm which of the four provisions the applicant would rely upon to comply with the current SF6 phase-out regulation and what the applicable phase-out date is based on the proposed GIE characteristics.

DR GHG-11. Please confirm which of the four provisions the applicant would rely upon to comply with the current SF6 phase-out regulation. If the project would not qualify for the exemption, please propose an alternative to SF6.

DR GHG-11 Response. The Project will comply with the Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear, specifically provision 3 of Section 95352:

1. The SF₆ GIE device was purchased by the GIE owner prior to the applicable phase-out date listed in Table 1 or Table 2 [Section 95352] for the relevant GIE characteristics, and enters California no later than 24 months after the purchase date.

DR GHG-12. If the applicant is going to use option 3 of the provisions shown above, please provide the voltage capacity and short-circuit current rating of the proposed circuit breakers and gas-insulated switchgear and applicable phase-out date. Please confirm whether the proposed circuit breakers and gas-insulated switchgear would be purchased prior to the applicable phase-out date and enter California no later than 24 months after the purchase date.

DR GHG-12 Response. Table 2 of Section 95352 states that the phase-out date for equipment, with a voltage capacity greater than 245 kV and all short-circuit current ratings, is January 1, 2033. The only Project equipment that may contain SF₆ would be the 7 × 3-pole breakers that are rated at 550 kV with a short circuit capability of 65 kiloamperes. All equipment has a voltage capacity greater than 245 kV and therefore must be purchased before January 1, 2033, and enter California within 24 months of purchase. The Project will comply with the state provision by procuring the SF₆-containing equipment, listed above, no later than January 2028 and will bring the equipment into California before February 2029.

6 Hazardous Materials Handling

Based on the results of the Phase I site assessments, Section 3.5, Hazards Materials Handling in the Application recommended measure Mitigation Measure (MM) HAZ-1 Railroad Soil and Ballast Management to mitigate potential public health and environmental effects. Under this measure, prior to grading within an approximately 100-foot buffer of the railroad track (“railroad area”), the Project Owner shall conduct sampling and analysis on the ballast rock and soils within this portion of the BESS Facility Site. Ballast rocks within the approximately 100-foot buffer of the railroad track (“railroad area”) will be evaluated for asbestos; asbestos survey, sampling, and analysis must be completed by a technician or supervisor certified for asbestos survey by the California Department of Health. Soils will be sampled and analyzed for polycyclic aromatic hydrocarbons, herbicides, metals, petroleum hydrocarbons, and volatile organic compounds. If analytical results exceed regulatory screening levels applicable to future project development a soil management plan (SMP) will be prepared to manage contaminated soils. According to the Application, the testing and potential development of the SMP shall be submitted to the CPM for review and approval before the Project Owner begins earthwork in the railroad area.

The Soil Sampling and conditional development of the SMP are proposed to be implemented as a mitigation measure (MM HAZ-1), but that testing must occur now during staff’s review of the application. This information will provide the required discussion per Appendix B (g) (1) of the existing site conditions and assist in evaluation of the expected direct, indirect, and cumulative impacts due to the construction, operation and maintenance of the project. Furthermore, the SMP may not be conditional, but must be developed (regardless of measured contamination levels in the sampling) to be in place during project construction to address protocol for suspected contaminated soils identified during construction.

DR HAZ-1. Please prepare and implement a soil sampling plan for the project site consistent with sampling identified in MM HAZ-1 from the application. The actions in the Soil Management Plan shall address contaminated soils identified prior to construction and protocol for suspected hazardous soils identified during construction.

DR HAZ-1 Response. A soil sampling plan was prepared and implemented consistent with the sampling identified in Mitigation Measure HAZ-1 from the application. On August 28, 2025, surface soil samples along the southern border of the Project adjoining the railroad were collected. The results of the sampling showed that no polycyclic aromatic hydrocarbons, total petroleum hydrocarbons, volatile organic compounds, or chlorinated herbicides were detected in any of the five (5) soil samples collected. Lithology observed at the sampling locations was uniform across the site. Lithology from 0 to 6 inches below ground surface consisted of dry, well-graded, light brown, gravelly silty soil. All gravel observed within the sampling areas appeared to be naturally occurring (i.e., not imported ballast rock). Ballast rock was only observed in the immediate vicinity of the railroad tracks, approximately 75 feet south of the Project site. Based on the results of the soil sampling and visual survey, the southern-adjoining railroad has not likely resulted in soil contamination or asbestos-containing ballast rock on the Project site. Additional details about the soil sampling methods and results are available in Appendix 3.5E, and a Soil Management Plan is included as Appendix 3.5F. These details have also been added in the redline version of Section 3.5, Hazardous Materials Handling, attached herein.

Subsection 3.5.2.3.1 of the Application does not adequately discuss fire and explosion risks associated with the project. Specifically, it does not directly discuss potential impacts of lithium battery fires during transportation of

lithium batteries to the project site. The project would increase the potential for an accident involving lithium batteries being transported to the project site. Recent semi-truck accidents involving lithium batteries have resulted in the shutdown of I-80 near Nyack and I-15 near Baker.

DR HAZ-2. Please discuss actions that the project would implement to reduce the probability of lithium battery fires during transportation of batteries to and from the project site and actions to reduce the impact of such fires (if they occur) to motorists and nearby sensitive receptors.

DR HAZ-2 Response. The Project would implement the following actions to reduce the probability of a lithium battery fire during transportation.

- The Project would follow the manufacturer's recommended transportation best practices, including, but not limited to, advanced route inspection to note road conditions, height limits, actual heights and widths, weight limits, traffic restrictions, potential obstructions, any potential weight limits on bridges, proper vertical transportation of the BESS units, properly securing the BESS during transport, and transporting the BESS with cells at a state of charge 30% or less.
- The Project would notice first responders along the route of the BESS deliveries and the duration of the delivery periods.
- The Project would also require the freight company to have a contingency plan prepared for emergency situations (vehicle breakdown, accident, diesel spill, fire, explosion, etc.) during transportation of goods. Once the freight company is selected, a contingency plan would be reviewed and available in every transport truck and on site.

Subject to the requirements of the individual freight companies, the following procedures will be followed in the event of a vehicle breakdown, accident, or other event.

TRANSPORTATION CONTINGENCY PLAN

This plan outlines the procedures and requirements for the safe and compliant transportation of lithium batteries in bulk by truck, in accordance with the U.S. Department of Transportation (DOT) Hazardous Materials Regulations (HMR), 49 C.F.R. Parts 171-180.

1. **REGULATORY FRAMEWORK:** All activities covered by this plan shall be conducted in strict adherence to:
 - 1.1. 49 C.F.R. Part 171: General Information, Regulations, and Definitions.
 - 1.2. 49 C.F.R. Part 172: Hazardous Materials Table, Special Provisions, Hazardous Materials Communications, Emergency Response Information, Training Requirements, and Security Plans.
 - 1.3. 49 C.F.R. Part 173: Shippers - General Requirements for Shipments and Packagings, specifically §173.185 Lithium cells and batteries.
 - 1.4. 49 C.F.R. Part 177: Carriage by Public Highway.
 - 1.5. 49 C.F.R. Parts 178 & 180: Specifications for Packagings & Continuing Qualification and Maintenance of Packagings (as applicable).

2. CLASSIFICATION OF LITHIUM BATTERIES (Ref: §172.101, §173.185)
 - 2.1. Responsibility: The shipper is responsible for correctly classifying the lithium batteries. The freight company will verify shipper documentation.
 - 2.2. Proper Shipping Name (PSN) & UN Number:
 - 2.2.1. UN3480, Lithium ion batteries
 - 2.2.2. UN3481, Lithium ion batteries contained in equipment / packed with equipment
 - 2.2.3. UN3090, Lithium metal batteries
 - 2.2.4. UN3091, Lithium metal batteries contained in equipment / packed with equipment
 - 2.3. Hazard Class: Class 9 (Miscellaneous hazardous material).
3. Immediate Response:
 - 3.1. Safety First:
 - 3.1.1. Apply the braking system, stop the engine and isolate the battery.
 - 3.1.2. Turn on hazard lights, set up warning devices (safety triangles), and ensure the driver's safety.
 - 3.1.3. When exiting the vehicle, take the transport documents and emergency procedure guides.
 - 3.1.4. Move away from the vicinity of the accident or emergency. Advise other persons to move away and follow the advice of the emergency services.
 - 3.1.5. Avoid sources of ignition. Do not smoke, use electronic cigarettes or similar devices, or switch on any electrical equipment.
 - 3.2. Contact and Reporting:
 - 3.2.1. Immediately notify dispatch or designated personnel about the breakdown, including location, nature of the problem, and any potential hazards.
 - 3.2.2. Where possible, make any mobile phone calls away from the vehicle.
 - 3.2.3. In the event of an accident or fire inform the appropriate emergency services, giving as much information about the incident or accident and substances involved as possible.
 - 3.2.4. Keep transport documents readily available for responders on arrival.
 - 3.2.5. Do not walk into or touch spilled substances. Avoid inhalation of fumes, smoke, dust and vapors by staying up-wind.
 - 3.3. Small Fires:
 - 3.3.1. Where appropriate and safe to do so, use fire extinguishers to put out small/initial fires in tires, brakes and engine compartments.
 - 3.3.2. Drivers should only fight fires directly involving dangerous goods if it is safe to do so.
 - 3.3.3. Where appropriate and safe to do so, use on-board equipment to prevent leakages into the environment or the sewage system and to contain spillages.
 - 3.4. Documentation: Document the incident, including time, location, driver's name, and any relevant details.
 - 3.5. Call for Assistance: Initiate the process for towing, repair, or alternative transportation, depending on the situation and location.

4. Communication:
 - 4.1. Internal Communication: Keep dispatch, management, and relevant departments informed about the breakdown and its potential impact.
 - 4.2. External Communication: Notify customers of the potential delay, providing estimated delivery times and any alternative options.
 - 4.3. Transparency: Maintain open communication with customers throughout the process, keeping them updated on the situation.
5. Long-Term Solutions and Alternatives:
 - 5.1. Identify Backup Resources: Have a plan for alternative vehicles, drivers, and routes in case of a breakdown.
 - 5.2. Evaluate Repair Options: Assess the feasibility of repairing the vehicle on-site, at a nearby facility, or at a designated maintenance location.
 - 5.3. Consider Alternatives: If repairs are not feasible, explore options like rerouting, rescheduling, or utilizing alternative transportation methods.
6. Additional Considerations:
 - 6.1. Technology: Utilize technology like GPS tracking, telematics, and communication tools to monitor vehicles and facilitate communication.
 - 6.2. Risk Assessment: Regularly assess potential risks and update the contingency plan accordingly, considering factors like weather, traffic, and road closures.
 - 6.3. Training: Provide adequate training for drivers on how to handle breakdowns and communicate effectively with dispatch and customers.
 - 6.4. Emergency Kit: Ensure vehicles have a well-stocked emergency kit with essential tools and supplies.

In addition to implementing the transportation best practices stated above, the Project will also implement site storage best practices for any BESS enclosure that is delivered to the site and stored for 30 days or more. Best practices include, but are not limited to, storing the BESS unit in areas that do not accumulate standing water during the rainy season; raising the container storage pad to a reasonable height based on geologic and meteorological conditions; storing the BESS on dry flat ground that does not exceed a slope of 5 degrees; ensuring all doors are closed and locked; limiting storage environment temperatures to be between -30 degrees Celsius and 50 degrees Celsius; storing in an area with a relative humidity between 0% and 100%; covering air inlets and outlets with a protective film to reduce the potential for rain, dust, or sand entry; and inspecting the equipment every 14 days.

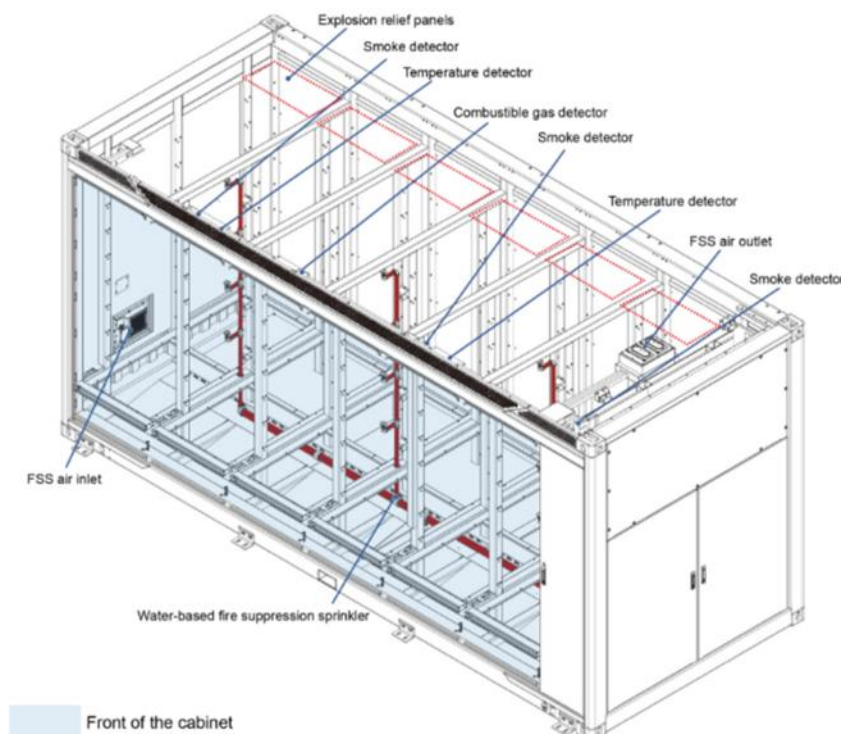
Subsection 3.17.2.4 also fails to adequately discuss fire and explosion risks associated with the project. The Application describes the representative BESS enclosure as the Sungrow Power Titan II, with a lithium iron phosphate battery technology. Subsection 3.17.2.4 states “Each BESS enclosure will be NFPA 855, NFPA 68, and NFPA 69 compliant. Each BESS enclosure will be equipped with an automatic fire alarm and linkage control system, an explosion relief system, a combustible gas detection and alarm system, and an exhaust system.” However, the Application does not provide detailed information on the explosion control and gas detection systems which are intended to mitigate fire and explosion risks.

Staff requires additional details for the project's proposed explosion control and gas detection systems in order to verify that the project has adequate features to mitigate adverse impacts to operations personnel, emergency first responders, and the public.

Staff requires complete descriptions of project features including but not limited to: the location(s) of project features, the specific listings and design standards, the more stringent local fire department requirements, and all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document.

DR HAZ-3. Provide a schematic and complete description of the proposed explosion-control systems (e.g., exhaust systems, deflagration-relief venting systems, barricades, etc.) for the representative BESS enclosure. Provide a description of how the proposed explosion control systems will comply with the applicable NFPA standards (e.g. NFPA 68, 69, 855, etc.) and the Los Angeles County Fire Department requirements.

DR HAZ-3 Response. The Power Titan II is equipped with an automatic fire alarm and linkage control system, vent panels, a combustible gas detection and alarm system, and an exhaust system. It is equipped with combustible gas detectors, smoke detectors, and temperature detectors. If any abnormality is detected, the battery system controller (BSC) connects to local controller (LC) via Ethernet for alarm signaling, control of the battery enclosure shutdown, and control of the system for corresponding logic control.



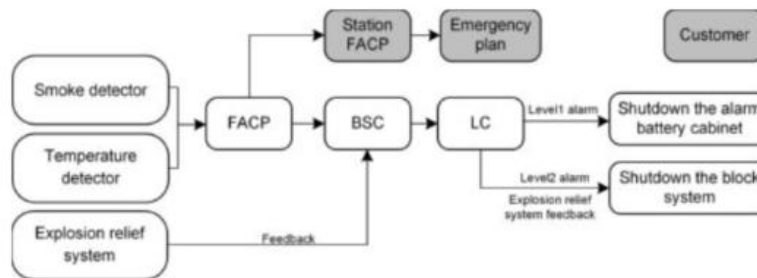
The Power Titan II includes a two-tiered explosion control system. The first is a passive system that consists of six deflagration vents (referred to in the System Manual as explosion relief plates) located on the roof of

the cabinet, which operate at 0.01 megapascals (Mpa). The system is designed in accordance with the guidelines of NFPA 68.

Explosion relief panels are considered a “passive” solution, which means they are triggered by pressure itself and do not require electronic intervention. When the pressure reaches 0.01 Mpa, the relief panels open and feedback the status of the relief panels.

1. When any one of the smoke and temperature detectors is triggered, it will be judged as a level 1 alarm, and the signal will be fed back to the BSC. The BSC transmits the alarm signal/feedback signal to the LC, which receives the level 1 alarm and controls the battery cabinet shutdown.
2. When the smoke and temperature detectors act at the same time, it will be judged as a level 2 alarm, and the signal will be fed back to the BSC. The BSC transmits the alarm signal/feedback signal to the LC, which receives the level 2 alarm and controls the enclosure system shutdown.
3. When the battery cabinet pressure reaches 0.01 Mpa, the relief panels open, and the feedback relief panels status is triggered. The BSC transmits the alarm signal/feedback signal to the LC. The LC receives the vent panel feedback signal and controls enclosure system shutdown.

The control logic for the explosion relief system is shown in the figure below. Note, NFPA 68 requires vent plates/panels to be secured to the container such that they do not become projectiles during a deflagration event.



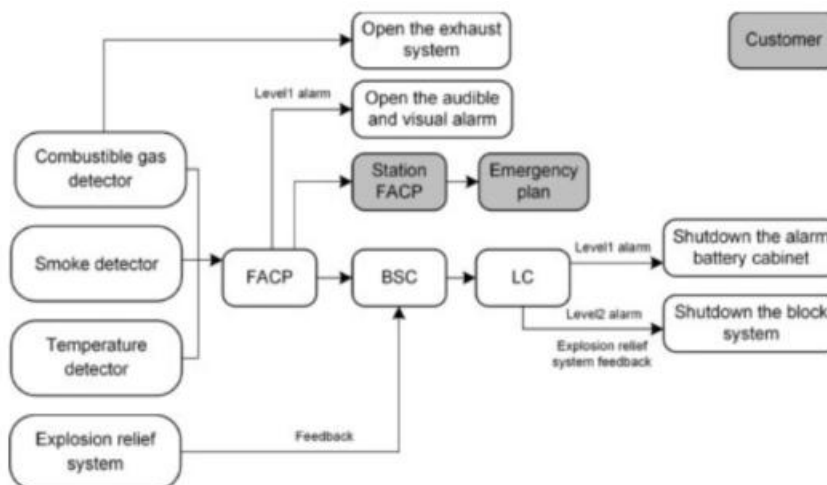
The Power Titan II is also equipped with an emergency ventilation system, also known as an explosion control system (ECS). The ECS is designed based on the principal of combustible concentration reduction in accordance with NFPA 69. The ECS includes an explosion-proof fan to exhaust concentrating gases and make-up air louvers.

The combustible gas alarm system and the ECS are installed in the battery cabinet for fire warning.

1. Once the concentration of combustible gas in the protected area reaches 10% lower explosive limit, the combustible gas detector operates and activates the exhaust system.
2. When any one of the detectors of combustible gas, smoke, or temperature detectors is triggered, it will be judged as a level 1 alarm and activate audible and visual alarms. The BSC transmits the alarm signal/feedback signal to the LC. The LC receives the level 1 alarm and activates the alarm battery cabinet shutdown.
3. When the smoke and temperature detectors act at the same time, it will be judged as a level 2 alarm, and the signal will be fed back to the BSC. The BSC transmits the alarm signal/feedback signal to the LC, which receives the level 2 alarm and activates the enclosure system shutdown.

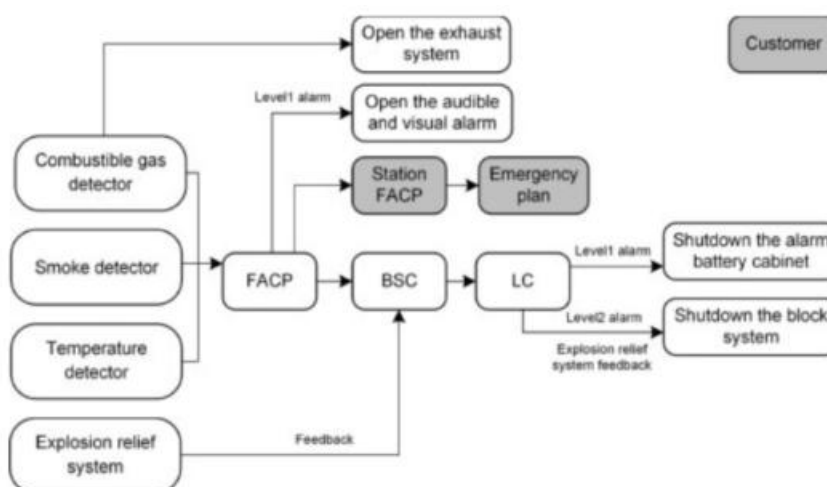
4. When the enclosure pressure reaches 0.01 Mpa, the relief panels open, and feedback relief panels status is updated. The BSC transmits the alarm signal/feedback signal to the LC. The LC receives the explosion relief panel feedback signal and activates the enclosure system shutdown.

The control logic for the ECS is shown in the figure below.



DR HAZ-4. Provide a schematic and complete description of the proposed gas detection systems for the representative BESS enclosure. Provide a discussion of the toxic vapors/emissions that could be produced if a battery container is damaged or thermal runaway occurs. Provide a discussion of the specific gas(es) or vapor(s) intended to be detected.

DR HAZ-4 Response. The BESS enclosure will be equipped with a flammable gas detector, an air inlet device, and an outlet device. When the gas concentration reaches 10% lower explosive limit, the flammable gas detector triggers to open the emergency ventilation system/ECS.



The UL9540A tests measured the volumes of gas released by the module during a thermal incident. The module level UL9540A test provides a representation of the types of emissions present if a thermal event were to occur. Per the UL9540A module level test, the following gases were measured.

Gas Name	Chemical Structure	Total Volume of Gas (L)
Carbon Monoxide	CO	161.06
Carbon Dioxide	CO ₂	492.30
Hydrogen	H ₂	897.30
Methane	CH ₄	104.20
Ethylene	C ₂ H ₄	79.72
Ethane	C ₂ H ₆	99.23
Propylene	C ₃ H ₆	269.60
Total Hydrocarbons	(Propane Equivalent)	734.20

Each Power Titan II enclosure is equipped with a combustible gas detection monitor. The gas detector monitors: hydrogen (H₂); carbon monoxide (CO); volatile organic compounds (VOCs); and electrolyte vapors, including diethyl carbonate (DEC), dimethyl carbonate (DMC), ethylene carbonate (EC), and propylene carbonate (PC). The gas detectors can trigger the ECS to open the air inlets/outlets. Gas detection and alarm signals are processed in real time, and faults are indicated within 200 seconds per NFPA 72.

7 Project Description

California Code of Regulations, title 20, Appendix B (b) (1) (C) requires a detailed description of the design, methods of construction (include depth of excavations and other ground disturbances) and operation. Section 2 Project Description, subsection 2.3.1.1 notes that the project will implement an augmentation strategy to maintain the contractually required capacity of the system as the battery cells will naturally degrade over time. Augmentation is described as entailing either a capacity maintenance approach of adding/replacing individual battery modules in the existing BESS yard or designing the BESS system to incorporate space for additional BESS enclosures for later augmentation. Table 2-8 includes one way vehicle trips, and a list of equipment used for battery enclosure/power conversion system installation with a note that the table includes augmentation assumptions.

DR PD-1. Please identify the augmentation assumptions used for preparing the environmental analysis.

DR PD-1 Response. The Project design and analysis front loads the work for the Project augmentation and assumes that it will install the end-of-life capacity at the start of construction. This assumption is made to capture augmentation impacts during construction instead of trying to assume the augmentation schedule for the Project. Equipment type/specifications, capacity agreements, and tax incentives can all change how and when augmentation is completed. Front loading augmentation to occur during construction creates a conservative case for the analysis of potential impacts that could arise from augmentation and sets a maximum impact envelope for the Project. During Project operations, the Project analysis assumes that one (1) crane and one (1) forklift will operate in support of augmentation once every 3 to 5 years for 8 hours per day.

The applicant response is also included in the redline to Section 2.3.1.1.

8 Socioeconomics

Appendix B (g)(7)(B)(j): An estimate of the number of workers to be employed each month by occupation during construction, and for operations, an estimate of the number of permanent operations workers during a year. Staff needs additional information on the construction workforce.

DR SOCIO-3. Section 3.10 Socioeconomics, Table 3.10-11 on page 3.10-15 of the application provides monthly employment estimates. The monthly estimates are listed by crew type. Provide the occupations that make up each crew and the number of workers in those occupations per month.

DR SOCIO-3 Response. Table 3.10-11 has been updated to include the monthly labor occupations that make up each crew type. Please see the updated Section 3.10 redline included with this data response. Note: Redlines from the applicants' previous response to DR SOCIO-1 and DR SOCIO-2 (TN265873 and TN265874) are included in the attached redline of Section 3.10.

9 Water Resources

Appendix 3-15A, Attachment J, Hydrology Study (TN 264384), is missing pages 3-5, which are supposed to include existing and proposed conditions, as well as surface runoff modeling and flood analysis results, as required by California Code of Regulations, Title 20, Appendix B (g)(14)(B)(ii).

DR WATER-1. Please submit a complete version of the hydrology study to the project docket.

DR WATER-1 Response. A standalone, complete version of the hydrology study (Appendix 3.15A, Attachment J (TN264384) is attached.

California Code of Regulations (CCR) Title 20, Appendix B (g) (14) (C) (ii) requires the physical and chemical characteristics of the water supply source to be described.

However, Table 3.15-2 of the application only includes concentrations of nitrates for four of the eight local wells listed and total dissolved solids (TDS) for one well.

DR WATER-2. Please submit a full suite of general water chemistry and organic compound analytical results for existing local wells.

DR WATER-2 Response. Title 22 water quality sampling was performed on the Project well on August 28, 2025. The groundwater sample (Sample ID: 1222SC) was analyzed for the full Title 22 analytical suite, including general chemical and physical, microbiological, metals, radiochemistry, volatile and semi-volatile organic compounds, synthetic organic compounds, and asbestos analyses by Clinical Laboratory. Constituents that were detected above laboratory reporting limits were compared against California Title 22 primary maximum contaminant levels for regulated constituents in drinking water and against secondary maximum contaminant levels related to aesthetic aspects of drinking water (i.e., taste, odor, and appearance). None of the constituents detected in the groundwater sample collected from the domestic well at 1222 Soledad Canyon Road exceeded respective primary or secondary maximum contaminant levels.

For a full results of the groundwater quality sampling analysis please see Appendix 3.15C, Title 22 Water Quality Sampling Memorandum.

Septic System

Several instances in the application note that the operations and maintenance (O&M) building will be serviced by a septic system to process sanitary wastewater (Section 2 Project Description, subsection 2.3.1.10, Section 3.6 Land Use, subsection 3.6.2.3.1, Section 3.10 Socioeconomics, subsection 3.10.1.7.3 and Section 3.11 Soils, subsection 3.11.2.3.4). However, some of these references are contradictory. In particular, Appendix 2A, drawing PSR-SE-101, depicts a leach field near the proposed O&M building, while Section 3.16 Wildfire, subsection 3.16.2.3.3, describes a septic tank to be periodically pumped out for off-site disposal.

DR WATER-3. Please clarify whether the proposed septic system will be a leach field system, or a septic tank with periodic off-site disposal.

DR WATER-3 Response. The proposed septic system will be tank based with periodic off-site disposal. Drawings PSR-SE-101_S001 (TN265873) and PSR-SE-101_S002 (TN265873) have been updated to reflect a septic tank system.

Subsection 2.3.1.10 indicates the facility will contain a septic system to service the O&M building. Drawing No. PSR-SE-101 (App 3-15A Water Quality Management Plan Part 1) depicts a septic field in the upper eastern corner of the western underground storm water detention area. In accordance with California's 2022 Water Supply Strategy, an advanced onsite wastewater treatment system (OWTS) could be employed to treat sanitary wastewater and use recycled water for non-potable applications, such as landscape irrigation. Please note that an advanced OWTS would require coverage under the Regional Board Order No. R4-2019-0024 "General Waste Discharge Requirements for Advanced Onsite Wastewater Treatment Systems".

DR WATER-4. Please evaluate if an advanced OWTS would be a feasible alternative to process sanitary wastewater from the O&M building.

DR WATER-4 Response. An advanced on-site wastewater treatment system would not be a feasible alternative to process sanitary wastewater from the O&M building due to the technological problems treating very low flows and is unnecessary because the wastewater will be adequately treated and the treated wastewater will not be lost to the system.

The intent of the 2022 California Water Supply Strategy is to secure California's water future, which includes four (4) primary objectives, including recycling wastewater that would otherwise be lost to the system, recharging the groundwater basins with non-potable water, creating groundwater storage, and increasing efficiency of water use. The request to assess the feasibility of advanced treatment was premised on the use of recycled water that would be discharged to the ocean (California Water Supply Strategy Section 1.1) or otherwise lost to the system. Here, however, the wastewater would not be discharged to the ocean and will not be lost as a resource due to utilization of a septic system that ultimately recharges the underlying aquifer. The wastewater here would instead remain available for reuse by being discharged to a septic system that utilizes the underlying soil to further treat the wastewater as it flows by gravity back to the underlying aquifer where it can be utilized again. Therefore, this Project is in compliance with the objectives of the California Water Supply Strategy because not only is this wastewater not lost to the system, this non-potable wastewater is being used to recharge the groundwater basin, which eliminates the entire need for an advanced on-site wastewater treatment system.

Regardless of the justification for assessing the feasibility of an advanced on-site wastewater treatment system, such a system would not be a feasible alternative to process sanitary wastewater from the O&M building due to the problems associated with low flows. Pursuant to its water supply assessment, once construction is complete, the Project will have an estimated operational water demand of 160 gallons per day (16 employees × 10 gallons per employee per shift) for 260 shifts per year (TN264388 and TN264389). This equates to approximately 114 gallons per day based on 365 days per year. An advanced wastewater treatment system differs from a septic field (as proposed by the Project) because an advanced wastewater treatment system relies on the additional use of biological treatment for the generated waste. In order to operate a biological treatment system on a consistent and reliable basis, there must be a sufficient amount of flow on a regular basis to ensure the microorganisms responsible for the biological treatment do not starve. Typically, a flow of at least 250 gallons per day is the minimum amount to ensure the consistent and efficient operation of an advanced wastewater treatment system. The National Sanitation Foundation, in conjunction with the American

National Standards Institute, certifies domestic wastewater treatment systems but does not have a standard for a flow below 400 gallons per day. Since the anticipated flow of the Project is less than half of the flow needed to ensure consistent and efficient operation of an advanced on-site wastewater treatment system, the use of an advanced on-site wastewater treatment system is not feasible.

Stormwater Management

Many of Appendix 2A design drawings (TN264409) depicting stormwater and erosion control features are not oriented consistently.

DR WATER-5. Please submit a revised version of Appendix 2A where all the design drawings are oriented in the same direction.

DR WATER-5 Response. A revised version of Appendix 2A design drawings (TN264409) where all the design drawings are oriented in the same direction is attached. Please note, the revised sheets discussed above in DR WATER-3 and other revised sheets provided in Data Request Response 1 Part 1 (TN265874) are included in this revised version. The drawings included in the revised version of Appendix 2A design drawings supersede the previously filed version (TN264409).

An incised ravine in the western portion of the proposed BESS facility, south of Soledad Canyon Road was noted as potential waters of the United States (NWW-1A) in the aquatic resources delineation (TN 264474). Appendix 2A, Grading and Drainage Plan, Drawing No. PSR-CS-004 S010 shows an existing culvert under Soledad Canyon Road leading to the ravine. Appendix 2A, Energy Dissipator Details, Drawing No. PSR-CS-010 depicts a pipe leading into the inlet box of the energy dissipator. However, there are no design plans showing a pipeline that diverts stormwater from the ravine under the southeast portion of the BESS facility.

DR WATER-6. Please provide design drawings and text that explains how stormwater from the ravine will be addressed if a pipeline under the southeast portion of the BESS facility is not used to convey stormwater from the ravine, or provide design drawings that depict the pipeline that connects with the inlet box of the energy dissipator.

DR WATER-6 Response. Revised Appendix 2A design drawing PSR-CS-004 S011 shows how flows from the 36-inch culvert crossing Soledad Canyon Road will be conveyed around the site. The site design shows the 36-inch culvert flowing into an open grate manhole connected to a 60-inch storm sewer pipe. That pipe will then head east, south, and west around the Project site until it connects to the hydraulic dissipator located on the southern boundary of the BESS site. There four (4) additional stormwater manholes that connect to the 60-inch storm sewer pipe before flows exit the site.

Stormwater Industrial General Permit

Based on the Applicant's Standard Industrial Classification Codes 3691 and 5063, the project is not covered by State Board Order WQ 2014-0057-DWQ, as Amended By Order WQ 2015-0122-DWQ & Order WQ 2018-0028-DWQ.

DR WATER-7. Please indicate in the pertinent section of the application whether enrollment under this order is necessary.

DR WATER-7 Response. Enrollment under State Board Order WQ 2014-0057-DWQ, as amended by Order WQ 2015-0122-DWQ and Order WQ 2018-0028-DWQ, is not necessary. Please refer to Section 3.15.5.2 (National Pollutant Discharge Elimination System Industrial General Permit subheading on page 3.15-24) for a redline of the original application section for additional details.

Basin Plan, Water Quality Objectives and Beneficial Uses

Section 3.15 Water Resources, subsection 3.15.1.3.1 of the Application should include the Water Quality Control Plan: Los Angeles Region Basin Plan for the Coastal Watersheds of Los Angeles and Ventura Counties (Los Angeles Basin Plan) and Water Quality Control Plan for the Lahontan Region (Lahontan Basin Plan), and the applicable groundwater quality objectives and beneficial uses for the Antelope Valley Groundwater Basin. Please note that the project overlies the Antelope Valley Groundwater Basin, which is included in the Lahontan Basin Plan and managed by the Lahontan Regional Water Quality Control Board; however, the facility location is within the jurisdiction of the Los Angeles Water Board.

DR WATER-8. Please include a narrative in Subsection 3.15.1.3.1 describing the Los Angeles and Lahontan basin plans.

DR WATER-8 Response. A narrative describing the Los Angeles and Lahontan basin plans has been added to the following Subsections: 3.15.1.2, 3.15.1.3.1, and 3.15.5.2. Please see attached for a redline of the original application section.

Dredge and Fill Permit Application

The Los Angeles Regional Water Quality Control Board (LARWQCB) conducted a review of the Clean Water Act Section 401 Water Quality Certification/Waste Discharge Requirements submittal as part of the Application for the Prairie Song Reliability Project (TN 264473 through TN 264475) and determined several elements were missing.

Moreover, there are some contradictions in the Aquatic Resources Delineation Report (TN 264474, Attachment D) regarding the assessment of Federal and State review areas. Table 3, USACE Aquatic Resource Summary of the Aquatic Resources Delineation for the Review Area shows the same acreage as non-wetland waters of the state shown in Table 4, RWQCB Aquatic Resource Summary for the Review Area. In addition, on page 7, it is stated that “Due to the arid conditions of the Review Area, non-wetland waters were delineated to the OHWM mark at the top of bank, if present.” Furthermore, according to the LARWQCB, no application for dredge and fill waste discharge requirements has been received by their office.

DR WATER-9. Please provide the following items that appear to be missing from dredge and fill waste discharge requirements application:

- Receiving Water Body, Hydrologic Unit Code (HUC-12) per the Los Angeles Water Board’s Basin Plan (reference the Chapter 2: Beneficial Uses Tables for the HUC & Appendix 1)
- An aquatic resources jurisdictional delineation map and report that identifies the waters of the state jurisdiction.
- An impact area map (temporary and permanent areas should be clearly identified).
- Site-specific BMPs (narrative format).

Please note that an application fee per the [Dredge or Fill Calculator](#) is required with the LARWQCB application submittal and additional project fees need to be confirmed with the assigned LARWQCB staff. Also, a CEQA Notice of Determination Form/State Clearinghouse No. and CEQA documents will be required when available.

DR WATER-9 Response. The receiving water body is Kentucky Springs Canyon (HUC 180701020102), which is a tributary to Santa Clara River Reach 8. The Aquatic Resources Delineation Report and Sections 3.2.1.8 have been revised with the additional features that were delineated and have consistent acreage for the waters of the state in the review area. Figure 4 in Attachment B of Appendix 3.2K, Figures, showed the permanent and temporary impacts by Project component, which has been updated with the additional delineated features. Site specific best management practices in a narrative format have been added to Section Eight, Avoidance and Minimization Measures, of the WDR application form, which will be submitted to the Los Angeles Regional Water Quality Control Board per DR WATER-11.

DR WATER-10. Please clarify the statement “Due to the arid conditions of the Review Area, non-wetland waters were delineated to the OHWM mark at the top of bank, if present,” since the top of bank is usually LARWQCB jurisdiction.

Please note that a site visit with LARWQCB staff will be necessary to confirm the delineation of the waters of the state for DR WATER-9 and DR-WATER-10. If the delineation needs to be updated, the permanent and temporary impacts should be recalculated.

DR WATER-10 Response. The waters of the state and CDFW’s streams were delineated at the top-of-bank for non-wetland waters. The statement in Section 3.2 in the Aquatic Resources Delineation Report has been revised to the following: “Non-wetland waters were delineated to the top of bank and are concurrent with CDFW jurisdictional limits.”

DR WATER-11. Please submit an application for dredge and fill waste discharge requirements to the LARWQCB office, addressed attention Celine Gallon and cc Adam Taing.

Be advised that LARWQCB staff are available to clarify any questions regarding data requests DR WATER-9 through DR WATER-11.

DR WATER-11 Response. Per Section 25545.1 (b) (2) of the Public Resources Code, the permitting authority of the State Water Resources Control Board and associated Regional Water Quality Control Boards are not superseded by the CEC “in-lieu of” authority.

If a 401 permit is required, the Los Angeles Regional Water Quality Control Board would retain their authority.

10 Worker Safety and Fire Protection

Section 3.17 Worker Health and Safety, subsections 3.17.2.3.1 and 3.17.2.3.2 of the Application outline components of the Construction Health and Safety Program and the Operation Health and Safety Program, respectively. The application includes Table 3.17- 5 listing Worker Health and Safety Laws, Ordinances, Regulations, and Standards (LORS). However, Table 3.17-5 does not provide a comprehensive list of critical LORS relied upon for the outlines of the Construction/Operation Health and Safety Programs as required by California Code of Regulation, title 20, Appendix B (i) (1) (A). Staff is not suggesting that all occupational safety and health LORS be discussed in detail, however, critical LORS must be explicitly listed and referenced. Furthermore, Table 3.17-6 does not specify the applicable permits as required by California Code of Regulation, title 20, Appendix B (i) (1) (B).

DR WS-1. Provide a revised Table 3.17-5 with specific section references to the Cal/OSHA regulation sections (Title 8 California Code of Regulations) for all programs outlined in Sections 3.17.2.3.1 and 3.17.2.3.2 for the Construction Health and Safety Program and the Operation Health and Safety Program, respectively.

DR WS-1 Response. Table 3.17-5 (now Table 3.17-6) has been updated to include specific section references to the California Occupational Safety and Health Administration regulation sections (Title 8 California Code of Regulations) for all programs outlined in Sections 3.17.2.3.1 and 3.17.2.3.2. Please see attached redline version of Section 3.17 of the application.

DR WS-2. Provide a revised Table 3.17-5 with the correct reference to the California Fire Code requirements for electrical energy storage systems: Title 24, Part 9, Chapter 12, Section 1207.

DR WS-2 Response. The reference has been corrected. Please see attached redline version of Section 3.17 of the application.

DR WS-3. Provide a revised Table 3.17-5 with a comprehensive list of NFPA standards relied upon for the project's fire suppression systems e.g. NFPA 22, 24, 850, 855, etc.

DR WS-3 Response. Table 3.17-5 (now Table 3.17-6) has been updated to include references to NFPA 855, 850, 72, 68, 69, 22, and 24. Please see attached redline version of Section 3.17 of the application.

DR WS-4. Provide a table of applicable state and local agencies with jurisdiction to issue permits, and a list of the specific permits, for worker health and safety, and fire extinguishing and fire suppression systems during construction and operations.

DR WS-4 Response. Table 3.17-8 has been added to the application section to describe applicable state and local agencies with jurisdiction to issue permits, and a list of the specific permits, for worker health and safety, and fire extinguishing and fire suppression systems during construction and operations. Please see attached redline version of Section 3.17 of the application.

California Code of Regulations, title 20, Appendix B (g) (11) (C) requires draft outlines including for the Operation Health and Safety Program, Fire Prevention Plan (8 Cal. Code Regs., § 3221). Furthermore, California Code of Regulations, title 20, Appendix B (g) (11) (A) requires a description of safety training programs. The application Sections 3.17.2.3.2 includes outlines of the operations Fire Protection and Prevention Program. However, the

outlines lack significant detail on project-specific potential fire hazards and control procedures as required by California Code of Regulations, title 20, section 3221.

DR WS-5. Provide a template for an Operations Fire Prevention Plan. Provide a discussion of project-specific potential fire hazards, control procedures, fire protection systems, etc.

DR WS-5 Response. The Project's Operation Fire Protection and Prevention Program will include the following elements.

- General requirements
- Fire hazard inventory, including ignition sources and mitigation
- Housekeeping and proper materials storage
- Employee alarm/communication system
- Portable fire extinguishers
- Fixed firefighting equipment
- Fire control
- Flammable and combustible liquid storage
- Use of flammable and combustible liquids
- Dispensing and disposal of liquids
- Training
- Personnel to contact for information on program contents

Project-specific hazards, control procedures, and fire protection systems will be addressed through the following measures.

Vegetation Management

All battery components for the BESS will be installed on concrete pads or pilings. The fenced BESS yard, on-site substation, and access roads will be surfaced with crushed rock and asphalt. O&M activities will include spot removal of any vegetation growth within the BESS and on-site substation areas as needed. Project design and maintenance activities will ensure no combustible vegetation will be present within these areas.

For Project site areas outside of the BESS and substation fence lines, O&M staff will inspect areas adjacent to the facility and gen-tie line to monitor vegetation management needs. All non-landscaping combustible vegetation will be mechanically cleared to the property line around the fenced BESS yard and on-site substation to maintain defensible space. The ground clearing, low fire fuel landscaping, and BESS yard management will create a fire break of at least 100 feet between neighboring properties and any BESS enclosure.

Additionally, vegetation management will occur along the gen-tie corridor up to the Point of Change of Ownership (POCO) and around the associated transmission towers in accordance with the North American Electric Reliability Corporation transmission vegetation management standards and California Fire Code requirements. All combustible vegetation will be mechanically cleared to a minimum of 10 feet around electric poles to maintain defensible space. Additionally, vegetation will not be allowed to encroach within 10 feet of conductors under any condition (accounting for maximum sag and horizontal wind sway). The gen-tie corridor

from the POCO to the Vincent Substation will be managed by SCE according to their vegetation management standards.

Per MM-WF-4 (see Section 3.16, Wildfire), as a further means of ensuring the vegetation management is maintained per this requirement, the proposed Project applicant or current owner will obtain an inspection and report from a County-authorized Wildland Fire Safety Inspector by June 1 of each year, certifying that vegetation management activities throughout the BESS facility site and gen-tie corridor up to the POCO have been performed pursuant to this plan. The gen-tie corridor from the POCO to the Vincent Substation will be managed by SCE according to their vegetation management standards. This effort further ensures vegetation maintenance and compliance.

On-Site Fuel Management

The hazardous materials used during operations will include gasoline, renewable diesel, and lubricants. These hazardous materials will be stored in temporary stationary tanks with secondary containment and will be located within the construction laydown area or near the O&M building. Operations workers will use drip trays under the fueling nozzle to prevent spillage during refueling. Equipment will be bonded and grounded to prevent static electricity buildup and discharge. Additionally, the fuel tanks will have secondary containment spill trays within which the fuel tanks will sit. These secondary containment spill trays will be sized to hold the entire amount of the fuel tank should a failure result in release of a full tank. Finally, spill kits will be maintained on site in the event that a spill occurs outside of the spill trays. A qualified employee will perform training for all operations workers to educate them on the proper methods for refueling and spill cleanup.

A spill prevention, control, and countermeasure plan will be developed and implemented prior to receiving hazardous materials (including fuel) on site in excess of reportable quantities during construction and operation.

Red Flag Warnings (Extreme Fire Ignition Avoidance)

MM-FIRE-1, Extreme Fire Day Ignition Avoidance and Fire Patrols, would be implemented during operations as well as construction. The National Weather Service defines a Red Flag Warning as environmental conditions where warm temperatures, very low humidities making vegetation dry and flammable, and stronger winds are expected to combine to produce an increased risk of fire danger. A Red Flag Warning is issued for a stated period by the National Weather Service using pre-determined criteria to identify particularly critical wildfire danger in a particular geographic area. Any work that would generate sparks or open flames, including activities involving heat or sparks, outdoor burning, and using power tools, shall temporarily cease during Red Flag Warnings to reduce the risk of starting a wildfire, unless the work is surrounded by at least 100 feet of fuel-free defensible space. The site superintendent or operations supervisor will coordinate with personnel to determine which low fire hazard activities may occur. Should the Los Angeles County Fire Department (LACoFD) or similar entity declare a Red Flag Warning affecting the Project site, the same work activity restrictions occurring during National Weather Service Red Flag Warning periods shall apply.

The Project will implement ongoing fire patrols during the fire season. The Project site is in a State Responsibility Area, so the Project will defer to the agency in charge. The Site Safety Director (SSD) will be assigned as fire patrol to monitor work activities when an activity risk exists for fire compliance. The SSD will verify proper tools and equipment are on site, assess any fire agency work restrictions, and serve as a lookout for fire starts, including staying behind (e.g., a fire watch) to make certain no residual fire exists. Fire watch may be performed

by any site personnel. The SSD or delegate will perform routine patrols of the Project site during the fire season, equipped with a portable fire extinguisher and communications equipment. Project staff will notify LACoFD of the name and contact information of the current SSD in the event of any change.

Battery Energy Storage Systems Enclosures and Transformers

Operational incidents involving BESS enclosures and transformers will be covered under the Project Emergency Response Plan, Hazard Mitigation Analysis, and trainings to address potential incidents and responses.

Fire Protection Systems

Site-specific fire protection systems will be addressed in the Project Emergency Response Plan, Hazard Mitigation Analysis, and Alternative Materials and Methods Review (AMMR) submittals to the CEC Compliance Project Manager and LACoFD. The site-specific fire protections include two 40,000-gallon water tanks; hydrants spaced no more than 300 feet apart; defensible space designed into the Project footprint; smoke alarms in buildings and portable fire extinguishers (see DR WS-15); and the remote monitoring and alarm systems designed into the BESS enclosures (see DR WS-12), visual cameras that cover the BESS yard, and visual and audible alarms in the BESS yards.

DR WS-6. Provide a complete description of the proposed training programs for the Operations Fire Prevention Program and Emergency Response/Action Plan. Provide a discussion of proposed training provided to the operations personnel and the local first response agencies (fire department).

DR WS-6 Response. An in-person training program will be developed for the local municipal fire departments, other local agencies, and site personnel. The applicant will consult with the local emergency management agencies, unified program agencies, and local first response agencies identified by LACoFD through its AMMR process to determine the agencies that should be invited to participate in the training. The program will include classroom training to familiarize the audience with the BESS equipment and safety features. The course will outline the actions to be taken during a BESS emergency to mitigate risk and ensure the safety of personnel operating on the scene of the incident. Topics will include but not be limited to emergency situation responsibilities; immediate emergency response actions; first-responders recommended actions by scenario; maps, figures, and failure safety areas; BESS enclosure specifics; cell information; transformer information; recommended personal protective equipment; on-site hazards; fire protection systems; and post incident operations.

California Code of Regulations, title 20, Appendix B (g) (11) (C) requires draft outlines including for the Operation Health and Safety Program, Emergency Action Plan (8 Cal. Code Regs., § 3220). The application Section 2.3 estimates 2,035 BESS enclosures as part of the 70.8-acre BESS Facility portion of the project. Appendix 2A includes site plans specifically drawing number PSR-SE-101, General Arrangement, and drawing number PSR-BE-100, Typical BESS and MVT Elevation. However, the application does not provide detailed information on the placement and distribution of BESS enclosures across the parcels, especially between internal access roads.

Staff requires additional details on the BESS enclosure locations, setbacks, and internal access roads in order to verify that the project has proposed adequate project features to mitigate adverse impacts during an emergency response.

DR WS-7. Provide a complete description of the distribution of BESS enclosures, including a revised drawing number PSR-SE-101, General Arrangement. Specify the number of BESS enclosures between the two BESS yards (north and south) bisected by Soledad Canyon Road. Specify the number of BESS enclosure in each area separated by internal access roads. Specify the maximum BESS grouping size in terms of number of BESS enclosures.

DR WS-7 Response. Please see updated drawing PSR-BE-101 in updated Appendix 2A for BESS enclosure numbers by grouping. As currently designed, at the end of the Project life there is expected to be 2,035 BESS enclosures on site. The BESS enclosure grouping numbers range between 60 and 630 enclosures within an internal access road area.

DR WS-8. Provide a discussion of how the project design satisfies the Los Angeles County Fire Department (LACoFD) requirements for minimum separation and setback distances (on each side within any proposed BESS groupings; between adjacent groupings of BESS enclosures, in each direction; to the other types of nearest exposures). Provide references for all significant assumptions, methodologies, and computational methods used in arriving at those conclusions.

DR WS-8 Response. The Project design incorporates design measures to comply with Los Angeles County requirements for minimum separation and setback distances, primarily guided by NFPA 855 2023 edition (Standard for the Installation of Stationary Energy Storage Systems). NFPA 855 addresses fire and explosion risks in energy storage facilities, including BESS installations. The Project ensures compliance through fire-resistant enclosures equipped with safety features, including smoke/fire detection sensors, ground fault detection, alarms, and electrical contact disconnection. Containers are spaced to prevent fire propagation, aligning with NFPA 855 and LACoFD guidelines. We understand that while the Los Angeles County Fire Code (LACFC) adopts a limited scope of standards for BESS enclosures, NFPA 855 provides detailed guidance for larger installations like this Project.

Separation Distances Within Battery Energy Storage System Enclosure Groupings

NFPA 855 Section 15.5 and LACFC Section 1207.5.1 specify required distances between BESS enclosures within BESS groupings (e.g., clusters of BESS enclosures) designed to prevent thermal runaway propagation by maintaining minimum separation distances. The standard states that individual BESS enclosures should be separated by at least 3 feet in all directions, including along walls or between opposing units, unless manufacturer documentation from large-scale fire testing (e.g., UL 9540A tests) shows a lack of propagation between units and the authority-having jurisdiction approves the reduced spacing.

The Project design includes groupings of two (2) BESS enclosures, each spaced 5 7/8 inches apart (see Sheet PSR-BE-100_S001 in Appendix 2A). This spacing is supported by UL 9540A test results provided in Appendix 3.17E.

Separation Distances Between Adjacent Battery Energy Storage System Groupings

NFPA 855 and LACFC Section 1207.5.1 specify a minimum of 3 feet separation in all directions (horizontal and vertical, where applicable) between adjacent BESS groupings. Spacing is calculated from the outer edges of BESS enclosures. Compliance is verified through site plans submitted to the authority-having jurisdiction, requiring no computational methods beyond geometric measurements.

The Project exceeds the adjacent BESS grouping separation standard. Within rows, BESS groupings are spaced 4 feet 11 inches from adjacent groupings and medium-voltage transformers. BESS units and medium-voltage transformers are separated by at least 12 feet 7 inches across rows. Refer to Sheet PSR-BE-100_S001 in Appendix 2A for a plan and profile view of these dimensions.

Setback Distances to Nearest Exposures

LACFC Section 1207.8.3 requires that minimum setback distances to exposures (e.g., lot lines, public ways, buildings, stored combustible materials, hazardous materials, high-piled stock, other exposure hazards, and vegetation) is 10 feet.

The Project exceeds these standards:

- BESS enclosures are set back 100 feet from all property lines.
- Soledad Canyon Road is between 10 and 20 feet from the Project's property line, resulting in an approximately 110-foot setback to the public thoroughfare.
- The O&M buildings are approximately 30 feet away from the nearest BESS enclosure.
- Hazardous and combustible materials will be stored in the O&M buildings or storage containers at the end of the Project substation. The minimum distance to any hazardous or combustible materials would be approximately 30 feet.
- BESS enclosures are set back a minimum of 60 feet from vegetation. In all instances there would be a solid wall separating a BESS enclosure and any vegetation.
- The two operations and maintenance buildings within the BESS yards are separated from the nearest BESS enclosure by approximately 30 feet.

Refer to Sheet PSR-SE-101_S001 in Appendix 2A (TN: 265873) for setbacks from walls, roadways, and occupiable spaces. Landscaping details are provided in Appendix 2B (TN:264410).

California Code of Regulations, title 20, Appendix B (g) (11) (C) requires draft outlines including for the Operation Health and Safety Program, Emergency Action Plan (8 Cal. Code Regs., § 3220). Furthermore, California Code of Regulations, title 20, Appendix (g)

(1) requires a discussion of the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation. Appendix 3.17C provides a template Emergency Response Plan with an example table of contents. However, the outlines lack significant detail on project-specific emergency procedures.

DR WS-9. Provide a discussion of the local emergency management agencies, unified program agencies, and local first response agencies that the applicant will coordinate with in developing the emergency response and emergency action plan.

DR WS-9 Response. The Project applicant is committed to completing the LACoFD AMMR process as a condition of certification. During the AMMR review process, LACoFD will determine which local emergency management agencies, unified program agencies, and local first response agencies the applicant will coordinate with in developing its emergency response and emergency action plan.

DR WS-10. Provide a discussion of the anticipated response time by local first response agencies for incidents involving a BESS enclosure e.g. thermal runaway and fire. Provide a discussion of the fire response capabilities, EMS capabilities, and hazardous materials team for incidents involving a BESS enclosure.

DR WS-10 Response. First response to an incident involving a BESS enclosure would be handled by LACoFD. Response times are usually calculated based on the following response NFPA 1710 categories: call processing time, turnout time, and travel time. Regarding the Project, the call processing time should be instantaneous because the logic controller in the BESS enclosure will send an emergency signal to the fire department and will bypass the standard call processing center. LACoFD strives to achieve the less-than-80-second turnout benchmark noted in NFPA 1710, and, as noted in Table 3.16-1, estimated travel time would be 2.35 minutes. The total estimated response time would be approximately 3.7 minutes. This response time is less than the LACoFD suburban performance standard of less than 8 minutes (see Table 3.16-2).

LACoFD has both specialty resources and highly skilled team members, including hazardous materials (Haz Mat) firefighters. LACoFD's Haz-Mat program is designed to address the natural, technological, or purposeful response challenges, including chemical, biological, radiological, nuclear, and explosive threats to communities and national security. There are two (2) Haz Mat units stationed near the Project site. Haz Mat 129 is located at 42110 6th Street West, Lancaster, California 93534, which is approximately 13.7 miles from the site. Haz Mat 150 is located at 19190 Golden Valley Road, Santa Clarita, California 91387 and is approximately 23.6 miles from the site. Per NFPA 1710 and the Insurance Services Office Public Protection Classification Program's Response Time Standard formula ($\text{Time} = 0.65 + 1.7[\text{Distance}]$) to these sites, the resulting response times are 23.94 minutes and 40.77 minutes, respectively.

Emergency management system services are part of LACoFD's core services and would be provided by the first responders at the site of the incident.

DR WS-11. Provide a discussion of actions or proposed measures that the project could implement to mitigate impacts to the local first response agencies (fire department) due to an incident involving a BESS enclosure.

DR WS-11 Response. The Project has included the following design measures to help mitigate potential impacts to local first response agencies during an incident involving a BESS enclosure: a water supply that exceeds industry standards (see Appendix 3.17A, Firefighting Water Supply Analysis), hydrants that are spaced no more than 300 feet apart throughout both BESS yards, circular drive paths throughout the BESS yards with no dead ends, adequate areas for incident command staging near entrances and water tanks, multiple entrances to each BESS yard, fire alarm and detection equipment included in each BESS enclosure, explosion control and gas detection equipment included in each BESS enclosure, cameras that cover the entire BESS yard, visual and audible alarms, and 24/7 remote site monitoring.

The Project will employ the following actions to help mitigate potential impacts to local first response agencies during an incident involving a BESS enclosure: annual first responder training, development of an Emergency Response Plan and Hazard Mitigation Analysis, compliance with LACoFD AMMR, and hiring a third-party incident subject matter expert to support local first responders during a BESS enclosure incident.

DR WS-12. Provide a discussion of the proposed remote monitoring capabilities, such as dedicated incident command center, thermal infrared cameras, air/water sampling plans, to aid the incident commander, local first response agencies, etc. during an incident involving a BESS enclosure.

DR WS-12 Response. To enhance safety and response effectiveness during an incident involving a BESS enclosure, a comprehensive remote monitoring framework is proposed to supplement the monitoring and maintenance conducted by on-site staff. This framework includes a dedicated Remote Operation Center, advanced fire alarm control panels, and robust air/water sampling plans, all designed to support the incident commander and local first response agencies.

Remote Operation Center

A 24/7 Remote Operation Center will be established to monitor and control critical equipment at the BESS site. This center will provide real-time data on key parameters, such as temperature, hydrogen levels, smoke, voltage, and amperage. This continuous monitoring enables rapid detection of anomalies, allowing for proactive response measures to mitigate potential incidents. If any abnormality is detected, the system sends a signal to the station-level alarm host through the battery supply panel module external terminal, which will alert the Remote Operating Center, for early warning of fire and to control the battery system with the corresponding logic control.

Incident Command Center Support

In the unlikely event of an incident, the Remote Operation Center will work in tandem with the local BESS emergency response contractor, which will serve as the Incident Command Center until emergency services and subject matter experts arrive on site. The emergency response contractor will assist in coordinating firefighter efforts and supporting emergency personnel during an incident. Both the Remote Operation Center and emergency response contractor will have round-the-clock access to site cameras, enabling remote troubleshooting and real-time coordination to streamline incident response.

Integrated System Management Unit

The Power Titan II has an integrated battery management unit (BMU) that tracks the performance, voltage, current, and state of charge (SOC) of the cells (among many other datapoints). The BMU is a layered system, where each battery module has its own BMU that monitors cell performance and communicates information to the battery system controller (BSC). The BSC is provided at the cabinet level and collects node signals from the BMU and fire protection system and relays the signals to the local controller or emergency management system for shutdown protection of the battery system. The BMS data is monitored remotely 24/7 by the Remote Operation Center.

Mini Fire Alarm Control Panel

The BESS cabinet is equipped with a gaseous fire extinguishing system, an automatic fire alarm and linkage control system, a combustible gas detection and alarm system, and an exhaust system. It is equipped with combustible gas detectors, smoke detectors, and temperature detectors. If any abnormality is detected, the system sends a signal to the station-level alarm host through the battery supply panel external terminal for early warning of fire and to control the battery system with the corresponding logic control.

Air and Water Sampling Plans

Within the BESS enclosures, gas sensors provided by original equipment manufacturers will deliver live readings of hydrogen levels, temperature, and smoke. These sensors are invaluable to firefighters, as they

provide real-time data on potential deflagration and the current status of the incident, enabling safer and more effective response strategies. Additionally, a site-wide weather station will be installed to monitor environmental conditions, including wind speed, wind direction, ambient temperature, humidity, and barometric pressure. This data will further inform response efforts by providing critical context about the site's environmental conditions during an incident.

In summary, the proposed remote monitoring capabilities—encompassing a 24/7 Remote Operation Center, emergency response contractor-supported incident command, mini fire alarm control panels and color camera systems, and comprehensive air/water sampling—will enhance the ability of incident commanders and first responders to manage BESS enclosure incidents efficiently and safely.

California Code of Regulations, title 20, Appendix B (g) (11) (B) requires a complete description of the fuel handling system and the fire suppression system. Appendix 2A includes site plans specifically drawing number PSR-BE-201_S001, Fire Safety and Water Circulation Plan, and drawing number PSR-SE-101, General Arrangement.

However, some text is not legible on drawing number PSR-BE-201_S001. Project features shown on drawing number PSR-SE-101 include the water tank, pump enclosure, and back-up generator pad at each BESS yard, as well as the existing well indicated at the south BESS yard. The application Sections 2.3.1.3 and 2.3.1.10 also describe a 26-foot-wide underground corridor under Soledad Canyon Road for a water line.

Staff requires a complete description of the locations of the project features related to the fire extinguishing and fire suppression systems.

DR WS-13. Provide a complete description of the underground corridor including a description of all the proposed utilities within the corridor. Provide a schematic and complete description of the route of the fire water line.

DR WS-13 Response. The Project design for the underground corridor across Soledad Canyon Road has been updated to separate out the medium-voltage feeders from the Project fire water line. The medium-voltage feeder corridor will contain 18 feeder lines, each spaced 10 feet apart. The feeders will be contained in 6-inch conduit and will be covered by a minimum of 42 inches of cover. The medium-voltage corridor will be placed just southwest of the opposed access points between the north and south BESS yards and will be 180 feet wide. The fire water line will run under Soledad Canyon Road along the northeast edge of the opposing first responder secondary access points between the north and south BESS yards. The water line will be covered by a minimum of 24 inches of material.

The work to install all medium-voltage feeders and the fire water line will be done via horizontal directional drilling. Traffic will be controlled via signage, and a flagger will notify drivers that work is being done near the roadway. It is not expected that lanes would need to be closed or traffic patterns altered to accommodate the installation of the two utility corridors under Soledad Canyon Road.

Please see PSR-BE-102 (TN:265873) for a plan and profile view of the two utility corridors.

The fire water line route has been highlighted in PSR-BE-201. PSR-BE-201 shows the existing well in the south BESS yard and the water line connection to the water tank in that same yard (approximately 245 feet to the northeast of the existing well). The water tank and associated pumphouse serve as the distribution point for the fire water line. Three (3) lines leave the pumphouse. Two (2) fire water lines support the hydrant system in

the south BESS yard. The loops follow the road and surround each of the BESS blocks. The third fire water line runs southwest along the northern road in the south BESS yard until it comes to the first responder secondary entrance. The fire water line then heads north and crosses Soledad Canyon Road along the northeastern side of the two (2) opposing first responder secondary entrances. Once in the north BESS yard, the fire water line heads back southwest along the southern road in the north BESS yard for approximately 1,030 feet. The fire water line then heads north and connects to the pump house and water tank in the north BESS yard. There are two (2) fire water lines that exit the pump house in the north BESS yard that serve the hydrants that are spaced along access roads and surround the BESS blocks.

Redlines reflecting the above information can be found in Sections 2.3.1.3, 2.3.1.9, and 2.3.1.10.

DR WS-14. Provide a higher resolution drawing number PSR-BE-201_S001, Fire Safety and Water Circulation Plan, with legible text for project features, including the locations of fire water line, fire water storage tanks, fire pumps, fire hydrants, etc.

DR WS-14 Response. Please see the updated drawing PSR-BE-201 (TN:265873).

California Code of Regulations, title 20, Appendix B (g) (11) (B) requires a complete description of the fuel handling system and the fire suppression system. The application Section 3.17.2.4 describes the water-based fire protection system for the project as a traditional water fire suppression system used to prevent the spread of fire to surrounding equipment. However, the application does not provide detailed information on the fire extinguishing and fire suppression systems for the O&M building and the BESS enclosures.

Staff requires additional details for the project's proposed fire extinguishing and fire suppression systems in order to verify that the project has proposed adequate project features to mitigate adverse impacts to operations personnel, emergency first responders, and the public. Staff requires complete descriptions of project features. A complete description specifies information including, but not limited to, the location(s) of project features, the specific listings and design standards, the more stringent local fire department requirements, and all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document.

DR WS-15. Provide a schematic and complete description of the proposed fire suppression systems for all project buildings, including the two O&M buildings, pump enclosure, control building, etc.

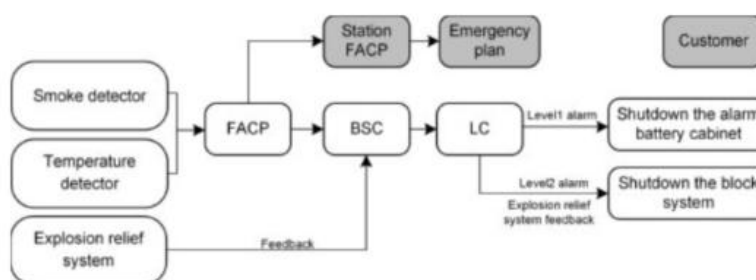
DR WS-15 Response. Per California Fire Code 903.2 – “An approved automatic fire sprinkler system is required in all new buildings and structures, notwithstanding the use and occupancy thereof, when the total aggregate floor area exceeds 5,000 square feet.” All Project structures will have a total aggregate floor area less than 5,000 square feet and will not contain sprinkler systems.

Fire detection systems with smoke detectors, manual pull stations, and indicating appliances will be provided for the Electrical Equipment Enclosure, Battery House, and O&M Building. There will be hydrants adjacent to the O&M Building. The Electrical Equipment Enclosure and Battery House will be equipped with portable fire extinguishers.

DR WS-16. Provide a schematic and complete description of the proposed fire suppression system (e.g. water-based, gaseous, etc.) for the representative BESS enclosure.

DR WS-16 Response. BESS enclosure fire suppression is not provided as it is not required by California Fire Code 1207.5.5.

However, the Power Titan II is equipped with an automatic fire alarm and linkage control system, vent panels, a combustible gas detection and alarm system, and an exhaust system. It is equipped with combustible gas detectors, smoke detectors, and temperature detectors. If any abnormality is detected, the BSC connects to local controller via Ethernet for alarm signaling, control of the battery enclosure shutdown, and control of the system for corresponding logic control. See logic control diagram below.



The Power Titan II emergency response guide suggests the best way to battle a thermal incident is to “[s]pray water in a curtain between each BESS from 150m (500ft) or less and allow the product to burn out. If there is a shortage of water, then direct spraying the container may be preferable. Many fire departments opt to let the primary source burn out and protect exposures.” The Project has designed on-site water tanks and hydrants to allow the fire department to cool neighboring BESS enclosures, see PSR-BE-201 (TN:265873) for a representation of water tanks, pumps, and hydrant locations.

California Code of Regulations, title 20, section 1704 (a) (3) (A), requires descriptions of all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document. California Code of Regulations, title 20, section 1704

(a) (3) (B), also requires the description to include the methodologies and findings of all major studies or research efforts undertaken and relied upon to provide information for the document. Subsection 3.17.2.4 of the Application references Appendix 3.17A which includes a water supply analysis for various exposure hazards. The analysis concludes the two (2) 40,000-gallon water supply tanks would provide an initial water supply for up to five hours from a single 1 3/4-inch handline flowing at 125 gallons per minute (gpm) for cooling exposures, controlling smoke, or extinguishing small vegetation fires during a representative BESS enclosure fire event. However, the analysis does not provide references for the 125 gpm flow other than mentioning “based on typical firefighting tactics and procedures.”

DR WS-17. Provide a discussion on the fire flow assumptions (125 gpm) for the representative SunGrow PowerTitan 2.0 Container Fire. Provide descriptions of all significant assumptions, methodologies, and computational methods used in arriving at those conclusions.

DR WS-17 Response. The water supply report recommends a flow rate of 125 gallons per minute (gpm) for a Power Titan II container as the UL 9540A tests and large-scale fire test showed no fire propagation to adjacent

containers. These results were achieved without any internal or external fire suppression systems. As such, the recommended flow rate is to further mitigate any potential fire spread to adjacent exposures. The basis for this recommendation is from typical tactics/procedures. Note, these are solely recommendations, and any tactics/procedures used during a fire event are at the discretion of the LACoFD.

Appendix 3.17A, Firefighting Water Supply Analysis, has been revised to include a reference to the response above. A redline version of Appendix 3.17A has been included in this submission.

DR WS-18. Provide a discussion of the estimated 15,000 gallons of water supply for the project's external exposures (vehicle exposure fire and the transformer exposure fire). Provide the project's worst-case fire flow requirements in GPM (gallons per minute).

DR WS-18 Response. Factory Mutual Data Sheet 5-4 provides firefighting guidance for transformers (see <https://fireprotectionsupport.nl/wp-content/uploads/2020/11/FMDS0504-2020-10-Transformers.pdf>).

Section 2.3.2.3 outlines hose stream flow rates dependent on the oil capacity of the transformers, and the transformers at the Prairie Song Reliability Project have an oil capacity of less than 1,000 gallons. As such, a flow rate of 250 gpm over a duration of 60 minutes is recommended, resulting in a total firefighting water supply of 15,000 gallons. For a vehicle exposure fire, the Firefighting Water Supply Analysis recommends two (2) hose streams flowing at 125 gpm for a total of 250 gpm over a duration of 60 minutes, resulting in a total firefighting water supply of 15,000 gallons. Therefore, the calculated worst-case fire flow scenario is a total of 15,000 gallons. The basis for these recommendations are typical firefighting tactics and procedures and published codes, standards, and data sheets. Note, these are solely recommendations, and any tactics or procedures used during a fire event are at the discretion of the LACoFD.

A redline of Appendix 3.17A, Firefighting Water Supply Analysis, that includes a reference to the response above as well as a reference to the Factory Mutual Data Sheet 5-4 Standards has been included in this submission.

California Code of Regulations, title 20, Appendix (g) (1) requires a discussion of the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation. The Application at section 3.17.2.4 states "During these initial 5 hours, a shuttle service can be set up by the fire service to provide additional water to the site if it is required." However, the application does not provide proposed measures if additional water is required by the fire service.

DR WS-19. Provide a complete description of the proposed measures for supplying additional fire water supply during extended emergency conditions.

DR WS-19 Response. Should LACoFD request additional water supply during extended emergency conditions, the Project will contract additional water from a regional water service delivery company that serves the area. A water company in Lancaster, California (S&S Sweeping & Water Trucks) was contacted via phone on August 26, 2025, and verified that they could provide a fire tender service. A few other companies in the area provide this service as well.

California Code of Regulations, title 20, section 1704 (a) (3) (A), requires descriptions of all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document. California Code of Regulations, title 20, section 1704

(a) (3) (B), also requires the description to include the methodologies and findings of all major studies or research efforts undertaken and relied upon to provide information for the document. Furthermore, California Code of Regulations, title 20, Appendix (g) (1) requires a discussion of the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation. The application describes the representative BESS enclosure as the Sungrow Power Titan II, with a lithium iron phosphate battery technology. Section 3.17.2.4 states a Hazard Mitigation Analysis (HMA) will be prepared per NFPA 855 and implemented during project operations. Appendix 3.17B provides a template HMA with an example executive summary and table of contents. Appendix 3.17A and 3.17D reference the UL 9540A cell level, module level, and unit level test results for the representative BESS enclosure.

Staff requires the hazard mitigation analysis to assess the hazards and impacts associated with the selected representative BESS enclosure.

DR WS-20. Provide the Safety Data Sheets for hazardous materials contained in the representative BESS enclosure, including related to the fire suppression system, air-cooled or liquid-coolant air conditioning system, and potential toxic vapors/emissions.

DR WS-20 Response. The BESS enclosures contain R-32 refrigerant for cooling and lithium ion cells. There are no other systems in the BESS enclosure that contain materials that require safety data sheets. Please see Appendix 3.17H for safety data sheets for R-32 refrigerant and lithium ion cells.

Neither of these two (2) substances emit potential toxic vapors during operations. In the event of an emergency/thermal event, lithium ion cells have the potential to release toxic vapors. The composition of the emissions can be found in plume studies prepared for the Project (TN264382 and TN265874).

DR WS-21. Provide the UL 9540A cell, module, and unit level test reports for the representative BESS enclosure, Sungrow Power Titan II.

DR WS-21 Response. The test reports were submitted with an application for confidential designation as part of Data Response 1. Subsequently, the applicant sought and received permission from the manufacturer to make the UL9540A reports public. The public reports are available at TN266065.

DR WS-22. Provide a complete description of how the Hazard Mitigation Analysis will comply with the California Fire Code section 1207.1.4 and the LACoFD requirements.

DR WS-22 Response. Appendix 3.17B, Hazard Mitigation Analysis Template, has been updated to 3.17B, Hazard Mitigation Analysis, and a full hazard mitigation analysis for the Power Titan II and the Project site has been included in the updated appendix. Please see this appendix, specifically Section 5, BESS Site Design Code Analysis, and Section 7, Hazard Mitigation Analysis, for a full analysis of California Fire Code Section 1207.1.4, LACFC requirements, and Project compliance.

DR WS-23. Provide the Hazard Mitigation Analysis for the representative BESS enclosure, Sungrow Power Titan II.

DR WS-23 Response. Appendix 3.17B, Hazard Mitigation Analysis Template, has been updated to 3.17B, Hazard Mitigation Analysis, and a full hazard mitigation analysis for the Power Titan II and the Project site has been included in the updated appendix.

DR WS-24. Provide a history of failure incidents utilizing the Sungrow Power Titan II technology. Provide a complete description of the proposed measures to prevent failure incidents for the proposed project.

DR WS-24 Response. The Sungrow Power Titan II has not experienced any thermal failure incidents (see email confirmation from supplier in Appendix 3.17G). The safety features included in the Sungrow Power Titan II have allowed it to recently receive both TM-2 approval and a Certificate of Approval from the New York City Fire Department (<https://www.solarpowerworldonline.com/2025/05/sungrows-5-mwh-ess-approved-for-installation-in-new-york-city/>).

The Project will employ the following measures to minimize the risk of failure incidents:

- Internal BESS enclosure monitoring and management – The Power Titan II has an integrated BMU that tracks the performance, voltage, current, and state of charge of the cells (among many other datapoints). The BMU is a layered system, where each battery module has its own BMU that monitors cell performance and communicates information to the BSC. The BSC is provided at the cabinet level and collects node signals from the BMU and fire protection system and relays the signals to the local controller or emergency management system for shutdown protection of the battery system.
- The BESS cabinet is also equipped with a gaseous fire extinguishing system, an automatic fire alarm and linkage control system, a combustible gas detection and alarm system, and an exhaust system. It is equipped with combustible gas detectors, smoke detectors, and temperature detectors. If any abnormality is detected, the system sends a signal to the station-level alarm host through the battery supply panel external terminal for early warning of fire and to control the battery system with the corresponding logic control for shutdown and potential prevention.
- Remote Operation Center – A 24/7 Remote Operation Center will be established to monitor and control critical equipment at the BESS site. This center will provide real-time data on key parameters, such as temperature, hydrogen levels, smoke, voltage, and amperage. This continuous monitoring enables rapid detection of anomalies, allowing for proactive response measures to mitigate potential incidents. If any abnormality is detected, the system sends a signal to the station-level alarm host through the battery supply panel module external terminal, which will alert the Remote Operating Center, for early warning of fire and to control the battery system with the corresponding logic control.
- Maintenance – Each BESS enclosure will be routinely inspected according to the manufacturer’s schedule. Expected actions and scheduled inspections are included in the table below.

Every Half a Year	
System conditions and cleanliness	▪ Clean the foundation (use a broom/vacuum cleaner). ▪ Check if there is dust or dirt on the outdoor cabinet inlet filter screen and clean it if necessary.
Components	▪ Check the cleanliness of circuit boards and components. ▪ Check the temperature of the top fan and dust. If necessary, use a water gun nozzle or vacuum cleaner to clean it. ▪ Conduct routine inspection of all metal components for corrosion. ▪ Conduct annual inspection of contactors (auxiliary switches and micro switches) to ensure their smooth mechanical operation.

Every Half a Year	
	Check the operating status of the top fan, whether it is blocked, and if there are any abnormal noises during operation.
Functionality	- Check the configurable parameters on the Web interface. - Check the battery cluster operation logs to ensure that the current, voltage, and temperature are within the operational range. - Check if the emergency stop button is functioning correctly. - Check the warning labels and other device labels on the equipment. If any of them are blurred or damaged, please replace them promptly. - If the battery energy storage system is not used for a long period, perform a charge-discharge cycle every 6 months to ensure the system state of charge reaches 30% to 40%. After recharging, the state of charge should remain consistent.
Liquid cooling system	- Check to see if the compressor sounds normal when running, and if there are any abnormal vibrations or noises. - Check if the dirty and blocked area of the heat emission and air inlet hole of the water pump is above 5%. If it exceeds this threshold, clean it with a brush. - Visually inspect the water pump body (excluding pipeline connections) for any noticeable dripping (excluding condensation). If there is noticeable dripping, please replace the water pump sealing ring. - Check through the host unit software if the water system high pressure is $\geq 3\text{bar}$ and if there are any alarms for excessive condenser-side outlet pressure. - Check the water tank level. If the level is below the minimum level indicated on the sight glass, please add coolant as needed. - Check if there are visible impurities in the coolant, the coolant is significantly darker, or the pH value is below 7.3.
Fire suppression system	Conduct combustible gas detector calibration

Annual Maintenance	
Appearance	- Check if there are any flammable objects around and on top of the outdoor cabinet. - Check if the welds between the outdoor cabinet and the foundation steel plate are secure and free from rust. - Check if there is any damage, paint peeling, or oxidation on the outdoor cabinet casing. - Check if the door locks and other components can open and close smoothly. If necessary, lubricate the locks and hinges. - Check if the sealing strips are securely fixed. The sealing strips being in good condition is crucial to preventing water ingress inside the product. Inspect them carefully and replace any damaged sealing strips immediately.
System conditions and cleanliness	- Check if there is any foreign object, dust, or dirt in the outdoor cabinet. Clean the dust in it if necessary. (Use a vacuum cleaner instead of a broom.) - Check if the air inlet or the air outlet of the outdoor cabinet is blocked. - Check if there are any loose screws in the outdoor cabinet. - Check if there is any water leakage in the outdoor cabinet.
Cable connections	- Check if the cable layout is standard and check for any short circuits. If any abnormalities are found, correct them immediately. - Check if the entry and exit holes of the outdoor cabinet are properly sealed.

Annual Maintenance	
	- Check if the cable connections are loose and re-tighten them according to the previously specified torque. - Check if the cables are damaged, especially if the insulation layer in contact with metal surfaces has signs of cuts. - Check if the insulation tape on the terminals has come off.
Grounding and equipotential bonding	- Check if the grounding connection is correct and ensure the grounding resistance value does not exceed 4Ω. - Check if the equipotential bonding is correct inside the system. - Check if the cable shielding layer is in good contact with the insulation sleeve and ensure the grounding copper busbar is properly secured.
Components	Check if the lightning protection devices and fuses are intact and operational. Replace damaged lightning protection devices and fuses in time.
Fire suppression system	- Visually inspect the detectors inside the outdoor cabinet. Check the appearance of the equipment for any damage or deformation and ensure that it is not being squeezed by surrounding equipment. Check if the equipment status indicators are functioning properly. - Check for any smoke inside the outdoor cabinet. Check the appearance of the equipment for any damage or deformation and ensure that it is not being squeezed by surrounding equipment. Check if the equipment status indicators are functioning properly. - Visually check the input/output modules. Check the appearance of the equipment for any damage or deformation and ensure that it is not being squeezed by surrounding equipment. Check if the equipment status indicators are functioning properly. - Visually check the sprinkler heads. Check the appearance of the equipment for any damage or deformation and ensure that it is not being squeezed by surrounding equipment. - Visually check the fire sprinkler piping. Check the appearance of the equipment for any damage or deformation and ensure that it is not being squeezed by surrounding equipment.

Every 2 Years	
System conditions and cleanliness	- Check if there is any damage or deformation to the equipment in the outdoor cabinet. - Check if there is any unusual noise from internal equipment during operation. - Check if the temperature inside the outdoor cabinet and on the casing is excessively high. - Check if the humidity inside the outdoor cabinet is within the normal range. - Check if there are signs of oxidation or rust inside the outdoor cabinet.

- Operations Management – The Project will operate within the manufacturer’s recommended operating tolerances: humidity between 0% and 100%, temperature ranges between -22 degrees Fahrenheit and 122 degrees Fahrenheit, and an altitude of less than 3,000 meters. If any of these parameters are exceeded, the Project will stop operations until the external parameter has returned to the operational range.

California Code of Regulations, title 20, Appendix B (g) (11) (B) requires a complete description of the fuel handling system and the fire suppression system. The Application at subsection 3.5.1.2.2 describes the use of diesel fuel for emergency operations. The application Table 3.5-2 lists diesel fuel and lead-acid storage batteries for emergency generators and backup power source for control equipment, respectively. However, the Application does not provide detailed information on the fuels required by emergency and standby power systems.

DR WS-25. Provide a schematic and complete description of the emergency and standby power systems, including what they serve, by what means, and the duration of these systems for each required load e.g. exhaust ventilation, gas detection systems, etc.

DR WS-25 Response. Schematics of the emergency and standby power systems are provided updated in the updated Appendix 2A, drawing PSR-SE-001_S008, Single Line Low Voltage Control Room, and drawing PSR-SE-001_S009, Single Line Low Voltage O&M Building.

The electrical equipment enclosure contains lead acid batteries to provide uninterrupted DC power to critical systems like control circuits, protection devices, and communication equipment, ensuring the grid's reliability during AC power outages. These batteries act as a reliable backup, allowing for the remote operation of switchgear and maintaining safety functions even when the primary AC power supply fails.

The electrical equipment enclosure will further be supported by two 500 kilovolt-ampere (kVA) transformers, each sized for 100% of the expected load, and programmed with an automatic transfer scheme. Should both transformer feeds fail, two 500 kVA backup diesel generators with day tanks are provided to operate in a primary and backup configuration. The generators are intended to support the lead acid batteries in the event of an extended power outage. The generators and day tanks will be sized to provide 8 hours of back-up power. See updated Appendix 2A, drawing PSR-SE-001_S008, Single Line Low Voltage Control Room, for a single line diagram showing the system described above.

The O&M building and fire/emergency system will be served by a 225 kVA diesel generator with a day tank that matches the main 225 kVA transformer feed that will operate should the transformer feed fail. The approximately 700-gallon-per-day tank will be sized to provide 24 hours of back of power to the emergency systems. See updated Appendix 2A, drawing PSR-SE-001_S009, Single Line Low Voltage O&M Building, for a single line diagram showing the system described above.

Attachment 1

Section 3.1, Air Quality - Redline Version

3.1 Air Quality

This section describes existing conditions related to air quality, identifies associated regulatory requirements, evaluates potential Prairie Song Reliability Project (Project) and cumulative impacts, and identifies mitigation measures for any significant or potentially significant impacts related to implementation of the Project. The Project will consist of an up to 1,150-megawatt (MW) containerized battery energy storage system (BESS) facility utilizing lithium-iron phosphate cells or similar technology, operations and maintenance (O&M) buildings, a Project substation, a 500-kilovolt (kV) overhead generation interconnection (gen-tie) transmission line, and interconnection facilities within the existing Southern California Edison (SCE) owned and operated Vincent Substation.

This analysis uses the significance thresholds in the California Environmental Quality Act (CEQA) Guidelines Appendix G (14 CCR 15000 et seq.) and the emissions-based significance thresholds recommended by the Antelope Valley Air Quality Management District (AVAQMD) and other applicable thresholds of significance.

- **Section 3.1.1** describes the air quality environment that might be affected by the Project;
- **Section 3.1.2** provides additional setting information regarding regional and local air quality;
- **Section 3.1.3** provides the thresholds for significance and includes an environmental analysis of Project construction and operation (including maintenance) impacts on air quality;
- **Section 3.1.4** lists the proposed mitigation measures;
- **Section 3.1.5** discusses the applicable laws, ordinances, regulations, and standards (LORS);
- **Section 3.1.6** lists the agencies involved and agency contacts;
- **Section 3.1.7** discusses permits and permit schedules; and
- **Section 3.1.8** lists reference materials used in preparing this section.

The environmental setting and impact evaluation in this section is based in part on the following Project-specific technical analysis:

- **Appendix 3.1A** – Air Quality and Greenhouse Gas Emissions Modeling and Calculations (provided via Kiteworks)
- **Appendix 3.1B** – Ambient Air Quality Analyses Files (provided via Kiteworks)
- **Appendix 3.1C** – Representative Tier 4 Emergency Generator Specifications Sheets
- **Appendix 3.1D** – AVAQMD Notice of Receipt of Complete Application
- **Appendix 3.1E** – CAISO Battery Charging & Renewable Integration Analysis

Potential emissions of toxic air contaminants (TACs) and the associated public health impacts are addressed in Section 3.9, Public Health, and are not discussed herein.

A summary of the air quality evaluation is provided in the table below.

	Potentially Significant Impact	Less Than Significant Impact With Mitigation Incorporated	Less Than Significant Impact	No Impact
Would the project:				
1) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☒	☐	☐
2) Result in a cumulatively considerable net increase of any criteria pollutant for which the Project region is non-attainment under an applicable federal or state ambient air quality standard?	☐	☒	☐	☐
3) Would the Project expose sensitive receptors to substantial pollutant concentrations?	☐	☒	☐	☐
4) Would the Project result in other emissions (such as those leading to odors) adversely affecting a substantial number of people?	☐	☐	☒	☐
5) Would the Project generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment, or would the Project conflict with an applicable plan, policy, or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☒	☐

3.1.1 Environmental Setting

3.1.1.1 Meteorological and Topographical Conditions

Air Quality

The metropolitan portions of Los Angeles County (the County) are generally within the South Coast Air Basin, and the desert portions of the County lie within the Mojave Desert Air Basin (MDAB). The Project area is located within the MDAB and subject to AVAQMD rules and regulations.¹ Additionally, the Project area as a whole is subject to the California Ambient Air Quality Standards (CAAQS) adopted by the California Air Resources Board (CARB) and the National Ambient Air Quality Standards (NAAQS) adopted by the U.S. Environmental Protection Agency (EPA).

Air pollutants are emitted by a variety of sources, including off-road equipment, mobile sources (vehicles), area sources (hearths [fireplaces], consumer product use, architectural coatings, and landscape maintenance equipment), energy sources (natural gas), and stationary sources (generators or other stationary equipment). Some air pollutants need to be examined at the local level, and others are predominantly an issue at the regional level. For instance, ozone (O₃) is formed in the atmosphere in the presence of sunlight by a series of chemical reactions

¹ AVAQMD has jurisdiction over the northern, desert portion of Los Angeles County and covers a western portion of the MDAB. This region includes the incorporated cities of Lancaster and Palmdale, Air Force Plant 42, and the southern portion of Edwards Air Force Base. The Kern County-Los Angeles County boundary forms the northern boundary of the AVAQMD; the San Bernardino-Los Angeles County boundary forms the eastern boundary of the AVAQMD.

involving oxides of nitrogen (NO_x) and volatile organic compounds (VOCs) (also termed reactive organic gases [ROGs]). Because these reactions are broad scale in effects, O₃ is typically analyzed at the regional level (i.e., in the MDAB) rather than the local level. On the other hand, air pollutants such as coarse particulate matter (particulate matter with an aerodynamic diameter less than or equal to 10 microns, or PM₁₀), fine particulate matter (particulate matter with an aerodynamic diameter less than or equal to 2.5 microns, or PM_{2.5}), and carbon monoxide (CO) are a potential concern in the immediate vicinity of the pollutant source because the pollutants are emitted directly by or are formed close to the source. Therefore, the study area for emissions of PM₁₀, PM_{2.5}, and CO is the local area near the source, such as in the vicinity of the Project site, and the study area for regional pollutants such as NO_x and VOCs is the entire MDAB.

Air quality is a function of the rate and location of pollutant emissions under the influence of meteorological conditions and topographic features that influence pollutant movement and dispersal. Atmospheric conditions such as wind speed, wind direction, atmospheric stability, and air temperature gradients interact with the physical features of the landscape to determine the movement and dispersal of air pollutants, and consequently affect air quality.

Most of the MDAB is commonly referred to as the “High Desert” because elevations range from approximately 2,000 to 5,000 feet above mean sea level. The MDAB is generally above the regional inversion layer and experiences relatively good dispersion conditions. The MDAB is separated from Southern California coastal regions and Central California valley regions by mountains extending up to 10,000 feet above mean sea level. As a result, the Mojave Desert is removed from the cooling effects of the Pacific Ocean and is characterized by extreme temperatures. The MDAB consists of an assemblage of mountain ranges interspersed with valleys that often contain dry lakes. Lower-elevation mountains scattered throughout the basin are generally 1,000 feet to 4,000 feet high. Mountain passes form channels for air masses flowing from the west and southwest, and the prevailing winds from the west and southwest are caused by the proximity of the MDAB to coastal and central regions and the blocking effect of the Sierra Nevada to the north.

This MDAB region is characterized by hot, dry summers and cool winters, with little precipitation. During the summer, the MDAB is generally influenced by a Pacific subtropical high-pressure cell that resides off the coast of California. This high-pressure cell prevents cloud formation and engenders daytime solar heating. The MDAB is rarely influenced by the cold air masses that move south from Canada and Alaska, as these frontal systems diffuse by the time they reach the MDAB. Most moisture arrives in frequent warm, moist, unstable air masses from the south. The MDAB is classified as a dry-hot desert climate, with portions classified as dry-very hot desert, to indicate at least 3 months have maximum average temperatures over 100.4 °F. In Palmdale, which is proximate to the Project site, the annual average precipitation is 7.4 inches (AVAQMD 2016).

Greenhouse Gases

Climate change refers to any significant change in measures of climate—such as temperature, precipitation, or wind patterns—lasting for an extended period (decades or longer). The Earth’s temperature depends on the balance between energy entering and leaving the planet’s system. Many factors, both natural and human, can cause changes in Earth’s energy balance, including variations in the sun’s energy reaching the Earth, changes in the reflectivity of Earth’s atmosphere and surface, and changes in the greenhouse effect, which affects the amount of heat retained by Earth’s atmosphere (EPA 2024a).

The greenhouse effect is the trapping and buildup of heat in the atmosphere near the Earth’s surface (troposphere). The greenhouse effect traps heat in the troposphere through a threefold process, as follows: short-wave radiation

emitted by the sun is absorbed by the Earth, the Earth emits a portion of this energy in the form of long-wave radiation, and greenhouse gases (GHGs) in the upper atmosphere absorb this long-wave radiation and emit it into space and toward the Earth. The greenhouse effect is a natural process that contributes to regulating the Earth's temperature and creates a pleasant, livable environment on the Earth. Human activities that emit additional GHGs to the atmosphere increase the amount of infrared radiation that gets absorbed before escaping into space, thus enhancing the greenhouse effect and causing the Earth's surface temperature to rise.

The scientific record of the Earth's climate shows that the climate system varies naturally over a wide range of time scales and that, in general, climate changes prior to the Industrial Revolution in the 1700s can be explained by natural causes, such as changes in solar energy, volcanic eruptions, and natural changes in GHG concentrations. However, recent climate changes, in particular the warming observed over the past century, cannot be explained by natural causes alone. Rather, it is extremely likely that human activities have been the dominant cause of warming since the mid-twentieth century and are the most significant driver of observed climate change (EPA 2024a; IPCC 2013). Human influence on the climate system is evident from the increasing GHG concentrations in the atmosphere, positive radiative forcing, observed warming, and improved understanding of the climate system (IPCC 2013). The atmospheric concentrations of GHGs have increased to levels unprecedented in the last 800,000 years, primarily from fossil fuel emissions and secondarily from emissions associated with land use changes (IPCC 2013).

3.1.1.2 Pollutants and Effects

3.1.1.2.1 Criteria Air Pollutants

Criteria air pollutants are defined as pollutants for which the federal and state governments have established ambient air quality standards, or criteria, for outdoor concentrations to protect public health. The national and California standards have been set, with an adequate margin of safety, at levels above which concentrations could be harmful to human health and welfare. These standards are designed to protect the most sensitive persons from illness or discomfort. Pollutants of concern include O₃, nitrogen dioxide (NO₂), CO, sulfur dioxide (SO₂), PM₁₀, PM_{2.5}, and lead. In California, sulfates, vinyl chloride, hydrogen sulfide, and visibility-reducing particles are also regulated as criteria air pollutants. These pollutants, as well as TACs, are discussed in the following paragraphs.²

Ozone. O₃ is a strong-smelling, pale blue, reactive, toxic chemical gas consisting of three oxygen atoms. It is a secondary pollutant formed in the atmosphere by a photochemical process involving the sun's energy and O₃ precursors. These precursors are mainly NO_x and VOCs. The maximum effects of precursor emissions on O₃ concentrations usually occur several hours after they are emitted and many miles from the source. Meteorology and terrain play major roles in O₃ formation, and ideal conditions occur during summer and early autumn on days with low wind speeds or stagnant air, warm temperatures, and cloudless skies. O₃ exists in the upper atmosphere ozone layer (stratospheric O₃) and at the Earth's surface in the troposphere (ground-level O₃).³ The O₃ that the EPA and the CARB regulate as a criteria air pollutant is produced close to the ground level, where people live, exercise, and breathe. Ground-level O₃ is a harmful air pollutant that causes numerous adverse health effects and is thus considered "bad" O₃. Stratospheric, or "good," O₃ occurs naturally in the upper atmosphere, where it reduces the

² The following descriptions of health effects for each of the criteria air pollutants associated with project construction and operations are based on the U.S. Environmental Protection Agency's "Criteria Air Pollutants" (EPA 2024b) and the California Air Resources Board's "Glossary of Air Pollutant Terms" (CARB 2024a) and CARB's "Common Air Pollutants" (CARB 2024b).

³ The troposphere is the layer of the Earth's atmosphere nearest to the surface of the Earth. The troposphere extends outward about 5 miles at the poles and about 10 miles at the equator.

amount of ultraviolet light (i.e., solar radiation) entering the Earth's atmosphere. Without the protection of the beneficial stratospheric O₃ layer, plant and animal life would be seriously harmed.

O₃ in the troposphere causes numerous adverse health effects; short-term exposures (lasting for a few hours) to O₃ can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes (EPA 2020). Inhalation of O₃ causes inflammation and irritation of the tissues lining human airways, causing and worsening a variety of symptoms. Exposure to O₃ can reduce the volume of air that the lungs breathe in, thereby causing shortness of breath. O₃ in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The occurrence and severity of health effects from O₃ exposure vary widely among individuals, even when the dose and the duration of exposure are the same. Research shows adults and children who spend more time outdoors participating in vigorous physical activities are at greater risk from the harmful health effects of O₃ exposure. While there are relatively few studies on the effects of O₃ on children, the available studies show that children are no more or less likely to suffer harmful effects than adults. However, there are a number of reasons why children may be more susceptible to O₃ and other pollutants. Children and teens spend nearly twice as much time outdoors and engaged in vigorous activities as adults. Children breathe more rapidly than adults and inhale more pollution per pound of their body weight than adults. Also, children are less likely than adults to notice their own symptoms and avoid harmful exposures. Further research may be able to better distinguish between health effects in children and adults. Children, adolescents, and adults who exercise or work outdoors, where O₃ concentrations are the highest, are at the greatest risk of harm from this pollutant (CARB 2024c).

Nitrogen Dioxide. NO₂ is a brownish, highly reactive gas that is present in all urban atmospheres. The major mechanism for the formation of NO₂ in the atmosphere is the oxidation of the primary air pollutant nitric oxide (NO), which is a colorless, odorless gas. NO_x plays a major role, together with VOCs, in the atmospheric reactions that produce O₃. NO_x is formed from fuel combustion under high temperature or pressure. In addition, NO_x is an important precursor to acid rain and may affect both terrestrial and aquatic ecosystems. The two major emissions sources are transportation and stationary fuel combustion sources such as electric utility and industrial boilers. NO₂ can irritate the lungs, cause bronchitis and pneumonia, and lower resistance to respiratory infections (EPA 2016).

A large body of health science literature indicates that exposure to NO₂ can induce adverse health effects. The strongest health evidence, and the health basis for the ambient air quality standards for NO₂, results from controlled human exposure studies that show that NO₂ exposure can intensify responses to allergens in allergic asthmatics. In addition, a number of epidemiological studies have demonstrated associations between NO₂ exposure and premature death, cardiopulmonary effects, decreased lung function and growth in children, respiratory symptoms, emergency room visits for asthma, and intensified allergic responses. Infants and children are particularly at risk because they have disproportionately higher exposure to NO₂ than adults due to their faster breathing rate for their body weight and their typically greater outdoor exposure duration. Several studies have shown that long-term NO₂ exposure during childhood, the period of rapid lung growth, can lead to smaller lungs at maturity in children with higher levels of exposure compared to children with lower exposure levels. In addition, children with asthma have a greater degree of airway responsiveness compared with adult asthmatics. In adults, the greatest risk is to people who have chronic respiratory diseases, such as asthma and chronic obstructive pulmonary disease (CARB 2024d).

Carbon Monoxide. CO is a colorless, odorless gas formed by the incomplete combustion of hydrocarbons, or fossil fuels. CO is emitted almost exclusively from motor vehicles, power plants, refineries, industrial boilers, ships, aircraft, and trains. In urban areas, automobile exhaust accounts for the majority of CO emissions. CO is a non-reactive air pollutant that dissipates relatively quickly; therefore, ambient CO concentrations generally follow the

spatial and temporal distributions of vehicular traffic. CO concentrations are influenced by local meteorological conditions—primarily wind speed, topography, and atmospheric stability. CO from motor vehicle exhaust can become locally concentrated when surface-based temperature inversions are combined with calm atmospheric conditions, which is a typical situation at dusk in urban areas from November to February. The highest levels of CO typically occur during the colder months of the year, when inversion conditions are more frequent.

CO is harmful because it binds to hemoglobin in the blood, reducing the blood's ability to carry oxygen. This interferes with oxygen delivery to the body's organs. The most common effects of CO exposure are fatigue, headaches, confusion and reduced mental alertness, light-headedness, and dizziness due to inadequate oxygen delivery to the brain. For people with cardiovascular disease, short-term CO exposure can further reduce their body's already compromised ability to respond to the increased oxygen demands of exercise, exertion, or stress. Inadequate oxygen delivery to the heart muscle leads to chest pain and decreased exercise tolerance. Unborn babies whose mothers experience high levels of CO exposure during pregnancy are at risk of adverse developmental effects. Unborn babies, infants, older people, and people with anemia or with a history of heart or respiratory disease are most likely to experience health effects with exposure to elevated levels of CO (CARB 2024e).

Sulfur Dioxide. SO₂ is a colorless, pungent gas formed primarily from incomplete combustion of sulfur-containing fossil fuels. The main sources of SO₂ are coal and oil used in power plants and industries; as such, the highest levels of SO₂ are generally found near large industrial complexes. In recent years, SO₂ concentrations have been reduced by the increasingly stringent controls placed on stationary-source emissions of SO₂ and limits on the sulfur content of fuels.

Controlled human exposure and epidemiological studies show that children and adults with asthma are more likely to experience adverse responses with SO₂ exposure, compared with the non-asthmatic population. Effects at levels near the 1-hour standard are those of asthma exacerbation, including bronchoconstriction accompanied by symptoms of respiratory irritation such as wheezing, shortness of breath, and chest tightness, especially during exercise or physical activity. Also, exposure at elevated levels of SO₂ (above 1 part per million [ppm]) results in increased incidence of pulmonary symptoms and disease, decreased pulmonary function, and increased risk of mortality. Older people and people with cardiovascular disease or chronic lung disease (such as bronchitis or emphysema) are most likely to experience these adverse effects (CARB 2024f).

SO₂ is of concern both because it is a direct respiratory irritant and because it contributes to the formation of sulfate and sulfuric acid in particulate matter (NRC 2005). People with asthma are of particular concern, both because they have increased baseline airflow resistance and because their SO₂-induced increase in airflow resistance is greater than in healthy people, and it increases with the severity of their asthma (NRC 2005). SO₂ is thought to induce airway constriction via neural reflexes involving irritant receptors in the airways (NRC 2005).

Particulate Matter. Particulate matter pollution consists of very small liquid and solid particles floating in the air, which can include smoke, soot, dust, salts, acids, and metals. Particulate matter can form when gases emitted from industries and motor vehicles undergo chemical reactions in the atmosphere. PM_{2.5} and PM₁₀ represent fractions of particulate matter. Coarse particulate matter (PM₁₀) consists of particulate matter that is 10 microns or less in diameter and is about 1/7 the thickness of a human hair. Major sources of PM₁₀ include crushing or grinding operations; dust stirred up by vehicles traveling on roads; wood-burning stoves and fireplaces; dust from construction, landfills, and agriculture; wildfires and brush/waste burning; industrial sources; windblown dust from open lands; and atmospheric chemical and photochemical reactions. Fine particulate matter (PM_{2.5}) consists of particulate matter that is 2.5 microns or less in diameter and is roughly 1/28 the diameter of a human hair. PM_{2.5} results from fuel combustion (e.g., from motor vehicles and power generation and industrial facilities), residential

fireplaces, and woodstoves. In addition, PM_{2.5} can be formed in the atmosphere from gases such as sulfur oxides (SO_x), NO_x, and VOCs.

PM_{2.5} and PM₁₀ pose a greater health risk than larger-size particles. When inhaled, these tiny particles can penetrate the human respiratory system's natural defenses and damage the respiratory tract. PM_{2.5} and PM₁₀ can increase the number and severity of asthma attacks, cause or aggravate bronchitis and other lung diseases, and reduce the body's ability to fight infections. Very small particles of substances such as lead, sulfates, and nitrates can cause lung damage directly or be absorbed into the blood stream, causing damage elsewhere in the body. Additionally, these substances can transport adsorbed gases such as chlorides or ammonium into the lungs, also causing injury. Whereas PM₁₀ tends to collect in the upper portion of the respiratory system, PM_{2.5} is so tiny that it can penetrate deeper into the lungs and damage lung tissue. Suspended particulates also damage and discolor surfaces on which they settle and produce haze and reduce regional visibility.

A number of adverse health effects have been associated with exposure to both PM_{2.5} and PM₁₀. For PM_{2.5}, short-term exposures (up to 24-hour duration) have been associated with premature mortality, increased hospital admissions for heart or lung causes, acute and chronic bronchitis, asthma attacks, emergency room visits, respiratory symptoms, and restricted activity days. These adverse health effects have been reported primarily in infants, children, and older adults with preexisting heart or lung diseases. In addition, of all the common air pollutants, PM_{2.5} is associated with the greatest proportion of adverse health effects related to air pollution, both in the United States and worldwide, based on the World Health Organization's Global Burden of Disease Project. Short-term exposures to PM₁₀ have been associated primarily with worsening of respiratory diseases, including asthma and chronic obstructive pulmonary disease, leading to hospitalization and emergency department visits (CARB 2024g).

Long-term exposure (months to years) to PM_{2.5} has been linked to premature death, particularly in people who have chronic heart or lung diseases, and reduced lung function and growth in children. The effects of long-term exposure to PM₁₀ are less clear, although several studies suggest a link between long-term PM₁₀ exposure and respiratory mortality. The International Agency for Research on Cancer published a review in 2015 that concluded that particulate matter in outdoor air pollution causes lung cancer (CARB 2024g).

Lead. Lead in the atmosphere occurs as particulate matter. Sources of lead include leaded gasoline; the manufacturing of batteries, paints, ink, ceramics, and ammunition; and secondary lead smelters. Prior to 1978, mobile emissions were the primary source of atmospheric lead. Between 1978 and 1987, the phaseout of leaded gasoline reduced the overall inventory of airborne lead by nearly 95%. With the phaseout of leaded gasoline, secondary lead smelters, battery recycling, and manufacturing facilities are becoming lead emissions sources of greater concern.

Prolonged exposure to atmospheric lead poses a serious threat to human health. Health effects associated with exposure to lead include gastrointestinal disturbances, anemia, kidney disease, and in severe cases, neuromuscular and neurological dysfunction. Of particular concern are low-level lead exposures during infancy and childhood. Such exposures are associated with decrements in neurobehavioral performance, including intelligence quotient performance, psychomotor performance, reaction time, and growth. Children are highly susceptible to the effects of lead.

Volatile Organic Compounds. Hydrocarbons are organic gases that are formed from hydrogen and carbon and sometimes other elements. Hydrocarbons that contribute to formation of O₃ are referred to and regulated as VOCs. Combustion engine exhaust, oil refineries, and fossil-fueled power plants are the main sources of hydrocarbons.

Other sources of hydrocarbons include evaporation from petroleum fuels, solvents, dry-cleaning solutions, and paint.

The primary health effects of VOCs result from the formation of O₃ and its related health effects. High levels of VOCs in the atmosphere can interfere with oxygen intake by reducing the amount of available oxygen through displacement. Carcinogenic forms of hydrocarbons, such as benzene, are considered TACs. There are no separate health standards for VOCs as a group.

Sulfates. Sulfates are the fully oxidized form of sulfur, which typically occur in combination with metals or hydrogen ions. Sulfates are produced from reactions of SO₂ in the atmosphere and can result in respiratory impairment, as well as reduced visibility.

Vinyl Chloride. Vinyl chloride is a colorless gas with a mild, sweet odor, which has been detected near landfills, sewage plants, and hazardous waste sites, due to the microbial breakdown of chlorinated solvents. Short-term exposure to high levels of vinyl chloride in air can cause nervous system effects, such as dizziness, drowsiness, and headaches. Long-term exposure through inhalation can cause liver damage, including liver cancer.

Hydrogen Sulfide. Hydrogen sulfide is a colorless and flammable gas that has a characteristic odor of rotten eggs. Sources of hydrogen sulfide include geothermal power plants, petroleum refineries, sewers, and sewage treatment plants. Exposure to hydrogen sulfide can result in nuisance odors, as well as headaches and breathing difficulties at higher concentrations.

Visibility-Reducing Particles. Visibility-reducing particles are any particles in the air that obstruct the range of visibility. Effects of reduced visibility can include obscuring the viewshed of natural scenery, reducing airport safety, and discouraging tourism. Sources of visibility-reducing particles are the same as for PM_{2.5}.

3.1.1.2.2 Non-Criteria Pollutants and Valley Fever

Odorous Compounds. Odors are generally regarded as an annoyance rather than a health hazard. Manifestations of a person's reaction to odors can range from psychological (e.g., irritation, anger, or anxiety) to physiological (e.g., circulatory and respiratory effects, nausea, vomiting, and headache). The ability to detect odors varies considerably among the population and overall is quite subjective. People may have different reactions to the same odor. An odor that is offensive to one person may be perfectly acceptable to another (e.g., a coffee roaster). An unfamiliar odor is more easily detected and is more likely to cause complaints than a familiar one. In a phenomenon known as odor fatigue, a person can become desensitized to almost any odor, and recognition may only occur with an alteration in the intensity. The occurrence and severity of odor impacts depend on the nature, frequency, and intensity of the source; wind speed and direction; and the sensitivity of receptors.

Valley Fever. Coccidioidomycosis, more commonly known as “valley fever,” is an infection caused by inhalation of the spores of the *Coccidioides immitis* fungus, which grows in the soils of the southwestern United States. The ecologic factors that appear to be most conducive to survival and replication of the spores are high summer temperatures, mild winters, sparse rainfall, and alkaline, sandy soils.

California Labor Code Section 6709 defines “highly endemic” areas for valley fever as those areas where the annual incidence rate is greater than 20 cases per 100,000 persons per year. Los Angeles County is not considered a highly endemic region for valley fever; the latest report from the California Department of Public Health indicated the County has 14.5 cases per 100,000 people (CDPH 2024). Although cases are reported County-wide, most cases

have occurred in northern areas, with an approximately ninefold higher rate of cases in Antelope Valley compared to other areas of the County (County of Los Angeles 2017). In contrast, in 2022, 309 cases were reported in the statewide annual incident Antelope Valley Service Planning Area 1, resulting in an incidence rate was 19.1 of approximately 74.5 cases per 100,000 people (LACDPH 2024, 2025). The California counties Therefore, Antelope Valley is considered a highly endemic area for valley fever include Kern (264.9 per 100,000), Kings (111.0 per 100,000), Tulare (65.7 per 100,000), San Luis Obispo (51.5 per 100,000), Fresno (44.3 per 100,000), Madera (32.4 per 100,000), and Ventura (28.3 per 100,000), which accounted for 50.5% of the reported cases in 2022 (CDPH 2024).

3.1.1.2.3 Greenhouse Gases

A GHG is any gas that absorbs infrared radiation in the atmosphere; in other words, GHGs trap heat in the atmosphere. As defined in California Health and Safety Code Section 38505(g), for purposes of administering many of the state's primary GHG emission reduction programs, GHGs include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), and nitrogen trifluoride (NF₃) (see also CEQA Guidelines Section 15364.5). Some GHGs, such as CO₂, CH₄, and N₂O, occur naturally and are emitted into the atmosphere through natural processes and human activities. Of these gases, CO₂ and CH₄ are emitted in the greatest quantities from human activities. Manufactured GHGs, which have a much greater heat-absorption potential than CO₂, include fluorinated gases, such as HFCs, PFCs, and SF₆, which are associated with certain industrial products and processes. The following paragraphs provide a summary of the most common GHGs and their sources.⁴

Carbon Dioxide. CO₂ is a naturally occurring gas and a by-product of human activities and is the principal anthropogenic (i.e., caused by human activity) GHG that affects the Earth's radiative balance. Natural sources of CO₂ include respiration of bacteria, plants, animals, and fungus; evaporation from oceans; volcanic out-gassing; and decomposition of dead organic matter. Human activities that generate CO₂ are the combustion of fuels such as coal, oil, natural gas, and wood and changes in land use.

Methane. CH₄ is produced through both natural and human activities. CH₄ is a flammable gas and is the main component of natural gas. CH₄ is produced through anaerobic (without oxygen) decomposition of waste in landfills, flooded rice fields, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion.

Nitrous Oxide. N₂O is produced through natural and human activities, mainly through agricultural activities and natural biological processes, although fuel burning and other processes also create N₂O. Sources of N₂O include soil cultivation practices (microbial processes in soil and water), especially the use of commercial and organic fertilizers; manure management; industrial processes (such as in nitric acid production, nylon production, and fossil-fuel-fired power plants); vehicle emissions, and using N₂O as a propellant (e.g., rockets, racecars, and aerosol sprays).

Fluorinated Gases. Fluorinated gases (also referred to as F-gases) are synthetic powerful GHGs emitted from many industrial processes. Fluorinated gases are commonly used as substitutes for stratospheric O₃-depleting substances (e.g., chlorofluorocarbons [CFCs], hydrochlorofluorocarbons [HCFCs], and halons). The most prevalent fluorinated gases include the following:

⁴ The descriptions of GHGs are summarized from the IPCC Fourth Assessment Report (2007), CARB's "Glossary of Terms Used in GHG Inventories" (CARB 2025a), and EPA's "Basics of Climate Change" (EPA 2024a).

- **Hydrofluorocarbons:** HFCs are compounds containing only hydrogen, fluorine, and carbon atoms. HFCs are synthetic chemicals used as alternatives to O₃-depleting substances in serving many industrial, commercial, and personal needs. HFCs are emitted as by-products of industrial processes and are used in manufacturing.
- **Perfluorocarbons:** PFCs are a group of human-made chemicals composed of carbon and fluorine only. These chemicals were introduced as alternatives, with HFCs, to the O₃-depleting substances. The two main sources of PFCs are primary aluminum production and semiconductor manufacturing. Since PFCs have stable molecular structures and do not break down through the chemical processes in the lower atmosphere, these chemicals have long lifetimes, ranging between 10,000 and 50,000 years.
- **Sulfur Hexafluoride:** SF₆ is a colorless gas soluble in alcohol and ether and slightly soluble in water. SF₆ is used for insulation in electric power transmission and distribution equipment, semiconductor manufacturing, and the magnesium industry, and is used as a tracer gas for leak detection.
- **Nitrogen Trifluoride:** NF₃ is used in the manufacture of a variety of electronics, including semiconductors and flat panel displays.

Chlorofluorocarbons. CFCs are synthetic chemicals that have been used as cleaning solvents, refrigerants, and aerosol propellants. CFCs are chemically unreactive in the lower atmosphere (troposphere) and the production of CFCs was prohibited in 1987 due to the chemical destruction of stratospheric O₃.

Hydrochlorofluorocarbons. HCFCs are a large group of compounds whose structure is very close to that of CFCs—containing hydrogen, fluorine, chlorine, and carbon atoms—but includes one or more hydrogen atoms. Like HFCs, HCFCs are used in refrigerants and propellants. HCFCs were also used in place of CFCs for some applications; however, their use in general is being phased out.

Black Carbon. Black carbon is a component of fine particulate matter, which has been identified as a leading environmental risk factor for premature death. It is produced from the incomplete combustion of fossil fuels and biomass burning, particularly from older diesel engines and forest fires. Black carbon warms the atmosphere by absorbing solar radiation, influences cloud formation, and darkens the surface of snow and ice, which accelerates heat absorption and melting. Black carbon is a short-lived species that varies spatially, which makes it difficult to quantify the global warming potential (GWP). Diesel particulate matter emissions are a major source of black carbon and are TACs that have been regulated and controlled in California for several decades to protect public health.

Water Vapor. The primary source of water vapor is evaporation from the ocean, with additional vapor generated by sublimation (change from solid to gas) from ice and snow, evaporation from other water bodies, and transpiration from plant leaves. Water vapor is the most important, abundant, and variable GHG in the atmosphere and maintains a climate necessary for life.

Ozone. Tropospheric O₃, which is created by photochemical reactions involving gases from both natural sources and human activities, acts as a GHG. Stratospheric O₃, which is created by the interaction between solar ultraviolet radiation and molecular oxygen (O₂), plays a decisive role in the stratospheric radiative balance. Depletion of stratospheric O₃ due to chemical reactions that may be enhanced by climate change results in an increased ground-level flux of ultraviolet-B radiation.

Aerosols. Aerosols are suspensions of PM in a gas emitted into the air through burning biomass (plant material) and fossil fuels. Aerosols can warm the atmosphere by absorbing and emitting heat and can cool the atmosphere by reflecting light.

3.1.1.2.4 Global Warming Potential

Gases in the atmosphere can contribute to climate change both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other GHGs, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the Earth (e.g., affect cloud formation or albedo) (EPA 2024a). The Intergovernmental Panel on Climate Change (IPCC) developed the GWP concept to compare the ability of each GHG to trap heat in the atmosphere relative to another gas. The GWP of a GHG is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram of a trace substance relative to that of 1 kilogram of a reference gas (IPCC 2014). The reference gas used is CO₂; therefore, GWP-weighted emissions are measured in metric tons (MT) of CO₂ equivalent (CO₂e).

The current version of the California Emissions Estimator Model (CalEEMod), Version 2022.1.1.29, assumes that the GWP for CH₄ is 25 (so emissions of 1 MT of CH₄ are equivalent to emissions of 25 MT of CO₂), and the GWP for N₂O is 298, based on the IPCC Fourth Assessment Report (IPCC 2007). The GWP values identified in CalEEMod were applied to the Project.

3.1.1.2.5 Potential Effects of Climate Change

Globally, climate change has the potential to affect numerous environmental resources through uncertain impacts related to future air temperatures and precipitation patterns. The 2014 IPCC Synthesis Report (IPCC 2014) indicated that warming of the climate system is unequivocal, and many of the changes observed since the 1950s are unprecedented over decades to millennia. Signs that global climate change has occurred include warming of the atmosphere and ocean, diminished amounts of snow and ice, rising sea levels, and ocean acidification (IPCC 2014).

In California, climate change impacts have the potential to affect sea level rise, agriculture, snowpack and water supply, forestry, wildfire risk, public health, frequency of severe weather events, and electricity demand and supply. The primary effect of global climate change has been a rise in average global tropospheric temperature. Global surface temperature in the first two decades of the twenty-first century (2001–2020) was 0.99°C (0.84°C to 1.10°C) higher than 1850–1900 (IPCC 2023). Global surface temperature has increased faster since 1970 than in any other 50-year period over at least the last 2000 years (IPCC 2023). Scientific modeling predicts that continued emissions of GHGs at or above current rates will induce more extreme climate changes during the twenty-first century than were observed during the twentieth century. Human activities, principally through emissions of GHGs, have unequivocally caused global warming, with global surface temperature reaching 1.1°C above 1850–1900 in 2011–2020 (IPCC 2023).

Although climate change is driven by global atmospheric conditions, climate change impacts are felt locally. A scientific consensus confirms that climate change is already affecting California. The California Office of Environmental Health Hazard Assessment identified various indicators of climate change in California, which are scientifically based measurements that track trends in various aspects of climate change. Many indicators reveal discernible evidence that climate change is occurring in California and is having significant, measurable impacts in the state. Changes in the state's climate have been observed including an increase in annual average air temperature, more frequent extreme heat events, more extreme drought, a decline in winter chill, an increase in cooling degree days and a decrease in heating degree days, and an increase in variability of statewide precipitation (OEHHA 2022).

Warming temperatures and changing precipitation patterns have altered California's physical systems—the ocean, lakes, rivers, and snowpack—on which the state depends. Winter snowpack and spring snowmelt runoff from the Sierra Nevada and southern Cascade Mountains provide approximately one-third of the state's annual water supply. Impacts of climate on physical systems have been observed such as high variability of snow-water content (i.e., amount of water stored in snowpack), decrease in spring snowmelt runoff, glacier change (loss in area), rise in sea levels, increase in average lake water temperature and coastal ocean temperature, and decrease in dissolved oxygen in coastal waters (OEHHA 2022).

Impacts of climate change on biological systems, including humans, wildlife, and vegetation, have also been observed, including climate change impacts on terrestrial, marine, and freshwater ecosystems. As with global observations, species responses include those consistent with warming: elevational or latitudinal shifts in range, changes in the timing of key plant and animal life cycle events, and changes in the abundance of species and in community composition. Humans are better able to adapt to a changing climate than plants and animals in natural ecosystems. Nevertheless, climate change poses a threat to public health as warming temperatures and changes in precipitation can affect vector-borne pathogen transmission and disease patterns in California as well as the variability of heat-related deaths and illnesses. In addition, since 1950, the area burned by wildfires each year has been increasing.

The California Natural Resources Agency (CNRA) has released four California Climate Change Assessments (in 2006, 2009, 2012, and 2018), which have addressed the following: acceleration of warming across the state, more intense and frequent heat waves, greater riverine flows, accelerating sea level rise, more intense and frequent drought, more severe and frequent wildfires, more severe storms and extreme weather events, shrinking snowpack and less overall precipitation, and ocean acidification, hypoxia, and warming. To address local and regional governments' need for information to support action in their communities, the Fourth Assessment includes reports for nine regions of the state. Key highlights for the Los Angeles region (LA region), where the Project site is located, include the following (CNRA 2018:6):

- Continued future warming over the LA region. Across the region, average maximum temperatures are projected to increase around 4–5 degrees F by the mid-century, and 5–8 degrees F by the late-century.
- Extreme temperatures are also expected to increase. The hottest day of the year may be up to 10 degrees F warmer for many locations across the LA region by the late-century under RCP8.5.⁵ The number of extremely hot days is also expected to increase across the region.
- Despite small changes in average precipitation, dry and wet extremes are both expected to increase. By the late 21st century, the wettest day of the year is expected to increase across most of the LA region, with some locations experiencing 25–30% increases under RCP8.5. Increased frequency and severity of atmospheric river events are also projected to occur for this region.
- Sea levels are projected to continue to rise in the future, but there is a large range based on emissions scenario and uncertainty in feedbacks in the climate system. Roughly 1–2 feet of sea level rise is projected by the mid-century, and the most extreme projections lead to 8–10 feet of sea level rise by the end of the century.
- Projections indicate that wildfire may increase over southern California, but there remains uncertainty in quantifying future changes of burned area over the LA region.

⁵ Representative Concentration Pathway (RCP) 8.5 is a greenhouse gas emissions scenario used in future projections that represents a “business-as-usual” scenario where CO₂ emissions continue to rise throughout the twenty-first century (van Vuuren et al. 2011). Data and detailed projections are available online at <https://cal-adapt.org/>.

3.1.1.3 Sensitive Receptors

Some land uses are considered more sensitive to changes in air quality than others, depending on the population groups and the activities involved. People most likely to be affected by air pollution include children, older adults, athletes, and people with cardiovascular and chronic respiratory diseases. Facilities and structures where these air-pollution-sensitive people live or spend considerable amounts of time are known as “sensitive receptors.” Land uses where air-pollution-sensitive individuals are most likely to spend time include schools and schoolyards, parks and playgrounds, daycare centers, nursing homes, hospitals, and residential communities (sensitive sites or sensitive land uses) (CARB 2005). AVAQMD identifies residences, daycare centers, playgrounds, and medical facilities as sensitive receptors for the purposes of identifying air quality impacts (AVAQMD 2016).

The closest sensitive receptors to the Project site are residences located immediately adjacent to the west (along Malinta Avenue), north (along Tortuga Street and Soledad Canyon Road), and south (across Soledad Canyon Road) of the BESS facility Project site boundary. Single-family residences are also located close to the gen-tie alignments. The nearest school is the Meadowlark Elementary School, approximately 2 miles to the west of the proposed BESS facility.

3.1.2 Regional and Local Air Quality

3.1.2.1 Los Angeles County Portion of Mojave Desert Air Basin - Attainment Designation

Pursuant to the 1990 federal Clean Air Act Amendments, the EPA classifies air basins (or portions thereof) as “attainment” or “nonattainment” for each criteria air pollutant, based on whether the NAAQS have been achieved. Generally, if the recorded concentrations of a pollutant are lower than the standard, the area is classified as “attainment” for that pollutant. If an area exceeds the standard, the area is classified as “nonattainment” for that pollutant. If there is not enough data available to determine whether the standard is exceeded in an area, the area is designated as “unclassified” or “unclassifiable.” The designation of “unclassifiable/attainment” means that the area meets the standard or is expected to meet the standard despite a lack of monitoring data. Areas that achieve the standards after a nonattainment designation are re-designated as maintenance areas and must have approved maintenance plans to ensure continued attainment of the standards. The California Clean Air Act, like its federal counterpart, called for the designation of areas as “attainment” or “nonattainment,” but based on the CAAQS rather than the NAAQS. Table 3.1-1 depicts the current attainment status of the Project area with respect to the NAAQS and CAAQS.

Table 3.1-1. Los Angeles County Portion of Mojave Desert Air Basin - Attainment Classification

Pollutant	Designation/Classification ^a	
	Federal Standards	State Standards
O ₃ – 1 hour	No federal standard	Nonattainment
O ₃ – 8 hours	Severe nonattainment	Nonattainment
NO ₂	Unclassifiable/attainment	Attainment
CO	Unclassifiable/attainment	Attainment
SO ₂	Unclassifiable/attainment	Attainment

Table 3.1-1. Los Angeles County Portion of Mojave Desert Air Basin - Attainment Classification

Pollutant	Designation/Classification ^a	
	Federal Standards	State Standards
PM ₁₀	Unclassifiable	Nonattainment
PM _{2.5}	Unclassifiable/attainment	Attainment
Lead	Unclassifiable/attainment	Attainment
Hydrogen sulfide	No federal standard	Unclassified
Sulfates	No federal standard	Attainment
Visibility-reducing particles	No federal standard	Unclassified
Vinyl chloride	No federal standard	No designation

Sources: CARB 2023 (state); EPA 2025a (federal).

Notes: O₃ = ozone; NO₂ = nitrogen dioxide; CO = carbon monoxide; SO₂ = sulfur dioxide; PM₁₀ = coarse particulate matter; PM_{2.5} = fine particulate matter.

^a Designations/classifications in **bold** type indicate nonattainment.

Definitions: attainment = meets the standards; attainment/maintenance = achieve the standards after a nonattainment designation; nonattainment = does not meet the standards; unclassified or unclassifiable = insufficient data to classify; unclassifiable/attainment = meets the standard or is expected to be meet the standard despite a lack of monitoring data.

In summary, the Project site is located in an area of the MDAB that is designated as a nonattainment area for federal and state O₃ standards and the state PM₁₀ standard, and unclassifiable/attainment for all other criteria air pollutants (CARB 2023; EPA 2025a).

Despite the current nonattainment status for O₃ and PM₁₀, air quality in the MDAB has generally improved since the inception of air pollutant monitoring. This improvement is mainly a result of lower-polluting on-road motor vehicles, more stringent regulation of industrial sources, and the implementation of emission reduction strategies by AVAQMD and nearby air districts including the Mojave Desert Air Quality Management District and the South Coast Air Quality Management District (SCAQMD), as well as CARB and EPA. This general trend toward cleaner air within the state, including the MDAB, has occurred in spite of continued population growth.

3.1.2.2 Air Quality Monitoring Data

CARB, air districts, and other agencies monitor ambient air quality at approximately 250 air quality monitoring stations across the state. AVAQMD monitors local ambient air quality in the Project area. Air quality monitoring stations usually measure pollutant concentrations 10 feet above ground level; therefore, air quality is often referred to in terms of ground-level concentrations. The most recent background ambient air quality data from 2021 to 2023 are presented in Table 3.1-2. The Lancaster Division Street monitoring station, located at 43301 Division Street, Lancaster, California, is the nearest air quality monitoring station to the Project site, and is located approximately 4.8 miles north of the Project site. However, monitoring at this station discontinued after 2022 and monitoring has since shifted to the Lancaster Fairgrounds monitoring station, located at 2551 West Avenue H, Lancaster, California, approximately 8.5 miles north of the Project site. The Downtown Los Angeles monitoring station, located at 1630 North Main Street, Los Angeles, California, is the nearest air quality monitoring station to the Project site that monitors SO₂, and is located approximately 30 miles south of the Project site. The combined data available from these stations are considered representative of the air quality experienced in the Project vicinity. The number of days exceeding the ambient air quality standards is also shown in Table 3.1-2.

Table 3.1-2. Local Ambient Air Quality Data

Averaging Time	Unit	Agency/ Method	Ambient Air Quality Standard	Measured Concentration by Year			Exceedances by Year		
				2021	2022	2023	2021	2022	2023
Ozone (O ₃) – Lancaster Division Street and Lancaster Fairgrounds Monitoring Stations									
Maximum 1-hour concentration	ppm	California	0.09	0.086	0.098	0.112	0	3	1
Maximum 8-hour concentration	ppm	California	0.070	0.080	0.083	0.089	4	36	6
		National	0.070	0.079	0.082	0.088	3	33	6
Nitrogen Dioxide (NO ₂) – Lancaster Division Street and Lancaster Fairgrounds Monitoring Stations									
Maximum 1-hour concentration	ppm	California	0.18	0.046	0.043	0.034	0	0	0
		National	0.100	0.046	0.043	0.034	0	0	0
Annual concentration	ppm	California	0.030	0.008	0.008	0.003	—	—	—
		National	0.053	0.008	0.008	0.003	—	—	—
Carbon Monoxide (CO) – Lancaster Division Street and Lancaster Fairgrounds Monitoring Stations									
Maximum 1-hour concentration	ppm	California	20	1.4	ND	ND	0	ND	ND
		National	35	1.4	ND	ND	0	ND	ND
Maximum 8-hour concentration	ppm	California	9.0	1.1	ND	ND	0	ND	ND
		National	9	1.1	ND	ND	0	ND	ND
Sulfur Dioxide (SO ₂) – Downtown Los Angeles Monitoring Station									
Maximum 1-hour concentration	ppm	National	0.075	0.002	0.007	0.008	0	0	0
Maximum 24-hour concentration	ppm	State	0.04	ND	ND	ND	ND	ND	ND
	ppm	National	0.140	0.001	0.001	0.002	0	0	0
Annual concentration	ppm	National	0.030	0.0004	0.0003	0.0002	—	—	—
Coarse Particulate Matter (PM ₁₀) ^a – Lancaster Division Street and Lancaster Fairgrounds Monitoring Stations									
Maximum 24-hour concentration	µg/m ³	California	50	ND	ND	118.3	ND (ND)	ND (ND)	7.1 (7)
		National	150	411.2	76.2	121.1	1.0 (0)	0.0 (0)	0.0 (0)
Annual concentration	µg/m ³	California	20	ND	ND	17.3	—	—	—
Fine Particulate Matter (PM _{2.5}) ^a – Lancaster Division Street and Lancaster Fairgrounds Monitoring Stations									
Maximum 24-hour concentration	µg/m ³	National	35	35.7	15.1	12.4	1.0 (1)	0.0 (0)	0.0 (0)

Table 3.1-2. Local Ambient Air Quality Data

Averaging Time	Unit	Agency/ Method	Ambient Air Quality Standard	Measured Concentration by Year			Exceedances by Year		
				2021	2022	2023	2021	2022	2023
Annual concentration	µg/m ³	California	12	8.1	ND	3.4	—	—	—
		National	9.0	8.1	7.5	3.3	—	—	—

Sources: CARB 2025b; EPA 2025b.

Notes: ppm = parts per million by volume; — = not available; µg/m³ = micrograms per cubic meter; ND = insufficient data available to determine the value.

The Lancaster Division Street monitoring station is located at 43301 Division Street, Lancaster, California 93535.

The Lancaster Fairgrounds monitoring station is located at 2551 West Avenue H, Lancaster, California 93536.

The Downtown Los Angeles monitoring station is located at 1630 North Main Street, Los Angeles, California 91002.

Data taken from CARB represent the highest concentrations experienced over a given year.

Exceedances of national and California standards are only shown for O₃ and particulate matter. Daily exceedances for particulate matter are estimated days because PM₁₀ and PM_{2.5} are not monitored daily. There is no national standard for 1-hour O₃ or annual PM₁₀, nor is there a California 24-hour standard for PM_{2.5}.

^a Measurements of PM₁₀ and PM_{2.5} are usually collected every 6 days and every 1 to 3 days, respectively. Number of days exceeding the standards is a mathematical estimate of the number of days concentrations will have been greater than the level of the standard had each day been monitored. The numbers in parentheses are the measured number of samples that exceeded the standard.

3.1.3 Impact Analysis

3.1.3.1 Significance Criteria and Methodology

3.1.3.1.1 Thresholds of Significance

Air Quality

The State of California has developed guidelines to address the significance of air quality impacts based on CEQA Guidelines Appendix G (14 CCR 15000 et seq.), which provides guidance that a project would have a significant environmental impact if it would:

Conflict with or obstruct implementation of the applicable air quality plan.

Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard.

Expose sensitive receptors to substantial pollutant concentrations.

Result in other emissions (such as those leading to odors) adversely affecting a substantial number of people.

CEQA Guidelines Appendix G indicates that, where available, the significance criteria established by the applicable air quality management district or pollution control district may be relied upon to determine whether the project would have a significant impact on air quality. As outlined in the AVAQMD CEQA Air and Federal Conformity Guidelines (CEQA Air Guidelines) (AVAQMD 2016), a project would result in a significant environmental impact if it:

1. Would generate total emissions (direct and indirect) in excess of the established significance thresholds (presented in Table 3.1-3).
2. Would generate a violation of any ambient air quality standard when added to the local background.

3. Does not conform with the applicable attainment or maintenance plan.⁶
4. Would expose sensitive receptors to substantial pollutant concentrations, including those resulting in a cancer risk greater than or equal to 10 in a million and/or a hazard index (non-cancerous) greater than or equal to 1.

Residences, schools, daycare centers, playgrounds, and medical facilities are considered sensitive receptor land uses. Notably, Threshold 4 above is evaluated in Section 3.9, Public Health.

The AVAQMD CEQA Air Guidelines sets forth quantitative emission significance thresholds for criteria air pollutants below which a project would not have a significant impact on ambient air quality (AVAQMD 2016). Project-related air quality emissions estimated in this environmental analysis would be considered significant if any of the applicable significance thresholds presented in Table 3.1-3 are exceeded. The emission-based thresholds for O₃ precursors are intended to serve as a surrogate for an “ozone significance threshold” (i.e., the potential for adverse O₃ impacts to occur) because O₃ itself is not emitted directly. AVAQMD recommends that its quantitative air pollution thresholds be used to determine the significance of Project emissions.

Table 3.1-3. Antelope Valley Air Quality Management District Daily Air Quality Significance Thresholds

Pollutant	Daily Threshold (Pounds per Day)
VOC	137
NO _x	137
CO	548
SO _x	137
PM ₁₀	82
PM _{2.5}	65
Hydrogen sulfide ^a	54
Lead ^a	3

Source: AVAQMD 2016.

Notes: VOC = volatile organic compound; NO_x = oxides of nitrogen; CO = carbon monoxide; SO_x = sulfur oxides; PM₁₀ = coarse particulate matter; PM_{2.5} = fine particulate matter.

^a The Project includes typical equipment and on-road vehicles, which result in negligible (if any) emissions of hydrogen sulfide and lead. Therefore, these pollutants are not discussed in this analysis.

Regarding localized CO, although AVAQMD does not have screening levels for intersection traffic that could result in potential CO hotspots, several other air districts have established these levels, which are described below to provide context of the magnitude of hourly volumes that could result in significant localized CO:

- SCAQMD conducted CO modeling for its 2003 Air Quality Management Plan (SCAQMD 2003) for the four worst-case intersections in the South Coast Air Basin. At the time the 2003 Air Quality Management Plan was prepared, the intersection of Wilshire Boulevard and Veteran Avenue was the most congested intersection in Los Angeles County, with an average daily traffic volume of approximately 100,000 vehicles per day. Using CO emission factors for 2002, the peak modeled CO 1-hour concentration was estimated to be 4.6 ppm at the intersection of Wilshire Boulevard and Veteran Avenue. Accordingly, CO concentrations

⁶ A project is deemed to not exceed this threshold, and hence not be significant, if it is consistent with the existing land use plan. Zoning changes, specific plans, general plan amendments and similar land use plan changes which do not increase dwelling unit density, do not increase vehicle trips, and do not increase vehicle miles traveled are also deemed to not exceed this threshold (AVAQMD 2016).

at congested intersections would not exceed the 1-hour or 8-hour CO CAAQS unless projected daily traffic would be at least more than 100,000 vehicles per day.

- The Bay Area Air District, formerly the Bay Area Air Quality Management District, determined that projects would result in a less than significant impact to localized CO concentrations if (1) project traffic would not increase traffic volumes at affected intersections to more than 44,000 vehicles per hour, or (2) project traffic would not increase traffic volumes at affected intersections to more than 24,000 vehicles per hour where vertical and/or horizontal mixing is substantially limited (e.g., tunnel, parking garage, bridge underpass, natural or urban street canyon, below-grade roadway) (BAAD 2023).

Based on the Project's proximity to the South Coast Air Basin, the SCAQMD screening criterion of 100,000 vehicles per day has been applied to this Project as a metric to evaluate CO hotspots.

The potential for the Project to result in other emissions, specifically an odor impact (CEQA Guidelines Appendix G, Air Quality Threshold 4), is based on the Project's land-use types and anticipated construction activity and the potential for the Project to create an odor nuisance.

Greenhouse Gas Emissions

The significance criteria used to evaluate the Project's GHG emissions impacts is based on the recommendations provided in CEQA Guidelines Appendix G. For the purposes of this GHG emissions analysis, a project would have a significant environmental impact if it would (14 CCR 15000 et seq.):

- A. Generate GHG emissions, either directly or indirectly, that may have a significant impact on the environment.

Conflict with an applicable plan, policy, or regulation adopted for the purpose of reducing the emissions of GHGs.

The Appendix G thresholds for GHGs do not prescribe specific methodologies for performing an assessment, do not establish specific thresholds of significance, and do not mandate specific mitigation measures. Rather, the CEQA Guidelines emphasize the lead agency's discretion to determine the appropriate methodologies and thresholds of significance consistent with the manner in which other impact areas are handled in CEQA (CNRA 2009). Additional guidance regarding assessment of GHGs is discussed below.

CEQA Guidelines

With respect to GHG emissions, CEQA Guidelines Section 15064.4(a) states that lead agencies "shall make a good-faith effort, based to the extent possible on scientific and factual data, to describe, calculate or estimate" GHG emissions resulting from a project. The CEQA Guidelines note that an agency has the discretion to either quantify a project's GHG emissions or rely on a "qualitative analysis or performance-based standards" (14 CCR 15064.4[a]). A lead agency may use a "model or methodology" to estimate GHG emissions and has the discretion to select the model or methodology it considers "most appropriate to enable decision makers to intelligently take into account the project's incremental contribution to climate change" (14 CCR 15064.4[c]). The CEQA Guidelines provide that the lead agency should consider the following when determining the significance of impacts from GHG emissions on the environment (14 CCR 15064.4[b]):

1. The extent a project may increase or reduce GHG emissions as compared to the existing environmental setting.

2. Whether the project emissions exceed a threshold of significance that the lead agency determines applies to the project.
3. The extent to which the project complies with regulations or requirements adopted to implement a statewide, regional, or local plan for the reduction or mitigation of GHG emissions.

In addition, the CEQA Guidelines do not indicate an amount of GHG emissions that constitutes a significant impact on the environment. Instead, the CEQA Guidelines specify that “[w]hen adopting or using thresholds of significance, a lead agency may consider thresholds of significance previously adopted or recommended by other public agencies, or recommended by experts, provided the decision of the lead agency to adopt such thresholds is supported by substantial evidence” (14 CCR 15064.7[c]).

The extent to which a project increases or decreases GHG emissions in the existing environmental setting should be estimated in accordance with Section 15064.4, Determining the Significance of Impacts from Greenhouse Gas Emissions, of the CEQA Guidelines. The CEQA Guidelines indicate that when calculating GHG emissions resulting from a project, lead agencies shall make a good-faith effort based on scientific and factual data (Section 15064.4[a]), and lead agencies have discretion to select the model or methodology deemed most appropriate for enabling decision makers to intelligently assess the project’s incremental contribution to climate change (Section 15064.4[c]).

The CEQA Guidelines also allow a lead agency to consider feasible means of mitigating the significant effects of GHG emissions, including reductions in emissions through the implementation of project features or off-site measures. The adopted amendments do not establish a GHG emissions threshold, instead allowing a lead agency to develop, adopt, and apply its own thresholds of significance or those developed by other agencies or experts. CNRA also acknowledged that a lead agency may consider compliance with regulations or requirements implementing Assembly Bill (AB) 32 in determining the significance of a project’s GHG emissions (CNRA 2009).

Governor’s Office of Planning and Research Advisory

The Governor’s Office of Planning and Research technical advisory titled “CEQA and Climate Change: Addressing Climate Change Through California Environmental Quality Act (CEQA) Review,” states that “public agencies are encouraged but not required to adopt thresholds of significance for environmental impacts. Even in the absence of clearly defined thresholds for GHG emissions, the law requires that such emissions from CEQA projects must be disclosed and mitigated to the extent feasible whenever the lead agency determines that the project contributes to a significant, cumulative climate change impact” (OPR 2008). Furthermore, the advisory document indicates that “in the absence of regulatory standards for GHG emissions or other scientific data to clearly define what constitutes a ‘significant impact,’ individual lead agencies may undertake a project-by-project analysis, consistent with available guidance and current CEQA practice” (OPR 2008).

The advisory indicated that the lead agency should identify and estimate a project’s GHG emissions, including those associated with vehicular traffic, energy consumption, water usage, and construction activities. The advisory further recommended that the lead agency determine significance of the impacts and impose all mitigation measures necessary to reduce GHG emissions to a level that is less than significant (OPR 2008). CNRA adopted the CEQA Guidelines amendments discussed above in December 2009, and they became effective in March 2010.

Approach to Determining Significance

Although AVAQMD has adopted a numerical threshold of significance for GHG emissions within the region, the Project's impacts related to GHG emissions rely on compliance with applicable plans, policies, or regulations adopted for the purpose of reducing the emissions of GHGs. The compliance evaluation is the sole basis for determining the significance of the Project's GHG-related impacts on the environment.

Nevertheless, and in accordance with Section 15064.4 of the CEQA Guidelines, GHG emissions resulting from construction and operation of the Project were quantitatively estimated. The GHG emissions associated with implementation of the Project were estimated using industry standard and accepted software tools, techniques, and emissions factors, as described for construction and operation under Section 3.1.3. Estimation of emissions is for informational purposes only, for comparison with existing environmental conditions. The significance of the Project's GHG impacts is based on the Project's compliance with local and statewide GHG reduction regulations and requirements. At the local level, guidance on reduction strategies for GHG emissions has been provided through the County of Los Angeles 2045 Climate Action Plan (2045 CAP), and at the state level, through the CARB Scoping Plans.

The Los Angeles County 2045 CAP was adopted in June 2024. The 2045 CAP builds on previous climate action work from the Unincorporated Los Angeles County Community Climate Action Plan 2020 (2020 CCAP), adopted in October 2015 as a subcomponent of the Air Quality Element of the Los Angeles County General Plan (County of Los Angeles 2015). The 2045 CAP is an update to the 2020 CCAP, and it sets new GHG emissions reduction targets beyond the 2020 timeframe that are consistent with state goals, including AB 32, Senate Bill (SB) 32, and Executive Order (EO) B-30-15 (County of Los Angeles 2024). The 2045 CAP includes 25 measures to reduce GHG emissions within the unincorporated portion of Los Angeles County. Those measures are grouped into five strategy areas: Energy Supply; Transportation; Building Energy and Water; Waste; and Agriculture, Forestry and Other Land Use. The 2045 CAP constitutes a qualified GHG emissions reduction plan under CEQA.

Statewide, the Scoping Plan (approved by CARB in 2008 and updated in 2014, 2017, and 2022) provides a framework for actions to reduce California's GHG emissions and requires CARB and other state agencies to adopt regulations and other initiatives to reduce GHGs. The Scoping Plan is not directly applicable to specific projects, nor is it intended to be used for project-level evaluations.⁷ Under the Scoping Plan, however, there are several state regulatory measures aimed at the identification and reduction of GHG emissions. CARB and other state agencies have adopted many of the measures identified in the Scoping Plan. Most of these measures focus on area source emissions (e.g., energy usage, high-GWP GHGs in consumer products) and changes to the vehicle fleet (i.e., hybrid, electric, and more fuel-efficient vehicles) and associated fuels (e.g., Low Carbon Fuel Standard), among others.

The Project's potential to conflict with the 2045 CAP and state plans adopted by CARB are used to evaluate the significance of the Project's potential GHG emissions.

⁷ The Final Statement of Reasons for the amendments to the CEQA Guidelines reiterates the statement in the Initial Statement of Reasons that "[t]he Scoping Plan may not be appropriate for use in determining the significance of individual projects because it is conceptual at this stage and relies on the future development of regulations to implement the strategies identified in the Scoping Plan" (CNRA 2009).

3.1.3.1.2 Approach and Methodology

Construction Emissions

Emissions from the construction phase of Project components were estimated using CalEEMod Version 2022.1.1.29.⁸ Per preliminary Project details, it is conservatively assumed that construction of the Project will begin in March 2027 and will last approximately 20 months, followed by a 6-month testing and commissioning phase, ending in April 2029. The Project is assumed to have a 40-year lifespan, and at the end of operation in 2069 it will be decommissioned. However, the EMFAC and OFFROAD models in CalEEMod only have emission factors through 2050. As such, the year 2050 was assumed for estimating emissions from the 12-month decommissioning phase. Detailed scheduling assumptions with overlapping phases are provided in Appendix 3.1A, Air Quality and Greenhouse Gas Emissions Modeling and Calculations. The analysis contained herein is based on the following schedule assumptions:

- Demolition – 2 weeks
- Site Preparation – 1.5 months
- Substation Site Preparation – 2 weeks
- Grading – 4 months
- Substation Site Grading – 1 month
- Paving – 1.5 months
- Battery/Container Installation – 12 months
- Substation Installation – 8 months
- Gen-Tie Foundation and Tower Erection – 4 months
- Gen-Tie Stringing and Pulling – 1 month
- SCE Interconnection Facility Upgrades – 6 months
- Commissioning – 6 months
- Decommissioning – 12 months

The construction schedule has been developed based on available information provided by the Project applicant, typical construction practices, and CalEEMod default assumptions. Construction phasing is intended to represent a schedule of anticipated activities for use in estimating potential Project-generated construction emissions. Table 3.1-4 provides the construction equipment mix and vehicle trips assumed for estimating Project-generated construction emissions. Additional details regarding construction assumptions are provided in the modeling output in Appendix 3.1A.

⁸ CalEEMod is a statewide land use emissions computer model designed to provide a uniform platform to calculate construction and operational emissions from land use development projects. The model was developed for the California Air Pollution Control Officers Association in collaboration with multiple air districts across the state. Numerous lead agencies in the state, including AVAQMD, use CalEEMod to estimate GHG emissions in accordance with CEQA Guidelines Section 15064.4(a)(1).

Table 3.1-4. Construction Scenario Assumptions

Construction Phase	One-Way Vehicle Trips				Equipment		
	Average Daily Worker Trips	Average Daily Vendor Truck Trips	Average Daily Haul Truck Trips	Average Daily On-Site Truck Trips	Equipment Type	Quantity	Usage Hours
Demolition	10	4	6	0	Rubber-tired dozers	1	10
					Concrete/ industrial saws	1	10
					Tractors/loaders/backhoes	2	10
Site Preparation	242	12	24	44	Tractors/loaders/backhoes	2	10
					Excavator	2	10
					Rubber-tired dozer	2	10
Substation Site Preparation	242	12	100	44	Tractors/loaders/backhoes	1	10
					Excavator	1	10
					Rubber-tired dozer	1	10
Grading	242	12	524	44	Graders	2	10
					Tractors/loaders/backhoes	2	10
					Rollers	2	10
Substation Grading	242	12	486	44	Graders	1	10
					Tractors/loaders/backhoes	1	10
					Rollers	1	10
Paving	16	4	0	0	Pavers	2	10
					Paving equipment	2	10
					Rollers	2	10
Battery/ Container Installation	242	12	20	44	Air compressors	1	10
					Cranes	1	10
					Forklift	1	10
					Tractors/loaders/backhoes	1	10
Substation Installation	121	12	4	44	Aerial lifts	1	10
					Air compressors	1	10
					Bore/drill rigs	1	10
					Forklifts	1	10
					Trenchers	1	10
Gen-Tie Foundation and Tower Erection	121	12	0	44	Air compressors	1	10
					Cranes	1	10
					Forklifts	1	10
					Pumps	1	10

Table 3.1-4. Construction Scenario Assumptions

Construction Phase	One-Way Vehicle Trips				Equipment		
	Average Daily Worker Trips	Average Daily Vendor Truck Trips	Average Daily Haul Truck Trips	Average Daily On-Site Truck Trips	Equipment Type	Quantity	Usage Hours
Gen-Tie Stringing and Pulling	121	12	0	44	Welders	1	10
					Aerial lift	1	10
					Tractors/loaders/backhoes	1	10
SCE Interconnection Facility Upgrades	121	12	0	44	Air compressors	4	10
					Cranes	2	10
					Excavators	2	10
					Rough-terrain forklifts	2	10
					Skid-steer loaders	2	10
					Tractors/loaders/backhoes	2	10
					Trenchers	1	10
Commissioning	242	12	0	44	N/A	N/A	N/A
Decommissioning	242	12	20	44	Concrete/industrial saws	2	10
					Cranes	2	10
					Rubber-tired dozers	2	10
					Tractors/loaders/backhoes	2	10

Note: N/A = not applicable.

The equipment mix assumptions were based on CalEEMod default assumptions based on proposed land use and is meant to represent a reasonably conservative estimate of construction activity. For the analysis, it is generally assumed that heavy construction equipment will be operating at the site for approximately 10 hours per day, 5 days per week. The number of worker trips, vendor truck trips, haul truck trips, and on-site truck trips were provided by the applicant. Default assumptions provided in CalEEMod were used to determine the vendor truck trip one-way distance of 10.2 miles. In the Battery/Container Installation phase and the Decommissioning phase, the haul truck trip one-way distance was assumed to be 81 miles, which is the approximate distance from the Project site to the Port of Long Beach. All other worker and haul truck trips were conservatively assumed to have a 75-mile one-way distance. On-site truck trips were assumed to have a 0.25-mile one-way distance (SJVAPCD 2018).

Based on Project-specific information, 449,685 cubic yards of net material import is expected from the construction of the Project during the Grading and Substation Grading phases. Entrained dust results from the exposure of earth surfaces to wind from the direct disturbance and movement of soil, resulting in PM₁₀ and PM_{2.5} emissions.

During the Commissioning phase, eight (8) 1,006-horsepower (hp) diesel generators will be used to power the facility. The commissioning generators will operate 8 hours per day for up to 60 days during the approximately

6-month Commissioning phase. Current CARB and EPA Tier 2 engine standards were assumed. For additional details, see Appendix 3.1A.

A helicopter may be used in the Gen-Tie Stringing and Pulling phase where the gen-tie crosses the railroad. For this portion of the stringing and pulling work it is assumed that a MD600 helicopter will be used for up to 3 10-hour days consisting of 1 day for mobilization, 1 day for stringing and pulling, and 1 day for demobilization. Helicopter emission factors from the Guidance on the Determination of Helicopter Emissions (FOCA 2015) were used in a spreadsheet model, assuming an 808 hp MD 600N helicopter will be representative for the Project per input from the applicant. For additional details, see Appendix 3.1A.

Internal combustion engines used by construction equipment, vendor trucks (i.e., delivery trucks), haul trucks, and worker vehicles, helicopters during Gen-Tie Stringing and Pulling, and diesel generators during Commissioning will result in emissions of VOC, NO_x, CO, SO_x, PM₁₀, and PM_{2.5}. The application of architectural coatings, such as exterior application/interior paint and other finishes, and application of asphalt pavement will also produce VOC emissions; however, the contractor is required to procure architectural coatings from a supplier in compliance with the requirements of AVAQMD's Rule 1113 (Architectural Coatings). For additional details see Appendix 3.1A.

Operation

Operation of the proposed Project will generate VOC, NO_x, CO, SO_x, PM₁₀, and PM_{2.5} emissions from area sources, energy sources, mobile sources, off-road sources, and stationary sources, which are discussed below. Emissions from these sources were estimated based on CalEEMod default assumptions for operations of the proposed Project land uses. It was assumed that the Project will be operational following the completion of construction, which will occur in 2029.

Area Sources

The area source category calculates direct sources of air pollutant emissions located at the Project site, including consumer product use, architectural coatings, and landscape maintenance equipment. CalEEMod defaults were used to estimate emissions from area sources during operation of the Project.

Consumer products are various solvents used in non-industrial applications that emit VOCs during their product use, including detergents; cleaning compounds; polishes; floor finishes; cosmetics; personal care products; home, lawn, and garden products; disinfectants; sanitizers; aerosol paints; and automotive specialty products. Consumer product VOC emissions are estimated in CalEEMod based on the floor area of buildings and on the default factor of pounds of VOC per building square foot per day. The CalEEMod default utilization rates and emission factors were assumed.

VOC off-gassing emissions result from evaporation of solvents contained in surface coatings such paints and primers using during building maintenance. CalEEMod calculates the VOC evaporative emissions from application of nonresidential surface coatings based on the VOC emission factor, the building square footage, the assumed fraction of surface area, and the reapplication rate. The VOC emission factor is based on the VOC content of the surface coatings, and AVAQMD's Rule 1113 (Architectural Coatings) governs the VOC content for interior and exterior coatings. The model default reapplication rate of 10% of area per year is assumed. Consistent with CalEEMod defaults, it is assumed that the nonresidential surface area for painting equals 2.0 times the floor square footage, with 75% assumed for interior coating and 25% assumed for exterior surface coating (CAPCOA 2022).

Landscape maintenance includes fuel combustion emissions from equipment such as lawnmowers, rototillers, shredders/grinders, blowers, trimmers, chainsaws, and hedge trimmers, as well as air compressors, generators, and pumps. The emissions associated with landscape equipment use were estimated using CalEEMod. The emission factors are multiplied by the number of summer days that represent the number of operational days.

Energy Sources

As represented in CalEEMod, energy sources include emissions associated with building electricity and natural gas usage. Electricity use will contribute indirectly to criteria air pollutant emissions; however, the emissions from electricity use are only quantified for GHGs in CalEEMod, since criteria pollutant emissions occur at the site of the power plant, which is typically off site. The Project does not include the use of natural gas during operation. Therefore, no emissions associated with energy sources were quantified for the air quality analysis.

GHGs are emitted from buildings as a result of activities for which electricity and natural gas are typically used as energy sources. Combustion of any type of fuel emits CO₂ and other GHGs directly into the atmosphere; these emissions are considered direct emissions associated with a building. GHGs are also emitted during the generation of electricity from fossil fuels; these emissions are considered to be indirect emissions. As the O&M buildings for the Project would be all electric, default CalEEMod values for natural gas demand were converted to electricity. In other words, electricity demand was increased to reflect the removal of natural gas; this ensures the portion of energy demand that would typically be assumed in CalEEMod to be met with natural gas usage is adequately covered in the energy consumption estimates. GHG emissions associated with ~~the electricity usage associated with the O&M buildings and~~ lighting for the parking lot were calculated by CalEEMod using default parameters. The electricity demands for the O&M buildings and parking lot lighting were estimated annual electricity consumption associated with the Project was estimated at 668,427,520 kilowatt-hours to be 49.52 megawatt-hours (MWh) per year; with the majority (approximately 668,378,000 kilowatt-hours and 5.34 MWh per year) related to round trip efficiency and transmission losses., respectively.

The CalEEMod default energy intensity factor (CO₂, CH₄, and N₂O mass emissions per kilowatt hour) for SCE was applied, which is based on the projected value for SCE's energy mix in 2029 (CAPCOA 2022). ~~As explained in Section 3.1.5.2.2, SB 100 and SB 1020 call for further development of renewable energy, with targets of 52% by December 31, 2027; 60% by December 31, 2030; 90% by December 31, 2035; 95% by December 31, 2040; and 100% by December 31, 2045. As such, GHG emissions associated with Project electricity demand will continue to decrease over time.~~

The Project would also have indirect GHG emissions during operations that are a result of system round-trip efficiency (RTE) losses. The system is expected to start with an RTE close to 88.9% and degrade at rate of approximately 0.2% a year until year 20 (representing the Project life mid-point or average), when it is expected to be approximately 85% (84% RTE including auxiliary loads). In year 20, the Project will require 10,777 MWh to deliver 9,200 MWh of energy to the grid. It is anticipated that the Project would have all 2,035 BESS units on site in year 20. This RTE results in a loss of 1,577 MWh per charge. The Project will cycle once per day, or approximately 365 times per year, which would equate to total annual RTE losses of 575,605 MWh.

An analysis of the California Independent System Operator (CAISO) Service Path 15 prices (where the Project will be injecting energy) and energy mix over the last 5 years was conducted to understand the carbon intensity of the energy used to charge the BESS (see Appendix 3.1E). The analysis assumed the BESS would charge during the lowest-priced 8 hours of the day and discharge during the most expensive 8 hours of the day. The analysis showed that the carbon intensity of energy during charging is between 30% and 40%, or 60% and 70% carbon free. To

provide a conservative analysis, the Project assumed a 40% carbon intensity (i.e., 60% of charging energy was carbon free). GHG emissions associated with RTE losses were estimated in a spreadsheet model to account for the 60% carbon-free energy during charging. This is a conservative estimate since the data in the analysis show an increasing trend of carbon-free energy in the CAISO energy mix over the last 5 years and the California regulatory standards require increased carbon-free energy over the next 20 years, which would further reduce the carbon intensity of energy used for charging. In fact, SB 1020 requires that 100% of retail sales of electricity to California end-use customers come from eligible renewable energy resources and zero-carbon resources by December 31, 2045, which would result in zero GHG emissions from RTE losses.

In addition to the indirect GHG emissions from system RTE losses, the Project will also generate indirect GHG emissions from energy used to power auxiliary systems, including, but not limited to, thermal management systems (TMS), supervisory control and data acquisition system (SCADA), and other energy-consuming equipment. In year 20, the system RTE, including auxiliary losses, is expected to be 84%. The system auxiliary load in year 20 is expected to be 23.17 MW. For the purposes of this analysis, auxiliary loads are counted in hours when the Project is not charging or discharging. Auxiliary loads accrue for approximately 8 hours a day, for a total expected auxiliary load of 185.4 MWh a day and an annual auxiliary load of 67,664 MWh per year. In CalEEMod, auxiliary loads were summed with the electricity demand for the O&M buildings and parking lot, described previously. The CalEEMod default energy intensity factors for SCE for year 2029 were applied to these components.

Mobile Sources

Following the completion of construction activities, the Project will generate criteria pollutant emissions from mobile sources (vehicular traffic) as a result of the periodic maintenance of the Project. The Project was assumed to require 16 employees visiting the BESS facility 5 days a week for maintenance. On Saturday and Sunday there will be four (4) employees visiting the BESS facility.

CalEEMod was used to estimate emissions from proposed vehicular sources (refer to Appendix 3.1A). CalEEMod default data, including temperature, trip characteristics, variable start information, and emissions factors, were conservatively used for the model inputs. The estimated trip lengths and trip modes were based on information provided by the applicant. Project-related traffic was assumed to include a mixture of vehicles in accordance with the associated use, as modeled in CalEEMod, which is based on the CARB EMFAC2021 model. Emission factors representing the vehicle mix and emissions for 2029 were used to estimate emissions associated with vehicular sources.

Off-Road Sources

During irregular maintenance, the Project may require the movement or replacement of battery enclosures every 2 to 3 years over the lifetime of the Project. As such, the use of one (1) crane and one (1) forklift were assumed to assist the lifting and movement of the BESS containers. CalEEMod was used to estimate criteria air pollutant emissions of the crane and forklift assuming 1 hour of operation on 1 day every year.

Stationary Sources

The Project will include installation of three emergency diesel generators (one [1] rated at 323 hp and two [2] rated at 744 hp) for emergency safety systems during a power outage and fire support. A spreadsheet model was used to estimate emissions of the generators, assuming 2 hours per day and 50 hours per year, pursuant to CARB's Air Toxic Control Measure for Stationary Compression Ignition Engines (17 CCR 93115), at 100% load for maintenance

and testing. Current CARB and EPA Tier 4 engine standards were assumed. Notably, the applicant has committed to using renewable diesel fuel for these emergency generators. However, default carbon intensity for non-renewable diesel was conservatively assumed in the analysis. See Appendix 3.1C, Representative Tier 4 Emergency Generator Specifications Sheets, for details of the generator specifications. Also, see Appendix 3.1D for the Notice of Receipt of Complete Application letter provided by AVAOMD for permitting these emergency generators.

Water and Wastewater

Water consumption estimates for the O&M buildings for indoor water use were based on CalEEMod default values. Outdoor water use was assumed to be 1,540,000 gallons per year based on the landscaping plan prepared for the Project. Electricity use for water supply is based on the electric pump rating, pump flow rate, electricity intensity factors from CalEEMod for the County.

Solid Waste

The Project will generate solid waste from the on-site employees and therefore will result in CO₂e emissions associated with landfill off-gassing. CalEEMod default values for solid waste generation were used to estimate GHG emissions associated with solid waste.

Refrigerants

Refrigerants are substances used in equipment for air conditioning and refrigeration. Most of the refrigerants used today are HFCs or blends thereof, which can have high GWP values. All equipment that uses refrigerants has a charge size (i.e., quantity of refrigerant the equipment contains) and an operational refrigerant leak rate, and each refrigerant has a GWP that is specific to that refrigerant.

During operations and maintenance, one of the sources of GHG emissions could potentially be fugitive SF₆ gas emissions from equipment installed at the proposed collector substation. SF₆ has a GWP of ~~24,300~~ 23,500 using CO₂ at a reference value of 1 (IPCC 2024). The substation will include seven breakers that will contain SF₆ gas. It is estimated that the Project will maintain a total of 1,160 pounds of SF₆ gas at the substation. Although leakage is unlikely, for the purposes of the Project's emissions inventory it was assumed that the breakers will have a maximum annual leak rate of 0.5% in accordance with the Institute of Electrical and Electronics Engineers C37.122-2021, Standard for High-Voltage Gas-Insulated Substations Rated Above 52 kV (IEEE 2018). Emissions from SF₆ gas are included as part of refrigerant source emissions.

According to the Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear, which became effective on January 1, 2022, starting on the applicable phase-out dates, no person may acquire SF₆ gas-insulated equipment (GIE) for use in California unless one of following provisions applies (17 CCR 95352):

1. An SF₆ phase-out exemption was approved by the Executive Officer of CARB, or SF₆ GIE were acquired in response to a failure, pursuant to Section 95357.
2. The SF₆ GIE device was present in California and reported to CARB pursuant to Section 95355(a) for a data year prior to the applicable phase-out date listed in Table 1 or Table 2 [Section 95352].
3. The SF₆ GIE device was purchased by the GIE owner prior to the applicable phase-out date listed in Table 1 or Table 2 [Section 95352] for the relevant GIE characteristics, and enters California no later than 24 months after the purchase date.

4. The SF₆ GIE manufacturer replaces a defective SF₆ GIE device under the terms of the manufacturer's warranty.

The Project will comply with the amendments to the regulation under Provision 3 above. Table 2 of Section 95352 states that the phase-out date for equipment, with a voltage capacity greater than 245 kV and all short-circuit current ratings, is January 1, 2033. The only project equipment that may contain SF₆ would be the seven breakers, which are rated at 550 kV, with a short-circuit capability of 65 kiloamperes. All equipment has a voltage capacity greater than 245 kV and therefore must be purchased before January 1, 2033, and enter California within 24 months of purchase. The Project will comply with the state provision by procuring the SF₆-containing equipment listed above no later than January 2028 and bringing the equipment into California before February 2029.

In addition, during operations and maintenance, one of the sources of GHG emissions could potentially be fugitive emissions from batteries and O&M building air conditioning equipment containing difluoromethane (R-32) gas. R-32 has a GWP of ~~771~~675 using CO₂ at a reference value of 1 (~~IPCC-2024~~CARB 2025c). Using the representative BESS enclosure for analysis, the BESS yards will include 2,035 Power Titan II batteries that will contain R-32 gas. It is estimated that the Project will maintain a total of 16,151 pounds of R-32 gas. Although leakage is unlikely, for the purposes of the Project's emissions inventory it was conservatively assumed that the batteries will have a maximum annual leak rate of 0.5%. In addition, the O&M building was assumed to utilize 1.6 pounds of R-32, based on the CalEEMod default refrigerant quantity per industrial land use area of 0.3 kilograms per 1,000 square feet.⁹ Emissions from R-32 gas are included as part of refrigerant source emissions. For additional details see Appendix 3.1A.

Ambient Air Quality Analyses

To evaluate the potential for localized criteria air pollutant emissions from Project construction or operations to exceed respective NAAQS and/or CAAQS, ambient air quality analyses (AAQA) were performed using a dispersion model. Air dispersion models calculate the atmospheric transport and fate of pollutants from the emission source. The models calculate the ground-level concentration (GLC) of selected pollutants at specific downwind points, such as residential receptors. The transformation (fate) of an airborne pollutant, its movement with the prevailing winds (transport), its crosswind and vertical movement due to atmospheric turbulence (dispersion), and its removal due to dry and wet deposition are influenced by the pollutant's physical and chemical properties and by meteorological and environmental conditions. Factors such as distance from the source to the receptor, meteorological conditions, intervening land use and terrain, pollutant release characteristics, and background pollutant concentrations affect the predicted air concentration of an air pollutant. Air dispersion models have the capability to take all of these factors into consideration when calculating downwind GLCs of pollutants. The dispersion modeling for the Project was performed using the American Meteorological Society/EPA Regulatory Model (AERMOD), which is the model AVAQMD requires for atmospheric dispersion of emissions. AERMOD is a steady-state Gaussian plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of surface and elevated sources, building downwash, and simple and complex terrain.

Because AVAQMD has not published guidance to conduct an AAQA, the San Joaquin Valley Air Pollution Control District's District Policy APR 1925 – Policy for District Rule 2201 AAQA Modeling (SJVAPCD 2024) was followed. For both Project construction and operations, a Level 1 analysis was performed using AERMOD for each averaging period where the maximum concentration for each source and receptor combination was generated to produce worst-case concentrations for each directly emitted criteria pollutant of concern (CO, NO₂, PM₁₀, PM_{2.5}, and SO₂), without respect to time of occurrence.

⁹ The CalEEMod default refrigerant for air conditioning and heat pumps is R-410A, which would not be used for the Project.

In the Level 1 analysis, all criteria pollutants were modeled together, with a normalized (i.e., unit) emission rate of 1 gram per second for each source. The use of a normalized emission rate enabled the modeling run outputs to be used for multiple pollutant analyses. For construction, as the maximum daily emissions for some pollutants were generated by on-site equipment and trucks and maximum daily emissions for other pollutants by generator usage during commissioning, and these phases will not overlap, separate source groups were specified in AERMOD for these sources. On-site equipment and vehicles were modeled as line volume sources, whereas the generators used during commissioning were modeled as point sources. Notably, the trip length for on-road vehicles were reduced to 0.25 miles to account for localized emissions only. For operations, the unit emission rates for the testing and maintenance of the three (3) emergency generators were normalized across the generator point sources. The Level 1 procedure is described as follows:

- For Step 1 of the AAQA analysis, the maximum background concentration for the monitoring stations closest to the Project site for each pollutant and averaging period combination (i.e., 1-hour, 3-hour, 8-hour, 24-hour, and PERIOD) was added to the corresponding maximum GLC (Project impact). The sum of these values was then compared to the corresponding CAAQS and NAAQS. If the Project impact did not cause an exceedance of an ambient air quality standard (AAQS), then the analysis was complete for that source/receptor/pollutant combination because no exceedance of an AAQS will occur. If the Project impact caused an exceedance of an AAQS, then the analysis proceeded to Step 2.
- Step 2 was similar to Step 1 with one major difference: If the background concentration plus GLC exceeds an AAQS, including instances where the background concentration alone exceeds an AAQS, the maximum GLC of each pollutant and averaging period combination will be compared to its corresponding significant impact level (SIL) as established by the EPA, where a value exceeding the SIL is considered an indicator that the GLC represents a substantial contribution to an exceedance of an AAQS. If the maximum GLC did not exceed the corresponding SIL, then the analysis was complete for that source/receptor/pollutant combination because the emissions will not be considered to contribute to an exceedance of an AAQS, and no further action was required.

Pollutants that are not screened out using a Level 1 AAQA (either in Step 1 or Step 2, as described above) proceed to a refined Level 2 AAQA. A Level 2 AAQA analysis is similar to a Level 1 analysis, with several differences. Unlike a Level 1 analysis, pollutants in a Level 2 analysis are not modeled together. Instead, each pollutant is modeled separately in AERMOD using its estimated emission rates rather than normalized emission rates. For a Level 2 analysis, additional refinements are required for NO₂ and PM_{2.5}, which are detailed in the Santa Barbara County Air Pollution Control District's Modeling Guidelines for Air Quality Impact Assessments (SBCAPCD 2025a), as follows:

- For NO₂ modeling, the Tier 2 Ambient Ratio Method Version 2 (ARM2) to predict NO₂/NO_x conversion ratios was used. In addition, to meet the 1-hour NO₂ NAAQS, the background concentration is based on the 3-year average of the annual 98th percentile, which is summed with the 8th Highest High (98th percentile) of the maximum daily 1-hour NO₂ from the Project and compared to the 1-hour NAAQS.
- For PM_{2.5} modeling, to meet the 24-hour NAAQS for PM_{2.5}, the background concentration is based on the 3-year average of the annual 98th percentile, which is summed with the Project's 8th Highest High (98th percentile) of the 24-hour results averaged over 5 years (assuming a 5-year meteorological data set is used) and compared to the 24-hour NAAQS.

As with the Level 1 AAQA, if the background concentration plus GLC exceeds an AAQS, the maximum GLC of each pollutant will then be compared to its corresponding SIL.

The Level 1 and Level 2 AAQA principal parameters of this modeling are presented in Table 3.1-5.

Table 3.1-5. AERMOD Principal Parameters – AAQA

Parameter	Details
Dispersion Model	The air dispersion model used was AERMOD Version 24142, with the Lakes Environmental Software implementation/user interface, AERMOD View, Version 13.0.0.
Meteorological Data	The latest 5-year meteorological data (2016–2020) for the Palmdale Station (KPMD) were obtained from CARB and used in the analysis as the most representative data set based on proximity and wind direction. The input data was also conservative, based on a test run that compared maximum concentrations using the Palmdale Station to the concentrations using meteorological data from the Santa Clarita Station (the other station in general proximity to the Project site).
Urban versus Rural Option	Urban areas typically have more surface roughness, as well as structures and low-albedo surfaces that absorb more sunlight—and thus more heat—relative to rural areas. Based on the land use procedure from 4.4.1 of the OEHHA Guidance Manual, the rural dispersion was appropriate for the Project site (OEHHA 2015).
Terrain Characteristics and Elevation Data	Digital elevation model files were imported into AERMOD so that complex terrain features were evaluated as appropriate, and elevations were assigned to the emission sources and receptors. Digital elevation data were obtained through AERMOD View in the U.S. Geological Survey’s National Elevation Dataset format with an approximately 1 arc-second resolution.
Emission Sources and Release Parameters	The following release parameters were input based on the best information available at the time of analysis. Construction - Off-road equipment and vehicles were modeled as a line of adjacent volume sources across the Project site with a release height of 5 meters, a plume height of 10 meters, and plume width of 10 meters (SCAQMD 2008). - The 8 1,006 hp diesel generators were modeled as point sources with a vertical stack height of 3.7 meters, inside stack diameter of 0.2 meters, gas exhaust temperature of 764 Kelvin, and gas exhaust velocity of 57.8 meters per second (SBCAPCD 2025b). Operations - The diesel generators were modeled as point sources with release parameters based on the specification sheets and default diesel-fired internal combustion stack parameters (SBCAPCD 2025b), if generator-specific information was not available. The 323 hp generator was modeled with a vertical stack height of 3.0 meters, inside stack diameter of 0.13 meters, gas exhaust temperature of 780 Kelvin, and gas exhaust velocity of 63.9 meters per second. Each 744 hp generator was modeled with a vertical stack height of 3.7 meters, inside stack diameter of 0.2 meters, gas exhaust temperature of 719.82 Kelvin, and gas exhaust velocity of 14.05 meters per second.
Receptors	For both construction and operations, a telescoping grid of receptors was generated with the following spacing to evaluate potential air pollutant impacts within a 6-mile radius of the Project: 25-meter spacing on the facility boundary; 25-meter spacing from the facility boundary out to 100 meters; 50-meter spacing from 100 meters to 250 meters; 100-meter spacing from 250 meters to 500 meters; 250-meter spacing from 500 meters to 1,000 meters;

Table 3.1-5. AERMOD Principal Parameters - AAQA

Parameter	Details
	▪ 500-meter spacing from 1,000 meters to 2,000 meters; and ▪ 1,500-meter spacing from 2,000 meters to 8,000 meters.

Sources: OEHHA 2015; SBCAPCD 2025b; SCAQMD 2008.

Notes: AERMOD = American Meteorological Society/EPA Regulatory Model; AAQA = Ambient Air Quality Analysis; CARB = California Air Resources Board; OEHHA = Office of Environmental Health Hazard Assessment; hp = horsepower.

See Appendix 3.1B for model outputs and parameters.

3.1.3.2 CEQA Appendix G Assessment Criteria

3.1.3.2.1 Would the Project conflict with or obstruct implementation of the applicable air quality plan?

Less than Significant with Mitigation. AVAQMD develops and administers air quality plans to outline air pollution control programs for attaining all CAAQS and NAAQS. Currently, the most recent approved AVAQMD air quality plan is the AVAQMD Federal 70 ppb Ozone Attainment Plan (Western Mojave Desert Nonattainment Area) (AVAQMD 2023; AVAQMD Ozone Attainment Plan). The AVAQMD Ozone Attainment Plan was developed to address the attainment of the 2015 8-hour O₃ NAAQS (70 parts per billion [ppb]). The AVAQMD Ozone Attainment Plan provides actions, strategies, and steps needed to reduce air pollutant emissions and meet the O₃ standard by 2033.

The purpose of a consistency finding is to determine if a project is inconsistent with the assumptions and objectives of the regional air quality plans, and thus if it will interfere with the region's ability to comply with federal and state air quality standards. A project is non-conforming with an air quality plan if it conflicts with or delays implementation of any applicable attainment or maintenance plan. A project is conforming if it complies with all applicable AVAQMD rules and regulations, complies with all proposed control measures that are not yet adopted from the applicable plan(s), and is consistent with the growth forecasts in the applicable plan(s) (or is directly included in the applicable plan). Zoning changes, specific plans, general plan amendments, and similar land use plan changes that do not increase dwelling unit density, do not increase vehicle trips, and do not increase vehicle miles traveled (VMT) are also deemed to comply with the applicable air quality plan (AVAQMD 2016).

AVAQMD primarily uses demographic growth forecasts for various socioeconomic categories (e.g., population, housing, employment by industry) developed by the Southern California Association of Governments (SCAG) for its 2024–2050 Regional Transportation Plan/Sustainable Communities Strategy, also known as Connect SoCal 2024 (SCAG 2024). This document, which is based on general plans for cities and counties within SCAG's jurisdiction, is used by AVAQMD to develop the air quality plan emissions inventory (AVAQMD 2023).¹⁰ Connect SoCal and the associated Regional Growth Forecast are generally consistent with the local plans; therefore, the AVAQMD air quality plan is generally consistent with local government plans.

The Project will be required to comply with all applicable AVAQMD rules and regulations, including, but not limited to Rules 401 (Visible Emissions), 402 (Nuisance), and 403 (Fugitive Dust). The Project will not require a General

¹⁰ Information necessary to produce the emissions inventory for the MDAB is obtained from AVAQMD and other governmental agencies, including CARB, California Department of Transportation (Caltrans), and SCAG. Each of these agencies is responsible for collecting data (e.g., industry growth factors, socioeconomic projections, travel activity levels, emission factors, emission speciation profile, and emissions) and developing methodologies (e.g., model and demographic forecast improvements) required to generate a comprehensive emissions inventory. SCAG incorporates these data into its Travel Demand Model for estimating/projecting vehicle miles traveled and driving speeds.

Plan amendment or zoning designation change within the Project area. Additionally, because the Project does not include new commercial space or residences, no increases to population or housing are anticipated as part of the Project. The Project will result in a small increase in employment in the Project area (16 employees). However, this increase in employees represents a negligible increase in employment compared to the SCAG forecast for the unincorporated portion of Los Angeles County, which estimates an increase in employment of 57,500 jobs between 2019 and 2050. As such, because the proposed Project is not anticipated to result in growth that will conflict with projections, it will not conflict with or exceed the assumptions in AVAQMD's air quality management and attainment plans.

Furthermore, as discussed below, construction of the Project will generate criteria air pollutant emissions that will have the potential to exceed AVAQMD mass-emission thresholds, and the Project's localized emissions will have the potential to exceed the applicable NAAQS thresholds prior to mitigation. Therefore, the Project will potentially increase the frequency or severity of a violation in the federal or state ambient air quality standard. The impact will be potentially significant.

However, after implementation of **Mitigation Measure (MM) AQ-1 through MM-AQ-3** (refer to Section 3.1.4 for all air quality mitigation measures), the Project will not exceed the AVAQMD mass-emission thresholds during construction or operations, and the Project's localized emissions will not exceed the applicable NAAQS thresholds. As such, the Project will not have the potential to increase the frequency or severity of a violation in the federal or state ambient air quality standard, and the Project will not conflict with or obstruct implementation of the applicable air quality plan with implementation of mitigation. The health effects of criteria air pollutants are discussed further in Section 3.1.3.2.2. The impact will be **less than significant with mitigation**.

3.1.3.2.2 Would the Project result in a cumulatively considerable net increase of any criteria pollutant for which the Project region is non-attainment under an applicable federal or state ambient air quality standard?

Less than Significant with Mitigation. Air pollution is largely a cumulative impact. The nonattainment status of regional pollutants is a result of past and present development, and AVAQMD develops and implements plans for future attainment of ambient air quality standards. Based on these considerations, project-level thresholds of significance for criteria pollutants are relevant in the determination of whether a project's individual emissions will have a cumulatively significant impact on air quality.

Construction and Decommissioning Emissions

Construction of the Project will result in the temporary addition of pollutants to the local airshed caused by on-site sources (i.e., off-road construction equipment, commissioning generators, soil disturbance, and VOC off-gassing) and off-site sources (i.e., on-road haul trucks, vendor trucks, worker vehicles, and helicopter). Construction emissions can vary substantially from day to day, depending on the level of activity, the specific type of operation, and for dust, the prevailing weather conditions. Therefore, such emission levels can only be approximately estimated with a corresponding uncertainty in precise ambient air quality impacts.

Construction of the Project will generate criteria air pollutant emissions from entrained dust, off-road equipment, vehicle emissions, commissioning generators, helicopter emissions, architectural coatings, and asphalt pavement application. Construction of the Project will also result in GHG emissions primarily associated with use of off-road

construction equipment, on-road truck and worker vehicle trips, commissioning generators, and helicopter emissions.

Entrained dust results from the exposure of earth surfaces to wind from the direct disturbance and movement of soil, resulting in PM₁₀ and PM_{2.5} emissions. Internal combustion engines used by construction equipment, haul trucks, vendor trucks (i.e., delivery trucks), and worker vehicles will result in emissions of VOCs, NO_x, CO, SO_x, PM₁₀, and PM_{2.5}. The application of architectural coatings, such as exterior application/interior paint and other finishes, and application of asphalt pavement will also produce VOC emissions.

As discussed in Section 3.1.3.1.2, Approach and Methodology, criteria air pollutant emissions associated with temporary construction activity were quantified using CalEEMod. CalEEMod calculates maximum daily emissions for summer and winter periods. The estimated maximum daily construction emissions without mitigation are summarized in Table 3.1-6. Detailed construction model outputs are presented in Appendix 3.1A.

Table 3.1-6. Estimated Maximum Daily Construction Criteria Air Pollutant Emissions – Unmitigated

Year	VOC	NO _x	CO	SO _x	PM ₁₀	PM _{2.5}
	Pounds per Day					
Summer						
2027 (Construction)	6.62	127.55	127.90	0.92	69.51	17.43
2028 (Construction)	22.27	91.46	268.68	0.17	36.54	9.45
2029 (Construction)	1.75	4.37	71.24	<0.01	12.94	3.04
2069 (Decommissioning)	2.71	18.92	54.02	0.11	14.88	3.82
Winter						
2027 (Construction)	6.11	50.99	94.60	0.12	38.17	9.15
2028 (Construction)	38.54	519.35	419.49	0.66	44.46	23.20
2029 (Construction)	1.64	4.85	45.26	<0.01	12.94	3.04
2069 (Decommissioning)	2.69	19.21	42.59	0.11	14.88	3.82
Maximum Daily Emissions	38.54	519.35	419.49	0.92	69.51	23.20
AVAQMD Threshold	137	137	548	137	82	65
Threshold Exceeded?	No	Yes	No	No	No	No

Source: Appendix 3.1A.

Notes: VOC = volatile organic compound; NO_x = oxides of nitrogen; CO = carbon monoxide; SO_x = sulfur oxides; PM₁₀ = coarse particulate matter; PM_{2.5} = fine particulate matter; AVAQMD= Antelope Valley Air Quality Management District; <0.01 = value is less than 0.005.

As depicted in Table 3.1-6, emissions resulting from the Project construction will exceed criteria pollutant thresholds established by AVAQMD for NO_x emissions. This impact will be **potentially significant** without mitigation.

Mitigation measures **MM-AQ-1 through MM-AQ-3** will be implemented to reduce Project-generated construction emissions. **MM-AQ-1** (Construction Equipment Emission Minimization) requires the use of 50 hp or greater equipment to have Tier 4 Final compliant engines, which are the cleanest engines currently available. **MM-AQ-2** (Commissioning Generators Emission Minimization) also requires all diesel generators used during commissioning to be Tier 4 Final. Finally, **MM-AQ-3** (Construction Dust Control Plan) specifies fugitive dust controls including, but

not limited to, watering exposed areas, the application of chemical dust suppressants, watering active demolition sites, and limiting vehicle speeds on unpaved roads.

The effectiveness of **MM-AQ-1 through MM-AQ-3** is quantified in the mitigated emissions estimate in Table 3.1-7. Detailed construction model outputs are presented in Appendix 3.1A.

Table 3.1-7. Estimated Maximum Daily Construction Criteria Air Pollutant Emissions - Mitigated

Year	VOC	NO _x	CO	SO _x	PM ₁₀	PM _{2.5}
	Pounds per Day					
Summer						
2027 (Construction)	5.33	114.25	129.79	0.92	53.35	15.31
2028 (Construction)	20.16	71.27	280.04	0.17	35.72	8.71
2029 (Construction)	1.75	4.37	71.24	<0.01	12.94	3.04
2069 (Decommissioning)	1.39	11.63	70.89	0.11	14.65	3.63
Winter						
2027 (Construction)	2.75	18.88	94.56	0.12	21.07	6.31
2028 (Construction)	20.26	88.58	428.51	0.66	30.33	9.14
2029 (Construction)	1.64	4.85	45.26	<0.01	12.94	3.04
2069 (Decommissioning)	1.37	11.91	59.46	0.11	14.65	3.63
Maximum Daily Emissions	20.26	114.25	428.51	0.92	53.35	15.31
AVAQMD Threshold	137	137	548	137	82	65
Threshold Exceeded?	No	No	No	No	No	No

Source: Appendix 3.1A.

Notes: VOC = volatile organic compound; NO_x = oxides of nitrogen; CO = carbon monoxide; SO_x = sulfur oxides; PM₁₀ = coarse particulate matter; PM_{2.5} = fine particulate matter; AVAQMD = Antelope Valley Air Quality Management District; <0.01 = value is less than 0.005.

After implementation of **MM-AQ-1 through MM-AQ-3**, regional construction emissions will not exceed the applicable AVAQMD thresholds of significance for any criteria pollutant. Therefore, with the incorporation of mitigation, short-term impacts associated with a cumulatively considerable net increase of any criteria pollutant for which the Project region is nonattainment will be **less than significant with mitigation**.

Construction Ambient Air Quality Analysis

Modeled on-site emission rates for criteria pollutants were determined for construction of the Project. Notably, O₃ is a photochemical oxidation product of NO_x and VOC emissions that is not evaluated in a source impact AAQA because it is not quantifiably present in combustion exhaust gases (i.e., not directly emitted). Fugitive dust was included in the construction AAQA. Table 3.1-8 summarizes the results of the Level 1 AAQA for unmitigated construction, which is fully detailed in Appendix 3.1B. Background ambient air quality data and AERMOD outputs are also contained in Appendix 3.1B.

Table 3.1-8. Level 1 Construction Ambient Air Quality Assessment Results - Unmitigated

Step 1 – Ambient Air Quality Standard Basis^a				
Impact Parameter	Applicable Standard	AAQS	Maximum Concentration: Project + Background Levels	
		µg/m³	µg/m³	Exceed AAQS?
1-hour CO	State	22,900	2,380.40	No
	Federal	40,100	2,380.40	No
8-hour CO	State	10,300	1,478.09	No
	Federal	10,300	1,478.09	No
1-hour NO ₂	State	339	1,152.06	Yes (Step 2)
	Federal	188	1,151.91	Yes (Step 2)
Annual NO ₂	State	57	50.24	No
	Federal	100	50.13	No
1-hour SO ₂	State	655	21.62	No
	Federal	196	21.57	No
3-hour SO ₂	Federal	1,300	20.93	No
24-Hour SO ₂	State	105	6.28	No
	Federal	367	6.27	No
Annual SO ₂	Federal	79	1.06	No
24-hour PM ₁₀	State	50	147.04	Yes (Step 2)
	Federal	150	439.94	Yes (Step 2)
Annual PM ₁₀	State	20	21.24	Yes (Step 2)
24-hour PM _{2.5}	Federal	35	45.28	Yes (Step 2)
Annual PM _{2.5}	State	12	9.41	No
	Federal	9	9.41	Yes (Step 2)
Step 2 – EPA SIL Basis^a				
Impact Parameter	Class II SILs		Maximum Project Contribution	
	µg/m³		µg/m³	Exceed SIL?
1-hour NO ₂	7.5		1,065.43	Yes
24-hour PM ₁₀	5		28.74	Yes
Annual PM ₁₀	1		3.94	Yes
24-hour PM _{2.5}	1.2		9.58	Yes
Annual PM _{2.5}	0.13		1.31	Yes

Source: Appendix 3.1B.

Notes: AAQS = Ambient Air Quality Standard; CO = carbon monoxide; EPA = U.S. Environmental Protection Agency; NO₂ = nitrogen dioxide; PM₁₀ = particulate matter less than or equal to 10 microns; PM_{2.5} = particulate matter less than or equal to 2.5 microns; SIL = significant impact level; SO₂ = sulfur dioxide.

^a Step 1: the AAQS basis compares the background concentrations plus Project contribution to the state and federal AAQS to determine if there will be an exceedance of the respective standard. For 24-hour PM₁₀ and 24-hour PM_{2.5}, background concentrations already exceed the applicable AAQS, so Step 2—the SIL basis—compares the Project contributions to levels determined by the EPA to cause or contribute to ambient air quality exceedances and impacts.

Steps 1 and 2 of the Level 1 AAQA show that unmitigated criteria pollutant emissions from construction of the Project will potentially contribute to a violation for the 1-hour NO₂ CAAQS and NAAQS, 24-hour PM₁₀ CAAQS and NAAQS, annual PM₁₀ CAAQS, 24-hour PM_{2.5} NAAQS, and annual PM_{2.5} NAAQS. This impact will be **potentially significant** without mitigation.

As discussed above, **MM-AQ-1 through MM-AQ-3** will be required to reduce construction criteria air pollutant emissions of exhaust and fugitive dust to the extent feasible. Table 3.1-9 summarizes the results of the Level 1 AAQA for the mitigated construction scenario. Complete details of the AAQA are included in Appendix 3.1B.

Table 3.1-9. Level 1 Construction Ambient Air Quality Assessment Results - Mitigated

Step 1 – Ambient Air Quality Standard Basis ^a				
Impact Parameter	Applicable Standard	AAQS	Maximum Concentration: Project + Background Levels	
		µg/m ³	µg/m ³	Exceed AAQS?
1-hour CO	State	22,900	2,380.40	No
	Federal	40,100	2,380.40	No
8-hour CO	State	10,300	1,478.09	No
	Federal	10,300	1,478.09	No
1-hour NO ₂	State	339	207.19	No
	Federal	188	207.04	Yes (Step 2)
Annual NO ₂	State	57	19.16	No
	Federal	100	19.06	No
1-hour SO ₂	State	655	21.62	No
	Federal	196	21.57	No
3-hour SO ₂	Federal	1,300	20.93	No
24-Hour SO ₂	State	105	6.28	No
	Federal	367	6.27	No
Annual SO ₂	Federal	79	1.06	No
24-hour PM ₁₀	State	50	122.82	Yes (Step 2)
	Federal	150	415.72	Yes (Step 2)
Annual PM ₁₀	State	20	17.92	No
24-hour PM _{2.5}	Federal	35	37.76	Yes (Step 2)
Annual PM _{2.5}	State	12	8.38	No
	Federal	9	8.38	No
Step 2 – EPA SIL Basis ^a				
Impact Parameter	Class II SILs		Maximum Project Contribution	
	µg/m ³		µg/m ³	Exceed SIL?
1-hour NO ₂	7.5		120.56	Yes
24-hour PM ₁₀	5		4.52	No
24-hour PM _{2.5}	1.2		2.06	Yes

Source: Appendix 3.1B.

Notes: AAQS = Ambient Air Quality Standard; CO = carbon monoxide; EPA = U.S. Environmental Protection Agency; NO₂ = nitrogen dioxide; PM₁₀ = particulate matter less than or equal to 10 microns; PM_{2.5} = particulate matter less than or equal to 2.5 microns; SIL = significant impact level; SO₂ = sulfur dioxide.

Emissions accounted for implementation of **MM-AQ-1 through MM-AQ-3**.

^a Step 1: the AAQS basis compares the background concentrations plus Project contribution to the state and federal AAQS to determine if there will be an exceedance of the respective standard. For 24-hour PM₁₀ and 24-hour PM_{2.5}, background concentrations already exceed the applicable AAQS, so Step 2—the SIL basis—compares the Project contributions to levels determined by the EPA to cause or contribute to ambient air quality exceedances and impacts.

Steps 1 and 2 of the Level 1 AAQA show that mitigated criteria pollutant emissions from construction of the Project will potentially contribute to a violation of the 1-hour NO₂ NAAQS and 24-hour PM_{2.5} NAAQS. Since the mitigated emissions still exceed the NAAQS using the Level 1 AAQA, these pollutants were individually evaluated in the refined Level 2 AAQA, as described in Section 3.1.3.1.2. Results of the Level 2 AAQA are summarized in Table 3.1-10.

Table 3.1-10. Level 2 Construction Ambient Air Quality Assessment Results – Mitigated

Step 1 – Ambient Air Quality Standard Basis ^a				
Impact Parameter	Applicable Standard	AAQS	Maximum Concentration: Project + Background Levels	
		µg/m ³	µg/m ³	Exceed AAQS?
1-hour NO ₂	Federal	188	94.22	No
24-hour PM _{2.5}	Federal	35	14.76	No

Source: Appendix 3.1B.

Notes: AAQS = Ambient Air Quality Standard; NO₂ = nitrogen dioxide; PM_{2.5} = particulate matter less than or equal to 2.5 microns; SIL = significant impact level.

Emissions accounted for implementation of **MM-AQ-1 through MM-AQ-3**.

^a Step 1: the AAQS basis compares the background concentrations plus Project contribution to the state and federal AAQS to determine if there will be an exceedance of the respective standard. As both pollutants passed this step, there was no need to continue to Step 2.

As shown in Table 3.1-10, after implementation of **MM-AQ-1 through MM-AQ-3**, localized construction emissions will not exceed the applicable NAAQS thresholds for NO₂ or PM_{2.5}. Therefore, impacts will be **less than significant with mitigation**.

Operational Emissions

Operation of the Project will generate criteria pollutant emissions from area sources (consumer products, architectural coatings, landscaping equipment), mobile sources (vehicular traffic), off-road equipment (diesel-fueled forklift and crane), and stationary sources (diesel-fueled emergency generators). The Project does not include the use of natural gas during operation; therefore, no emissions associated with energy sources were quantified for the air quality analysis. Table 3.1-11 summarizes the unmitigated maximum daily operational emissions associated with the Project. Detailed operational model outputs are presented in Appendix 3.1A.

Table 3.1-11. Estimated Potential Maximum Daily Operational Criteria Air Pollutant Emissions – Unmitigated

Emissions Source	VOC	NO _x	CO	SO _x	PM ₁₀	PM _{2.5}
	Pounds per Day					
Summer						
Mobile	0.17	0.17	1.94	<0.01	0.41	0.11
Area	0.17	0.00	0.38	<0.01	<0.01	<0.01
Energy	0.00	0.00	0.00	0.00	0.00	0.00
Off-Road Equipment	0.40	3.35	4.05	0.01	0.14	0.13
Stationary	1.12	2.40	20.76	0.04	0.08	0.08
Total Daily Summer Emissions	1.86	5.92	27.13	0.05	0.63	0.31
Winter						
Mobile	0.15	0.18	1.48	<0.01	0.41	0.11
Area	0.11	0.00	0.00	0.00	0.00	0.00
Energy	0.00	0.00	0.00	0.00	0.00	0.00
Off-Road Equipment	0.40	3.35	4.05	0.01	0.14	0.13
Stationary	1.12	2.40	20.76	0.04	0.08	0.08
Total Daily Winter Emissions	1.78	5.93	26.28	0.05	0.63	0.31
Maximum Daily Emissions	1.86	5.93	27.13	0.05	0.63	0.31
AVAQMD Threshold	137	137	548	137	82	65
Threshold Exceeded?	No	No	No	No	No	No

Source: Appendix 3.1A.

Notes: VOC = volatile organic compound; NO_x = oxides of nitrogen; CO = carbon monoxide; SO_x = sulfur oxides; PM₁₀ = coarse particulate matter; PM_{2.5} = fine particulate matter; AVAQMD = Antelope Valley Air Quality Management District; <0.01 = value is less than 0.005.

As shown in Table 3.1-11, the Project will not exceed the numerical thresholds of significance established by AVAQMD during operations. This impact will be **less than significant**.

Operational Ambient Air Quality Analysis

Modeled on-site emission rates for criteria pollutants were determined for operation of the Project, specifically the routine testing and maintenance of the diesel emergency generators. Table 3.1-12 summarizes the results of the Level 1 AAQA for unmitigated operations. The complete AAQA, background ambient air quality data, and AERMOD outputs are provided in Appendix 3.1B.

Table 3.1-12. Level 1 Operational Ambient Air Quality Assessment Results - Unmitigated

Step 1 – Ambient Air Quality Standard Basis ^a				
Impact Parameter	Applicable Standard	AAQS	Maximum Concentration: Project + Background Levels	
		µg/m ³	µg/m ³	Exceed AAQS?
1-hour CO	State	22,900	1,745.25	No
	Federal	40,100	1,745.25	No
8-hour CO	State	10,300	1,384.81	No
	Federal	10,300	1,384.81	No
1-hour NO ₂	State	339	99.69	No
	Federal	188	99.53	No
Annual NO ₂	State	57	16.93	No
	Federal	100	16.82	No
1-hour SO ₂	State	655	20.44	No
	Federal	196	20.39	No
3-hour SO ₂	Federal	1,300	20.27	No
24-Hour SO ₂	State	105	6.18	No
	Federal	367	6.17	No
Annual SO ₂	Federal	79	1.05	No
24-hour PM ₁₀	State	50	118.59	Yes (Step 2)
	Federal	150	411.49	Yes (Step 2)
Annual PM ₁₀	State	20	17.36	No
24-hour PM _{2.5}	Federal	35	35.99	Yes (Step 2)
Annual PM _{2.5}	State	12	8.16	No
	Federal	9	8.16	No
Step 2 – EPA SIL Basis ^a				
Impact Parameter	Class II SILs		Maximum Project Contribution	
	µg/m ³	µg/m ³	µg/m ³	Exceed SIL?
24-hour PM ₁₀	5	4.41	0.29	No
24-hour PM _{2.5}	1.2	4.41	0.29	No

Source: Appendix 3.1B.

Notes: AAQS = Ambient Air Quality Standard; CO = carbon monoxide; EPA = U.S. Environmental Protection Agency; NO₂ = nitrogen dioxide; PM₁₀ = particulate matter less than or equal to 10 microns; PM_{2.5} = particulate matter less than or equal to 2.5 microns; SIL = significant impact level; SO₂ = sulfur dioxide.

^a Step 1: the AAQS basis compares the background concentrations plus Project contribution to the state and federal AAQS to determine if there will be an exceedance of the respective standard. For 24-hour PM₁₀ and 24-hour PM_{2.5}, background concentrations already exceed the applicable AAQS, so Step 2—the SIL basis—compares the Project contributions to levels determined by the EPA to cause or contribute to ambient air quality exceedances and impacts.

Steps 1 and 2 of the Level 1 AAQA show that localized operational emissions associated with the periodic routine testing and maintenance of the emergency diesel generators will not exceed the applicable AAQS thresholds for any criteria air pollutants. Therefore, impacts will be **less than significant**.

3.1.3.2.3 Would the Project expose sensitive receptors to substantial pollutant concentrations?

Less than Significant with Mitigation. The potential impact of Project-generated air pollutant emissions to sensitive receptors has been considered. As described in Section 3.1.1.3, Sensitive Receptors, the closest sensitive receptors to the Project site are residences located immediately adjacent to the west (along Malinta Avenue), north (along Tortuga Street and Soledad Canyon Road), and south (across Soledad Canyon Road) of the BESS facility Project site boundary. Single-family residences are also located close to the gen-tie alignments.

Carbon Monoxide Hotspots

Mobile source impacts occur on two scales of motion. Regionally, Project-related travel will add to regional trip generation and increase VMT within the local airshed and the MDAB. Locally, Project-generated traffic will be added to the roadway system near the Project site. If such traffic occurs during periods of poor atmospheric ventilation, is composed of a large number of vehicles “cold-started” and operating at pollution-inefficient speeds, and operates on roadways already crowded with non-Project traffic, there is a potential for the formation of microscale CO hotspots in the area immediately around points of congested traffic. However, because of continued improvement in vehicular emissions at a rate faster than the rate of increased vehicle numbers and/or congestion, the potential for CO hotspots in the MDAB is steadily decreasing.

The AVAQMD thresholds of significance for local CO emissions are the 1-hour and 8-hour CAAQS of 20 ppm and 9 ppm, respectively. By definition, these represent levels that are protective of public health. As noted previously, the MDAB is currently designated attainment for both state and national CO ambient air quality standards, and the Project area typically experiences low background CO concentrations.

As described in Section 3.1.3.1.1, Thresholds of Significance, CO concentrations at congested intersections are not anticipated to exceed the 1-hour or 8-hour CO CAAQS unless projected daily traffic will be at least over 100,000 vehicles per day at a given intersection. During construction, the peak day of construction for the Project will generate approximately 798 daily trips. All construction-related traffic will be temporary and short term and will cease upon completion of the Project. Accordingly, it is not anticipated that the Project will result in a new congested intersection or that it will substantially exacerbate conditions at existing congested intersections. Additionally, the proposed Project will not result in an increase of intersection volumes to more than 100,000 vehicles per day at any given intersection in the Project area. Therefore, a CO hotspot is not anticipated to occur, and potential Project-generated impacts associated with CO hotspots during construction will be **less than significant**.

During operations, the Project is anticipated to require an average of 16 employees per day, resulting in 32 one-way trips per day. Implementation of the Project will result in a minimal regional increase in vehicle trips and VMT. Accordingly, it is not anticipated that the Project will result in a new congested intersection or that it will substantially exacerbate conditions at existing congested intersections. Additionally, the proposed Project will not result in an increase of intersection volumes to more than 100,000 vehicles per day at any given intersection in the Project area. Therefore, a CO hotspot is not anticipated to occur, and potential Project-generated impacts associated with CO hotspots during operation will be **less than significant**.

Fugitive Dust and Valley Fever

In order to reduce fugitive dust from the Project and minimize adverse air quality impacts, the Project will employ measures that address dust in accordance with AVAQMD Rules 401, 402, and 403, which limit the amount of

fugitive dust generated during construction. Specifically, Rule 403 includes requirements for a Dust Control Plan, signage, and fencing, as well as surface watering and stabilization with chemicals, gravel, and asphaltic pavement to minimize visible fugitive dust from vehicular travel, earthwork, and wind erosion. **MM-AQ-3** (Construction Dust Control Plan) goes beyond requirements of AVAQMD Rules 401, 402, and 403 and will be implemented to reduce fugitive dust generated by the Project during construction. As such, potential sensitive receptor exposure to fugitive dust emissions and will be reduced to a **less than significant level with mitigation**.

Regarding Valley Fever, compliance with AVAQMD Rules 401 and 403 is also consistent with California Department of Public Health recommendations for the implementation of dust control measures, including regular application of water during soil-disturbance activities to reduce exposure to valley fever by minimizing the potential that the fungal spores become airborne (CDPH 2013). Further, while requirements listed in AVAQMD Rules 401 and 403 are not specifically directed at valley fever impacts, these dust control strategies will further reduce the generation of potential for fugitive dust, thereby minimizing the potential for fungal spores to become airborne and the potential for sensitive receptors to be exposed to valley fever spores. In addition, regulations designed to minimize exposure to valley fever hazards are included in Title 8 of the California Code of Regulations and will be complied with during the Project's construction phase (California Department of Industrial Relations 2022). ~~However, as discussed in Section 3.1.1.2.2, Non-Criteria Pollutants and Valley Fever, Los Angeles County is not considered a highly endemic region for valley fever and, even~~ Even if spores are present at the site, construction activities may not result in increased incidence of valley fever. Propagation of valley fever is dependent on climatic conditions, with the potential for growth and surface exposure highest following early seasonal rains and long dry spells. Valley fever spores can be released when filaments are disturbed by earthmoving activities, although receptors must be exposed to and inhale the spores to be at increased risk of developing valley fever. Moreover, exposure to valley fever does not guarantee that an individual will become ill—approximately 60% of people exposed to the fungal spores are asymptomatic and show no signs of an infection (USGS 2000). ~~Based on the preceding, the Project will not result in a significant impact attributable to valley fever exposure based on its geographic location and compliance with the applicable AVAQMD fugitive dust regulatory standards listed above, which will serve to minimize the release of and exposure to fungal spores. Therefore, impacts associated with valley fever exposure for sensitive receptors will be less than significant.~~

Regardless, as discussed in Section 3.1.1.2.2, Non-Criteria Pollutants and Valley Fever, Los Angeles County is not considered a highly endemic region for valley fever. However, the Antelope Valley Service Planning Area within Los Angeles County is considered a highly endemic area for valley fever. Risk of valley fever infection exists for construction workers and nearby sensitive receptors in the peak summer and fall months, which is the timeframe when valley fever incidence rates are the highest. The Project would implement **MM-AQ-4** (Valley Fever Exposure Minimization), which would require public notification of construction activities and information about valley fever, incorporate additional dust control measures into the Construction Dust Control Plan between June 1 and November 30, and implement a worker training program that would identify valley fever safety measures.

Health Effects of Criteria Air Pollutants

Construction of the Project will generate criteria air pollutant emissions that will have the potential to exceed AVAQMD mass-emission thresholds during construction, and the Project's localized emissions will have the potential to exceed the applicable NAAQS thresholds prior to mitigation. Therefore, the Project will potentially result in a significant contribution to local or regional concentrations of nonattainment pollutants and will potentially result in a significant contribution to the adverse health impacts associated with those pollutants. The impact will be **potentially significant** prior to mitigation. However, with incorporation of **MM-AQ-1 through MM-AQ-3**, the Project will

not exceed the AVAQM mass-emission thresholds during construction or operations, and the Project's localized emissions will not exceed the applicable NAAQS thresholds.

The MDAB is designated as nonattainment for O₃ for the NAAQS and CAAQS. Thus, existing O₃ levels in the MDAB are at unhealthy levels during certain periods. The health effects associated with O₃ generally relate to reduced lung function. Because the Project will not involve construction or operational activities that will result in O₃ precursor emissions (VOC or NO_x) that will exceed the AVAQM thresholds with incorporation of mitigation, the Project is not anticipated to substantially contribute to regional O₃ concentrations and associated health impacts. Furthermore, during operations, the AVAQM thresholds for VOC and NO_x will not be exceeded.

In addition to O₃, NO_x emissions contribute to potential exceedances of the NAAQS and CAAQS for NO₂ (because NO₂ is a constituent of NO_x). Exposure to NO₂ can cause lung irritation, bronchitis, and pneumonia, and can lower resistance to respiratory infections. As depicted in Table 3.1-7, Project construction will not exceed the AVAQM thresholds for NO_x with incorporation of mitigation, and as depicted in Table 3.1-11, Project operations will not exceed the AVAQM thresholds for NO_x. Furthermore, as shown in Table 3.1-10 and Table 3.1-12, localized mitigated construction and unmitigated operational emissions will not exceed the applicable NAAQS thresholds for NO₂. Thus, construction and operation of the Project are not expected to exceed the NO₂ standards or contribute to associated health effects.

CO tends to be a localized impact associated with congested intersections. CO competes with oxygen, often replacing it in the blood, reducing the blood's ability to transport oxygen to vital organs. The results of excess CO exposure can include dizziness, fatigue, and impairment of central nervous system functions. CO hotspots were discussed previously as a less-than-significant impact. Thus, the Project's CO emissions will not contribute to the health effects associated with this pollutant.

The MDAB is designated as nonattainment for PM₁₀ under the CAAQS. Health effects associated with PM₁₀ and PM_{2.5} include premature death and hospitalization, primarily for worsening of respiratory disease. As shown in Tables 3.1-6 and 3.1-11, the Project will not generate emissions of PM₁₀ or PM_{2.5} that will exceed AVAQM's regional thresholds during construction or operation. In addition, as shown in Table 3.1-10 and Table 3.1-12, the Project's localized mitigated construction and unmitigated operational emissions will not exceed the applicable NAAQS thresholds for PM₁₀ or PM_{2.5}. Furthermore, the Project will apply all required dust mitigation under AVAQM Rule 403 and **MM-AQ-3**. Accordingly, the Project's PM₁₀ and PM_{2.5} emissions are not expected to cause any increase in related regional health effects for these pollutants.

In summary, the Project will not result in a significant contribution to local or regional concentrations of nonattainment pollutants and not potentially result in a significant contribution to the adverse health impacts associated with those pollutants with incorporation of mitigation. Therefore, the impact will be **less than significant with mitigation**.

3.1.3.2.4 Would the Project result in other emissions (such as those leading to odors) adversely affecting a substantial number of people?

Less than Significant. Based on available information, the Project is not anticipated to result in other emissions that have not been addressed in Sections 3.1.3.2.1 through 3.1.3.2.3. As such, this analysis focuses on the potential for the Project to generate odors.

The occurrence and severity of potential odor impacts depends on numerous factors. The nature, frequency, and intensity of the source; the wind speeds and direction; and the sensitivity of receiving location each contribute to the intensity of the impact. Although offensive odors seldom cause physical harm, they can be annoying and cause distress among members of the public and generate citizen complaints.

Odors will be generated from vehicles and/or equipment exhaust emissions during construction of the Project. Odors produced during construction will be attributable to concentrations of unburned hydrocarbons from tailpipes of construction equipment and asphalt pavement application. Such odors are temporary and for the types of construction activities anticipated for Project components will generally occur at magnitudes that will not affect substantial numbers of people. Odors are strongest near the source and will quickly dissipate. Therefore, impacts associated with odors during construction will be considered less than significant.

Land uses most commonly associated with odor complaints generally include agricultural uses (livestock and farming), wastewater treatment plants, food-processing plants, chemical plants, composting operations, refineries, landfills, dairies, and fiberglass molding facilities. The Project does not include uses that will be substantive sources of objectionable odors. The Project will also be required to comply with AVAQMD Rule 402 (Nuisance). Rule 402 provides that “[a] person shall not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property” (AVAQMD 2002). Based on the preceding, the potential impacts from the Project creating objectionable odors affecting a substantial number of people will be **less than significant**.

3.1.3.2.5 Would the Project generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment, or would the Project conflict with an applicable plan, policy, or regulation adopted for the purpose of reducing the emissions of greenhouse gases?

Less than Significant. As described in Section 3.1.3.2.2, the Project’s potential to conflict with applicable plans, policies, or regulations adopted by CARB and other state and local agencies for the purpose of reducing GHG emissions is used to evaluate the significance of the Project’s GHG emissions.

Project Potential to Conflict with County of Los Angeles 2045 CAP

A qualitative analysis describing the Project’s potential to conflict with the most applicable strategies set forth in the 2045 CAP is summarized in Table 3.1-13.

Table 3.1-13. Project Potential to Conflict with the 2045 CAP

2045 CAP Strategies	Project Potential to Conflict
Energy Supply	No Conflict. The Project is a battery energy storage facility that will balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability, thereby increasing energy resilience in the region. In addition, the Project will provide new energy storage capacity to assist California electric utilities in meeting obligations under California’s RPS Program and SB 100 and SB 1020, as well as assist the State of California in meeting its goals of decarbonizing the electricity

Table 3.1-13. Project Potential to Conflict with the 2045 CAP

2045 CAP Strategies	Project Potential to Conflict
	sector and reducing statewide annual GHG emissions. The Project will not conflict with the County’s ability to implement this strategy.
Transportation	No Conflict. The increase in traffic during Project construction will be temporary in nature and will cease at the conclusion of construction activities. During operation, the Project will require 16 routine permanent staff on weekdays and will not generate a net increase of 110 daily vehicle trips. As such, the Project will comply with the County’s Transportation Demand Management Ordinance and Transportation Impact Guidelines. The Project will not conflict with the County’s ability to implement this strategy.
Building Energy and Water	No Conflict. The Project will be fully electric with no natural gas infrastructure or appliances. The Project will balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability and support demand management and peak shaving. The Project will comply with water conservation ordinance in place and CALGreen water conservation and efficiency measures. In addition, the Project will include water-efficient landscape design that is compliant with the Department of Water Resources (DWR) 2015 Model Water Efficient Landscape Ordinance (MWELO) and drought-tolerant and native plant species only. The Project will comply with all County codes and ordinances regarding building material carbon intensity and high-GWP refrigerants and other gases. The Project will not conflict with the County’s ability to implement this strategy.
Agriculture, Forestry, and Other Land Use (AFOLU)	No Conflict. The Project will have minimal landscaping. However, a conceptual landscape plan was developed for the Project to meet the appropriate County of Los Angeles Planning and Zoning Standards Code for Electrical Distribution Substations. Planting design emphasizes drought-tolerant landscaping that is compliant with the Los Angeles County Water Efficiency Standards and the State of California MWELO. The Project will not conflict with the County’s ability to implement this strategy.

Source: County of Los Angeles 2024.

Notes: CAP = Climate Action Plan; RPS = Renewables Portfolio Standard; SB = Senate Bill; GHG = greenhouse gas emissions; CALGreen = California Green Building Standards; GWP = global warming potential.

As shown in Table 3.1-13, the Project will not conflict with the core strategies in the 2045 CAP. In addition, the Project will assist Los Angeles County in meeting its long-term renewable energy and energy resilience goals by improving energy grid reliability and supporting the integration of additional intermittent renewable energy sources, such as wind and solar.

Project Potential to Conflict with State Reduction Targets and CARB’s Scoping Plan

The California State Legislature passed AB 32 to provide initial direction to limit California’s GHG emissions to 1990 levels by 2020 and initiate the state’s long-range climate objectives. Since the passage of AB 32, the state has adopted GHG emissions reduction targets for future years beyond the initial 2020 horizon year. CARB is required to develop a Scoping Plan, which provides the framework for actions to achieve the state’s GHG emission targets. Although the Scoping Plan is not directly applicable to specific projects, nor is it intended to be used as the sole basis for project-level evaluations, it is the official framework for the measures and regulations that will be implemented to reduce California’s GHG emissions in alignment with the adopted targets. Therefore, a project will be found to not conflict with the statutes if it meets the Scoping Plan policies and will not impede attainment of the goals therein.

For the Project, the relevant GHG emissions reduction targets include those established by SB 32 and AB 1279, which require that GHG emissions be reduced to 40% below 1990 levels by 2030, and 85% below 1990 levels by 2045, respectively. In addition, AB 1279 requires that the state achieve net zero GHG emissions by no later than 2045 and achieve and maintain net negative GHG emissions thereafter. CARB's 2017 Scoping Plan update was the first to address the state's strategy for achieving the 2030 GHG reduction target set forth in SB 32 (CARB 2017), and the most recent CARB 2022 Scoping Plan update outlines the state's plan to reduce emissions and achieve carbon neutrality by 2045 in alignment with AB 1279 and assesses the progress made toward the 2030 SB 32 target (CARB 2022). As such, given that SB 32 and AB 1279 are the relevant GHG emission targets, the 2017 and 2022 Scoping Plan updates that outline the strategy to achieve those targets are the most applicable to the Project.

The 2017 Scoping Plan included measures to promote renewable energy and energy efficiency (including the mandates of SB 350),¹¹ measures to increase stringency of the low-carbon fuel standard, measures identified in the Mobile Source and Freight Strategies, measures identified in the proposed Short-Lived Climate Pollutants plan, and measures to increase stringency of SB 375 targets.¹² The 2022 Scoping Plan builds on and accelerates programs currently in place, including moving to zero-emission transportation; phasing out use of fossil gas use for heating homes and buildings; reducing chemical and refrigerants with high GWP; providing communities with sustainable options for walking, biking, and public transit; and displacing fossil-fuel fired electrical generation through use of renewable energy alternatives (e.g., solar arrays and wind turbines) (CARB 2022). Many of the measures and programs included in the Scoping Plan will result in the reduction of Project-related GHG emissions with no action required at the project level, including GHG emission reductions through increased energy efficiency and renewable energy production, reduction in carbon intensity of transportation fuels (low-carbon fuel standard), and the accelerated efficiency and electrification of the statewide vehicle fleet (Mobile Source Strategy).

Table 3.1-14 evaluates the Project's potential to conflict with the 2017 Scoping Plan recommended actions.

Table 3.1-14. Project Potential to Conflict with 2017 Scoping Plan

Recommended Action Summary	Lead Agencies	Potential to Conflict
Implement SB 350 by 2030 ▪ Increase Renewables Portfolio Standard ▪ Establish annual targets for statewide energy efficiency ▪ Reduce GHG emissions in the electricity sector	CPUC, CEC, CARB	No Conflict. This action is directed towards policymakers and will not be directly applicable to the Project. Nonetheless, the Project will improve energy grid reliability and support the integration of additional intermittent renewable energy sources, such as wind and solar, reducing the need to operate natural gas power plants.
Implement Mobile Source Strategy (Cleaner Technology and Fuels) ▪ Increase zero emission and plug-in hybrid electric vehicles ▪ Increase GHG stringency on light-duty vehicles beyond Advanced Clean Cars	CARB, CalSTA, SGC, CalTrans, CEC, OPR, local agencies	No Conflict. These actions are part of the CARB Mobile Source Strategy that pertains to vehicle fleet standards. As this is a CARB enforced standard, vehicles that access the Project are required to comply with the standards

¹¹ SB 350 expanded the Renewables Portfolio Standard program by establishing a goal that 50% of the total electricity sold to retail customers in California per year be from renewable energy sources by December 31, 2030. In addition, SB 350 included the goal to double the energy efficiency savings in electricity and natural gas final end uses (such as heating, cooling, lighting, or class of energy uses on which an energy-efficiency program is focused) of retail customers through energy conservation and efficiency.

¹² Pursuant to SB 375, CARB set per capita GHG emissions reduction targets from passenger vehicles for each of the state's 18 metropolitan planning organizations.

Table 3.1-14. Project Potential to Conflict with 2017 Scoping Plan

Recommended Action Summary	Lead Agencies	Potential to Conflict
- Medium- and heavy-duty GHG Phase 2 - Innovative Clean Transit - Last Mile Delivery - Further reduce VMT through SB 375 and regional Sustainable Communities Strategy		and will therefore comply with the strategy.
Increase stringency of SB 375 Sustainable Communities Strategy (2035 targets)	CARB	No Conflict. This action is directed toward policymakers and will not be directly applicable to the Project.
Adjust performance measures used to select and design transportation facilities by 2019	CalSTA and SGC, OPR, CARB, GoBiz, IBank, DOF, CTC, Caltrans	No Conflict. The action is directed toward CARB and Caltrans and the Project will not impede implementation.
Develop pricing policies to support low-GHG transportation (e.g., low-emission vehicle zones for heavy-duty, road user, parking pricing, transit discounts) by 2019	CalSTA, Caltrans, CTC, OPR/SGC, CARB	No Conflict. This action is directed towards policymakers and will not be directly applicable to the Project.
Implement California Sustainable Freight Action Plan	CalSTA, CalEPA, CNRA, CARB, CalTrans, CEC, GoBiz	No Conflict. This measure will apply to all trucks accessing the Project sites, including existing trucks or new trucks that are part of the statewide goods movement sector. Thus, the Project will not obstruct or interfere with agency efforts to improve freight system efficiency but rather will comply with all applicable standards.
Adopt a Low Carbon Fuel Standard with a carbon intensity reduction of 18%	CARB	No Conflict. This measure, which was increased to 20% reduction in carbon intensity by 2030 (see 2022 Scoping Plan), applies to all fuel purchased and used by the Project in the state. Thus, the Project will not obstruct or interfere with agency efforts to implement a Low Carbon Fuel Standard but rather will comply with all applicable standards.
Implement the Short-Lived Climate Pollutant Strategy by 2030	CARB, CalRecycle, CDFA, SWRCB, Local air districts	No Conflict. The Project will be required to comply with the Short-Lived Climate Pollutant Strategy to the extent it is applicable.
Develop regulations and programs to support organic waste landfill reduction goals in the Short-Lived Climate Pollutant Strategy and SB 1383 by 2019	CARB, CalRecycle, CDFA, SWRCB, local air districts	No Conflict. This action is not within the purview of this Project.
Implement the post-2020 Cap-and-Trade Program with declining annual caps	CARB	No Conflict. The Project is not subject to the California Cap-and-Trade Program.

Table 3.1-14. Project Potential to Conflict with 2017 Scoping Plan

Recommended Action Summary	Lead Agencies	Potential to Conflict
Develop Integrated Natural and Working Lands Implementation Plan to secure California's land base as a net carbon sink by 2018	CNRA and departments within, CDFA, CalEPA, CARB	No Conflict. This action is not within the purview of this Project.
Establish a carbon accounting framework for natural and working lands as described in SB 859 by 2018	CARB	No Conflict. This action is not within the purview of this Project.
Implement Forest Carbon Plan	CNRA, CAL FIRE, CalEPA and departments within	No Conflict. This action is not within the purview of this Project.
Identify and expand funding and financing mechanisms to support GHG reductions across all sectors.	State Agencies & Local Agencies	No Conflict. This action is not within the purview of this Project.

Source: CARB 2017.

Notes: SB = Senate Bill; GHG = greenhouse gas; CPUC = California Public Utilities Commission; CEC = California Energy Commission; CARB = California Air Resources Board; VMT = vehicle miles traveled; CalSTA = California State Transportation Agency; SGC = Strategic Growth Council; CalTrans = California Department of Transportation; OPR = Governor's Office of Planning and Research; GoBiz = Governor's Office of Business and Economic Development; IBank = California Infrastructure Economic Development Bank; DOF = Department of Finance; CTC = California Transportation Commission; CalEPA = California Environmental Protection Agency; CNRA = California Natural Resources Agency; CalRecycle = California Department of Resources Recycling and Recovery; CDFA = California Department of Food and Agriculture; SWRCB = State Water Resources Control Board; CAL FIRE = California Department of Forestry and Fire Protection.

Table 3.1-15 evaluates the Project's potential to conflict with the measures from the 2022 Scoping Plan that are relevant and applicable to the Project.

Table 3.1-15. Project Potential to Conflict with 2022 Scoping Plan

Sector	Action	Potential to Conflict
GHG Emissions Reductions Relative to the SB 32 Target	40% below 1990 levels by 2030	No Conflict. While the SB 32 GHG emissions reduction target is not an action that is analyzed independently, it is included in Table 2-1 of the 2022 Scoping Plan for reference. The Project will not obstruct or interfere with agency efforts to meet the SB 32 reduction goal. Specifically, the Project will allow for increased energy storage from intermittent renewable energy sources, thereby increasing grid reliability and increasing the opportunity for renewable energy development.
Smart Growth/VMT	VMT per capita reduced 25% below 2019 levels by 2030, and 30% below 2019 levels by 2045	No Conflict. The Project will not obstruct or interfere with agency efforts to meet this regional VMT reduction goal, including through implementation of SB 375.
Light-duty Vehicle (LDV) Zero Emission Vehicles (ZEVs)	100% of LDV sales are ZEV by 2035	No Conflict. As this action pertains to LDV sales within California, the Project will not

Table 3.1-15. Project Potential to Conflict with 2022 Scoping Plan

Sector	Action	Potential to Conflict
		obstruct or interfere with its implementation.
Truck ZEVs	100% of medium-duty vehicle (MDV)/ heavy-duty vehicle (HDV) sales are ZEV by 2040	No Conflict. As this action pertains to MDV and HDV sales within California, the Project will not obstruct or interfere with its implementation.
Electricity Generation	▪ Sector GHG target of 38 million metric tons of carbon dioxide equivalent (MMTCO₂e) in 2030 and 30 MMTCO₂e in 2035 ▪ Retail sales load coverage ▪ 20 gigawatts (GW) of offshore wind by 2045 ▪ Meet increased demand for electrification without new fossil gas-fired resources	No Conflict. As this action pertains to the statewide procurement of renewable energy, the Project will not obstruct or interfere with its implementation. Rather, the Project will support increased usage of renewable electricity by allowing for a more reliable local electric grid and reducing reliance on natural gas power plants.
New Residential and Commercial Buildings	All electric appliances beginning 2026 (residential) and 2029 (commercial), contributing to 6 million heat pumps installed statewide by 2030	No Conflict. The Project will not obstruct or interfere with CARB's efforts to meet the all-electric appliance and heat pump goals. The Project's appliances and heating, ventilation, and air conditioning (HVAC) system will be electrically powered.
Construction Equipment	25% of energy demand electrified by 2030 and 75% electrified by 2045	No Conflict. As this action pertains to the electrification of off-road equipment across California, the Project will not obstruct or interfere with its implementation. Instead, construction equipment used at the Project site will conform to state standards.
Low Carbon Fuels for Transportation	Biomass supply is used to produce conventional and advanced biofuels, as well as hydrogen	No Conflict. The Project will not obstruct or interfere with CARB's efforts to increase the provision of low carbon fuels for transportation. The development and use of biofuels in trucks and automobiles will occur at the state and regional level. Any equipment at the Project site using biofuels will conform to state standards.
Low Carbon Fuels for Buildings and Industry	▪ In 2030s biomethane blended in pipeline ▪ Renewable hydrogen blended in fossil gas pipeline at 7% energy (~20% by volume), ramping up between 2030 and 2040 ▪ In 2030s, dedicated hydrogen pipelines constructed to serve certain industrial clusters	No Conflict. The Project will not obstruct or interfere with CARB's efforts to increase the provision of low carbon fuels for use in buildings and industry. The blending of biomethane and use of renewable hydrogen in existing natural gas pipelines will happen at the scale of the utility provider and without action required by the Project.
High GWP Potential Emissions	Low GWP refrigerants introduced as building electrification increases, mitigating HFC emissions	No Conflict. The Project will not obstruct or interfere with agency efforts to introduce low GWP refrigerants. The State has

Table 3.1-15. Project Potential to Conflict with 2022 Scoping Plan

Sector	Action	Potential to Conflict
		established a prohibition on the sale or distribution of bulk HFCs identified as having a high GWP through SB 1206. All refrigerants used at the Project site will conform to state standards.

Source: CARB 2022.

Notes: GHG = greenhouse gas; SB = Senate Bill; VMT = vehicle miles traveled; CARB = California Air Resources Board; GWP = global warming potential; HFC = hydrofluorocarbon.

As shown in Tables 3.1-14 and 3.1-15, the Project will not conflict with the applicable strategies and measures in the 2017 Scoping Plan and 2022 Scoping Plan, respectively. In addition, the Project will not impede the state and authoritative lead agencies from implementing incentives or regulations to achieve the Scoping Plan goals.

Estimated GHG Emissions

Project-generated GHG emissions are presented for informational purposes and are not used in determining the significance of potential GHG-related impacts.

Construction and Decommissioning Emissions

Both construction and decommissioning of the Project will result in GHG emissions, which are primarily associated with use of off-road construction equipment, on-road trucks, and worker vehicles. Helicopter usage will also result in GHG emissions during construction. The total construction GHG emissions were calculated, amortized over 40 years, and added to the operational emissions. For conservative purposes, GHG emissions associated with decommissioning have also been amortized and have been added to the operational emissions. Table 3.1-16 presents construction GHG emissions for the Project and decommissioning emission sources.

Table 3.1-16. Estimated Annual Construction GHG Emissions

	CO ₂	CH ₄	N ₂ O	R	CO ₂ e
Year	Metric Tons				
2027 (Construction)	7,868.43	0.06	1.05	7.79	8,189.17
2028 (Construction)	5,450.09	0.19	0.21	4.64	5,520.79
2029 (Construction)	366.21	<0.01	0.01	0.53	371.06
2069 ^a (Decommissioning)	2,531.69	0.04	0.08	0.14	2,557.47
Total^b					16,638.48
<i>Annualized emissions over 40 years (metric tons per year)</i>					<i>415.96</i>

Notes: GHG = greenhouse gas; CO₂ = carbon dioxide; CH₄ = methane; N₂O = nitrous oxide; R = refrigerants; CO₂e = carbon dioxide equivalent; <0.01 = value is less than 0.005.

^a 2050 emission factors were used to represent the decommissioning phase of the Project in CalEEMod.

^b Total may not sum precisely due to rounding.

See Appendix 3.1A for complete results. As shown in Table 3.1-16, the estimated total GHG emissions during construction and decommissioning of the Project will be approximately 16,638 MT CO₂e. Estimated Project-generated construction and decommissioning emissions amortized over 40 years will be approximately 416 MT CO₂e per year.

Operational Emissions

As described in Section 3.1.3.1.2, operational GHG emissions from associated with the Project would be generated by area, energy (i.e., electricity consumption for building energy, parking lot lighting, auxiliary loads, and RTE losses), mobile, and off-road sources. Emissions from each category are discussed in the following text with respect to the Project. For additional details, see Section 3.1.3.1.2 for a discussion of operational emission calculation methodology and assumptions. Operational year 2029 was assumed as the first year of operation. Table 3.1-17 presents the GHG emissions of the Project during operation from these sources and sums the annual operational GHGs and the amortized construction/decommissioning emissions.

Table 3.1-17. Estimated Annual Operational GHG Emissions

Emissions Source	CO ₂	CH ₄	N ₂ O	R	CO ₂ e
Metric Tons per Year					
Mobile	54.31	<0.01	<0.01	0.08	55.16
Area	0.13	<0.01	<0.01	0.00	0.13
Building Energy/Lighting/ Auxiliary Loads ^a	~~104,965.40~~ 10,634.03	~~101.01~~	~~1.210.12~~	0.00	~~105,576.95~~ 10,695.99
RTE Losses	~~105,077.49~~	~~0~~	~~0~~	~~0~~	~~105,077.49~~
Water	1.70	0.02	0.00	0.00	2.29
Waste	0.27	0.03	0.00	0.00	0.93
Refrigerants ^{ab}	0.00	0.00	0.00	~~46.89~~ 44.25	~~46.89~~ 44.25
Offroad Equipment	0.52	<0.01	<0.01	0.00	0.52
Stationary	47.23	<0.01	<0.01	0.00	47.39
Total					~~105,730.26~~ 115,924.15
<i>Amortized construction and decommissioning emissions</i>					415.96
Total with amortized construction emissions					~~106,146.23~~ 116,340.11

Notes: GHG = greenhouse gas; CO₂ = carbon dioxide; CH₄ = methane; N₂O = nitrous oxide; R = refrigerants; CO₂e = carbon dioxide equivalent; RTE = round-trip efficiency; <0.01 = value is less than 0.005.

See Appendix 3.1A for complete results.

^{aa} Indirect annual operational GHG emissions.

^b Refrigerants include SF₆ and R-32 gas emissions.

As shown in Table 3.1-17, the estimated total GHG emissions during operation of the Project will be approximately ~~106,146~~**116,340** MT CO₂e per year, including amortized construction and decommissioning emissions.

GHG emissions emitted by the Project are primarily a result of energy consumption associated with ~~round trip efficiency~~RTE and transmission losses when operating the BESS facility. As SCE, the energy provider for the Project, moves toward meeting the state's Renewables Portfolio Standard goals of 100% renewable energy by 2045 as established in SB 100 and SB 1020, GHG emissions from the Project will be reduced. Additionally, the Project will assist SCE and the state in meeting ~~RPS~~Renewables Portfolio Standard goals by supporting the use of intermittent renewable energy sources, such as solar and wind. Therefore, the Project's emissions associated with electricity will become net zero over time as SCE's electricity generation sources shift toward renewables, and the Project will assist the state and local utility in meeting its renewable energy goals outlined in SB 100 and SB 1020.

Conclusion

The Project will not conflict with the core strategies of the 2045 CAP. In addition, the Project will not conflict with the applicable goals and strategies of CARB’s 2017 and 2022 Scoping Plans. Furthermore, the Project will not impede the state and authoritative lead agencies from implementing incentives or regulations to achieve the 2017 Scoping Plan and 2022 Scoping Plan goals. As stated in the CARB 2022 Scoping Plan, energy storage is a “crucial pillar” in decarbonizing the electricity sector and to the state’s GHG emission reduction goals.

Based on these considerations, the Project will neither generate GHG emissions, either directly or indirectly, that may have a significant impact on the environment, nor will it conflict with plans, policies, or regulations adopted for the purpose of reducing GHG emissions; therefore, the Project will result in a **less than significant impact**.

3.1.4 Mitigation Measures

To reduce the potential emissions of criteria air pollutants as a result of construction and operation of the Project, the applicant shall implement the following mitigation measures:

MM-AQ-1 Construction Equipment Emission Minimization. Prior to the commencement of construction activities for the Project, the applicant or its designee shall require its construction contractor to demonstrate that all 50-horsepower or greater diesel-powered off-road equipment is powered with California Air Resources Board–certified Tier 4 Final or better engines, if available or Tier 3, where Tier 4 engines are not available.

In the event of changed circumstances (e.g., changes in the availability of specific types of construction equipment), the construction contractor may submit a request to the California Energy Commission (CEC) Compliance Project Manager (CPM) to apply an equivalent method of achieving Project-generated construction emissions that fall below the mass daily thresholds established by the Antelope Valley Air Quality Management District (AVAQMD). Documentation using industry-standard emission estimation methodologies shall be furnished to the CEC demonstrating that estimated Project-generated construction emissions will not exceed the applicable AVAQMD thresholds with the alternate construction method(s). If the documentation demonstrates that Project-generated construction emissions will remain below the applicable AVAQMD thresholds, then the CPM may approve the alternate construction method(s). Required construction equipment fleet and methodologies approved by the CPM shall be included in the contract specifications for the construction contractor.

MM-AQ-2 Commissioning Generators Emission Minimization. Prior to the commencement of construction activities for the Project, the applicant or its designee shall require its construction contractor to demonstrate that all diesel generators used during commissioning of the Project are powered with California Air Resources Board–certified Tier 4 Final or better engines, if available or Tier 3, where Tier 4 engines are not available.

In the event of changed circumstances (e.g., changes in the availability of specific types of construction equipment), the construction contractor may submit a request to the California Energy Commission Compliance Project Manager to apply an equivalent method of achieving Project-generated construction emissions.

- MM-AQ-3 **Construction Dust Control Plan.** Prior to the issuance of grading permits, the Project applicant or its designee shall develop and implement a dust control plan to reduce Project-generated dust during construction and ensure compliance with all applicable Antelope Valley Air Quality Management District rules and regulations, including, but not limited to, Rules 401 (Visible Emissions), 402 (Nuisance), and 403 (Fugitive Dust). The dust control plan shall include the following control strategies at a minimum:
- A. Water shall be used on the exposed areas at least three times daily.
 - Dust suppressants shall be applied on all unpaved roads within the Project construction footprint.
 - Water shall be used on the active demolition sites at least two times daily.
 - A 15 mph speed limit on unpaved surfaces shall be enforced.
 - All main roadways shall be constructed and paved as early as possible in the construction process.
 - Building pads shall be finalized as soon as possible following site preparation and grading activities.
 - Grading areas shall be stabilized as quickly as possible.
 - Chemical stabilizer shall be applied, a gravel pad shall be installed, or the last 100 feet of internal travel path within the construction site shall be paved prior to public road entry, as well as for all haul roads.
 - Wheel washers shall be installed adjacent to the apron for tire inspection and washing prior to vehicle entry on public roads.
 - Visible track-out into traveled public streets shall be removed with the use of sweepers, water trucks, or a similar method within 30 minutes of occurrence.
 - Sufficient perimeter erosion control shall be provided to prevent washout of silty material onto public roads.
 - Unpaved construction site egress points shall be graveled to prevent track-out.
 - Construction access points shall be wet-washed at the end of the workday if any vehicle travel on unpaved surfaces has occurred.
 - Transported material in haul trucks shall be watered or treated.
 - All soil disturbance and travel on unpaved surfaces shall be suspended if winds (instantaneous gusts) exceed 25 mph.
 - On-site stockpiles of excavated material shall be covered.
 - Haul truck staging areas shall be provided for loading and unloading of soil and materials and shall be located away from sensitive receptors at the farthest feasible distance.
 - Construction traffic control plans shall route delivery and haul trucks required during construction away from sensitive receptor locations and congested intersections to the extent feasible. Construction traffic control plans shall be finalized and approved prior to issuance of grading permits.

MM-AQ-4 Valley Fever Exposure Minimization. Prior to the commencement of any construction activities, the Project applicant or its designee shall implement the following valley fever provisions:

- A. The applicant or its designees shall provide evidence to the California Energy Commission (CEC) that a construction relations officer has been employed who will address community concerns regarding on-site construction activity. The applicant shall provide public notification in the form of a visible sign containing the contact information of the construction relations officer, who shall document complaints and concerns regarding on-site construction activity. The sign shall include information about valley fever (coccidioidomycosis), including what it is, common symptoms, and what to do if you suspect you or someone you know is infected. The sign shall be placed in easily accessible locations and noted on grading and improvement plans.
- B. Between June 1 and November 30, when valley fever rates of infection are the highest, additional dust suppression measures (such as additional water or the application of additional soil stabilizer) will be implemented prior to and immediately following ground-disturbing activities if wind speeds exceed 15 mph or temperatures exceed 95 ° F for 3 consecutive days. The additional dust suppression will continue until winds are 10 mph or lower and outdoor air temperatures are below 90 ° F for at least 2 consecutive days. The additional dust suppression measures will be incorporated into the Construction Dust Control Plan.
- C. The applicant or its designees will prepare and implement a worker training program that describes potential health hazards associated with valley fever, common symptoms, proper safety procedures to minimize health hazards, and notification procedures if suspected work-related symptoms are identified during construction and operation. The worker training program will identify safety measures to be implemented by the Project applicant or its contractor during construction and operation. Safety measures will include the following:
- Provide HEPA-filtered air-conditioned enclosed cabs on heavy equipment. Train workers on proper use of cabs, such as turning on air conditioning prior to using the equipment.
 - Provide communication methods, such as two-way radios, for use by workers in enclosed cabs.
 - Provide personal protective equipment (PPE), such as half-mask and/or full-mask respirators equipped with particulate filtration, to workers active in dusty work areas.
 - Provide separate, clean eating areas with hand-washing facilities for workers.
 - Clean equipment, vehicles, and other items before they are moved off site to other work locations.
 - Provide training for workers so they can recognize the symptoms of valley fever and promptly report suspected symptoms of work-related valley fever to a supervisor.
 - Direct workers that exhibit valley fever symptoms to immediately seek medical evaluation.

3.1.5 Laws, Ordinances, Regulations, and Statutes

Table 3.1-18 presents the laws, ordinances, regulations, and standards (LORS) pertaining to the Project.

Table 3.1-18. LORS Applicable to Air Quality

Jurisdiction	LORS	Applicability	Project Conformity	Opt-In Application Reference
Federal	Clean Air Act and Regulations	Establishes national ambient	Yes. To evaluate the potential for localized	Section 3.1.3.1.2

Table 3.1-18. LORS Applicable to Air Quality

Jurisdiction	LORS	Applicability	Project Conformity	Opt-In Application Reference
		air quality standards (NAAQS) for criteria air pollutants	criteria air pollutant emissions from Project construction or operations to exceed respective NAAQS, ambient air quality analyses (AAQAs) were performed. The Project will not exceed the NAAQS.	Section 3.1.5.1.1
State	Clean Air Act	Establishes state ambient air quality standards (CAAQS) for criteria air pollutants	Yes. To evaluate the potential for localized criteria air pollutant emissions from Project construction or operations to exceed respective CAAQS, AAQAs were performed. The Project will not exceed the CAAQS.	Section 3.1.3.1.2 Section 3.1.5.2.1
State	State Climate Change Targets LORS	Establishes statewide goals to reduce greenhouse gas (GHG) emissions to address climate change	Yes. The Project's potential to conflict with state climate change targets, including the 2017 and 2022 California Air Resources Board (CARB) Scoping Plans, was assessed qualitatively. The Project would not conflict with the key strategies and measures of these plans.	Section 3.1.3.2.5 Section 3.1.5.2.2
State	Building Energy LORS	Establishes building standards for all occupancies throughout the state	Yes. The Project would comply with all Title 24 mandatory requirements.	Section 3.1.3.2.5 Section 3.1.5.2.2
State	Renewable Energy and Energy Procurement LORS	Establishes statewide goals and frameworks for transitioning to renewable energy resources and zero-carbon resources	Yes. The Project will support increased usage of renewable electricity by allowing for a more reliable local electric grid, support the integration of additional intermittent renewable energy sources, such as wind and solar, and reduce the need to operate natural gas power plants.	Section 3.1.3.2.5 Section 3.1.5.2.2
State	Mobile Sources LORS	Establishes statewide goals and requirements for reducing GHG	Yes. The Project would create minimal trips during operation, and emissions associated with the Project's mobile sources	Section 3.1.3.2.5 Section 3.1.5.2.2

Table 3.1-18. LORS Applicable to Air Quality

Jurisdiction	LORS	Applicability	Project Conformity	Opt-In Application Reference
		emissions from vehicles	were quantified. The Project would not obstruct or interfere with the implementation of mobile source regulations for the purpose of reducing GHG emissions.	
State	Solid Waste LORS	Establishes goals and requirements for reducing solid waste	Yes. Emissions associated with the Project's solid waste consumption were quantified. The Project would not obstruct or interfere with the implementation of solid waste source regulations for the purpose of reducing GHG emissions.	Section 3.1.3.2.5 Section 3.1.5.2.2
State	Water LORS	Establishes goals and requirements for reducing water	Yes. Emissions associated with the Project's water consumption were quantified. The Project would not obstruct or interfere with the implementation of water source regulations for the purpose of reducing GHG emissions.	Section 3.1.3.2.5 Section 3.1.5.2.2
Local	Antelope Valley Air Quality Management District Rules and Air Quality Management Plans	Regulates air pollutant emissions throughout the in the Los Angeles County portion of the MDAB	Yes. The Project would be required to comply with all applicable AVAQMD rules and regulations.	Section 3.1.3.2.1 Section 3.1.3.2.2 Section 3.1.3.2.3 Section 3.1.3.2.4 Section 3.1.5.3.1
Local	County of Los Angeles Climate Action Plan	Establishes new GHG emissions reduction targets for unincorporated Los Angeles County that are consistent with state goals	Yes. The Project's potential to conflict with County's CAP was assessed qualitatively. The Project would not conflict with the key strategies and measures of the CAP.	Section 3.1.3.2.5 Section 3.1.5.3.2

Notes: LORS = laws, ordinances, regulations, and standards; MDAB = Mojave Desert Air Basin; AVAQMD = Antelope Valley Air Quality Management District; CAP = climate action plan.

3.1.5.1 Federal LORS

3.1.5.1.1 The Federal Clean Air Act: Criteria Air Pollutants

The federal Clean Air Act, passed in 1970 and last amended in 1990, forms the basis for the national air pollution control effort. The EPA is responsible for implementing most aspects of the Clean Air Act, including setting NAAQS for major air pollutants; setting hazardous air pollutant (HAP) standards; approving state attainment plans; setting motor vehicle emission standards; issuing stationary source emission standards and permits; and establishing acid rain control measures, stratospheric O₃ protection measures, and enforcement provisions. Under the Clean Air Act, NAAQS are established for the following criteria pollutants: O₃, CO, NO₂, SO₂, PM₁₀, PM_{2.5}, and lead.

The NAAQS describe acceptable air quality conditions designed to protect the health and welfare of the citizens of the nation. The NAAQS (other than for O₃, NO₂, SO₂, PM₁₀, PM_{2.5}, and those based on annual averages or arithmetic mean) are not to be exceeded more than once per year. NAAQS for O₃, NO₂, SO₂, PM₁₀, and PM_{2.5} are based on statistical calculations over 1- to 3-year periods, depending on the pollutant. The Clean Air Act requires the EPA to reassess the NAAQS at least every 5 years to determine whether adopted standards are adequate to protect public health based on current scientific evidence. States with areas that exceed the NAAQS must prepare a State Implementation Plan that demonstrates how those areas will attain the NAAQS within mandated time frames. The NAAQS and CAAQS are presented in Table 3.1-19.

Table 3.1-19. Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards ^a	National Standards ^b	
		Concentration ^c	Primary ^{c,d}	Secondary ^{c,e}
O ₃	1 hour	0.09 ppm (180 µg/m ³)	—	Same as primary standard ^f
	8 hours	0.070 ppm (137 µg/m ³)	0.070 ppm (137 µg/m ³) ^f	
NO ₂ ^g	1 hour	0.18 ppm (339 µg/m ³)	0.100 ppm (188 µg/m ³)	Same as primary standard
	Annual arithmetic mean	0.030 ppm (57 µg/m ³)	0.053 ppm (100 µg/m ³)	
CO	1 hour	20 ppm (23 mg/m ³)	35 ppm (40 mg/m ³)	None
	8 hours	9.0 ppm (10 mg/m ³)	9 ppm (10 mg/m ³)	
SO ₂ ^h	1 hour	0.25 ppm (655 µg/m ³)	0.075 ppm (196 µg/m ³)	—
	3 hours	—	—	0.5 ppm (1,300 µg/m ³)
	24 hours	0.04 ppm (105 µg/m ³)	0.14 ppm (for certain areas) ^g	—
	Annual	—	0.030 ppm (for certain areas) ^g	—
PM ₁₀ ⁱ	24 hours	50 µg/m ³	150 µg/m ³	Same as primary standard
	Annual arithmetic mean	20 µg/m ³	—	
PM _{2.5} ⁱ	24 hours	—	35 µg/m ³	Same as primary standard

Table 3.1-19. Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards ^a	National Standards ^b	
		Concentration ^c	Primary ^{c,d}	Secondary ^{c,e}
	Annual arithmetic mean	12 µg/m ³	9.0 µg/m ³	15.0 µg/m ³
Lead ^{j, k}	30-day average	1.5 µg/m ³	—	—
	Calendar quarter	—	1.5 µg/m ³ (for certain areas) ^k	Same as primary standard
	Rolling 3-month average	—	0.15 µg/m ³	
Hydrogen sulfide	1 hour	0.03 ppm (42 µg/m ³)	—	—
Vinyl chloride ^l	24 hours	0.01 ppm (26 µg/m ³)	—	—
Sulfates	24- hours	25 µg/m ³	—	—
Visibility reducing particles	8 hour (10:00 a.m. to 6:00 p.m. PST)	Insufficient amount to produce an extinction coefficient of 0.23 per kilometer due to the number of particles when the relative humidity is less than 70%	—	—

Source: CARB 2024i.

Notes: O₃ = ozone; ppm = parts per million by volume; µg/m³ = micrograms per cubic meter; NO₂ = nitrogen dioxide; CO = carbon monoxide; mg/m³ = milligrams per cubic meter; SO₂ = sulfur dioxide; PM₁₀ = particulate matter with an aerodynamic diameter less than or equal to 10 microns; PM_{2.5} = particulate matter with an aerodynamic diameter less than or equal to 2.5 microns.

^a California standards for O₃, CO, SO₂ (1-hour and 24-hour), NO₂, suspended particulate matter (PM₁₀, PM_{2.5}), and visibility-reducing particles are values that are not to be exceeded. All others are not to be equaled or exceeded. CAAQS are listed in the Table of Standards in Section 70200 of Title 17 of the California Code of Regulations.

^b National standards (other than O₃, NO₂, SO₂, particulate matter, and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once per year. The O₃ standard is attained when the fourth-highest 8-hour concentration measured at each site in a year, averaged over 3 years, is equal to or less than the standard. For PM₁₀, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 µg/m³ is equal to or less than 1. For PM_{2.5}, the 24-hour standard is attained when 98% of the daily concentrations, averaged over 3 years, are equal to or less than the standard.

^c Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based on a reference temperature of 25 °Celsius (°C) and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25 °C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

^d National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect the public health.

^e National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

^f On October 1, 2015, the national 8-hour ozone primary and secondary standards were lowered from 0.075 to 0.070 ppm.

^g To attain the national 1-hour standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 parts per billion (ppb). Note that the national 1-hour standard is in units of ppb. California standards are in units of ppm. To directly compare the national 1-hour standard to the California standards, the units can be converted from ppb to ppm. In this case, the national standard of 100 ppb is identical to 0.100 ppm.

^h On June 2, 2010, a new 1-hour SO₂ standard was established, and the existing 24-hour and annual primary standards were revoked. To attain the national 1-hour standard, the 3-year average of the annual 99th percentile of the 1-hour daily maximum concentrations at each site must not exceed 75 ppb. The 1971 SO₂ national standards (24-hour and annual) remain in effect until 1 year after an area is designated for the 2010 standard, except that in areas designated nonattainment of the 1971 standards, the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved.

ⁱ On February 7, 2024, the national annual PM_{2.5} primary standard was lowered from 12.0 mg/m³ to 9.0 mg/m³. The existing national 24-hour PM_{2.5} standards (primary and secondary) were retained at 35 µg/m³, as was the annual secondary standard of 15 µg/m³. The existing 24-hour PM₁₀ standards (primary and secondary) of 150 µg/m³ were also retained. The form of the annual primary and secondary standards is the annual mean averaged over 3 years.

- ^j CARB has identified lead and vinyl chloride as TACs with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.
- ^k The national standard for lead was revised on October 15, 2008, to a rolling 3-month average. The 1978 lead standard (1.5 µg/m³ as a quarterly average) remains in effect until 1 year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

3.1.5.1.2 The Federal Clean Air Act: New Source Review

The EPA has also adopted technology-based standards that limit the emissions of criteria pollutants from new or modified facilities in specific source categories. These standards are referred to as New Source Performance Standards and are found in Title 40 of the Code of Federal Regulations, Part 60. The applicability of these standards depends on the equipment size or rating; material or fuel process rate; and/or the date of construction, modification, or reconstruction. In the event that emergency backup generators are required for Project facilities, the Project's diesel-powered emergency generators will be subject to Subpart IIII, which establishes emission and operational limits of criteria pollutants for new stationary compression ignition engines. To comply with the requirements of Subpart IIII, the Project's diesel-fired emergency generators will be operated and maintained as per the manufacturer specifications and will be certified to comply with Tier 4 Final emission rates.

To evaluate the potential for localized criteria air pollutant emissions from Project construction or operations to exceed respective NAAQS, AAQAs were performed. The Project will not exceed the NAAQS.

3.1.5.2 State LORS

3.1.5.2.1 Criteria Air Pollutants

The California Clean Air Act was adopted in 1988 and establishes the state's air quality goals, planning mechanisms, regulatory strategies, and standards of progress. Under the California Clean Air Act, the task of air quality management and regulation has been legislatively granted to CARB, with subsidiary responsibilities assigned to air quality management districts and air pollution control districts at the regional and county levels. CARB is responsible for ensuring implementation of the California Clean Air Act, responding to the federal Clean Air Act, and regulating emissions from motor vehicles and consumer products. Pursuant to the authority granted to it, CARB has established CAAQS, which are generally more restrictive than the NAAQSs. The CAAQS are presented in Section 3.1.5.1.1 in Table 3.1-19.

To evaluate the potential for localized criteria air pollutant emissions from Project construction or operations to exceed respective CAAQS, AAQAs were performed. The Project will not exceed the CAAQS.

3.1.5.2.2 Greenhouse Gas Emissions

State Climate Change Targets

The state has taken a number of actions to address climate change. These include executive orders, legislation, and CARB plans and requirements.

EO S-3-05. EO S-3-05 (June 2005) established the following statewide goals: GHG emissions should be reduced to 2000 levels by 2010, to 1990 levels by 2020, and to 80% below 1990 levels by 2050.

AB 32. In furtherance of the goals established in EO S-3-05, the legislature enacted AB 32 (Núñez and Pavley). AB 32 provided initial direction on creating a comprehensive multiyear program to limit California’s GHG emissions to 1990 levels by 2020 and initiate the transformations required to achieve the state’s long-range climate objectives.

SB 32. SB 32 and AB 197 (enacted in 2016) are companion bills that set a new statewide GHG reduction target, make changes to CARB’s membership, increase legislative oversight of CARB’s climate change-based activities, and expand dissemination of GHG and other air-quality-related emissions data to enhance transparency and accountability. More specifically, SB 32 codified the 2030 emissions reduction goal by requiring CARB to ensure that statewide GHG emissions are reduced to 40% below 1990 levels by 2030.

AB 1279. The legislature enacted AB 1279, the California Climate Crisis Act, in September 2022. The bill declares the policy of the state to achieve net zero GHG emissions as soon as possible, but no later than 2045, and achieve and maintain net negative GHG emissions thereafter. Additionally, the bill requires that by 2045, statewide anthropogenic GHG emissions be reduced to at least 85% below 1990 levels. AB 1279 establishes an overall policy to achieve net zero GHG emissions as soon as possible, but no later than 2045, recognizing the need to implement CO₂ removal and carbon capture, utilization, and storage technologies; the legislature also established a specific target of 85% below 1990 levels by 2045 for anthropogenic GHG emissions. Therefore, the net zero target does not directly apply to development projects, but the 2045 target of 85% below 1990 levels represents the reductions required to contribute to accomplishing the state’s overall net zero policy.

CARB’s Climate Change Scoping Plan. One specific requirement of AB 32 was for CARB to prepare a scoping plan for achieving the maximum technologically feasible and cost-effective GHG emission reductions by 2020 (California Health and Safety Code Section 38561[a]), and to update the plan at least once every 5 years. In 2008, CARB approved the first scoping plan. The Climate Change Scoping Plan: A Framework for Change (Scoping Plan) included a mix of recommended strategies to meet the 2020 statewide GHG emissions limit and initiate the transformations needed to achieve the state’s long-range climate objectives (CARB 2008).

The Scoping Plan also identified local governments as essential partners in achieving California’s goals to reduce GHG emissions. Specifically, the Scoping Plan encouraged local governments to adopt a reduction goal for municipal operations, and for communities to reduce GHG emissions by approximately 15% from then levels (2008) by 2020. Many local governments developed community-scale local GHG reduction plans based on this Scoping Plan recommendation.

In 2014, CARB approved the first update to the Scoping Plan. The First Update to the Climate Change Scoping Plan: Building on the Framework (First Update) defined the state’s GHG emission reduction priorities for the next 5 years and laid the groundwork to start the transition to the post-2020 goals. The First Update concluded that California is on track to meet the 2020 target but recommended that a 2030 mid-term GHG reduction target be established to ensure a continuum of action to reduce emissions. CARB recalculated the state’s 1990 emissions level, using more recent GWPs identified by IPCC, from 427 MMT CO₂e to 431 MMT CO₂e (CARB 2014).

In December 2017, CARB adopted California’s 2017 Climate Change Scoping Plan (2017 Scoping Plan) for public review and comment (CARB 2017). The 2017 Scoping Plan builds on the successful framework established in the initial Scoping Plan and First Update while identifying new, technologically feasible and cost-effective strategies that will serve as the framework to achieve the 2030 GHG target as established by SB 32 and define the state’s climate change priorities to 2030 and beyond.

CARB adopted the 2022 Scoping Plan Update in December 2022, which outlines the state’s plan to reach carbon neutrality by 2045 or earlier, while also assessing the progress the state is making toward reducing GHG emissions by at least 40% below 1990 levels by 2030, as is required by SB 32 and laid out in the Second Update. The carbon neutrality goal requires CARB to expand proposed actions from only the reduction of anthropogenic sources of GHG emissions to also include those that capture and store carbon (e.g., through natural and working lands or mechanical technologies). The carbon reduction programs build on and accelerate those currently in place, including moving to zero-emission transportation; phasing out use of fossil gas use for heating homes and buildings; reducing use of chemicals and refrigerants with high GWP; providing communities with sustainable options for walking, biking, and public transit; displacement of fossil-fuel fired electrical generation through use of renewable energy alternatives (e.g., solar arrays and wind turbines); and scaling up new options such as green hydrogen (CARB 2022).

The 2022 Scoping Plan also emphasizes that there is no realistic path to carbon neutrality without carbon removal and sequestration, and that to achieve the state’s carbon neutrality goal, carbon reduction programs must be supplemented by strategies to remove and sequester carbon.

SB 605 and SB 1383. SB 605 (2014) required CARB to complete a comprehensive strategy to reduce emissions of short-lived climate pollutants in the state, and SB 1383 (2016) required CARB to approve and implement that strategy by January 1, 2018. The Short-Lived Climate Pollutants Reduction Strategy was approved by CARB in March 2017 and lays out a range of options to reduce short-lived climate pollutant emissions in California, including regulations, incentives, and other market-supporting activities. SB 1383 also establishes specific targets for the reduction of short-lived climate pollutants (40% below 2013 levels by 2030 for CH₄ and HFCs, and 50% below 2013 levels by 2030 for anthropogenic black carbon) and provides direction for reductions from dairy and livestock operations and landfills.

The Project’s potential to conflict with state climate change targets, including the 2017 and 2022 CARB Scoping Plans, was assessed qualitatively in Section 3.1.3.2.5. The Project would not conflict with the key strategies and measures of these plans.

Building Energy

Title 24, CCR Part 6. Title 24 of the California Code of Regulations (CCR) was established in 1978 and serves to enhance and regulate California’s building standards. Although not initially promulgated to reduce GHG emissions, Part 6 of Title 24 specifically established building energy efficiency standards that are designed to ensure new and existing buildings in California achieve energy efficiency and preserve outdoor and indoor environmental quality. The Building Standards Commission and CEC review these energy efficiency standards every few years and revise them if necessary (California Public Resources Code Section 25402[b][1]). The regulations receive input from members of industry and the public, with the goal of “reducing of wasteful, uneconomic, inefficient, or unnecessary consumption of energy” (California Public Resources Code Section 25402). These regulations are carefully scrutinized and analyzed for technological and economic feasibility (California Public Resources Code Section 25402[d]) and cost effectiveness (California Public Resources Code Sections 25402[b][2] and [b][3]). As a result, these standards save energy, increase electricity supply reliability, increase indoor comfort, avoid the need to construct new power plants, and help preserve the environment.

The 2022 Title 24 standards are the currently applicable building energy efficiency standards and became effective on January 1, 2023. The 2022 Title 24 standards improve upon the 2019 standards for new construction of, and additions and alterations to, residential and nonresidential buildings.

Title 24, CCR Part 11. In addition to CEC’s efforts, in 2008, the California Building Standards Commission adopted the nation’s first green building standards. The California Green Building Standards Code (Part 11 of Title 24) is commonly referred to as CALGreen and establishes minimum mandatory standards and voluntary standards pertaining to the planning and design of sustainable site development, energy efficiency (in excess of the California Energy Code requirements), water conservation, material conservation, and interior air quality. The CALGreen 2022 standards, which are the current standards, became effective January 1, 2023.

The Project would comply with all Title 24 mandatory requirements.

Renewable Energy and Energy Procurement

SB 1078. SB 1078 (2002) established the Renewables Portfolio Standard program, which requires an annual increase in renewable generation by the utilities.

SB 1368. SB 1368 (September 2006) required CEC to develop and adopt regulations for GHG emission performance standards for the long-term procurement of electricity by local publicly owned utilities. These standards must be consistent with the standards adopted by the California Public Utilities Commission.

SB X1-2. SB X1-2 expanded the Renewables Portfolio Standard by establishing a renewable energy target of 20% of the total electricity sold to retail customers in California per year by December 31, 2013, and 33% by December 31, 2020. Under the bill, a renewable electrical generation facility is one that uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation (30 megawatts or less), digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and that meets other specified requirements with respect to its location.

SB 350. SB 350 (October 2015, Clean Energy and Pollution Reduction Act) further expanded the Renewables Portfolio Standard by establishing a goal of 50% of the total electricity sold to retail customers in California per year by December 31, 2030. In addition, SB 350 included the goal to double the energy efficiency savings in electricity and natural gas final end uses (e.g., heating, cooling, lighting, or class of energy uses on which an energy efficiency program is focused) of retail customers through energy conservation and efficiency.

SB 100. SB 100 (2018) increased the standards set forth in SB 350, establishing that the following percentages of the total electricity sold to retail customers in California per year be secured from qualifying renewable energy sources: 44% by December 31, 2024; 52% by December 31, 2027; and 60% by December 31, 2030. SB 100 states that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of the retail sales of electricity to California. This bill requires that the achievement of 100% zero-carbon electricity resources not increase the carbon emissions elsewhere in the western grid and that the goal not be achieved through resource shuffling.

SB 1020. SB 1020 (September 2022) revises the standards from SB 100, requiring that the following percentage of retail sales of electricity to California end-use customers come from eligible renewable energy resources and zero-carbon resources: 90% by December 31, 2035; 95% by December 31, 2040; and 100% by December 31, 2045.

The Project will support increased usage of renewable electricity by allowing for a more reliable local electric grid, support the integration of additional intermittent renewable energy sources, such as wind and solar, and reduce the need to operate natural gas power plants.

Mobile Sources

State Vehicle Standards (AB 1493 and EO B-16-12). AB 1493 (July 2002) was enacted in response to the transportation sector accounting for more than half of California's CO₂ emissions. AB 1493 required CARB to set GHG emission standards for passenger vehicles, light-duty trucks, and other vehicles determined by CARB to be vehicles primarily used for noncommercial personal transportation in the state. AB 1493 required that CARB set GHG emission standards for motor vehicles manufactured in 2009 and all subsequent model years. CARB adopted the standards in September 2004. EO B-16-12 (March 2012) required that state entities under the governor's direction and control support and facilitate the rapid commercialization of zero-emission vehicles (ZEVs). It ordered CARB, CEC, the California Public Utilities Commission, and other relevant agencies to work with the Plug-In Electric Vehicle Collaborative and the California Fuel Cell Partnership to establish benchmarks to help achieve goals by 2015, 2020, and 2025. On a statewide basis, EO B-16-12 established a target reduction of GHG emissions from the transportation sector equaling 80% less than 1990 levels by 2050.

In March 2022, EPA reinstated California's authority under the federal Clean Air Act to implement its own GHG emission standards and ZEV sales mandate. EPA's action concludes its reconsideration of the SAFE-1 by finding that the actions taken under the previous administration as a part of SAFE-1 were decided in error and are now entirely rescinded.

EO S-1-07. Issued on January 18, 2007, EO S-1-07 sets a declining Low Carbon Fuel Standard for GHG emissions measured in CO₂e grams per unit of fuel energy sold in California. The initial target of the Low Carbon Fuel Standard was to reduce the carbon intensity of California passenger vehicle fuels by at least 10% by 2020. The Low Carbon Fuel Standard was subsequently amended in 2018 to require a 20% reduction in carbon intensity by 2030. This new requirement aligns with California's overall 2030 target, set by SB 32, of reducing climate changing emissions to 40% below 1990 levels by 2030. CARB has adopted implementing regulations for both the 10% and 20% carbon intensity reduction targets.

SB 375. SB 375 (2008) addresses GHG emissions associated with the transportation sector through regional transportation and sustainability plans. SB 375 required CARB to adopt regional GHG reduction targets for the automobile and light-truck sector for 2020 and 2035. SB 375 requires the state's 18 regional metropolitan planning organizations to prepare a Sustainable Communities Strategy as part of their Regional Transportation Plan that will achieve the GHG-reduction targets set by CARB. If a Sustainable Communities Strategy is unable to achieve the GHG reduction target, a metropolitan planning organization must prepare an Alternative Planning Strategy demonstrating how the GHG reduction target will be achieved through alternative development patterns, infrastructure, or additional transportation measures or policies.

Pursuant to California Government Code Section 65080(b)(2)(K), a Sustainable Communities Strategy does not regulate the use of land; supersede the land use authority of cities and counties; or require that a city's or county's land use policies and regulations, including those in a General Plan, be consistent with it. Nonetheless, SB 375 makes regional and local planning agencies responsible for developing those strategies as part of the federally required metropolitan transportation planning process and the state-mandated housing element process.

Advanced Clean Cars Program. The Advanced Clean Cars program (January 2012) is an emissions control program for model years 2015–2025. The program combines the control of smog- and soot-causing pollutants and GHG emissions into a single coordinated package. The package includes elements to reduce smog-forming pollution, reduce GHG emissions, promote the sale of clean cars (fuel efficient/electric), and provide the fuels for clean cars. To reduce GHG emissions, CARB, in conjunction with EPA and the National Highway Traffic Safety Administration,

adopted new GHG standards for model year 2017–2025 vehicles; the new standards are estimated to reduce GHG emissions by 34% in 2025. The ZEV program will act as the focused technology of the Advanced Clean Cars program by requiring manufacturers to produce increasing numbers of ZEVs and plug-in hybrid electric vehicles in the 2018–2025 model years.

The Advanced Clean Cars II program establishes the next set of low-emissions vehicle and ZEV requirements for model years after 2025, to contribute to meeting federal ambient air quality O₃ standards and California’s carbon neutrality standards (CARB 2024j). The Advanced Clean Cars II rulemaking package also considers technological feasibility, equity, and environmental, economic, and consumer impacts.

Advanced Clean Trucks Regulation. The purpose of the Advanced Clean Trucks Regulation (June 2020) is to accelerate the market for ZEVs in the medium- and heavy-duty truck sector and to reduce emissions of NO_x, PM_{2.5}, TACs, GHGs, and other criteria pollutants generated from on-road mobile sources (CARB 2024k). Requiring medium- and heavy-duty vehicles to transition to zero-emission technology will reduce health risks to people living in and visiting California and is needed to help California meet established near- and long-term air quality and climate mitigation targets.

EO N-79-20. EO N-79-20 (September 2020) requires CARB to develop (1) passenger vehicle and truck regulations requiring increasing volumes of new ZEVs sold in the state, with a target of 100% of in-state sales by 2035; (2) medium- and heavy-duty vehicle regulations requiring increasing volumes of new zero-emission trucks and buses sold and operated in the state, with the target of 100% of the fleet transitioning to ZEVs by 2045 everywhere feasible, and for all drayage trucks to be ZEVs by 2035; and (3) strategies, in coordination with other state agencies, EPA, and local air districts, to achieve 100% zero emissions from off-road vehicles and equipment operations in the state by 2035.

EO B-16-12. EO B-16-12 (2012) directs state entities under the governor’s direction and control to support and facilitate development and distribution of ZEVs. On a statewide basis, EO B-16-12 also establishes a GHG emissions reduction target from the transportation sector equaling 80% less than 1990 levels by 2050.

The Project would create minimal trips during operation, and emissions associated with the Project’s mobile sources were quantified in Section 3.1.3.2.5. The Project would not obstruct or interfere with the implementation of mobile source regulations for the purpose of reducing GHG emissions.

Solid Waste

AB 939, AB 341, AB 1826, and SB 1383. In 1989, AB 939, known as the Integrated Waste Management Act (California Public Resources Code Section 40000 et seq.), was passed because of the increase in waste stream and decrease in landfill capacity. The statute established the California Integrated Waste Management Board, which oversees a disposal reporting system. AB 939 mandated a reduction in waste disposal in which jurisdictions were required to meet diversion goals of all solid waste through source reduction, recycling, and composting activities of 25% by 1995 and 50% by 2000.

AB 341 (Chapter 476, Statutes of 2011 [Chesbro]) amended the California Integrated Waste Management Act of 1989 to include a provision declaring that it is the policy goal of the state that not less than 75% of solid waste generated be source-reduced, recycled, or composted by 2020 and annually thereafter. CalRecycle identified five priority strategies that will assist the state in reaching the 75% goal by 2020, legislative and regulatory recommendations, and an evaluation of program effectiveness (CalRecycle 2015).

AB 1826 (Chapter 727, Statutes of 2014, effective 2016) required businesses to recycle their organic waste (i.e., food waste, green waste, landscape and pruning waste, nonhazardous wood waste, and food-soiled paper waste mixed in with food waste) depending on the amount of waste they generate per week. This law also requires local jurisdictions across the state to implement an organic waste recycling program to divert organic waste generated by businesses, including multifamily residential dwellings that consist of five or more units.

SB 1383 (Chapter 395, Statutes of 2016) establishes targets to achieve a 50% reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75% reduction by 2025. SB 1383 granted CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and established an additional target that not less than 20% of currently disposed edible food is recovered for human consumption by 2025 (CalRecycle 2020).

Emissions associated with the Project's solid waste consumption were quantified in Section 3.1.3.2.5. The Project would not obstruct or interfere with the implementation of solid waste source regulations for the purpose of reducing GHG emissions.

Water

EO B-29-15. In response to the ongoing drought in California, EO B-29-15 (April 2015) set a goal of achieving a statewide reduction in potable urban water usage of 25% relative to water use in 2013. In response to EO B-29-15, the California Department of Water Resources modified and adopted a revised version of the Model Water Efficient Landscape Ordinance that, among other changes, significantly increased the requirements for landscape water use efficiency and broadened its applicability to include new development projects with smaller landscape areas.

Emissions associated with the Project's water consumption were quantified in Section 3.1.3.2.5. The Project would not obstruct or interfere with the implementation of water source regulations for the purpose of reducing GHG emissions.

3.1.5.3 Local LORS

3.1.5.3.1 Criteria Air Pollutants

AVAQMD is the regional agency responsible for the regulation and enforcement of federal, state, and local air pollution control regulations in the Los Angeles County portion of the MDAB, where the Project is located. AVAQMD operates monitoring stations in the MDAB, develops rules and regulations for stationary sources and equipment, prepares emissions inventory and air quality management planning documents, and conducts source testing and inspections. AVAQMD's air quality management plans include control measures and strategies to be implemented to attain the CAAQS and NAAQS in the MDAB. AVAQMD then implements these control measures as regulations to control or reduce criteria pollutant emissions from stationary sources or equipment. AVAQMD's most recent air quality plan is the Federal 70 ppb Ozone Attainment Plan (Western Mojave Desert Nonattainment Area) (O₃ Attainment Plan) (AVAQMD 2023).

Applicable Rules. Emissions that will result from mobile, area, and stationary sources during construction and operation of the Project are subject to the rules and regulations of AVAQMD. AVAQMD rules applicable to the Project may include, but are not limited to, the following:

- **Rule 201 – Permit to Construct.** This rule requires that a person not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization.
- **Rule 203 – Permit to Operate.** This rule requires that a person not operate or use any equipment, the use of which may cause the issuance of air contaminants, or the use of which may reduce or control the issuance of air contaminants, without first obtaining a written permit to operate.
- **Rule 219 – Equipment Not Requiring a Permit:** The rule identifies equipment exempt from permit requirements of District Rules 201 and 203. District permit required for internal combustion engines with manufacturer’s maximum continuous rating greater than or equal to 50 brake horsepower.
- **Rule 401 – Visible Emissions:** This rule establishes the limit for visible emissions from stationary sources.
- **Rule 402 – Nuisance:** This rule prohibits the discharge of air contaminants or other material that cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or that endanger the comfort, repose, health, or safety of any such persons or the public, or that cause, or have a natural tendency to cause, injury or damage to business or property.
- **Rule 403 – Fugitive Dust:** Rule 403 includes requirements for a Dust Control Plan, signage, and fencing, as well as surface watering and stabilization with chemicals, gravel, and asphaltic pavement to minimize visible fugitive dust from vehicular travel, earthwork, and wind erosion.
- **Rule 404 – Particulate Matter - Concentration.** The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission concentration limit.
- **Rule 431.2 – Sulfur Content of Liquid Fuels.** The purpose of this rule is to limit the sulfur content in diesel and other liquid fuels for the purpose both of reducing the formation of SO_x and particulates during combustion and of enabling the use of add-on control devices for diesel-fueled internal combustion engines. The rule applies to all refiners, importers, and other fuel suppliers such as distributors, marketers, and retailers, as well as to users of diesel, low-sulfur diesel, and other liquid fuels for stationary-source applications in the AVAQMD. The rule also affects diesel fuel supplied for mobile source applications.
- **Rule 442 – Usage of Solvents:** The purpose of this rule is to reduce VOC emissions from VOC-containing materials or equipment that is not subject to limits of any rule found in District Regulation XI – Source Specific Standards.
- **Rule 900 – Federal New Source Performance Standards (NSPS).** This rule adopts by reference the rules, standards, criteria and requirements of Part 60, Chapter 1, Title 40, Code of Federal Regulations, which apply to all new sources of air contaminants or modifications to existing sources for identified category types subject to NSPS.
- **Rule 1000 – National Emission Standards for Hazardous Air Pollutants (NESHAPs).** This rule adopts by reference the NESHAP provisions of Part 61, Chapter 1, Title 40, Code of Federal Regulations.
- **Rule 1110.2 – Emissions from Stationary, Non-Road and Portable Internal Combustion Engines.** The purpose of this rule is to limit emissions of NO_x, VOCs, and CO from internal combustion engines over 50 brake horsepower.
- **Rule 1113 – Architectural Coatings.** This rule requires manufacturers, distributors, and end users of architectural and industrial maintenance coatings to reduce VOC emissions from the use of these coatings, primarily by placing limits on the VOC content of various coating categories.

The Project would be required to comply with all applicable AVAQMD rules and regulations.

3.1.5.3.2 Greenhouse Gas Emissions

2045 Los Angeles County Climate Action Plan

The 2045 CAP was adopted in April 2024 and builds on previous climate action work from the 2020 CCAP, adopted in October 2015 as a subcomponent of the Air Quality Element of the Los Angeles County General Plan (County of Los Angeles 2015). The 2045 CAP is an update to the 2020 CCAP, and it sets new GHG emissions reduction targets beyond the 2020 timeframe that are consistent with state goals, including AB 32, SB 32, and EO B-30-15 (County of Los Angeles 2024). The 2045 CAP includes 25 measures to reduce GHG emissions within the unincorporated portion of Los Angeles County. The 2045 CAP includes the following strategies to reduce GHG emissions:

- **Strategy 1:** Decarbonize the Energy Supply
- **Strategy 2:** Increase Densities and Diversity of Land Uses Near Transit
- **Strategy 3:** Reduce Single-Occupancy Vehicle Trips
- **Strategy 4:** Institutionalize Low-Carbon Transportation
- **Strategy 5:** Decarbonize Buildings
- **Strategy 6:** Improve Efficiency of Existing Building Energy Use
- **Strategy 7:** Conserve Water
- **Strategy 8:** Minimize Waste and Recover Energy and Materials from the Waste Stream
- **Strategy 9:** Conserve and Connect Wildlands and Working Lands
- **Strategy 10:** Sequester Carbon and Implement Sustainable Agriculture

The Project’s potential to conflict with County’s CAP was assessed qualitatively in Section 3.1.3.2.5. The Project would not conflict with the key strategies and measures of the CAP.

3.1.6 Agency Jurisdiction and Contacts

Table 3.1-20 contains contact information for agencies related to air quality.

Table 3.1-20. Permits and Agency Contacts

Issue/ Approval	Agency	Contact	Applicability
Public exposure to air pollutants	Antelope Valley Air Quality Management District	Taylor Morais, Air Quality Engineer Antelope Valley Air Quality Management District tmorais@avaqmd.ca.gov (661) 723-8070, ext. 24	Authority to Construct/ Permit to Operate for emergency generators

3.1.7 Permit Requirements and Schedules

Pursuant to Assembly Bill 205 Subsection 25545.1(b)(1), CEC retains exclusive authority over permitting and supersedes any applicable statute, ordinance, or regulation of a local air quality management district. The applicant

and CEC will collaborate with AVAQMD on review of this Opt-In Application to ensure compliance with AVAQMD rules and regulations. AVAQMD will provide an authority to construct (ATC), which will contain proposed permit conditions for the Project stationary sources that AVAQMD would impose but for CEC's in-lieu authority over the Project. These AVAQMD conditions will be reflected in CEC's Final Decision.

3.1.8 References

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Attachment 2

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Prairie Song Reliability Project Detailed Report

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1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	Prairie Song Reliability Project
Construction Start Date	3/1/2027
Operational Year	2029
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	4.50
Precipitation (days)	13.0
Location	34.48412492724056, -118.14298967079657
County	Los Angeles-Mojave Desert
City	Unincorporated
Air District	Antelope Valley AQMD
Air Basin	Mojave Desert
TAZ	3626
EDFZ	7
Electric Utility	Southern California Edison
Gas Utility	Southern California Gas
App Version	2022.1.1.30

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
General Light Industry	2.40	1000sqft	115	2,400	100,809	—	—	O&M buildings - 1,200 SF each

Parking Lot	16.0	Space	0.14	6,400	0.00	—	—	Parking Lot - stone surfaced
Other Asphalt Surfaces	7.80	Acre	7.80	0.00	0.00	—	—	Internal roads

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-5	Use Advanced Engine Tiers
Construction	C-9	Use Dust Suppressants
Construction	C-10-B	Water Active Demolition Sites
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	11.7	9.65	128	253	0.92	2.61	66.9	69.5	2.54	14.9	17.4	—	140,899	140,899	1.59	19.8	306	147,121
Mit.	9.05	7.54	114	265	0.92	1.98	51.4	53.3	1.97	13.3	15.3	—	140,899	140,899	1.59	19.8	306	147,121
% Reduced	23%	22%	10%	-4%	—	24%	23%	23%	23%	10%	12%	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	9.17	7.49	53.2	150	0.15	1.66	36.5	38.2	1.53	7.62	9.15	—	40,398	40,398	1.30	2.02	2.68	41,035
Mit.	6.97	5.77	36.8	159	0.15	0.49	27.8	28.3	0.47	6.59	7.07	—	40,398	40,398	1.30	2.02	2.68	41,035

% Reduced	24%	23%	31%	-6%	—	70%	24%	26%	69%	13%	23%	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	5.08	4.14	45.5	94.4	0.29	0.88	26.3	27.2	0.86	5.84	6.70	—	47,526	47,526	0.76	6.31	47.0	49,463
Mit.	4.04	3.33	39.4	98.7	0.29	0.61	20.0	20.6	0.61	5.21	5.82	—	47,526	47,526	0.76	6.31	47.0	49,463
% Reduced	20%	20%	13%	-5%	—	31%	24%	24%	29%	11%	13%	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.93	0.75	8.30	17.2	0.05	0.16	4.80	4.96	0.16	1.07	1.22	—	7,868	7,868	0.13	1.05	7.79	8,189
Mit.	0.74	0.61	7.19	18.0	0.05	0.11	3.65	3.76	0.11	0.95	1.06	—	7,868	7,868	0.13	1.05	7.79	8,189
% Reduced	20%	20%	13%	-5%	—	31%	24%	24%	29%	11%	13%	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	7.59	6.62	128	128	0.92	2.61	66.9	69.5	2.54	14.9	17.4	—	140,899	140,899	0.70	19.8	306	147,121
2028	11.7	9.65	63.0	253	0.17	1.42	34.3	35.7	1.32	8.13	9.45	—	52,507	52,507	1.59	2.31	127	53,360
2029	2.18	1.75	4.37	71.2	< 0.005	< 0.005	12.9	12.9	< 0.005	3.04	3.04	—	13,547	13,547	0.44	0.49	41.6	13,744
2050	3.16	2.71	18.9	54.0	0.11	0.44	14.4	14.9	0.38	3.45	3.82	—	22,397	22,397	0.32	0.70	2.82	22,617
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	7.39	6.11	51.0	94.6	0.12	1.66	36.5	38.2	1.53	7.62	9.15	—	27,374	27,374	0.77	1.69	1.72	27,897
2028	9.17	7.49	53.2	150	0.15	1.15	27.8	28.9	1.07	6.59	7.66	—	40,398	40,398	1.30	2.02	2.68	41,035
2029	2.07	1.64	4.85	45.3	< 0.005	< 0.005	12.9	12.9	< 0.005	3.04	3.04	—	12,086	12,086	0.05	0.49	1.08	12,234

2050	3.14	2.69	19.2	42.6	0.11	0.44	14.4	14.9	0.38	3.45	3.82	—	21,192	21,192	0.32	0.70	0.07	21,409
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	2.93	2.46	45.5	49.9	0.29	0.88	26.3	27.2	0.86	5.84	6.70	—	47,526	47,526	0.36	6.31	47.0	49,463
2028	5.08	4.14	27.6	94.4	0.07	0.56	17.4	18.0	0.51	4.13	4.65	—	23,963	23,963	0.76	1.17	28.0	24,360
2029	0.37	0.29	0.93	9.14	< 0.005	< 0.005	2.28	2.29	< 0.005	0.54	0.54	—	2,212	2,212	0.01	0.09	3.20	2,241
2050	2.25	1.92	13.7	32.1	0.08	0.31	10.2	10.5	0.27	2.44	2.70	—	15,292	15,292	0.22	0.50	0.87	15,447
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	0.53	0.45	8.30	9.10	0.05	0.16	4.80	4.96	0.16	1.07	1.22	—	7,868	7,868	0.06	1.05	7.79	8,189
2028	0.93	0.75	5.04	17.2	0.01	0.10	3.18	3.28	0.09	0.75	0.85	—	3,967	3,967	0.13	0.19	4.64	4,033
2029	0.07	0.05	0.17	1.67	< 0.005	< 0.005	0.42	0.42	< 0.005	0.10	0.10	—	366	366	< 0.005	0.01	0.53	371
2050	0.41	0.35	2.50	5.85	0.01	0.06	1.86	1.92	0.05	0.44	0.49	—	2,532	2,532	0.04	0.08	0.14	2,557

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	5.99	5.33	114	130	0.92	1.98	51.4	53.3	1.97	13.3	15.3	—	140,899	140,899	0.70	19.8	306	147,121
2028	9.05	7.54	42.8	265	0.17	0.61	34.3	34.9	0.58	8.13	8.71	—	52,507	52,507	1.59	2.31	127	53,360
2029	2.18	1.75	4.37	71.2	< 0.005	< 0.005	12.9	12.9	< 0.005	3.04	3.04	—	13,547	13,547	0.44	0.49	41.6	13,744
2050	1.48	1.39	11.6	70.9	0.11	0.22	14.4	14.7	0.18	3.45	3.63	—	22,397	22,397	0.32	0.70	2.82	22,617
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	3.25	2.75	18.9	94.6	0.12	0.27	20.8	21.1	0.27	6.04	6.31	—	27,374	27,374	0.77	1.69	1.72	27,897
2028	6.97	5.77	36.8	159	0.15	0.49	27.8	28.3	0.47	6.59	7.07	—	40,398	40,398	1.30	2.02	2.68	41,035
2029	2.07	1.64	4.85	45.3	< 0.005	< 0.005	12.9	12.9	< 0.005	3.04	3.04	—	12,086	12,086	0.05	0.49	1.08	12,234
2050	1.46	1.37	11.9	59.5	0.11	0.22	14.4	14.7	0.18	3.45	3.63	—	21,192	21,192	0.32	0.70	0.07	21,409

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	2.15	1.83	39.4	50.7	0.29	0.61	20.0	20.6	0.61	5.21	5.82	—	47,526	47,526	0.36	6.31	47.0	49,463
2028	4.04	3.33	19.7	98.7	0.07	0.24	17.4	17.7	0.23	4.13	4.36	—	23,963	23,963	0.76	1.17	28.0	24,360
2029	0.37	0.29	0.93	9.14	< 0.005	< 0.005	2.28	2.29	< 0.005	0.54	0.54	—	2,212	2,212	0.01	0.09	3.20	2,241
2050	1.05	0.99	8.48	44.1	0.08	0.15	10.2	10.4	0.13	2.44	2.56	—	15,292	15,292	0.22	0.50	0.87	15,447
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2027	0.39	0.33	7.19	9.25	0.05	0.11	3.65	3.76	0.11	0.95	1.06	—	7,868	7,868	0.06	1.05	7.79	8,189
2028	0.74	0.61	3.59	18.0	0.01	0.04	3.18	3.23	0.04	0.75	0.80	—	3,967	3,967	0.13	0.19	4.64	4,033
2029	0.07	0.05	0.17	1.67	< 0.005	< 0.005	0.42	0.42	< 0.005	0.10	0.10	—	366	366	< 0.005	0.01	0.53	371
2050	0.19	0.18	1.55	8.04	0.01	0.03	1.86	1.89	0.02	0.44	0.47	—	2,532	2,532	0.04	0.08	0.14	2,557

2.4. Operations Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.84	0.74	3.52	6.37	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,831	65,834	6.46	0.77	1.60	66,227
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.76	0.66	3.53	5.52	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,791	65,793	6.46	0.77	0.24	66,185
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.28	0.26	0.16	1.46	< 0.005	< 0.005	0.32	0.32	< 0.005	0.08	0.08	2.67	64,571	64,574	6.41	0.76	0.68	64,961
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.05	0.05	0.03	0.27	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	0.44	10,691	10,691	1.06	0.13	0.11	10,755

2.5. Operations Emissions by Sector, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Sector	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Area	0.18	0.17	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Total	0.84	0.74	3.52	6.37	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,831	65,834	6.46	0.77	1.60	66,227
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Area	0.11	0.11	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Total	0.76	0.66	3.53	5.52	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,791	65,793	6.46	0.77	0.24	66,185
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.13	0.12	0.15	1.26	< 0.005	< 0.005	0.32	0.32	< 0.005	0.08	0.08	—	328	328	0.01	0.01	0.47	333

Area	0.14	0.14	< 0.005	0.19	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.78	0.78	< 0.005	< 0.005	—	0.78
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	3.13	3.13	< 0.005	< 0.005	—	3.14
Total	0.28	0.26	0.16	1.46	< 0.005	< 0.005	0.32	0.32	< 0.005	0.08	0.08	2.67	64,571	64,574	6.41	0.76	0.68	64,961
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2
Area	0.03	0.03	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	10,634	10,634	1.01	0.12	—	10,696
Water	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29
Waste	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03
Off-Road	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.52	0.52	< 0.005	< 0.005	—	0.52
Total	0.05	0.05	0.03	0.27	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	0.44	10,691	10,691	1.06	0.13	0.11	10,755

2.6. Operations Emissions by Sector, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Sector	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Area	0.18	0.17	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8

Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Total	0.84	0.74	3.52	6.37	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,831	65,834	6.46	0.77	1.60	66,227
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Area	0.11	0.11	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Total	0.76	0.66	3.53	5.52	0.01	0.14	0.41	0.55	0.13	0.10	0.23	2.67	65,791	65,793	6.46	0.77	0.24	66,185
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.13	0.12	0.15	1.26	< 0.005	< 0.005	0.32	0.32	< 0.005	0.08	0.08	—	328	328	0.01	0.01	0.47	333
Area	0.14	0.14	< 0.005	0.19	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.78	0.78	< 0.005	< 0.005	—	0.78
Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	64,230	64,230	6.12	0.74	—	64,604
Water	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Waste	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Off-Road	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	3.13	3.13	< 0.005	< 0.005	—	3.14
Total	0.28	0.26	0.16	1.46	< 0.005	< 0.005	0.32	0.32	< 0.005	0.08	0.08	2.67	64,571	64,574	6.41	0.76	0.68	64,961
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mobile	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2
Area	0.03	0.03	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13

Energy	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	10,634	10,634	1.01	0.12	—	10,696
Water	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29
Waste	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93
Refrig.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03
Off-Road	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.52	0.52	< 0.005	< 0.005	—	0.52
Total	0.05	0.05	0.03	0.27	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	0.44	10,691	10,691	1.06	0.13	0.11	10,755

3. Construction Emissions Details

3.1. Decommissioning (2050) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.71	2.27	13.8	21.7	0.07	0.37	—	0.37	0.34	—	0.34	—	7,256	7,256	0.29	0.06	—	7,281
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.68	0.62	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	104	104	< 0.005	0.02	< 0.005	109
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.71	2.27	13.8	21.7	0.07	0.37	—	0.37	0.34	—	0.34	—	7,256	7,256	0.29	0.06	—	7,281

Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.74	0.64	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	107	107	< 0.005	0.02	< 0.005	112
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.93	1.62	9.85	15.5	0.05	0.26	—	0.26	0.24	—	0.24	—	5,169	5,169	0.21	0.04	—	5,186
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.03	0.03	0.50	0.45	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	75.0	75.0	< 0.005	0.01	< 0.005	78.5
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.35	0.30	1.80	2.82	0.01	0.05	—	0.05	0.04	—	0.04	—	856	856	0.03	0.01	—	859
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.09	0.08	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	12.4	12.4	< 0.005	< 0.005	< 0.005	13.0
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.33	0.33	0.88	31.1	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,043	11,043	0.02	0.02	2.08	11,051
Vendor	0.01	0.01	0.23	0.10	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	222	222	< 0.005	0.03	< 0.005	233
Hauling	0.06	0.06	3.30	0.46	0.04	0.07	1.50	1.57	0.04	0.41	0.45	—	3,771	3,771	< 0.005	0.58	0.73	3,943
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.32	0.31	0.89	19.7	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	9,834	9,834	0.02	0.02	0.05	9,839
Vendor	0.01	0.01	0.25	0.11	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	223	223	< 0.005	0.03	< 0.005	233

Hauling	0.06	0.05	3.50	0.47	0.04	0.07	1.50	1.57	0.04	0.41	0.45	—	3,772	3,772	< 0.005	0.58	0.02	3,944
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.23	0.23	0.63	15.7	0.00	0.00	9.06	9.06	0.00	2.12	2.12	—	7,203	7,203	0.01	0.01	0.64	7,207
Vendor	0.01	0.01	0.17	0.08	< 0.005	< 0.005	0.07	0.07	< 0.005	0.02	0.02	—	159	159	< 0.005	0.02	< 0.005	166
Hauling	0.04	0.04	2.51	0.33	0.03	0.05	1.06	1.11	0.03	0.29	0.32	—	2,686	2,686	< 0.005	0.41	0.22	2,809
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.04	0.12	2.87	0.00	0.00	1.65	1.65	0.00	0.39	0.39	—	1,193	1,193	< 0.005	< 0.005	0.11	1,193
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	26.3	26.3	< 0.005	< 0.005	< 0.005	27.5
Hauling	0.01	0.01	0.46	0.06	< 0.005	0.01	0.19	0.20	< 0.005	0.05	0.06	—	445	445	< 0.005	0.07	0.04	465

3.2. Decommissioning (2050) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.03	0.96	6.53	38.6	0.07	0.14	—	0.14	0.14	—	0.14	—	7,256	7,256	0.29	0.06	—	7,281
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.68	0.62	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	104	104	< 0.005	0.02	< 0.005	109
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.03	0.96	6.53	38.6	0.07	0.14	—	0.14	0.14	—	0.14	—	7,256	7,256	0.29	0.06	—	7,281

Demoliti	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.74	0.64	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	107	107	< 0.005	0.02	< 0.005	112
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.73	0.68	4.65	27.5	0.05	0.10	—	0.10	0.10	—	0.10	—	5,169	5,169	0.21	0.04	—	5,186
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.03	0.03	0.50	0.45	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	75.0	75.0	< 0.005	0.01	< 0.005	78.5
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.12	0.85	5.01	0.01	0.02	—	0.02	0.02	—	0.02	—	856	856	0.03	0.01	—	859
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.09	0.08	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	12.4	12.4	< 0.005	< 0.005	< 0.005	13.0
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.33	0.33	0.88	31.1	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,043	11,043	0.02	0.02	2.08	11,051
Vendor	0.01	0.01	0.23	0.10	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	222	222	< 0.005	0.03	< 0.005	233
Hauling	0.06	0.06	3.30	0.46	0.04	0.07	1.50	1.57	0.04	0.41	0.45	—	3,771	3,771	< 0.005	0.58	0.73	3,943
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.32	0.31	0.89	19.7	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	9,834	9,834	0.02	0.02	0.05	9,839
Vendor	0.01	0.01	0.25	0.11	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	223	223	< 0.005	0.03	< 0.005	233

Hauling	0.06	0.05	3.50	0.47	0.04	0.07	1.50	1.57	0.04	0.41	0.45	—	3,772	3,772	< 0.005	0.58	0.02	3,944
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.23	0.23	0.63	15.7	0.00	0.00	9.06	9.06	0.00	2.12	2.12	—	7,203	7,203	0.01	0.01	0.64	7,207
Vendor	0.01	0.01	0.17	0.08	< 0.005	< 0.005	0.07	0.07	< 0.005	0.02	0.02	—	159	159	< 0.005	0.02	< 0.005	166
Hauling	0.04	0.04	2.51	0.33	0.03	0.05	1.06	1.11	0.03	0.29	0.32	—	2,686	2,686	< 0.005	0.41	0.22	2,809
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.04	0.12	2.87	0.00	0.00	1.65	1.65	0.00	0.39	0.39	—	1,193	1,193	< 0.005	< 0.005	0.11	1,193
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	26.3	26.3	< 0.005	< 0.005	< 0.005	27.5
Hauling	0.01	0.01	0.46	0.06	< 0.005	0.01	0.19	0.20	< 0.005	0.05	0.06	—	445	445	< 0.005	0.07	0.04	465

3.3. Demolition (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.86	1.56	14.3	15.7	0.03	0.55	—	0.55	0.51	—	0.51	—	2,754	2,754	0.11	0.02	—	2,764
Demolition	—	—	—	—	—	—	0.48	0.48	—	0.07	0.07	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road	0.05	0.04	0.39	0.43	< 0.005	0.02	—	0.02	0.01	—	0.01	—	75.5	75.5	< 0.005	< 0.005	—	75.7
Demolition	—	—	—	—	—	—	0.01	0.01	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.07	0.08	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	12.5	12.5	< 0.005	< 0.005	—	12.5
Demolition	—	—	—	—	—	—	< 0.005	< 0.005	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.09	0.07	0.19	2.10	0.00	0.00	0.53	0.53	0.00	0.12	0.12	—	498	498	0.02	0.02	0.05	504
Vendor	< 0.005	< 0.005	0.12	0.04	< 0.005	< 0.005	0.03	0.04	< 0.005	0.01	0.01	—	115	115	< 0.005	0.02	0.01	121
Hauling	0.02	0.01	1.23	0.15	0.01	0.02	0.42	0.44	0.02	0.11	0.13	—	1,391	1,391	< 0.005	0.22	0.07	1,457
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.07	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	14.0	14.0	< 0.005	< 0.005	0.02	14.2
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.16	3.16	< 0.005	< 0.005	< 0.005	3.30
Hauling	< 0.005	< 0.005	0.03	< 0.005	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	38.1	38.1	< 0.005	0.01	0.03	39.9
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.01	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	2.33	2.33	< 0.005	< 0.005	< 0.005	2.36
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	0.52	0.52	< 0.005	< 0.005	< 0.005	0.55

Hauling	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	6.31	6.31	< 0.005	< 0.005	0.01	6.61

3.4. Demolition (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.48	0.44	3.02	15.8	0.03	0.08	—	0.08	0.08	—	0.08	—	2,754	2,754	0.11	0.02	—	2,764
Demolition	—	—	—	—	—	—	0.31	0.31	—	0.05	0.05	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.08	0.43	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	75.5	75.5	< 0.005	< 0.005	—	75.7
Demolition	—	—	—	—	—	—	0.01	0.01	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	< 0.005	< 0.005	0.02	0.08	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	12.5	12.5	< 0.005	< 0.005	—	12.5

Demoliti	—	—	—	—	—	—	< 0.005	< 0.005	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.09	0.07	0.19	2.10	0.00	0.00	0.53	0.53	0.00	0.12	0.12	—	498	498	0.02	0.02	0.05	504
Vendor	< 0.005	< 0.005	0.12	0.04	< 0.005	< 0.005	0.03	0.04	< 0.005	0.01	0.01	—	115	115	< 0.005	0.02	0.01	121
Hauling	0.02	0.01	1.23	0.15	0.01	0.02	0.42	0.44	0.02	0.11	0.13	—	1,391	1,391	< 0.005	0.22	0.07	1,457
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.07	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	14.0	14.0	< 0.005	< 0.005	0.02	14.2
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.16	3.16	< 0.005	< 0.005	< 0.005	3.30
Hauling	< 0.005	< 0.005	0.03	< 0.005	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	38.1	38.1	< 0.005	0.01	0.03	39.9
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.01	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	2.33	2.33	< 0.005	< 0.005	< 0.005	2.36
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	0.52	0.52	< 0.005	< 0.005	< 0.005	0.55
Hauling	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	6.31	6.31	< 0.005	< 0.005	0.01	6.61

3.5. Site Preparation (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road	3.20	2.69	24.5	24.5	0.04	1.01	—	1.01	0.92	—	0.92	—	4,527	4,527	0.18	0.04	—	4,543
Dust From Material Movement	—	—	—	—	—	—	4.26	4.26	—	2.19	2.19	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	16.2	16.2	< 0.005	1.62	1.62	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.20	2.69	24.5	24.5	0.04	1.01	—	1.01	0.92	—	0.92	—	4,527	4,527	0.18	0.04	—	4,543
Dust From Material Movement	—	—	—	—	—	—	4.26	4.26	—	2.19	2.19	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.76	0.57	< 0.005	< 0.005	16.2	16.2	< 0.005	1.62	1.62	—	120	120	< 0.005	0.02	< 0.005	126
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.30	0.25	2.28	2.28	< 0.005	0.09	—	0.09	0.09	—	0.09	—	422	422	0.02	< 0.005	—	423
Dust From Material Movement	—	—	—	—	—	—	0.40	0.40	—	0.20	0.20	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.07	0.05	< 0.005	< 0.005	1.45	1.45	< 0.005	0.15	0.15	—	11.0	11.0	< 0.005	< 0.005	< 0.005	11.6
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.05	0.42	0.42	< 0.005	0.02	—	0.02	0.02	—	0.02	—	69.8	69.8	< 0.005	< 0.005	—	70.1

Dust From Material Movement	—	—	—	—	—	—	0.07	0.07	—	0.04	0.04	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	0.27	0.27	< 0.005	0.03	0.03	—	1.83	1.83	< 0.005	< 0.005	< 0.005	1.92
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	0.07	0.06	4.70	0.58	0.04	0.08	1.67	1.75	0.08	0.46	0.54	—	5,563	5,563	< 0.005	0.88	11.6	5,837
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.10	1.68	4.59	50.8	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	12,057	12,057	0.45	0.42	1.26	12,195
Vendor	0.01	0.01	0.36	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.02	362
Hauling	0.06	0.06	4.92	0.59	0.04	0.08	1.67	1.75	0.08	0.46	0.54	—	5,564	5,564	< 0.005	0.88	0.30	5,827
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.16	0.47	5.38	0.00	0.00	1.18	1.18	0.00	0.28	0.28	—	1,156	1,156	0.04	0.04	1.96	1,170
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	32.3	32.3	< 0.005	< 0.005	0.03	33.7
Hauling	0.01	0.01	0.46	0.05	< 0.005	0.01	0.15	0.16	0.01	0.04	0.05	—	518	518	< 0.005	0.08	0.46	543
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.08	0.98	0.00	0.00	0.22	0.22	0.00	0.05	0.05	—	191	191	0.01	0.01	0.32	194
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	5.34	5.34	< 0.005	< 0.005	0.01	5.58
Hauling	< 0.005	< 0.005	0.08	0.01	< 0.005	< 0.005	0.03	0.03	< 0.005	0.01	0.01	—	85.8	85.8	< 0.005	0.01	0.08	89.9

3.6. Site Preparation (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.45	0.45	3.70	24.4	0.04	0.08	—	0.08	0.08	—	0.08	—	4,527	4,527	0.18	0.04	—	4,543
Dust From Material Movement	—	—	—	—	—	—	4.26	4.26	—	2.19	2.19	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.66	0.66	< 0.005	0.07	0.07	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.45	0.45	3.70	24.4	0.04	0.08	—	0.08	0.08	—	0.08	—	4,527	4,527	0.18	0.04	—	4,543
Dust From Material Movement	—	—	—	—	—	—	4.26	4.26	—	2.19	2.19	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.76	0.57	< 0.005	< 0.005	0.66	0.66	< 0.005	0.07	0.07	—	120	120	< 0.005	0.02	< 0.005	126
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.04	0.04	0.34	2.27	< 0.005	0.01	—	0.01	0.01	—	0.01	—	422	422	0.02	< 0.005	—	423
Dust From Material Movement	—	—	—	—	—	—	0.40	0.40	—	0.20	0.20	—	—	—	—	—	—	—

Onsite truck	< 0.005	< 0.005	0.07	0.05	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.01	—	11.0	11.0	< 0.005	< 0.005	< 0.005	11.6
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.06	0.41	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	69.8	69.8	< 0.005	< 0.005	—	70.1
Dust From Material Movement	—	—	—	—	—	—	0.07	0.07	—	0.04	0.04	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	1.83	1.83	< 0.005	< 0.005	< 0.005	1.92
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	0.07	0.06	4.70	0.58	0.04	0.08	1.67	1.75	0.08	0.46	0.54	—	5,563	5,563	< 0.005	0.88	11.6	5,837
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.10	1.68	4.59	50.8	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	12,057	12,057	0.45	0.42	1.26	12,195
Vendor	0.01	0.01	0.36	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.02	362
Hauling	0.06	0.06	4.92	0.59	0.04	0.08	1.67	1.75	0.08	0.46	0.54	—	5,564	5,564	< 0.005	0.88	0.30	5,827
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.16	0.47	5.38	0.00	0.00	1.18	1.18	0.00	0.28	0.28	—	1,156	1,156	0.04	0.04	1.96	1,170
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	32.3	32.3	< 0.005	< 0.005	0.03	33.7
Hauling	0.01	0.01	0.46	0.05	< 0.005	0.01	0.15	0.16	0.01	0.04	0.05	—	518	518	< 0.005	0.08	0.46	543
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.08	0.98	0.00	0.00	0.22	0.22	0.00	0.05	0.05	—	191	191	0.01	0.01	0.32	194

Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	5.34	5.34	< 0.005	< 0.005	0.01	5.58
Hauling	< 0.005	< 0.005	0.08	0.01	< 0.005	< 0.005	0.03	0.03	< 0.005	0.01	0.01	—	85.8	85.8	< 0.005	0.01	0.08	89.9

3.7. Substation Site Preparation (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.60	1.35	12.3	12.3	0.02	0.50	—	0.50	0.46	—	0.46	—	2,264	2,264	0.09	0.02	—	2,271
Dust From Material Movement	—	—	—	—	—	—	2.13	2.13	—	1.09	1.09	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	16.2	16.2	< 0.005	1.62	1.62	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.04	0.37	0.37	< 0.005	0.02	—	0.02	0.01	—	0.01	—	68.2	68.2	< 0.005	< 0.005	—	68.5
Dust From Material Movement	—	—	—	—	—	—	0.06	0.06	—	0.03	0.03	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	0.47	0.47	< 0.005	0.05	0.05	—	3.57	3.57	< 0.005	< 0.005	< 0.005	3.74

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.07	0.07	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	11.3	11.3	< 0.005	< 0.005	—	11.3
Dust From Material Movement	—	—	—	—	—	—	0.01	0.01	—	0.01	0.01	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	0.09	0.09	< 0.005	0.01	0.01	—	0.59	0.59	< 0.005	< 0.005	< 0.005	0.62
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	0.27	0.26	19.6	2.42	0.17	0.33	6.95	7.28	0.33	1.90	2.23	—	23,178	23,178	0.01	3.67	48.2	24,320
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.15	1.74	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	374	374	0.01	0.01	0.63	379
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.4	10.4	< 0.005	< 0.005	0.01	10.9
Hauling	0.01	0.01	0.62	0.07	0.01	0.01	0.21	0.22	0.01	0.06	0.07	—	699	699	< 0.005	0.11	0.63	732
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.32	0.00	0.00	0.07	0.07	0.00	0.02	0.02	—	61.9	61.9	< 0.005	< 0.005	0.11	62.7
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.73	1.73	< 0.005	< 0.005	< 0.005	1.80
Hauling	< 0.005	< 0.005	0.11	0.01	< 0.005	< 0.005	0.04	0.04	< 0.005	0.01	0.01	—	116	116	< 0.005	0.02	0.10	121

3.8. Substation Site Preparation (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.22	0.22	1.85	12.2	0.02	0.04	—	0.04	0.04	—	0.04	—	2,264	2,264	0.09	0.02	—	2,271
Dust From Material Movement	—	—	—	—	—	—	2.13	2.13	—	1.09	1.09	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.66	0.66	< 0.005	0.07	0.07	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.06	0.37	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	68.2	68.2	< 0.005	< 0.005	—	68.5
Dust From Material Movement	—	—	—	—	—	—	0.06	0.06	—	0.03	0.03	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	—	3.57	3.57	< 0.005	< 0.005	< 0.005	3.74
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	< 0.005	< 0.005	0.01	0.07	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	11.3	11.3	< 0.005	< 0.005	—	11.3

Dust From Material Movement	—	—	—	—	—	—	0.01	0.01	—	0.01	0.01	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	0.59	0.59	< 0.005	< 0.005	< 0.005	0.62
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	0.27	0.26	19.6	2.42	0.17	0.33	6.95	7.28	0.33	1.90	2.23	—	23,178	23,178	0.01	3.67	48.2	24,320
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.15	1.74	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	374	374	0.01	0.01	0.63	379
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.4	10.4	< 0.005	< 0.005	0.01	10.9
Hauling	0.01	0.01	0.62	0.07	0.01	0.01	0.21	0.22	0.01	0.06	0.07	—	699	699	< 0.005	0.11	0.63	732
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.32	0.00	0.00	0.07	0.07	0.00	0.02	0.02	—	61.9	61.9	< 0.005	< 0.005	0.11	62.7
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.73	1.73	< 0.005	< 0.005	< 0.005	1.80
Hauling	< 0.005	< 0.005	0.11	0.01	< 0.005	< 0.005	0.04	0.04	< 0.005	0.01	0.01	—	116	116	< 0.005	0.02	0.10	121

3.9. Grading (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.61	1.35	10.7	16.4	0.02	0.50	—	0.50	0.46	—	0.46	—	2,501	2,501	0.10	0.02	—	2,510
Dust From Material Movement	—	—	—	—	—	—	0.47	0.47	—	0.06	0.06	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	16.2	16.2	< 0.005	1.62	1.62	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.38	0.32	2.56	3.90	0.01	0.12	—	0.12	0.11	—	0.11	—	596	596	0.02	< 0.005	—	598
Dust From Material Movement	—	—	—	—	—	—	0.11	0.11	—	0.01	0.01	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.17	0.13	< 0.005	< 0.005	3.72	3.72	< 0.005	0.37	0.37	—	28.2	28.2	< 0.005	< 0.005	0.01	29.6
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.47	0.71	< 0.005	0.02	—	0.02	0.02	—	0.02	—	98.7	98.7	< 0.005	< 0.005	—	99.0
Dust From Material Movement	—	—	—	—	—	—	0.02	0.02	—	< 0.005	< 0.005	—	—	—	—	—	—	—

Onsite truck	< 0.005	< 0.005	0.03	0.02	< 0.005	< 0.005	0.68	0.68	< 0.005	0.07	0.07	—	4.68	4.68	< 0.005	< 0.005	< 0.005	4.90
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	1.43	1.35	103	12.7	0.88	1.73	36.4	38.2	1.73	9.97	11.7	—	121,453	121,453	0.05	19.2	253	127,435
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.50	0.40	1.19	13.8	0.00	0.00	3.03	3.03	0.00	0.71	0.71	—	2,957	2,957	0.11	0.10	5.02	2,995
Vendor	< 0.005	< 0.005	0.09	0.03	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	82.5	82.5	< 0.005	0.01	0.08	86.2
Hauling	0.33	0.31	25.7	3.04	0.21	0.41	8.63	9.04	0.41	2.36	2.78	—	28,952	28,952	0.01	4.58	26.0	30,343
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.09	0.07	0.22	2.51	0.00	0.00	0.55	0.55	0.00	0.13	0.13	—	490	490	0.02	0.02	0.83	496
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	13.7	13.7	< 0.005	< 0.005	0.01	14.3
Hauling	0.06	0.06	4.70	0.55	0.04	0.08	1.57	1.65	0.08	0.43	0.51	—	4,793	4,793	< 0.005	0.76	4.30	5,024

3.10. Grading (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	0.58	0.52	3.21	17.4	0.02	0.13	—	0.13	0.12	—	0.12	—	2,501	2,501	0.10	0.02	—	2,510
Dust From Material Movement	—	—	—	—	—	—	0.47	0.47	—	0.06	0.06	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.66	0.66	< 0.005	0.07	0.07	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.14	0.12	0.76	4.16	0.01	0.03	—	0.03	0.03	—	0.03	—	596	596	0.02	< 0.005	—	598
Dust From Material Movement	—	—	—	—	—	—	0.11	0.11	—	0.01	0.01	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.17	0.13	< 0.005	< 0.005	0.15	0.15	< 0.005	0.02	0.02	—	28.2	28.2	< 0.005	< 0.005	0.01	29.6
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.03	0.02	0.14	0.76	< 0.005	0.01	—	0.01	0.01	—	0.01	—	98.7	98.7	< 0.005	< 0.005	—	99.0
Dust From Material Movement	—	—	—	—	—	—	0.02	0.02	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.03	0.02	< 0.005	< 0.005	0.03	0.03	< 0.005	< 0.005	< 0.005	—	4.68	4.68	< 0.005	< 0.005	< 0.005	4.90
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	1.43	1.35	103	12.7	0.88	1.73	36.4	38.2	1.73	9.97	11.7	—	121,453	121,453	0.05	19.2	253	127,435
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.50	0.40	1.19	13.8	0.00	0.00	3.03	3.03	0.00	0.71	0.71	—	2,957	2,957	0.11	0.10	5.02	2,995
Vendor	< 0.005	< 0.005	0.09	0.03	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	82.5	82.5	< 0.005	0.01	0.08	86.2
Hauling	0.33	0.31	25.7	3.04	0.21	0.41	8.63	9.04	0.41	2.36	2.78	—	28,952	28,952	0.01	4.58	26.0	30,343
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.09	0.07	0.22	2.51	0.00	0.00	0.55	0.55	0.00	0.13	0.13	—	490	490	0.02	0.02	0.83	496
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	13.7	13.7	< 0.005	< 0.005	0.01	14.3
Hauling	0.06	0.06	4.70	0.55	0.04	0.08	1.57	1.65	0.08	0.43	0.51	—	4,793	4,793	< 0.005	0.76	4.30	5,024

3.11. Substation Site Grading (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.80	0.68	5.37	8.18	0.01	0.25	—	0.25	0.23	—	0.23	—	1,251	1,251	0.05	0.01	—	1,255

Dust From Material Movement	—	—	—	—	—	—	0.29	0.29	—	0.04	0.04	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	16.2	16.2	< 0.005	1.62	1.62	—	117	117	< 0.005	0.02	0.07	123
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.04	0.32	0.49	< 0.005	0.02	—	0.02	0.01	—	0.01	—	75.4	75.4	< 0.005	< 0.005	—	75.6
Dust From Material Movement	—	—	—	—	—	—	0.02	0.02	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.04	0.03	< 0.005	< 0.005	0.94	0.94	< 0.005	0.09	0.09	—	7.14	7.14	< 0.005	< 0.005	< 0.005	7.49
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.06	0.09	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	12.5	12.5	< 0.005	< 0.005	—	12.5
Dust From Material Movement	—	—	—	—	—	—	< 0.005	< 0.005	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	0.17	0.17	< 0.005	0.02	0.02	—	1.18	1.18	< 0.005	< 0.005	< 0.005	1.24
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765

Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	1.33	1.25	95.1	11.7	0.81	1.61	33.8	35.4	1.61	9.25	10.9	—	112,645	112,645	0.04	17.8	234	118,193
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.10	0.30	3.48	0.00	0.00	0.77	0.77	0.00	0.18	0.18	—	748	748	0.03	0.03	1.27	757
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	20.9	20.9	< 0.005	< 0.005	0.02	21.8
Hauling	0.08	0.07	6.04	0.71	0.05	0.10	2.02	2.12	0.10	0.55	0.65	—	6,790	6,790	< 0.005	1.07	6.09	7,117
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.05	0.63	0.00	0.00	0.14	0.14	0.00	0.03	0.03	—	124	124	< 0.005	< 0.005	0.21	125
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.46	3.46	< 0.005	< 0.005	< 0.005	3.61
Hauling	0.01	0.01	1.10	0.13	0.01	0.02	0.37	0.39	0.02	0.10	0.12	—	1,124	1,124	< 0.005	0.18	1.01	1,178

3.12. Substation Site Grading (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.29	0.26	1.60	8.72	0.01	0.06	—	0.06	0.06	—	0.06	—	1,251	1,251	0.05	0.01	—	1,255
Dust From Material Movement	—	—	—	—	—	—	0.29	0.29	—	0.04	0.04	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.66	0.66	< 0.005	0.07	0.07	—	117	117	< 0.005	0.02	0.07	123

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.02	0.02	0.10	0.53	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	75.4	75.4	< 0.005	< 0.005	—	75.6
Dust From Material Movement	—	—	—	—	—	—	0.02	0.02	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.04	0.03	< 0.005	< 0.005	0.04	0.04	< 0.005	< 0.005	< 0.005	—	7.14	7.14	< 0.005	< 0.005	< 0.005	7.49
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	< 0.005	< 0.005	0.02	0.10	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	12.5	12.5	< 0.005	< 0.005	—	12.5
Dust From Material Movement	—	—	—	—	—	—	< 0.005	< 0.005	—	< 0.005	< 0.005	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	1.18	1.18	< 0.005	< 0.005	< 0.005	1.24
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.61	2.19	4.18	80.4	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,580	13,580	0.44	0.42	48.8	13,765
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.79	362
Hauling	1.33	1.25	95.1	11.7	0.81	1.61	33.8	35.4	1.61	9.25	10.9	—	112,645	112,645	0.04	17.8	234	118,193
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.10	0.30	3.48	0.00	0.00	0.77	0.77	0.00	0.18	0.18	—	748	748	0.03	0.03	1.27	757
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	20.9	20.9	< 0.005	< 0.005	0.02	21.8
Hauling	0.08	0.07	6.04	0.71	0.05	0.10	2.02	2.12	0.10	0.55	0.65	—	6,790	6,790	< 0.005	1.07	6.09	7,117
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.05	0.63	0.00	0.00	0.14	0.14	0.00	0.03	0.03	—	124	124	< 0.005	< 0.005	0.21	125
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.46	3.46	< 0.005	< 0.005	< 0.005	3.61
Hauling	0.01	0.01	1.10	0.13	0.01	0.02	0.37	0.39	0.02	0.10	0.12	—	1,124	1,124	< 0.005	0.18	1.01	1,178

3.13. Substation Installation (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.74	0.62	5.94	8.89	0.01	0.14	—	0.14	0.13	—	0.13	—	1,336	1,336	0.05	0.01	—	1,341
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.74	0.62	5.94	8.89	0.01	0.14	—	0.14	0.13	—	0.13	—	1,336	1,336	0.05	0.01	—	1,341
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.35	0.30	2.83	4.24	0.01	0.07	—	0.07	0.06	—	0.06	—	637	637	0.03	0.01	—	639
Onsite truck	0.02	0.02	0.34	0.27	< 0.005	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	—	55.3	55.3	< 0.005	0.01	0.01	58.0
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.06	0.05	0.52	0.77	< 0.005	0.01	—	0.01	0.01	—	0.01	—	105	105	< 0.005	< 0.005	—	106
Onsite truck	< 0.005	< 0.005	0.06	0.05	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.16	9.16	< 0.005	< 0.005	< 0.005	9.61
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.01	0.01	0.76	0.10	0.01	0.01	0.28	0.29	0.01	0.08	0.09	—	903	903	< 0.005	0.14	1.79	947
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.01	0.01	0.80	0.10	0.01	0.01	0.28	0.29	0.01	0.08	0.09	—	903	903	< 0.005	0.14	0.05	945
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.49	0.39	1.09	12.9	0.00	0.00	3.03	3.03	0.00	0.71	0.71	—	2,905	2,905	0.11	0.10	4.61	2,942
Vendor	0.01	< 0.005	0.16	0.06	< 0.005	< 0.005	0.05	0.05	< 0.005	0.01	0.01	—	161	161	< 0.005	0.02	0.14	168
Hauling	0.01	< 0.005	0.38	0.05	< 0.005	0.01	0.13	0.14	0.01	0.04	0.04	—	431	431	< 0.005	0.07	0.37	451
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.09	0.07	0.20	2.35	0.00	0.00	0.55	0.55	0.00	0.13	0.13	—	481	481	0.02	0.02	0.76	487
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	26.7	26.7	< 0.005	< 0.005	0.02	27.8
Hauling	< 0.005	< 0.005	0.07	0.01	< 0.005	< 0.005	0.02	0.03	< 0.005	0.01	0.01	—	71.3	71.3	< 0.005	0.01	0.06	74.6

3.14. Substation Installation (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.57	0.49	4.08	9.32	0.01	0.09	—	0.09	0.09	—	0.09	—	1,336	1,336	0.05	0.01	—	1,341
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.57	0.49	4.08	9.32	0.01	0.09	—	0.09	0.09	—	0.09	—	1,336	1,336	0.05	0.01	—	1,341
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.27	0.23	1.94	4.44	0.01	0.04	—	0.04	0.04	—	0.04	—	637	637	0.03	0.01	—	639
Onsite truck	0.02	0.02	0.34	0.27	< 0.005	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	—	55.3	55.3	< 0.005	0.01	0.01	58.0

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.04	0.35	0.81	< 0.005	0.01	—	0.01	0.01	—	0.01	—	105	105	< 0.005	< 0.005	—	106
Onsite truck	< 0.005	< 0.005	0.06	0.05	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.16	9.16	< 0.005	< 0.005	< 0.005	9.61
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.01	0.01	0.76	0.10	0.01	0.01	0.28	0.29	0.01	0.08	0.09	—	903	903	< 0.005	0.14	1.79	947
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.01	0.01	0.80	0.10	0.01	0.01	0.28	0.29	0.01	0.08	0.09	—	903	903	< 0.005	0.14	0.05	945
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.49	0.39	1.09	12.9	0.00	0.00	3.03	3.03	0.00	0.71	0.71	—	2,905	2,905	0.11	0.10	4.61	2,942
Vendor	0.01	< 0.005	0.16	0.06	< 0.005	< 0.005	0.05	0.05	< 0.005	0.01	0.01	—	161	161	< 0.005	0.02	0.14	168
Hauling	0.01	< 0.005	0.38	0.05	< 0.005	0.01	0.13	0.14	0.01	0.04	0.04	—	431	431	< 0.005	0.07	0.37	451
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.09	0.07	0.20	2.35	0.00	0.00	0.55	0.55	0.00	0.13	0.13	—	481	481	0.02	0.02	0.76	487
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	26.7	26.7	< 0.005	< 0.005	0.02	27.8
Hauling	< 0.005	< 0.005	0.07	0.01	< 0.005	< 0.005	0.02	0.03	< 0.005	0.01	0.01	—	71.3	71.3	< 0.005	0.01	0.06	74.6

3.15. Gen-Tie Foundation and Tower Erection (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.18	0.98	8.14	9.53	0.02	0.27	—	0.27	0.25	—	0.25	—	2,013	2,013	0.08	0.02	—	2,020
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.18	0.98	8.14	9.53	0.02	0.27	—	0.27	0.25	—	0.25	—	2,013	2,013	0.08	0.02	—	2,020
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.28	0.23	1.94	2.27	< 0.005	0.06	—	0.06	0.06	—	0.06	—	480	480	0.02	< 0.005	—	481
Onsite truck	0.01	0.01	0.17	0.13	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	27.7	27.7	< 0.005	< 0.005	0.01	29.0
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.04	0.35	0.41	< 0.005	0.01	—	0.01	0.01	—	0.01	—	79.4	79.4	< 0.005	< 0.005	—	79.7
Onsite truck	< 0.005	< 0.005	0.03	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	4.58	4.58	< 0.005	< 0.005	< 0.005	4.80

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.25	0.20	0.55	6.43	0.00	0.00	1.52	1.52	0.00	0.36	0.36	—	1,452	1,452	0.05	0.05	2.30	1,471
Vendor	< 0.005	< 0.005	0.08	0.03	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	80.5	80.5	< 0.005	0.01	0.07	84.0
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.05	0.04	0.10	1.17	0.00	0.00	0.28	0.28	0.00	0.06	0.06	—	240	240	0.01	0.01	0.38	244
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	13.3	13.3	< 0.005	< 0.005	0.01	13.9
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.16. Gen-Tie Foundation and Tower Erection (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road	0.70	0.60	4.36	11.9	0.02	0.11	—	0.11	0.11	—	0.11	—	2,013	2,013	0.08	0.02	—	2,020
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.70	0.60	4.36	11.9	0.02	0.11	—	0.11	0.11	—	0.11	—	2,013	2,013	0.08	0.02	—	2,020
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.17	0.14	1.04	2.83	< 0.005	0.03	—	0.03	0.03	—	0.03	—	480	480	0.02	< 0.005	—	481
Onsite truck	0.01	0.01	0.17	0.13	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	27.7	27.7	< 0.005	< 0.005	0.01	29.0
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.03	0.03	0.19	0.52	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	79.4	79.4	< 0.005	< 0.005	—	79.7
Onsite truck	< 0.005	< 0.005	0.03	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	4.58	4.58	< 0.005	< 0.005	< 0.005	4.80
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.25	0.20	0.55	6.43	0.00	0.00	1.52	1.52	0.00	0.36	0.36	—	1,452	1,452	0.05	0.05	2.30	1,471
Vendor	< 0.005	< 0.005	0.08	0.03	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	80.5	80.5	< 0.005	0.01	0.07	84.0
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.05	0.04	0.10	1.17	0.00	0.00	0.28	0.28	0.00	0.06	0.06	—	240	240	0.01	0.01	0.38	244
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	13.3	13.3	< 0.005	< 0.005	0.01	13.9
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.17. Gen-Tie Stringing and Pulling (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.20	0.17	2.10	3.36	0.01	0.04	—	0.04	0.04	—	0.04	—	547	547	0.02	< 0.005	—	549
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.13	0.20	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	33.0	33.0	< 0.005	< 0.005	—	33.1
Onsite truck	< 0.005	< 0.005	0.04	0.03	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	7.00	7.00	< 0.005	< 0.005	< 0.005	7.34
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	< 0.005	< 0.005	0.02	0.04	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	5.46	5.46	< 0.005	< 0.005	—	5.48
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.16	1.16	< 0.005	< 0.005	< 0.005	1.21
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.14	1.63	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	367	367	0.01	0.01	0.58	372
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	20.4	20.4	< 0.005	< 0.005	0.02	21.2
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.30	0.00	0.00	0.07	0.07	0.00	0.02	0.02	—	60.8	60.8	< 0.005	< 0.005	0.10	61.6
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.37	3.37	< 0.005	< 0.005	< 0.005	3.52
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.18. Gen-Tie Stringing and Pulling (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.09	0.08	1.08	3.50	0.01	0.01	—	0.01	0.01	—	0.01	—	547	547	0.02	< 0.005	—	549
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	< 0.005	0.07	0.21	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	33.0	33.0	< 0.005	< 0.005	—	33.1
Onsite truck	< 0.005	< 0.005	0.04	0.03	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	7.00	7.00	< 0.005	< 0.005	< 0.005	7.34
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	< 0.005	< 0.005	0.01	0.04	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	5.46	5.46	< 0.005	< 0.005	—	5.48
Onsite truck	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.16	1.16	< 0.005	< 0.005	< 0.005	1.21
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.14	1.63	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	367	367	0.01	0.01	0.58	372
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	20.4	20.4	< 0.005	< 0.005	0.02	21.2
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.30	0.00	0.00	0.07	0.07	0.00	0.02	0.02	—	60.8	60.8	< 0.005	< 0.005	0.10	61.6
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.37	3.37	< 0.005	< 0.005	< 0.005	3.52
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.19. SCE Interconnection Facility Upgrades (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.09	2.58	23.5	33.4	0.06	0.67	—	0.67	0.62	—	0.62	—	6,214	6,214	0.25	0.05	—	6,235
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	3.09	2.58	23.5	33.4	0.06	0.67	—	0.67	0.62	—	0.62	—	6,214	6,214	0.25	0.05	—	6,235
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.10	0.92	8.36	11.9	0.02	0.24	—	0.24	0.22	—	0.22	—	2,213	2,213	0.09	0.02	—	2,221
Onsite truck	0.02	0.01	0.26	0.20	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	41.3	41.3	< 0.005	0.01	0.01	43.4
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.20	0.17	1.53	2.17	< 0.005	0.04	—	0.04	0.04	—	0.04	—	366	366	0.01	< 0.005	—	368
Onsite truck	< 0.005	< 0.005	0.05	0.04	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	6.84	6.84	< 0.005	< 0.005	< 0.005	7.18
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.37	0.29	0.82	9.61	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,170	2,170	0.08	0.08	3.44	2,198
Vendor	< 0.005	< 0.005	0.12	0.04	< 0.005	< 0.005	0.04	0.04	< 0.005	0.01	0.01	—	120	120	< 0.005	0.02	0.11	126
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.15	1.75	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	359	359	0.01	0.01	0.57	364
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	19.9	19.9	< 0.005	< 0.005	0.02	20.8
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.20. SCE Interconnection Facility Upgrades (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.65	1.46	13.7	39.5	0.06	0.25	—	0.25	0.23	—	0.23	—	6,214	6,214	0.25	0.05	—	6,235
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.65	1.46	13.7	39.5	0.06	0.25	—	0.25	0.23	—	0.23	—	6,214	6,214	0.25	0.05	—	6,235
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road	0.59	0.52	4.89	14.1	0.02	0.09	—	0.09	0.08	—	0.08	—	2,213	2,213	0.09	0.02	—	2,221
Onsite truck	0.02	0.01	0.26	0.20	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	41.3	41.3	< 0.005	0.01	0.01	43.4
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.11	0.09	0.89	2.57	< 0.005	0.02	—	0.02	0.02	—	0.02	—	366	366	0.01	< 0.005	—	368
Onsite truck	< 0.005	< 0.005	0.05	0.04	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	6.84	6.84	< 0.005	< 0.005	< 0.005	7.18
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.09	0.87	1.88	37.7	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	6,669	6,669	0.22	0.21	22.4	6,759
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.03	0.82	2.09	23.9	0.00	0.00	6.41	6.41	0.00	1.50	1.50	—	5,922	5,922	0.22	0.21	0.58	5,991
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.37	0.29	0.82	9.61	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,170	2,170	0.08	0.08	3.44	2,198
Vendor	< 0.005	< 0.005	0.12	0.04	< 0.005	< 0.005	0.04	0.04	< 0.005	0.01	0.01	—	120	120	< 0.005	0.02	0.11	126
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.15	1.75	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	359	359	0.01	0.01	0.57	364
Vendor	< 0.005	< 0.005	0.02	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	19.9	19.9	< 0.005	< 0.005	0.02	20.8

Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.21. Commissioning (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	20.7	20.7	< 0.005	< 0.005	0.01	21.7
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.42	3.42	< 0.005	< 0.005	< 0.005	3.59
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.06	1.64	4.18	47.9	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,845	11,845	0.45	0.42	1.16	11,983
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.37	0.29	0.82	9.61	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,170	2,170	0.08	0.08	3.44	2,198
Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	60.2	60.2	< 0.005	0.01	0.05	62.8
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.15	1.75	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	359	359	0.01	0.01	0.57	364
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.96	9.96	< 0.005	< 0.005	0.01	10.4
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.22. Commissioning (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	20.7	20.7	< 0.005	< 0.005	0.01	21.7
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.42	3.42	< 0.005	< 0.005	< 0.005	3.59
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.06	1.64	4.18	47.9	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,845	11,845	0.45	0.42	1.16	11,983
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.37	0.29	0.82	9.61	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,170	2,170	0.08	0.08	3.44	2,198
Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	60.2	60.2	< 0.005	0.01	0.05	62.8
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.15	1.75	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	359	359	0.01	0.01	0.57	364
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.96	9.96	< 0.005	< 0.005	0.01	10.4
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.23. Commissioning (2029) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.69	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	113	113	< 0.005	0.02	0.06	118
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	< 0.005	121
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	20.3	20.3	< 0.005	< 0.005	< 0.005	21.2
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.36	3.36	< 0.005	< 0.005	< 0.005	3.51
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.12	1.70	3.36	70.6	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,105	13,105	0.44	0.42	40.9	13,283
Vendor	0.01	0.01	0.32	0.12	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	329	329	< 0.005	0.05	0.62	343
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.02	1.60	3.77	44.6	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,642	11,642	0.05	0.42	1.06	11,770
Vendor	0.01	0.01	0.33	0.12	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	329	329	< 0.005	0.05	0.02	343
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.36	0.29	0.74	9.02	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,133	2,133	0.01	0.08	3.15	2,159
Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	58.5	58.5	< 0.005	0.01	0.05	61.1
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.14	1.65	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	353	353	< 0.005	0.01	0.52	357
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.69	9.69	< 0.005	< 0.005	0.01	10.1
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.24. Commissioning (2029) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.69	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	113	113	< 0.005	0.02	0.06	118
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	< 0.005	121
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	20.3	20.3	< 0.005	< 0.005	< 0.005	21.2
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.36	3.36	< 0.005	< 0.005	< 0.005	3.51
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.12	1.70	3.36	70.6	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,105	13,105	0.44	0.42	40.9	13,283
Vendor	0.01	0.01	0.32	0.12	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	329	329	< 0.005	0.05	0.62	343
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.02	1.60	3.77	44.6	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,642	11,642	0.05	0.42	1.06	11,770
Vendor	0.01	0.01	0.33	0.12	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	329	329	< 0.005	0.05	0.02	343
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.36	0.29	0.74	9.02	0.00	0.00	2.26	2.26	0.00	0.53	0.53	—	2,133	2,133	0.01	0.08	3.15	2,159

Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	58.5	58.5	< 0.005	0.01	0.05	61.1
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.05	0.14	1.65	0.00	0.00	0.41	0.41	0.00	0.10	0.10	—	353	353	< 0.005	0.01	0.52	357
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	9.69	9.69	< 0.005	< 0.005	0.01	10.1
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.25. Battery/Container Installation (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.01	0.85	7.50	9.38	0.02	0.27	—	0.27	0.25	—	0.25	—	2,014	2,014	0.08	0.02	—	2,020
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.76	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	120	120	< 0.005	0.02	< 0.005	126
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.18	0.15	1.35	1.69	< 0.005	0.05	—	0.05	0.04	—	0.04	—	363	363	0.01	< 0.005	—	364

Architectural	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	21.3	21.3	< 0.005	< 0.005	0.01	22.4
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.03	0.03	0.25	0.31	< 0.005	0.01	—	0.01	0.01	—	0.01	—	60.0	60.0	< 0.005	< 0.005	—	60.2
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.53	3.53	< 0.005	< 0.005	< 0.005	3.70
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.10	1.68	4.59	50.8	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	12,057	12,057	0.45	0.42	1.26	12,195
Vendor	0.01	0.01	0.36	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.02	362
Hauling	0.05	0.05	4.40	0.51	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	5,005	5,005	< 0.005	0.79	0.27	5,241
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.38	0.30	0.90	10.4	0.00	0.00	2.29	2.29	0.00	0.54	0.54	—	2,234	2,234	0.08	0.08	3.79	2,262
Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	62.3	62.3	< 0.005	0.01	0.06	65.1
Hauling	0.01	0.01	0.80	0.09	0.01	0.01	0.27	0.28	0.01	0.07	0.09	—	901	901	< 0.005	0.14	0.81	944
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.16	1.90	0.00	0.00	0.42	0.42	0.00	0.10	0.10	—	370	370	0.01	0.01	0.63	375
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	0.01	10.8
Hauling	< 0.005	< 0.005	0.15	0.02	< 0.005	< 0.005	0.05	0.05	< 0.005	0.01	0.02	—	149	149	< 0.005	0.02	0.13	156

3.26. Battery/Container Installation (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.36	2.27	11.8	0.02	0.07	—	0.07	0.06	—	0.06	—	2,014	2,014	0.08	0.02	—	2,020
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.76	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	120	120	< 0.005	0.02	< 0.005	126
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.41	2.13	< 0.005	0.01	—	0.01	0.01	—	0.01	—	363	363	0.01	< 0.005	—	364
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.01	0.01	0.13	0.10	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	21.3	21.3	< 0.005	< 0.005	0.01	22.4
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	0.01	0.01	0.07	0.39	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	60.0	60.0	< 0.005	< 0.005	—	60.2
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.02	0.02	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	3.53	3.53	< 0.005	< 0.005	< 0.005	3.70
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.10	1.68	4.59	50.8	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	12,057	12,057	0.45	0.42	1.26	12,195
Vendor	0.01	0.01	0.36	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	346	346	< 0.005	0.05	0.02	362
Hauling	0.05	0.05	4.40	0.51	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	5,005	5,005	< 0.005	0.79	0.27	5,241
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.38	0.30	0.90	10.4	0.00	0.00	2.29	2.29	0.00	0.54	0.54	—	2,234	2,234	0.08	0.08	3.79	2,262
Vendor	< 0.005	< 0.005	0.06	0.02	< 0.005	< 0.005	0.02	0.02	< 0.005	0.01	0.01	—	62.3	62.3	< 0.005	0.01	0.06	65.1
Hauling	0.01	0.01	0.80	0.09	0.01	0.01	0.27	0.28	0.01	0.07	0.09	—	901	901	< 0.005	0.14	0.81	944
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.16	1.90	0.00	0.00	0.42	0.42	0.00	0.10	0.10	—	370	370	0.01	0.01	0.63	375
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	0.01	10.8
Hauling	< 0.005	< 0.005	0.15	0.02	< 0.005	< 0.005	0.05	0.05	< 0.005	0.01	0.02	—	149	149	< 0.005	0.02	0.13	156

3.27. Battery/Container Installation (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.97	0.82	7.04	9.37	0.02	0.24	—	0.24	0.22	—	0.22	—	2,014	2,014	0.08	0.02	—	2,021
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.97	0.82	7.04	9.37	0.02	0.24	—	0.24	0.22	—	0.22	—	2,014	2,014	0.08	0.02	—	2,021
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.52	0.44	3.79	5.04	0.01	0.13	—	0.13	0.12	—	0.12	—	1,084	1,084	0.04	0.01	—	1,088
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Onsite truck	0.02	0.02	0.39	0.30	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	62.5	62.5	< 0.005	0.01	0.02	65.5
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.10	0.08	0.69	0.92	< 0.005	0.02	—	0.02	0.02	—	0.02	—	179	179	0.01	< 0.005	—	180
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.07	0.06	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	< 0.005	10.8
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.17	1.75	3.77	75.5	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,337	13,337	0.44	0.42	44.8	13,518
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.06	0.05	4.09	0.50	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	4,874	4,874	< 0.005	0.76	9.65	5,109
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.06	1.64	4.18	47.9	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,845	11,845	0.45	0.42	1.16	11,983
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.05	0.05	4.29	0.51	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	4,875	4,875	< 0.005	0.76	0.25	5,100
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.12	0.89	2.47	29.0	0.00	0.00	6.84	6.84	0.00	1.60	1.60	—	6,559	6,559	0.24	0.23	10.4	6,643
Vendor	0.01	< 0.005	0.19	0.07	< 0.005	< 0.005	0.05	0.06	< 0.005	0.02	0.02	—	182	182	< 0.005	0.03	0.16	190
Hauling	0.03	0.03	2.32	0.27	0.02	0.04	0.80	0.84	0.04	0.22	0.26	—	2,623	2,623	< 0.005	0.41	2.24	2,747
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.16	0.45	5.30	0.00	0.00	1.25	1.25	0.00	0.29	0.29	—	1,086	1,086	0.04	0.04	1.72	1,100

Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	30.1	30.1	< 0.005	< 0.005	0.03	31.4
Hauling	0.01	0.01	0.42	0.05	< 0.005	0.01	0.15	0.15	0.01	0.04	0.05	—	434	434	< 0.005	0.07	0.37	455

3.28. Battery/Container Installation (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.39	0.35	2.23	11.8	0.02	0.06	—	0.06	0.06	—	0.06	—	2,014	2,014	0.08	0.02	—	2,021
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.05	0.04	0.70	0.56	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	115	115	< 0.005	0.02	0.07	120
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.39	0.35	2.23	11.8	0.02	0.06	—	0.06	0.06	—	0.06	—	2,014	2,014	0.08	0.02	—	2,021
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.04	0.04	0.75	0.57	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	117	117	< 0.005	0.02	< 0.005	123
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	0.21	0.19	1.20	6.37	0.01	0.03	—	0.03	0.03	—	0.03	—	1,084	1,084	0.04	0.01	—	1,088
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.02	0.02	0.39	0.30	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	62.5	62.5	< 0.005	0.01	0.02	65.5
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.04	0.03	0.22	1.16	< 0.005	0.01	—	0.01	0.01	—	0.01	—	179	179	0.01	< 0.005	—	180
Architectural Coatings	< 0.005	< 0.005	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	< 0.005	< 0.005	0.07	0.06	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	< 0.005	10.8
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.17	1.75	3.77	75.5	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	13,337	13,337	0.44	0.42	44.8	13,518
Vendor	0.01	0.01	0.33	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.70	353
Hauling	0.06	0.05	4.09	0.50	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	4,874	4,874	< 0.005	0.76	9.65	5,109
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	2.06	1.64	4.18	47.9	0.00	0.00	12.8	12.8	0.00	3.01	3.01	—	11,845	11,845	0.45	0.42	1.16	11,983
Vendor	0.01	0.01	0.34	0.13	< 0.005	< 0.005	0.10	0.11	< 0.005	0.03	0.03	—	338	338	< 0.005	0.05	0.02	352
Hauling	0.05	0.05	4.29	0.51	0.04	0.07	1.50	1.57	0.07	0.41	0.48	—	4,875	4,875	< 0.005	0.76	0.25	5,100
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	1.12	0.89	2.47	29.0	0.00	0.00	6.84	6.84	0.00	1.60	1.60	—	6,559	6,559	0.24	0.23	10.4	6,643

Vendor	0.01	< 0.005	0.19	0.07	< 0.005	< 0.005	0.05	0.06	< 0.005	0.02	0.02	—	182	182	< 0.005	0.03	0.16	190
Hauling	0.03	0.03	2.32	0.27	0.02	0.04	0.80	0.84	0.04	0.22	0.26	—	2,623	2,623	< 0.005	0.41	2.24	2,747
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.16	0.45	5.30	0.00	0.00	1.25	1.25	0.00	0.29	0.29	—	1,086	1,086	0.04	0.04	1.72	1,100
Vendor	< 0.005	< 0.005	0.03	0.01	< 0.005	< 0.005	0.01	0.01	< 0.005	< 0.005	< 0.005	—	30.1	30.1	< 0.005	< 0.005	0.03	31.4
Hauling	0.01	0.01	0.42	0.05	< 0.005	0.01	0.15	0.15	0.01	0.04	0.05	—	434	434	< 0.005	0.07	0.37	455

3.29. Paving (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.10	0.92	8.68	12.4	0.02	0.37	—	0.37	0.34	—	0.34	—	1,889	1,889	0.08	0.02	—	1,895
Paving	0.60	0.60	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.10	0.09	0.81	1.16	< 0.005	0.03	—	0.03	0.03	—	0.03	—	176	176	0.01	< 0.005	—	177
Paving	0.06	0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.02	0.02	0.15	0.21	< 0.005	0.01	—	0.01	0.01	—	0.01	—	29.1	29.1	< 0.005	< 0.005	—	29.2
Paving	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.17	0.14	0.28	5.31	0.00	0.00	0.85	0.85	0.00	0.20	0.20	—	898	898	0.03	0.03	3.23	910
Vendor	< 0.005	< 0.005	0.11	0.04	< 0.005	< 0.005	0.03	0.04	< 0.005	0.01	0.01	—	115	115	< 0.005	0.02	0.26	121
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.36	0.00	0.00	0.08	0.08	0.00	0.02	0.02	—	76.4	76.4	< 0.005	< 0.005	0.13	77.4
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.8	10.8	< 0.005	< 0.005	0.01	11.2
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.06	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	12.7	12.7	< 0.005	< 0.005	0.02	12.8
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.78	1.78	< 0.005	< 0.005	< 0.005	1.86
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.30. Paving (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.53	0.46	2.91	13.3	0.02	0.12	—	0.12	0.11	—	0.11	—	1,889	1,889	0.08	0.02	—	1,895
Paving	0.60	0.60	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.05	0.04	0.27	1.23	< 0.005	0.01	—	0.01	0.01	—	0.01	—	176	176	0.01	< 0.005	—	177
Paving	0.06	0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.01	0.01	0.05	0.23	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	29.1	29.1	< 0.005	< 0.005	—	29.2
Paving	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.17	0.14	0.28	5.31	0.00	0.00	0.85	0.85	0.00	0.20	0.20	—	898	898	0.03	0.03	3.23	910
Vendor	< 0.005	< 0.005	0.11	0.04	< 0.005	< 0.005	0.03	0.04	< 0.005	0.01	0.01	—	115	115	< 0.005	0.02	0.26	121
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.03	0.36	0.00	0.00	0.08	0.08	0.00	0.02	0.02	—	76.4	76.4	< 0.005	< 0.005	0.13	77.4
Vendor	< 0.005	< 0.005	0.01	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	10.8	10.8	< 0.005	< 0.005	0.01	11.2
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.06	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	12.7	12.7	< 0.005	< 0.005	0.02	12.8
Vendor	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	1.78	1.78	< 0.005	< 0.005	< 0.005	1.86
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

4. Operations Emissions Details

4.1. Mobile Emissions by Land Use

4.1.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2

4.1.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

General Light Industry	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.19	0.17	0.17	1.94	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	448	448	0.02	0.02	1.39	455
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.17	0.15	0.18	1.48	< 0.005	< 0.005	0.41	0.41	< 0.005	0.10	0.11	—	409	409	0.02	0.02	0.04	414
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.02	0.02	0.03	0.23	< 0.005	< 0.005	0.06	0.06	< 0.005	0.01	0.02	—	54.3	54.3	< 0.005	< 0.005	0.08	55.2

4.2. Energy

4.2.1. Electricity Emissions By Land Use - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	47.0	47.0	< 0.005	< 0.005	—	47.2
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	5.07	5.07	< 0.005	< 0.005	—	5.10
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	64,178	64,178	6.12	0.74	—	64,552
Total	—	—	—	—	—	—	—	—	—	—	—	—	64,230	64,230	6.12	0.74	—	64,604
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	47.0	47.0	< 0.005	< 0.005	—	47.2
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	5.07	5.07	< 0.005	< 0.005	—	5.10
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	64,178	64,178	6.12	0.74	—	64,552
Total	—	—	—	—	—	—	—	—	—	—	—	—	64,230	64,230	6.12	0.74	—	64,604
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	7.78	7.78	< 0.005	< 0.005	—	7.82
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	0.84	0.84	< 0.005	< 0.005	—	0.84
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	10,625	10,625	1.01	0.12	—	10,687

Total	—	—	—	—	—	—	—	—	—	—	—	—	10,634	10,634	1.01	0.12	—	10,696

4.2.2. Electricity Emissions By Land Use - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	47.0	47.0	< 0.005	< 0.005	—	47.2
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	5.07	5.07	< 0.005	< 0.005	—	5.10
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	64,178	64,178	6.12	0.74	—	64,552
Total	—	—	—	—	—	—	—	—	—	—	—	—	64,230	64,230	6.12	0.74	—	64,604
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	47.0	47.0	< 0.005	< 0.005	—	47.2
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	5.07	5.07	< 0.005	< 0.005	—	5.10
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	64,178	64,178	6.12	0.74	—	64,552
Total	—	—	—	—	—	—	—	—	—	—	—	—	64,230	64,230	6.12	0.74	—	64,604
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	7.78	7.78	< 0.005	< 0.005	—	7.82

Parking Lot	—	—	—	—	—	—	—	—	—	—	—	—	0.84	0.84	< 0.005	< 0.005	—	0.84
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	—	10,625	10,625	1.01	0.12	—	10,687
Total	—	—	—	—	—	—	—	—	—	—	—	—	10,634	10,634	1.01	0.12	—	10,696

4.2.3. Natural Gas Emissions By Land Use - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00

4.2.4. Natural Gas Emissions By Land Use - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00

Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	—	0.00	—	0.00	0.00	0.00	0.00	—	0.00

4.3. Area Emissions by Source

4.3.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Source	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Consumer Products	0.08	0.08	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.03	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Landscape Equipment	0.07	0.06	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58

Total	0.18	0.17	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Consumer Products	0.08	0.08	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.03	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	0.11	0.11	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Consumer Products	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Landscape Equipment	0.01	0.01	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13
Total	0.03	0.03	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13

4.3.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Source	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Consumer Product	0.08	0.08	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.03	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Landscape Equipment	0.07	0.06	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58
Total	0.18	0.17	< 0.005	0.38	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	1.57	1.57	< 0.005	< 0.005	—	1.58
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Consumer Products	0.08	0.08	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.03	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	0.11	0.11	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Consumer Products	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Architectural Coatings	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Landscape Equipment	0.01	0.01	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13
Total	0.03	0.03	< 0.005	0.03	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.13	0.13	< 0.005	< 0.005	—	0.13

4.4. Water Emissions by Land Use

4.4.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29

Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29

4.4.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.06	9.22	10.3	0.11	< 0.005	—	13.8

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	0.18	1.53	1.70	0.02	< 0.005	—	2.29

4.5. Waste Emissions by Land Use

4.5.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61

Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93

4.5.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	1.60	0.00	1.60	0.16	0.00	—	5.61
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93
Parking Lot	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Other Asphalt Surfaces	—	—	—	—	—	—	—	—	—	—	—	0.00	0.00	0.00	0.00	0.00	—	0.00
Total	—	—	—	—	—	—	—	—	—	—	—	0.27	0.00	0.27	0.03	0.00	—	0.93

4.6. Refrigerant Emissions by Land Use

4.6.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20

Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03

4.6.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.20	0.20
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

General Light Industry	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.03	0.03

4.7. Offroad Emissions By Equipment Type

4.7.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipment Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	0.41	0.34	2.79	3.01	0.01	0.12	—	0.12	0.11	—	0.11	—	990	990	0.04	0.01	—	994
Forklifts	0.07	0.06	0.57	1.03	< 0.005	0.02	—	0.02	0.02	—	0.02	—	152	152	0.01	< 0.005	—	153
Total	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	0.41	0.34	2.79	3.01	0.01	0.12	—	0.12	0.11	—	0.11	—	990	990	0.04	0.01	—	994
Forklifts	0.07	0.06	0.57	1.03	< 0.005	0.02	—	0.02	0.02	—	0.02	—	152	152	0.01	< 0.005	—	153
Total	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.45	0.45	< 0.005	< 0.005	—	0.45
Forklifts	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.07	0.07	< 0.005	< 0.005	—	0.07
Total	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.52	0.52	< 0.005	< 0.005	—	0.52

4.7.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipm Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	0.41	0.34	2.79	3.01	0.01	0.12	—	0.12	0.11	—	0.11	—	990	990	0.04	0.01	—	994
Forklifts	0.07	0.06	0.57	1.03	< 0.005	0.02	—	0.02	0.02	—	0.02	—	152	152	0.01	< 0.005	—	153
Total	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	0.41	0.34	2.79	3.01	0.01	0.12	—	0.12	0.11	—	0.11	—	990	990	0.04	0.01	—	994
Forklifts	0.07	0.06	0.57	1.03	< 0.005	0.02	—	0.02	0.02	—	0.02	—	152	152	0.01	< 0.005	—	153
Total	0.48	0.40	3.35	4.05	0.01	0.14	—	0.14	0.13	—	0.13	—	1,143	1,143	0.05	0.01	—	1,147
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cranes	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.45	0.45	< 0.005	< 0.005	—	0.45
Forklifts	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.07	0.07	< 0.005	< 0.005	—	0.07
Total	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005	—	< 0.005	< 0.005	—	< 0.005	—	0.52	0.52	< 0.005	< 0.005	—	0.52

4.8. Stationary Emissions By Equipment Type

4.8.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipm ent Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.8.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipm ent Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.9. User Defined Emissions By Equipment Type

4.9.1. Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipm ent Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.9.2. Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Equipm ent Type	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10. Soil Carbon Accumulation By Vegetation Type

4.10.1. Soil Carbon Accumulation By Vegetation Type - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Vegetati on	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10.2. Above and Belowground Carbon Accumulation by Land Use Type - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10.3. Avoided and Sequestered Emissions by Species - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Species	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Removed	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Removed	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Removed	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10.4. Soil Carbon Accumulation By Vegetation Type - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Vegetation	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10.5. Above and Belowground Carbon Accumulation by Land Use Type - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Land Use	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

4.10.6. Avoided and Sequestered Emissions by Species - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Species	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Removed	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Removed	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avoided	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sequestered	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Remove	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Subtotal	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Decommissioning	Demolition	1/1/2050	12/31/2050	5.00	260	—
Demolition	Demolition	3/1/2027	3/12/2027	5.00	10.0	—
Site Preparation	Site Preparation	3/1/2027	4/15/2027	5.00	34.0	—
Substation Site Preparation	Site Preparation	4/16/2027	4/30/2027	5.00	11.0	—
Grading	Grading	5/1/2027	8/31/2027	5.00	87.0	—
Substation Site Grading	Grading	9/1/2027	9/30/2027	5.00	22.0	—
Substation Installation	Building Construction	2/1/2028	10/1/2028	5.00	174	—
Gen-Tie Foundation and Tower Erection	Building Construction	2/1/2028	5/31/2028	5.00	87.0	—
Gen-Tie Stringing and Pulling	Building Construction	6/1/2028	7/1/2028	5.00	22.0	—
SCE Interconnection Facility Upgrades	Building Construction	4/1/2028	10/1/2028	5.00	130	—
Commissioning	Building Construction	10/2/2028	4/1/2029	5.00	130	—
Battery/Container Installation	Building Construction	10/1/2027	10/1/2028	5.00	261	—
Paving	Paving	8/15/2027	9/30/2027	5.00	34.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Decommissioning	Concrete/Industrial Saws	Diesel	Average	2.00	10.0	33.0	0.73
Decommissioning	Cranes	Diesel	Average	2.00	10.0	367	0.29
Decommissioning	Rubber Tired Dozers	Diesel	Average	2.00	10.0	367	0.40
Decommissioning	Tractors/Loaders/Back hoes	Diesel	Average	2.00	10.0	84.0	0.37
Demolition	Rubber Tired Dozers	Diesel	Average	1.00	10.0	367	0.40
Demolition	Concrete/Industrial Saws	Diesel	Average	1.00	10.0	33.0	0.73
Demolition	Tractors/Loaders/Back hoes	Diesel	Average	2.00	10.0	84.0	0.37
Site Preparation	Tractors/Loaders/Back hoes	Diesel	Average	2.00	10.0	84.0	0.37
Site Preparation	Excavators	Diesel	Average	2.00	10.0	36.0	0.38
Site Preparation	Rubber Tired Dozers	Diesel	Average	2.00	10.0	367	0.40
Substation Site Preparation	Tractors/Loaders/Back hoes	Diesel	Average	1.00	10.0	84.0	0.37
Substation Site Preparation	Excavators	Diesel	Average	1.00	10.0	36.0	0.38
Substation Site Preparation	Rubber Tired Dozers	Diesel	Average	1.00	10.0	367	0.40
Grading	Graders	Diesel	Average	2.00	10.0	148	0.41
Grading	Tractors/Loaders/Back hoes	Diesel	Average	2.00	10.0	84.0	0.37
Grading	Rollers	Diesel	Average	2.00	10.0	36.0	0.38
Substation Site Grading	Graders	Diesel	Average	1.00	10.0	148	0.41
Substation Site Grading	Tractors/Loaders/Back hoes	Diesel	Average	1.00	10.0	84.0	0.37
Substation Site Grading	Rollers	Diesel	Average	1.00	10.0	36.0	0.38
Substation Installation	Aerial Lifts	Diesel	Average	1.00	10.0	46.0	0.31

Substation Installation	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48
Substation Installation	Bore/Drill Rigs	Diesel	Average	1.00	10.0	83.0	0.50
Substation Installation	Forklifts	Diesel	Average	1.00	10.0	82.0	0.20
Substation Installation	Trenchers	Diesel	Average	1.00	10.0	40.0	0.50
Gen-Tie Foundation and Tower Erection	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48
Gen-Tie Foundation and Tower Erection	Cranes	Diesel	Average	1.00	10.0	367	0.29
Gen-Tie Foundation and Tower Erection	Forklifts	Diesel	Average	1.00	10.0	82.0	0.20
Gen-Tie Foundation and Tower Erection	Pumps	Diesel	Average	1.00	10.0	11.0	0.74
Gen-Tie Foundation and Tower Erection	Welders	Diesel	Average	1.00	10.0	46.0	0.45
Gen-Tie Stringing and Pulling	Aerial Lifts	Diesel	Average	1.00	10.0	46.0	0.31
Gen-Tie Stringing and Pulling	Tractors/Loaders/Back hoes	Diesel	Average	1.00	10.0	84.0	0.37
SCE Interconnection Facility Upgrades	Air Compressors	Diesel	Average	4.00	10.0	37.0	0.48
SCE Interconnection Facility Upgrades	Cranes	Diesel	Average	2.00	10.0	367	0.29
SCE Interconnection Facility Upgrades	Excavators	Diesel	Average	2.00	10.0	36.0	0.38
SCE Interconnection Facility Upgrades	Rough Terrain Forklifts	Diesel	Average	2.00	10.0	96.0	0.40
SCE Interconnection Facility Upgrades	Skid Steer Loaders	Diesel	Average	2.00	10.0	71.0	0.37
SCE Interconnection Facility Upgrades	Tractors/Loaders/Back hoes	Diesel	Average	2.00	10.0	84.0	0.37
SCE Interconnection Facility Upgrades	Trenchers	Diesel	Average	1.00	10.0	40.0	0.50
Battery/Container Installation	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48

Battery/Container Installation	Cranes	Diesel	Average	1.00	10.0	367	0.29
Battery/Container Installation	Forklifts	Diesel	Average	1.00	10.0	82.0	0.20
Battery/Container Installation	Tractors/Loaders/Back hoes	Diesel	Average	1.00	10.0	84.0	0.37
Paving	Pavers	Diesel	Average	2.00	10.0	81.0	0.42
Paving	Paving Equipment	Diesel	Average	2.00	10.0	89.0	0.36
Paving	Rollers	Diesel	Average	2.00	10.0	36.0	0.38

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Decommissioning	Concrete/Industrial Saws	Diesel	Average	2.00	10.0	33.0	0.73
Decommissioning	Cranes	Diesel	Tier 4 Final	2.00	10.0	367	0.29
Decommissioning	Rubber Tired Dozers	Diesel	Tier 4 Final	2.00	10.0	367	0.40
Decommissioning	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	2.00	10.0	84.0	0.37
Demolition	Rubber Tired Dozers	Diesel	Tier 4 Final	1.00	10.0	367	0.40
Demolition	Concrete/Industrial Saws	Diesel	Average	1.00	10.0	33.0	0.73
Demolition	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	2.00	10.0	84.0	0.37
Site Preparation	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	2.00	10.0	84.0	0.37
Site Preparation	Excavators	Diesel	Tier 4 Final	2.00	10.0	36.0	0.38
Site Preparation	Rubber Tired Dozers	Diesel	Tier 4 Final	2.00	10.0	367	0.40
Substation Site Preparation	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	1.00	10.0	84.0	0.37
Substation Site Preparation	Excavators	Diesel	Tier 4 Final	1.00	10.0	36.0	0.38

Substation Site Preparation	Rubber Tired Dozers	Diesel	Tier 4 Final	1.00	10.0	367	0.40
Grading	Graders	Diesel	Tier 4 Final	2.00	10.0	148	0.41
Grading	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	2.00	10.0	84.0	0.37
Grading	Rollers	Diesel	Average	2.00	10.0	36.0	0.38
Substation Site Grading	Graders	Diesel	Tier 4 Final	1.00	10.0	148	0.41
Substation Site Grading	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	1.00	10.0	84.0	0.37
Substation Site Grading	Rollers	Diesel	Average	1.00	10.0	36.0	0.38
Substation Installation	Aerial Lifts	Diesel	Average	1.00	10.0	46.0	0.31
Substation Installation	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48
Substation Installation	Bore/Drill Rigs	Diesel	Tier 4 Final	1.00	10.0	83.0	0.50
Substation Installation	Forklifts	Diesel	Tier 4 Final	1.00	10.0	82.0	0.20
Substation Installation	Trenchers	Diesel	Average	1.00	10.0	40.0	0.50
Gen-Tie Foundation and Tower Erection	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48
Gen-Tie Foundation and Tower Erection	Cranes	Diesel	Tier 4 Final	1.00	10.0	367	0.29
Gen-Tie Foundation and Tower Erection	Forklifts	Diesel	Tier 4 Final	1.00	10.0	82.0	0.20
Gen-Tie Foundation and Tower Erection	Pumps	Diesel	Average	1.00	10.0	11.0	0.74
Gen-Tie Foundation and Tower Erection	Welders	Diesel	Average	1.00	10.0	46.0	0.45
Gen-Tie Stringing and Pulling	Aerial Lifts	Diesel	Average	1.00	10.0	46.0	0.31
Gen-Tie Stringing and Pulling	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	1.00	10.0	84.0	0.37
SCE Interconnection Facility Upgrades	Air Compressors	Diesel	Average	4.00	10.0	37.0	0.48

SCE Interconnection Facility Upgrades	Cranes	Diesel	Tier 4 Final	2.00	10.0	367	0.29
SCE Interconnection Facility Upgrades	Excavators	Diesel	Tier 4 Final	2.00	10.0	36.0	0.38
SCE Interconnection Facility Upgrades	Rough Terrain Forklifts	Diesel	Tier 4 Final	2.00	10.0	96.0	0.40
SCE Interconnection Facility Upgrades	Skid Steer Loaders	Diesel	Tier 4 Final	2.00	10.0	71.0	0.37
SCE Interconnection Facility Upgrades	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	2.00	10.0	84.0	0.37
SCE Interconnection Facility Upgrades	Trenchers	Diesel	Average	1.00	10.0	40.0	0.50
Battery/Container Installation	Air Compressors	Diesel	Average	1.00	10.0	37.0	0.48
Battery/Container Installation	Cranes	Diesel	Tier 4 Final	1.00	10.0	367	0.29
Battery/Container Installation	Forklifts	Diesel	Tier 4 Final	1.00	10.0	82.0	0.20
Battery/Container Installation	Tractors/Loaders/Back hoes	Diesel	Tier 4 Final	1.00	10.0	84.0	0.37
Paving	Pavers	Diesel	Tier 4 Final	2.00	10.0	81.0	0.42
Paving	Paving Equipment	Diesel	Tier 4 Final	2.00	10.0	89.0	0.36
Paving	Rollers	Diesel	Average	2.00	10.0	36.0	0.38

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Site Preparation	—	—	—	—
Site Preparation	Worker	242	75.0	LDA,LDT1,LDT2
Site Preparation	Vendor	12.0	10.2	HHDT,MHDT
Site Preparation	Hauling	24.0	75.0	HHDT

Site Preparation	Onsite truck	44.0	0.25	HHDT
Substation Site Preparation	—	—	—	—
Substation Site Preparation	Worker	242	75.0	LDA,LDT1,LDT2
Substation Site Preparation	Vendor	12.0	10.2	HHDT,MHDT
Substation Site Preparation	Hauling	100	75.0	HHDT
Substation Site Preparation	Onsite truck	44.0	0.25	HHDT
Grading	—	—	—	—
Grading	Worker	242	75.0	LDA,LDT1,LDT2
Grading	Vendor	12.0	10.2	HHDT,MHDT
Grading	Hauling	524	75.0	HHDT
Grading	Onsite truck	44.0	0.25	HHDT
Substation Site Grading	—	—	—	—
Substation Site Grading	Worker	242	75.0	LDA,LDT1,LDT2
Substation Site Grading	Vendor	12.0	10.2	HHDT,MHDT
Substation Site Grading	Hauling	486	75.0	HHDT
Substation Site Grading	Onsite truck	44.0	0.25	HHDT
Battery/Container Installation	—	—	—	—
Battery/Container Installation	Worker	242	75.0	LDA,LDT1,LDT2
Battery/Container Installation	Vendor	12.0	10.2	HHDT,MHDT
Battery/Container Installation	Hauling	20.0	81.0	HHDT
Battery/Container Installation	Onsite truck	44.0	0.25	HHDT
Substation Installation	—	—	—	—
Substation Installation	Worker	121	75.0	LDA,LDT1,LDT2
Substation Installation	Vendor	12.0	10.2	HHDT,MHDT
Substation Installation	Hauling	4.00	75.0	HHDT
Substation Installation	Onsite truck	44.0	0.25	HHDT
Gen-Tie Foundation and Tower Erection	—	—	—	—

Gen-Tie Foundation and Tower Erection	Worker	121	75.0	LDA,LDT1,LDT2
Gen-Tie Foundation and Tower Erection	Vendor	12.0	10.2	HHDT,MHDT
Gen-Tie Foundation and Tower Erection	Hauling	0.00	20.0	HHDT
Gen-Tie Foundation and Tower Erection	Onsite truck	44.0	0.25	HHDT
Decommissioning	—	—	—	—
Decommissioning	Worker	242	75.0	LDA,LDT1,LDT2
Decommissioning	Vendor	12.0	10.2	HHDT,MHDT
Decommissioning	Hauling	20.0	81.0	HHDT
Decommissioning	Onsite truck	44.0	0.25	HHDT
Gen-Tie Stringing and Pulling	—	—	—	—
Gen-Tie Stringing and Pulling	Worker	121	75.0	LDA,LDT1,LDT2
Gen-Tie Stringing and Pulling	Vendor	12.0	10.2	HHDT,MHDT
Gen-Tie Stringing and Pulling	Hauling	0.00	20.0	HHDT
Gen-Tie Stringing and Pulling	Onsite truck	44.0	0.25	HHDT
SCE Interconnection Facility Upgrades	—	—	—	—
SCE Interconnection Facility Upgrades	Worker	121	75.0	LDA,LDT1,LDT2
SCE Interconnection Facility Upgrades	Vendor	12.0	10.2	HHDT,MHDT
SCE Interconnection Facility Upgrades	Hauling	0.00	20.0	HHDT
SCE Interconnection Facility Upgrades	Onsite truck	44.0	0.25	HHDT
Commissioning	—	—	—	—
Commissioning	Worker	242	75.0	LDA,LDT1,LDT2
Commissioning	Vendor	12.0	10.2	HHDT,MHDT
Commissioning	Hauling	0.00	20.0	HHDT

Commissioning	Onsite truck	44.0	0.25	HHDT
Paving	—	—	—	—
Paving	Worker	16.0	75.0	LDA,LDT1,LDT2
Paving	Vendor	4.00	10.2	HHDT,MHDT
Paving	Hauling	0.00	20.0	HHDT
Paving	Onsite truck	0.00	—	HHDT
Demolition	—	—	—	—
Demolition	Worker	10.0	75.0	LDA,LDT1,LDT2
Demolition	Vendor	4.00	10.2	HHDT,MHDT
Demolition	Hauling	6.00	75.0	HHDT
Demolition	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Site Preparation	—	—	—	—
Site Preparation	Worker	242	75.0	LDA,LDT1,LDT2
Site Preparation	Vendor	12.0	10.2	HHDT,MHDT
Site Preparation	Hauling	24.0	75.0	HHDT
Site Preparation	Onsite truck	44.0	0.25	HHDT
Substation Site Preparation	—	—	—	—
Substation Site Preparation	Worker	242	75.0	LDA,LDT1,LDT2
Substation Site Preparation	Vendor	12.0	10.2	HHDT,MHDT
Substation Site Preparation	Hauling	100	75.0	HHDT
Substation Site Preparation	Onsite truck	44.0	0.25	HHDT
Grading	—	—	—	—
Grading	Worker	242	75.0	LDA,LDT1,LDT2
Grading	Vendor	12.0	10.2	HHDT,MHDT
Grading	Hauling	524	75.0	HHDT

Grading	Onsite truck	44.0	0.25	HHDT
Substation Site Grading	—	—	—	—
Substation Site Grading	Worker	242	75.0	LDA,LDT1,LDT2
Substation Site Grading	Vendor	12.0	10.2	HHDT,MHDT
Substation Site Grading	Hauling	486	75.0	HHDT
Substation Site Grading	Onsite truck	44.0	0.25	HHDT
Battery/Container Installation	—	—	—	—
Battery/Container Installation	Worker	242	75.0	LDA,LDT1,LDT2
Battery/Container Installation	Vendor	12.0	10.2	HHDT,MHDT
Battery/Container Installation	Hauling	20.0	81.0	HHDT
Battery/Container Installation	Onsite truck	44.0	0.25	HHDT
Substation Installation	—	—	—	—
Substation Installation	Worker	121	75.0	LDA,LDT1,LDT2
Substation Installation	Vendor	12.0	10.2	HHDT,MHDT
Substation Installation	Hauling	4.00	75.0	HHDT
Substation Installation	Onsite truck	44.0	0.25	HHDT
Gen-Tie Foundation and Tower Erection	—	—	—	—
Gen-Tie Foundation and Tower Erection	Worker	121	75.0	LDA,LDT1,LDT2
Gen-Tie Foundation and Tower Erection	Vendor	12.0	10.2	HHDT,MHDT
Gen-Tie Foundation and Tower Erection	Hauling	0.00	20.0	HHDT
Gen-Tie Foundation and Tower Erection	Onsite truck	44.0	0.25	HHDT
Decommissioning	—	—	—	—
Decommissioning	Worker	242	75.0	LDA,LDT1,LDT2
Decommissioning	Vendor	12.0	10.2	HHDT,MHDT
Decommissioning	Hauling	20.0	81.0	HHDT

Decommissioning	Onsite truck	44.0	0.25	HHDT
Gen-Tie Stringing and Pulling	—	—	—	—
Gen-Tie Stringing and Pulling	Worker	121	75.0	LDA,LDT1,LDT2
Gen-Tie Stringing and Pulling	Vendor	12.0	10.2	HHDT,MHDT
Gen-Tie Stringing and Pulling	Hauling	0.00	20.0	HHDT
Gen-Tie Stringing and Pulling	Onsite truck	44.0	0.25	HHDT
SCE Interconnection Facility Upgrades	—	—	—	—
SCE Interconnection Facility Upgrades	Worker	121	75.0	LDA,LDT1,LDT2
SCE Interconnection Facility Upgrades	Vendor	12.0	10.2	HHDT,MHDT
SCE Interconnection Facility Upgrades	Hauling	0.00	20.0	HHDT
SCE Interconnection Facility Upgrades	Onsite truck	44.0	0.25	HHDT
Commissioning	—	—	—	—
Commissioning	Worker	242	75.0	LDA,LDT1,LDT2
Commissioning	Vendor	12.0	10.2	HHDT,MHDT
Commissioning	Hauling	0.00	20.0	HHDT
Commissioning	Onsite truck	44.0	0.25	HHDT
Paving	—	—	—	—
Paving	Worker	16.0	75.0	LDA,LDT1,LDT2
Paving	Vendor	4.00	10.2	HHDT,MHDT
Paving	Hauling	0.00	20.0	HHDT
Paving	Onsite truck	0.00	—	HHDT
Demolition	—	—	—	—
Demolition	Worker	10.0	75.0	LDA,LDT1,LDT2
Demolition	Vendor	4.00	10.2	HHDT,MHDT
Demolition	Hauling	6.00	75.0	HHDT

Demolition	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)
Battery/Container Installation	0.00	0.00	0.00	0.00	376

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (Ton of Debris)	Acres Paved (acres)
Decommissioning	0.00	0.00	0.00	0.00	—
Demolition	0.00	0.00	0.00	4,560	—
Site Preparation	—	—	42.5	0.00	—
Substation Site Preparation	—	—	6.88	0.00	—
Grading	364,155	—	87.0	0.00	—
Substation Site Grading	85,530	—	11.0	0.00	—
Paving	0.00	0.00	0.00	0.00	7.94

5.6.2. Construction Earthmoving Control Strategies

Control Strategies Applied	Frequency (per day)	PM10 Reduction	PM2.5 Reduction
Water Exposed Area	3	74%	74%

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
General Light Industry	0.00	0%
Parking Lot	0.14	0%
Other Asphalt Surfaces	7.80	100%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2027	0.00	532	0.03	< 0.005
2028	0.00	532	0.03	< 0.005
2029	0.00	532	0.03	< 0.005
2050	0.00	532	0.03	< 0.005

5.9. Operational Mobile Sources

5.9.1. Unmitigated

Land Use Type	Trips/Weekday	Trips/Saturday	Trips/Sunday	Trips/Year	VMt/Weekday	VMt/Saturday	VMt/Sunday	VMt/Year
General Light Industry	32.0	7.99	7.99	9,174	578	144	144	165,788
Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

5.9.2. Mitigated

Land Use Type	Trips/Weekday	Trips/Saturday	Trips/Sunday	Trips/Year	VMt/Weekday	VMt/Saturday	VMt/Sunday	VMt/Year
General Light Industry	32.0	7.99	7.99	9,174	578	144	144	165,788

Parking Lot	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Asphalt Surfaces	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

5.10. Operational Area Sources

5.10.1. Hearths

5.10.1.1. Unmitigated

5.10.1.2. Mitigated

5.10.2. Architectural Coatings

Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)
0	0.00	3,600	1,200	20,752

5.10.3. Landscape Equipment

Season	Unit	Value
Snow Days	day/yr	0.00
Summer Days	day/yr	180

5.10.4. Landscape Equipment - Mitigated

Season	Unit	Value
Snow Days	day/yr	0.00
Summer Days	day/yr	180

5.11. Operational Energy Consumption

5.11.1. Unmitigated

Electricity (kWh/yr) and CO2 and CH4 and N2O and Natural Gas (kBTU/yr)

Land Use	Electricity (kWh/yr)	CO2	CH4	N2O	Natural Gas (kBTU/yr)
General Light Industry	49,520	346	0.0330	0.0040	0.00
Parking Lot	5,342	346	0.0330	0.0040	0.00
Other Asphalt Surfaces	67,664,000	346	0.0330	0.0040	0.00

5.11.2. Mitigated

Electricity (kWh/yr) and CO2 and CH4 and N2O and Natural Gas (kBTU/yr)

Land Use	Electricity (kWh/yr)	CO2	CH4	N2O	Natural Gas (kBTU/yr)
General Light Industry	49,520	346	0.0330	0.0040	0.00
Parking Lot	5,342	346	0.0330	0.0040	0.00
Other Asphalt Surfaces	67,664,000	346	0.0330	0.0040	0.00

5.12. Operational Water and Wastewater Consumption

5.12.1. Unmitigated

Land Use	Indoor Water (gal/year)	Outdoor Water (gal/year)
General Light Industry	555,000	1,540,000
Parking Lot	0.00	0.00
Other Asphalt Surfaces	0.00	0.00

5.12.2. Mitigated

Land Use	Indoor Water (gal/year)	Outdoor Water (gal/year)
General Light Industry	555,000	1,540,000
Parking Lot	0.00	0.00
Other Asphalt Surfaces	0.00	0.00

5.13. Operational Waste Generation

5.13.1. Unmitigated

Land Use	Waste (ton/year)	Cogeneration (kWh/year)
General Light Industry	2.98	—
Parking Lot	0.00	—
Other Asphalt Surfaces	0.00	—

5.13.2. Mitigated

Land Use	Waste (ton/year)	Cogeneration (kWh/year)
General Light Industry	2.98	—
Parking Lot	0.00	—
Other Asphalt Surfaces	0.00	—

5.14. Operational Refrigeration and Air Conditioning Equipment

5.14.1. Unmitigated

Land Use Type	Equipment Type	Refrigerant	GWP	Quantity (kg)	Operations Leak Rate	Service Leak Rate	Times Serviced
General Light Industry	Other commercial A/C and heat pumps	User Defined	675	0.30	4.00	4.00	18.0

5.14.2. Mitigated

Land Use Type	Equipment Type	Refrigerant	GWP	Quantity (kg)	Operations Leak Rate	Service Leak Rate	Times Serviced
General Light Industry	Other commercial A/C and heat pumps	User Defined	675	0.30	4.00	4.00	18.0

5.15. Operational Off-Road Equipment

5.15.1. Unmitigated

Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Cranes	Diesel	Average	1.00	8.00	367	0.29
Forklifts	Diesel	Average	1.00	8.00	82.0	0.20

5.15.2. Mitigated

Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Cranes	Diesel	Average	1.00	8.00	367	0.29
Forklifts	Diesel	Average	1.00	8.00	82.0	0.20

5.16. Stationary Sources

5.16.1. Emergency Generators and Fire Pumps

Equipment Type	Fuel Type	Number per Day	Hours per Day	Hours per Year	Horsepower	Load Factor

5.16.2. Process Boilers

Equipment Type	Fuel Type	Number	Boiler Rating (MMBtu/hr)	Daily Heat Input (MMBtu/day)	Annual Heat Input (MMBtu/yr)

5.17. User Defined

Equipment Type	Fuel Type

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

6. Climate Risk Detailed Report

6.1. Climate Risk Summary

Cal-Adapt midcentury 2040–2059 average projections for four hazards are reported below for your project location. These are under Representation Concentration Pathway (RCP) 8.5 which assumes GHG emissions will continue to rise strongly through 2050 and then plateau around 2100.

Climate Hazard	Result for Project Location	Unit

Temperature and Extreme Heat	31.1	annual days of extreme heat
Extreme Precipitation	3.05	annual days with precipitation above 20 mm
Sea Level Rise	—	meters of inundation depth
Wildfire	44.5	annual hectares burned

Temperature and Extreme Heat data are for grid cell in which your project are located. The projection is based on the 98th historical percentile of daily maximum/minimum temperatures from observed historical data (32 climate model ensemble from Cal-Adapt, 2040–2059 average under RCP 8.5). Each grid cell is 6 kilometers (km) by 6 km, or 3.7 miles (mi) by 3.7 mi.

Extreme Precipitation data are for the grid cell in which your project are located. The threshold of 20 mm is equivalent to about $\frac{3}{4}$ an inch of rain, which would be light to moderate rainfall if received over a full day or heavy rain if received over a period of 2 to 4 hours. Each grid cell is 6 kilometers (km) by 6 km, or 3.7 miles (mi) by 3.7 mi.

Sea Level Rise data are for the grid cell in which your project are located. The projections are from Radke et al. (2017), as reported in Cal-Adapt (Radke et al., 2017, CEC-500-2017-008), and consider inundation location and depth for the San Francisco Bay, the Sacramento-San Joaquin River Delta and California coast resulting different increments of sea level rise coupled with extreme storm events. Users may select from four scenarios to view the range in potential inundation depth for the grid cell. The four scenarios are: No rise, 0.5 meter, 1.0 meter, 1.41 meters

Wildfire data are for the grid cell in which your project are located. The projections are from UC Davis, as reported in Cal-Adapt (2040–2059 average under RCP 8.5), and consider historical data of climate, vegetation, population density, and large (> 400 ha) fire history. Users may select from four model simulations to view the range in potential wildfire probabilities for the grid cell. The four simulations make different assumptions about expected rainfall and temperature are: Warmer/drier (HadGEM2-ES), Cooler/wetter (CNRM-CM5), Average conditions (CanESM2), Range of different rainfall and temperature possibilities (MIROC5). Each grid cell is 6 kilometers (km) by 6 km, or 3.7 miles (mi) by 3.7 mi.

6.2. Initial Climate Risk Scores

Climate Hazard	Exposure Score	Sensitivity Score	Adaptive Capacity Score	Vulnerability Score
Temperature and Extreme Heat	N/A	N/A	N/A	N/A
Extreme Precipitation	N/A	N/A	N/A	N/A
Sea Level Rise	N/A	N/A	N/A	N/A
Wildfire	N/A	N/A	N/A	N/A
Flooding	N/A	N/A	N/A	N/A
Drought	N/A	N/A	N/A	N/A
Snowpack Reduction	N/A	N/A	N/A	N/A
Air Quality Degradation	N/A	N/A	N/A	N/A

The sensitivity score reflects the extent to which a project would be adversely affected by exposure to a climate hazard. Exposure is rated on a scale of 1 to 5, with a score of 5 representing the greatest exposure.

The adaptive capacity of a project refers to its ability to manage and reduce vulnerabilities from projected climate hazards. Adaptive capacity is rated on a scale of 1 to 5, with a score of 5 representing the greatest ability to adapt.

The overall vulnerability scores are calculated based on the potential impacts and adaptive capacity assessments for each hazard. Scores do not include implementation of climate risk reduction measures.

6.3. Adjusted Climate Risk Scores

Climate Hazard	Exposure Score	Sensitivity Score	Adaptive Capacity Score	Vulnerability Score
Temperature and Extreme Heat	N/A	N/A	N/A	N/A
Extreme Precipitation	N/A	N/A	N/A	N/A
Sea Level Rise	N/A	N/A	N/A	N/A
Wildfire	N/A	N/A	N/A	N/A
Flooding	N/A	N/A	N/A	N/A
Drought	N/A	N/A	N/A	N/A
Snowpack Reduction	N/A	N/A	N/A	N/A
Air Quality Degradation	N/A	N/A	N/A	N/A

The sensitivity score reflects the extent to which a project would be adversely affected by exposure to a climate hazard. Exposure is rated on a scale of 1 to 5, with a score of 5 representing the greatest exposure.

The adaptive capacity of a project refers to its ability to manage and reduce vulnerabilities from projected climate hazards. Adaptive capacity is rated on a scale of 1 to 5, with a score of 5 representing the greatest ability to adapt.

The overall vulnerability scores are calculated based on the potential impacts and adaptive capacity assessments for each hazard. Scores include implementation of climate risk reduction measures.

6.4. Climate Risk Reduction Measures

7. Health and Equity Details

7.1. CalEnviroScreen 4.0 Scores

The maximum CalEnviroScreen score is 100. A high score (i.e., greater than 50) reflects a higher pollution burden compared to other census tracts in the state.

Indicator	Result for Project Census Tract
Exposure Indicators	—
AQ-Ozone	93.9
AQ-PM	47.5
AQ-DPM	11.9
Drinking Water	70.5
Lead Risk Housing	15.1
Pesticides	0.00
Toxic Releases	55.2

Traffic	86.0
Effect Indicators	—
CleanUp Sites	25.6
Groundwater	0.00
Haz Waste Facilities/Generators	0.00
Impaired Water Bodies	0.00
Solid Waste	35.7
Sensitive Population	—
Asthma	36.7
Cardio-vascular	33.5
Low Birth Weights	1.68
Socioeconomic Factor Indicators	—
Education	36.6
Housing	42.3
Linguistic	28.0
Poverty	33.0
Unemployment	55.0

7.2. Healthy Places Index Scores

The maximum Health Places Index score is 100. A high score (i.e., greater than 50) reflects healthier community conditions compared to other census tracts in the state.

Indicator	Result for Project Census Tract
Economic	—
Above Poverty	60.3105351
Employed	26.07468241
Median HI	70.81996664
Education	—
Bachelor's or higher	59.373797
High school enrollment	100

Preschool enrollment	8.507635057
Transportation	—
Auto Access	81.29090209
Active commuting	1.039394328
Social	—
2-parent households	83.60066727
Voting	61.83754652
Neighborhood	—
Alcohol availability	86.05158476
Park access	45.14307712
Retail density	17.13075837
Supermarket access	31.22032593
Tree canopy	54.26664956
Housing	—
Homeownership	89.31092006
Housing habitability	74.78506352
Low-inc homeowner severe housing cost burden	64.04465546
Low-inc renter severe housing cost burden	61.6963942
Uncrowded housing	36.04516874
Health Outcomes	—
Insured adults	33.59425125
Arthritis	0.0
Asthma ER Admissions	72.6
High Blood Pressure	0.0
Cancer (excluding skin)	0.0
Asthma	0.0
Coronary Heart Disease	0.0
Chronic Obstructive Pulmonary Disease	0.0

Diagnosed Diabetes	0.0
Life Expectancy at Birth	29.2
Cognitively Disabled	46.5
Physically Disabled	76.0
Heart Attack ER Admissions	40.6
Mental Health Not Good	0.0
Chronic Kidney Disease	0.0
Obesity	0.0
Pedestrian Injuries	74.9
Physical Health Not Good	0.0
Stroke	0.0
Health Risk Behaviors	—
Binge Drinking	0.0
Current Smoker	0.0
No Leisure Time for Physical Activity	0.0
Climate Change Exposures	—
Wildfire Risk	96.6
SLR Inundation Area	0.0
Children	24.2
Elderly	39.0
English Speaking	51.9
Foreign-born	12.1
Outdoor Workers	51.5
Climate Change Adaptive Capacity	—
Impervious Surface Cover	96.7
Traffic Density	70.3
Traffic Access	23.0
Other Indices	—

Hardship	49.6
Other Decision Support	—
2016 Voting	52.8

7.3. Overall Health & Equity Scores

Metric	Result for Project Census Tract
CalEnviroScreen 4.0 Score for Project Location (a)	24.0
Healthy Places Index Score for Project Location (b)	54.0
Project Located in a Designated Disadvantaged Community (Senate Bill 535)	No
Project Located in a Low-Income Community (Assembly Bill 1550)	No
Project Located in a Community Air Protection Program Community (Assembly Bill 617)	No

a: The maximum CalEnviroScreen score is 100. A high score (i.e., greater than 50) reflects a higher pollution burden compared to other census tracts in the state.

b: The maximum Health Places Index score is 100. A high score (i.e., greater than 50) reflects healthier community conditions compared to other census tracts in the state.

7.4. Health & Equity Measures

No Health & Equity Measures selected.

7.5. Evaluation Scorecard

Health & Equity Evaluation Scorecard not completed.

7.6. Health & Equity Custom Measures

No Health & Equity Custom Measures created.

8. User Changes to Default Data

Screen	Justification
Construction: Construction Phases	Schedule provided by applicant.
Construction: Off-Road Equipment	Assumptions provided by applicant.
Construction: Trips and VMT	Assumptions provided by applicant.
Construction: On-Road Fugitive Dust	Assumed site is 100% paved after paving phase.

Operations: Vehicle Data	There will be 16 total onsite employees. Monday-Friday there will be 16 employees on-site from 8am-5pm. On Saturday and Sunday there will be 4 on-site employees from 8am-5pm.
Operations: Energy Use	General Light Industry land use also includes electricity for the all-electric O&M buildings. Annual RTE energy losses accounted for in a spreadsheet outside of CalEEMod. Auxiliary energy losses provided by applicant inputted into Other Asphalt Surfaces land use.
Operations: Off-Road Equipment	Project would involve using 1 crane and 1 forklift once every 2 to 3 years during routine maintenance to be able to lift and move the modular containers.
Construction: Dust From Material Movement	Assumptions provided by applicant. 3x watering per day as a mitigation measure but added here because 3x would not stick in the mitigation module.
Construction: Architectural Coatings	Assumed application of architectural coatings for O&M buildings during Battery/Container Installation phase.
Construction: Paving	Parking lot assumed to be stone surfaced.
Operations: Water and Waste Water	Annual outdoor water use was estimated from the project's landscape plan.
Land Use	BESS facility on a total of 70.8 acres. Transmission/interconnection assumed to result in approximately 52.6 acres disturbed. The total lot acreages input into the model account for these areas to be graded.
Characteristics: Utility Information	Assumes GHG intensity factors in 2029 with renewables per RPS based on the current SCE energy mix.
Operations: Refrigerants	Project applicant has committed to using R-32 in the O&M buildings.

Prairie Song Reliability Project
Generator Sets

Construction - Commissioning							Emission Factors ²								Emission Rates																
Equipment Description	Quantity	Rating		Operating Parameters/unit ¹			ROG	NOx	CO	SOx	PM10	PM2.5	CO2	CH4	N2O	ROG	NOx	CO	SOx	PM10	PM2.5	ROG	NOx	CO	SOx	PM10	PM2.5	CO2	CH4	N2O	CO2e
		kW	HP	Load Factor	hr/day	hr/yr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	MT/yr	MT/yr	MT/yr	MT/yr
Unmitigated																															
Construction/Commissioning: Diesel Generators - 2028	8	750	1,006	0.73	8	480	0.2997	4.50	2.6	0.0049	0.15	0.15	521.64	0.020944	0.004087	31.05	466.16	269.34	0.51	15.54	15.54	0.93	13.98	8.08	0.02	0.466	0.466	1,470.69	0.06	0.01	1,475.60
Mitigated																															
Construction/Commissioning: Diesel Generators - 2028	8	750	1,006	0.73	8	480	0.1399	0.50	2.6	0.0049	0.02	0.02	521.64	0.020944	0.004087	14.49	51.80	269.34	0.51	2.07	2.07	0.43	1.55	8.08	0.02	0.062	0.062	1,470.69	0.06	0.01	1,475.60

Source:

1. Operational information based on applicant input.
2. Unmitigated based on current CARB and EPA Tier 2 engine standards for Construction/Commissioning Diesel Generators. Mitigation = Tier 4 Final engines for Construction/Commissioning Diesel Generators

Operations - Testing and Maintenance							Emission Factors ²								Emission Rates																
Equipment Description	Quantity	Rating		Operating Parameters/unit ¹			ROG	NOx	CO	SOx	PM10	PM2.5	CO2	CH4	N2O	ROG	NOx	CO	SOx	PM10	PM2.5	ROG	NOx	CO	SOx	PM10	PM2.5	CO2	CH4	N2O	CO2e
		kW	HP	Load Factor	hr/day	hr/yr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	g/hp-hr	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	MT/yr	MT/yr	MT/yr	MT/yr
Operations/Backup: 275 kVa Diesel Generator	1	220	323	1.00	2	50	0.1399	0.30	2.6	0.0049	0.01	0.01	521.64	0.020944	0.004087	0.20	0.43	3.70	0.01	0.01	0.01	0.00	0.01	0.05	0.00	0.000	0.000	8.42	0.00	0.00	8.45
Operations/Backup: 500 kW Diesel Generators	2	500	744	1.00	2	50	0.1399	0.30	2.6	0.0049	0.01	0.01	521.64	0.020944	0.004087	0.92	1.97	17.06	0.03	0.07	0.07	0.01	0.02	0.21	0.00	0.001	0.001	38.81	0.00	0.00	38.94

Source:

1. Operational information based on applicant input.
2. Based on current CARB and EPA Tier 4 standards for Operations/Backup Diesel Generators. Load factor of 1 assumed for testing/maintenance and permitting. https://ww2.arb.ca.gov/sites/default/files/2020-03/Tier_Color_Chart_Off_Road_Diesel_Stds_R.pdf

Conversions:

1 kW =	1.34102	hp
1 lb =	453.6	g
1 MT =	2204.623	lb
1 MT =	1000000	g

Helicopter Emissions

Criteria Air Pollutants						Emission Factors (lb/hr)*				Emissions (lbs/day)				Emissions (tons/year)			
Helicopter	Mode	Average #LTO/Hr	Days	Hours/Day	Horsepower	ROC	NOx	CO	PM10	ROC	NOx	CO	PM10	ROC	NOx	CO	PM10
MD 600N	LTO	0.6	3	1.3	808	0.56	0.37	0.70	0.01	0.72	0.48	0.92	0.01	0.00	0.00	0.00	0.00
MD 600N	Operation	N/A	3	8.7	808	1.37	3.22	1.68	0.09	11.89	28.00	14.58	0.81	0.02	0.04	0.02	0.00
MD 600N	Total	N/A								12.62	28.49	15.49	0.82	0.02	0.04	0.02	0.00

*Federal Office of Civil Aviation (FOCA). n.d. Guidance on Determination of Helicopter Emissions.

Greenhouse Gas Emissions												
Helicopter	Mode	Average #LTO/Hr	Days	Hours/Day	Horsepower	Fuel (kg)/hr	Fuel (kg) per day	Gallons Per day	CO2 MT/yr	CH4 MT/yr	N2O/yr	CO2E/yr
MD 600N	LTO	0.6	3	1.3	808	26.7	34.71	409.3780211	11.974307	0.00	0.00	12.08
MD 600N	Operation	N/A	3	8.7	808	175.7	1,528.59					
MD 600N	Total	N/A					1,563.30					

*Federal Office of Civil Aviation (FOCA). n.d. Guidance on Determination of Helicopter Emissions.
The Climate Registry 2023

Notes		
Jet Fuel Density Kg/m3	840	
Kg to pounds	2.20462	
grams to pounds	0.00220462	
kg to metric tons	0.001	
g to metric tons	0.000001	
CO2 kg/gallon	9.75	
CH4 g/gallon	0	
N2O g/gallon	0.3	

SF6 Emissions

Enter Data here		Industry Standard	Conversion		Conversion	
lb SF6		% leak rate ^a	lb SF6/year	SF6 GWP ^b	lb/MT	CO2e/year
1,610		0.50%	3.22	23,500	2204.62	34.32

^a https://19january2021snapshot.epa.gov/sites/static/files/2016-02/documents/leakrates_circuitbreakers.pdf

^b <https://ghgprotocol.org/sites/default/files/2024-08/Global-Warming-Potential-Values%20%28August%202024%29.pdf>

R-32 Emissions

Enter Data here		Industry Standard	Conversion		Conversion	
kg R-32 ^c	lb R-32	% leak rate	lb R32/year	R-32 GWP ^d	lb/MT	CO2e/year
7,326	16,151	0.50%	32.30213063	675	2204.62	9.89

^c Includes 3.6 kg of R-32 per Power Titan II battery unit, equating to 7,326 kg for BESS cooling.

^d <https://ww2.arb.ca.gov/resources/documents/high-gwp-refrigerants>

Attachment 3

Appendix 3.1D - Antelope Valley AQMD - Application
Notice of Completeness



Antelope Valley Air Quality Management District

2551 West Avenue H Lancaster, CA 93536

661-723-8070

www.avaqmd.ca.gov

Barbara Lods, Executive Director/APCO

August 14, 2025

Garrett Lehman
Prairie Song Reliability Project LLC
140 Broadway, 46th Floor
New York, NY 10005-1155

Re: Notice of Receipt of Compete Application

Dear Mr. Lehman

The Antelope Valley Air Quality Management District (District) has received an application package from Prairie Song Reliability Project, LLC for the following equipment:

- Emergency Diesel Internal Combustion Engine - 323-brake horsepower, John Deere 6068HFG06
- Emergency Diesel Internal Combustion Engines - two engines, each 744-brake horsepower, Perkins 2806F-E18TAG1.

These units are proposed to be located approximately one mile west of the Southern California Edison (SCE) Vincent Substation at 33301 Angeles Forest Highway in unincorporated Los Angeles County, California.

Following our initial review, the applications appear to be complete. With that being said, please note, that additional information may be requested during the review process to clarify, correct, or supplement the information submitted.

Pursuant to District Rules 212 and 1401, this project does not require public notification, as the preliminary health risk assessment for the three (3) engines does not trigger public notice thresholds. The current estimated timeline for permit issuance is approximately sixty (60) days from the date the application is deemed complete.

Please be advised that this letter does not constitute a permit and does not authorize commencement of the project. If approved, final authorization will be issued in the form of an Authority to Construct (ATC) permit following completion of the District's evaluation.

Sincerely,

Barbara Lods
Executive Director

Antelope Valley Air Quality Management District

Barbara Lods, *EXECUTIVE DIRECTOR*

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Attachment 4

Appendix 3.1E - CAISO Charging and Renewables Analysis

Prairie Song – CAISO Battery Charging & Renewable Integration Analysis

Summary

This report evaluates the California ISO (CAISO) supply stack from 2020 to 2025, focusing on the interaction between battery storage and the resource mix. The primary objective is to analyze the CAISO hourly battery profile (BESS) to understand how the supply stack mix has changed during the charging block of hours. This includes examining the percentage of charging that occurs when the CAISO energy mix has a certain percentage of renewables or non-carbon penetration.

The analysis is built exclusively from raw CAISO data organized into five explicit categories: Renewables (solar, wind, geothermal, biomass, biogas, small hydro), Hydro (large hydro), Nuclear, Thermal (gas/oil/coal), and Imports. Battery storage is tracked separately outside of the summed categories. We quantify how batteries align with the renewable supply mix during charging hours, how the overall stack composition has shifted over time, and how market pricing translates into arbitrage economics.

Two operating strategies are assessed: a 4-hour battery and an 8-hour battery. For each day, charging windows are the 4 or 8 most negative battery hours, and discharging windows are the 4 or 8 most positive hours. Prices use SP15 LMPs RTPD and are volume-weighted by energy in the respective windows.

The scope of work includes analyzing data from a holistic CAISO perspective, covering both 4 and 8-hour BESS charging requirements. A summary document detailing the findings, reference data, and calculations will be delivered. Additionally, any questions arising from the document will be addressed in a 15-30 minute call.

Discussion

System-Wide Perspective (Monthly View)

Figure 1 highlights the monthly renewable share of total generation, with yearly peaks labeled. Renewable penetration has steadily grown since 2020, with visible seasonal fluctuations. Spring months tend to record the highest shares, driven by abundant hydro and solar production coupled with milder demand. Summer peaks are slightly lower due to higher thermal and import reliance during hot weather. The annual peaks demonstrate how CAISO's renewable penetration is moving consistently upward, signaling that renewable generation is setting new highs almost every year.

- Renewables now routinely exceed 50% of the stack in peak months, an inflection point for market
- The rise in peaks suggests growing stress on mid-day oversupply periods, directly tied to battery charging opportunities.

Figure 1 | CAISO Renewable Share by Month

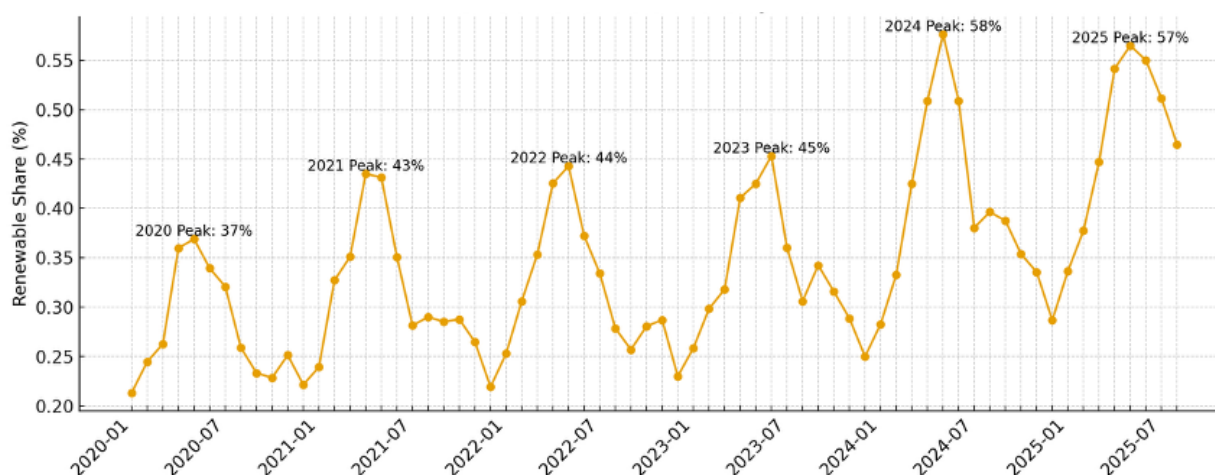
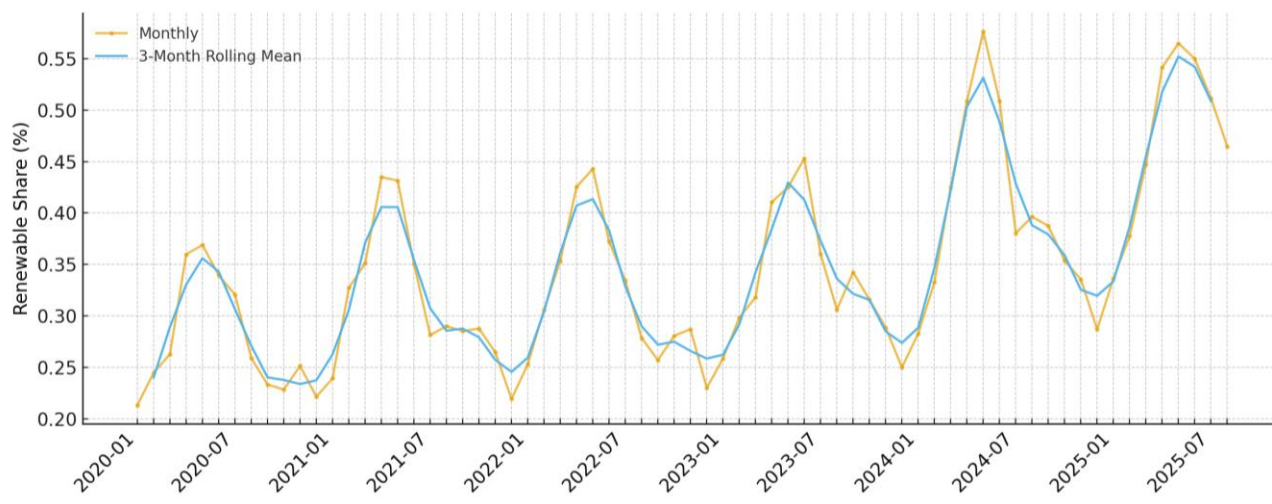


Figure 2 provides the renewable share of generation with a rolling average which smooths volatility and shows clearer trends. The upward slope across years illustrates structural growth in renewable capacity, rather than short-term weather effects. Seasonal troughs — often in late summer or early winter — are muted, while spring surges stand out.

- The rolling trend confirms a long-term upward trajectory, with renewables becoming a larger share of the baseline resource mix.
- This structural change reinforces the importance of batteries in absorbing midday surpluses and redeploying them later in the day.

Figure 2 | CAISO Renewable Share by Month (3-Month Rolling Mean)



The stack plot in Figure 3 displays the key supply components tied to the CAISO market. The purpose of this graph is to serve as an anchor to the changing supply dynamics as it reveals how different categories have shifted over time. Nuclear remains flat, thermal generation has been oscillating over the past five years, net imports are declining, while hydro varies depending on the weather pattern. Renewables, specifically solar, is the primary growth component given California's Renewable Portfolio Standard (RPS) goals.

- **Nuclear** | two Diablo Canyon units are functioning at full capacity outside of any unplanned outages and refueling maintenance cycles. The conversation around retiring these units keeps getting pushed further out on the curve
- **Thermal** | the past five years have seen the thermal demand oscillate around adjacent balancing authorities structural load growth, renewable penetration and escalating battery capacity. The two calendar years that display supportive thermal generation are 2022 and 2023 where the former was being impacted by lower hydro and structural demand growth in the Pacific Northwest/Desert Southwest while the latter saw spiking early due to a cold winter while the back half of the year started to see the batteries penetrate the energy market.
- **Imports** | this component has a lot of moving parts given it represents the net of imports and export volumes. It is tethered by market price signals in both the day-ahead bilateral market, CAISO auction clears associated to the day-ahead, real-time 15-minute market and ultimately the real-time settlements. A key piece to this number is the long-term contracts associated to renewable generation that sits outside of California but gets schedule into the CAISO markets. It should be noted that the Desert Southwest has seen an increase in their renewable buildout over the past few years, which decreases export volume throughout the day. Another piece to this component is the Pacific Northwest Water Year conditions, which vary depending on the weather patterns in the Pacific Ocean or coming down from the arctic circle (Western Canada).
- **Renewables** | the push for more utility-scaled solar development continues to be in play across the California footprint. The latest development projects angle for solar plus storage (batteries), which ties out to the renewable penetration numbers growing along with the battery capacity.

Figure 3 | CAISO Supply Stack Evolution by Month

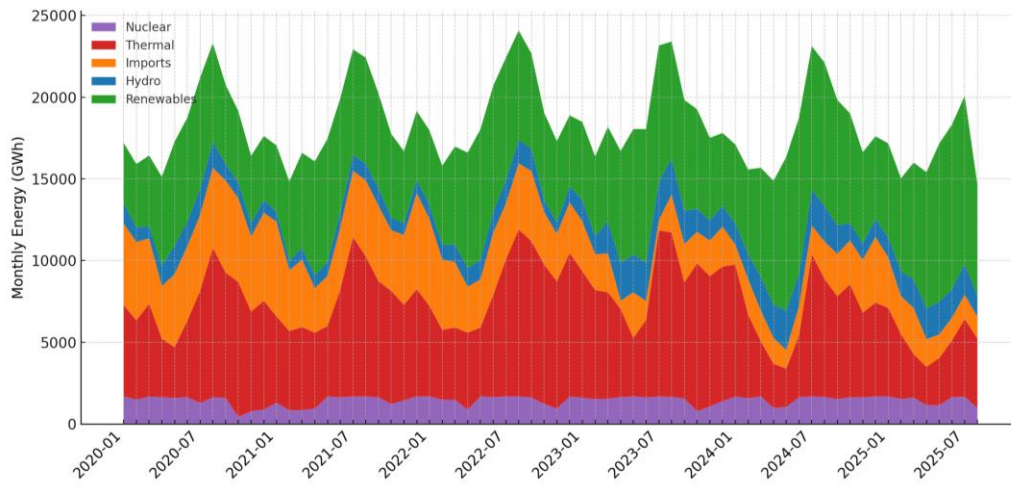
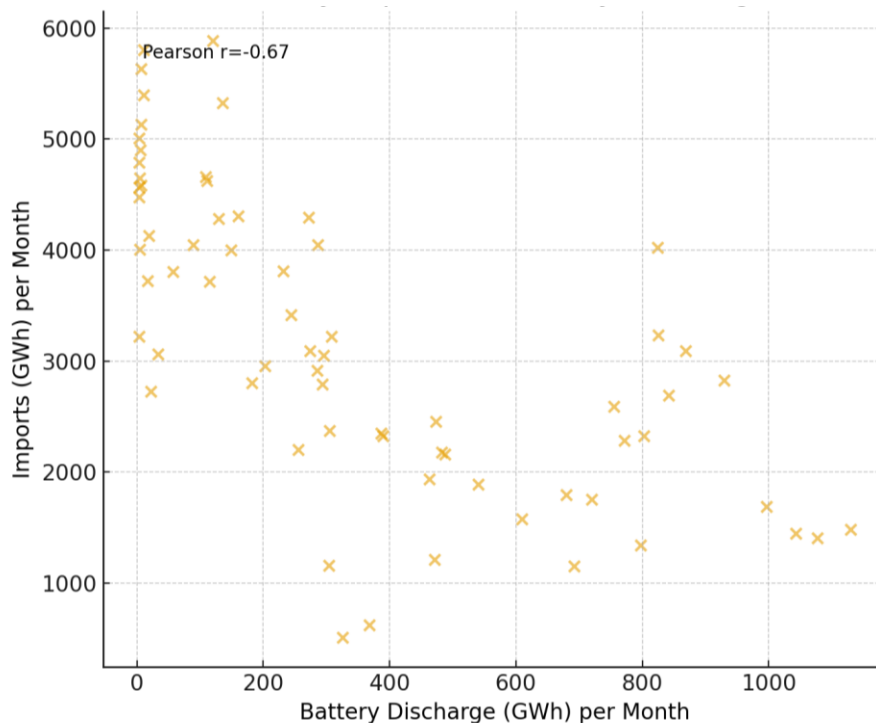


Figure 4 shows the monthly imports as it relates to the battery discharge. The scatter plot compares imports with battery discharge. The correlation highlights that as battery discharge has scaled up, imports have often moved inversely — batteries increasingly displace imports during evening peaks.

- Batteries are acting as a domestic reliability buffer, reducing dependency on in-state thermal and/or imported supply when discharging.
- The negative correlation indicates that battery storage is beginning to play a system-level balancing role, which in turn displaces the more expensive peaking units and imported volume. We have seen the impact of the battery fleet's discharge volume in the form of more natural gas molecules ending up in both PG&E and SoCal Gas storage facilities throughout the spring and summer (Gas refill season) and less withdrawals from storage in the winter months (power burn demand is lower).

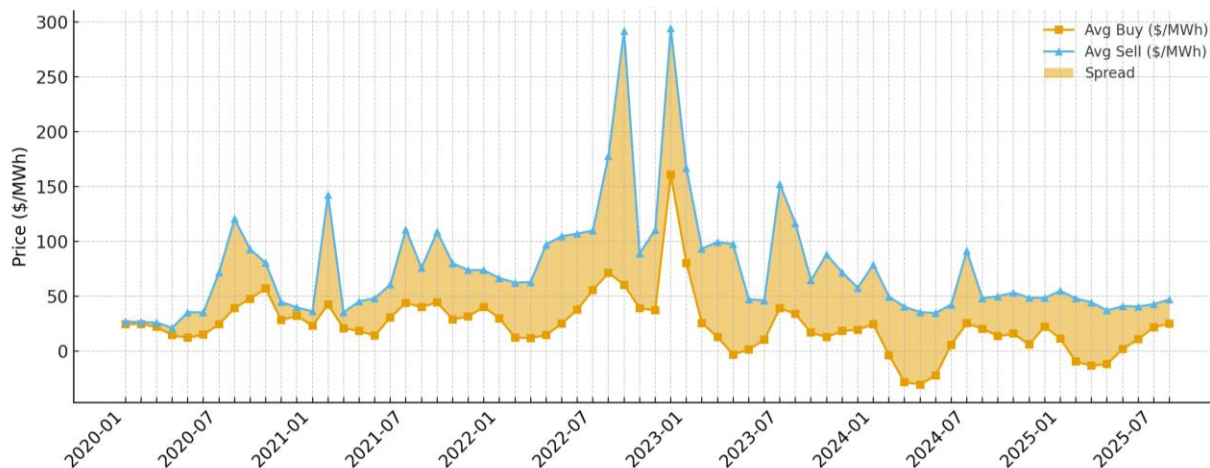
Figure 4 | Monthly Imports vs Battery Discharge



4-Hour Battery Analysis

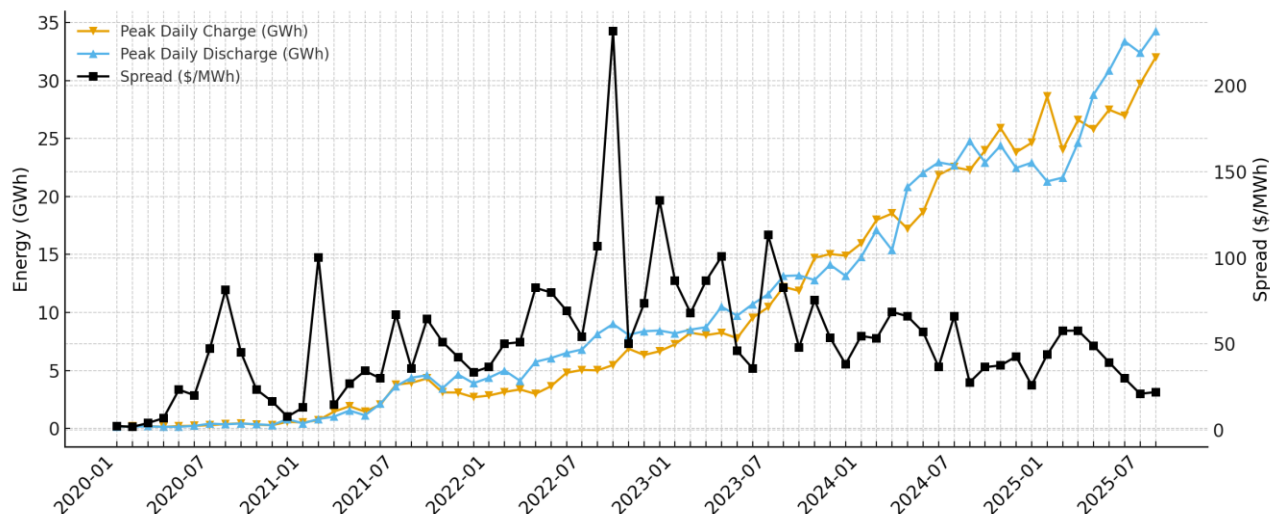
The 4-hour strategy is closely aligned with the steepest portion of CAISO's net load curve. By concentrating charging into the four most negative hours each day, batteries absorb energy precisely when solar generation peaks. As a result, charging windows consistently coincide with periods of high renewable availability, often yielding very low or even negative buy prices. Discharging occurs during the evening ramp, when demand is rising and renewable output is falling, and spreads remain strong. In this configuration, the 4-hour battery functions primarily as a solar-balancing tool: it shifts energy from periods of oversupply to those of highest demand, reducing ramping stress and capturing significant arbitrage value. Figure 5 displays the optimal monthly arbitrage opportunity for the CAISO 4-hour battery fleet. The spread value between the top and bottom four is displayed by the gold shaded area.

Figure 5 | 4h Window — Average Buy & Sell Prices



There are several moving parts to the spread calculation where the bottom four values consistently take on negative priced settles in the second quarter of a calendar year as power demand shifts down, renewables are strong, and the hydro snowpack melts push through the river system. Another factor that is tied to negative prices is the renewable energy credit (REC) valuation renewables must take into consideration when placing their offer curve associated with curtailments. Back in 2022 and 2023, the value of such RECs was strong thus producing deeply negative prices in the spring months. Another factor that comes into play is natural gas pricing given that the midday block of hours tends to fall out of the natural gas supply stack during long stretches or sit lower in the thermal (natural gas) portion of the supply curve. If spot natural gas prices are high (like Fall 2022 and Calendar Year 2023), the spread can move out as the marginal megawatt in the evening ramp still competes with the natural gas megawatt. The final piece factors in the battery capacity build out where the growth saturates the ancillary service market and the volume playing in the energy markets increases to a point where there is an inflection point where the flexible thermal and hydro resources are marginalized.

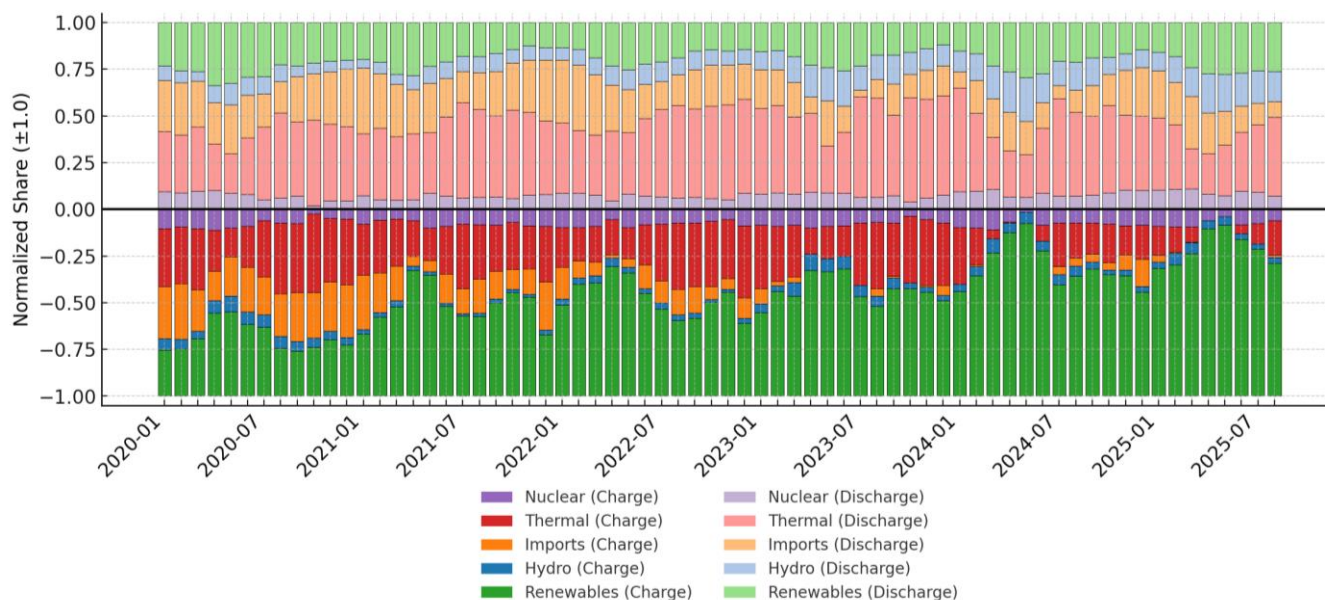
Figure 6 | 4h Window — Spread and Peak Daily Charge/Discharge



The figure above displays the spread shown in the previous graph (black line) along with the escalating battery charge and discharge volume. The inflection point reference in the previous paragraph sits in Q3-2023 and has not looked back since as the price of RECs are lower, California hydro is on its third good Water Year, natural gas premiums have been taken out of the market and the battery fleet continues to forge ahead.

The final graph (Figure 7) compares the monthly average stack composition during the daily 4-hour charging windows (negative axis) and 4-hour discharging windows (positive axis). Each side is normalized to 1.0 across Nuclear, Thermal, Imports, Hydro, and Renewables. This visualization highlights that charging draws heavily on renewable, while discharging offsets imports and thermal, confirming the balancing role of batteries.

Figure 7 | 4h Window — Charging vs Discharging Stack (Monthly Averages)



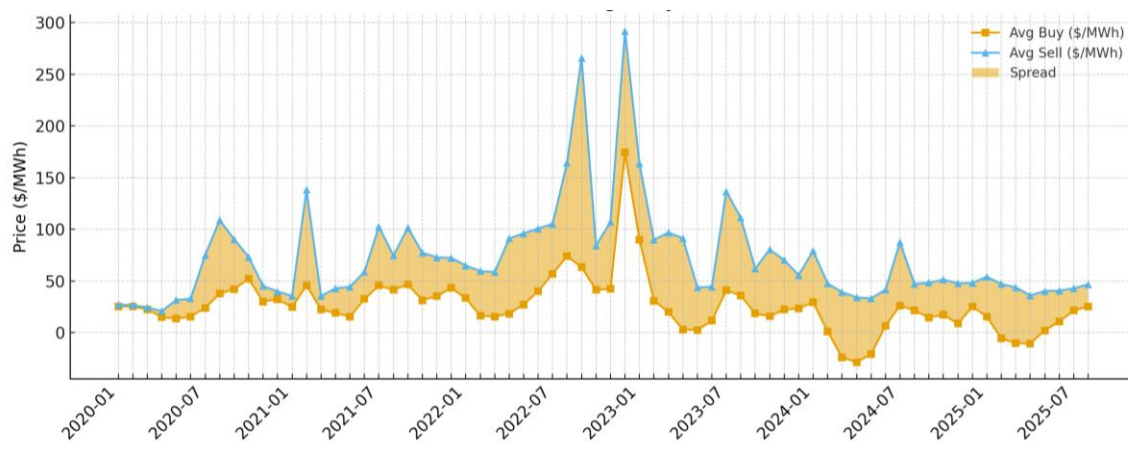
Looking at the percentage breakdown for the discharge periods associated to the battery fleet, the thermal displacement varied with the most pronounced delta change showing up during the non-Q2 months as the evening ramp demand for energy carries a marginal cost that sits in the natural gas/import portion of the supply stack. Take for example, the month of February went from a thermal stack percentage of 47% in 2023, down to 41% in 2024 and 34% in 2025. This month is

a good proxy given the temperatures across California were similar which allowed for similar load numbers throughout the month.

8-Hour Battery Analysis

The 8-hour strategy expands this operational window, capturing a broader block of daytime hours for charging and extending discharges deeper into the evening. This longer duration slightly dilutes the renewable share of charging energy, since shoulder periods are included alongside mid-day solar peaks. Consequently, buy prices are somewhat higher than in the 4-hour case. Nevertheless, sell prices remain elevated as discharges extend into late evening peaks, allowing the battery to provide longer-lasting reliability benefits. The 8-hour battery therefore complements the 4-hour design: rather than focusing purely on solar integration and arbitrage, it offers system capacity and firming over extended hours when imports and thermal plants would otherwise be required.

Figure 8 | 8h Window — Average Buy & Sell Prices



The 8-h battery scenario has the light load to thank given that we have seen the evening ramp and light load price levels converge thus it allows for the longer window to capture value when discharging.

Figure 9 | 8h Window — Spread and Peak Daily Charge/Discharge

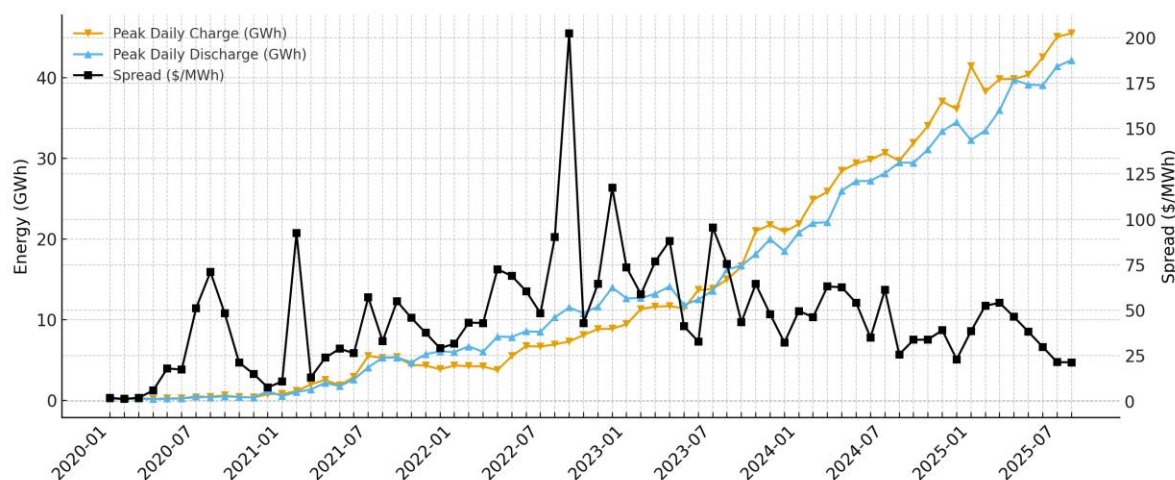
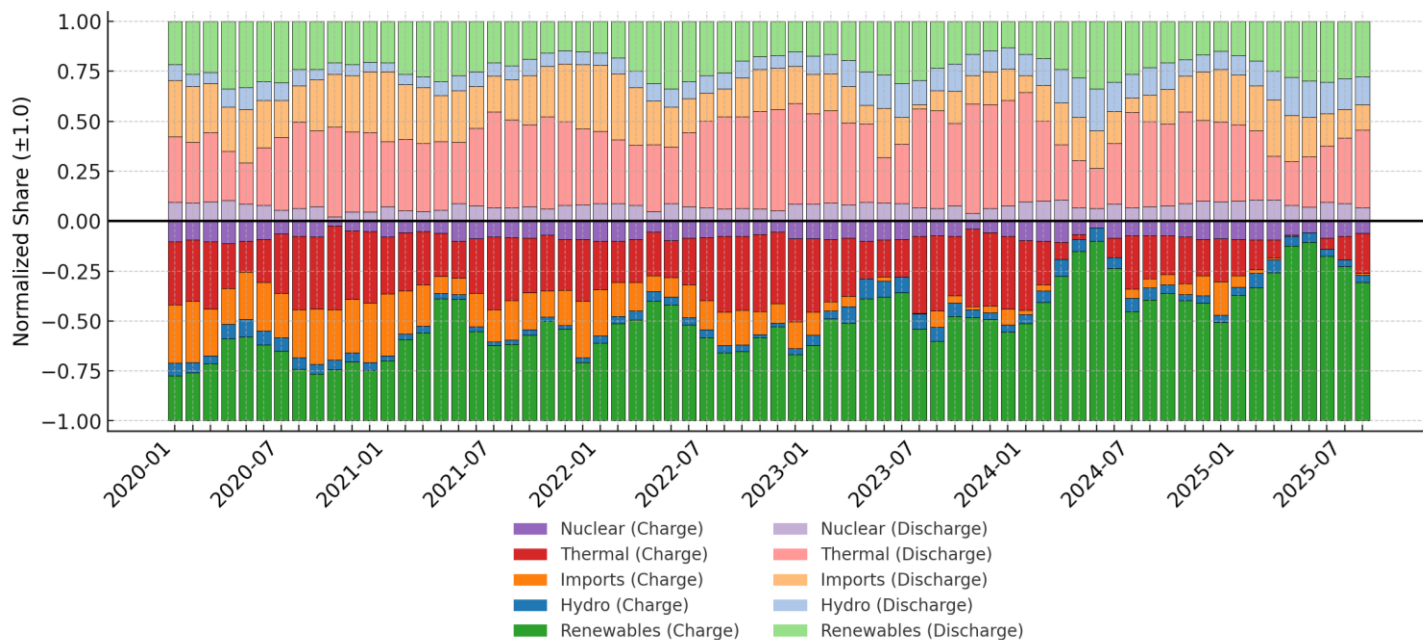


Figure 10 below shows the 8-hour charging and discharging stacks, normalized to 1.0. Charging remains predominantly renewable-driven, while discharging offsets a more diverse mix of thermal and imports. Distinct color palettes differentiate the charge and discharge halves, highlighting the resource shifts batteries bridge over longer durations.

Figure 10 | 8h Window — Charging vs Discharging Stack (Monthly Averages)



Similar to the 4-hour battery scenario, the 8-hour battery charge has had an impact on the thermal values where Q4-2024 shifted down to 40-45% compared to 50% handles the previous two years while Q1 saw February run as a similar rate as the 4-hour fleet.

4-Hour versus 8-Hour

Taken together, the two battery strategies highlight different but complementary system roles. The 4-hour battery is highly efficient in aligning with renewable surpluses: on average, more than 70–80% of its charging energy comes from renewables and buy prices during these windows are frequently close to \$0/MWh, with negative prices stretching into adjacent months around Q2. When discharging, spreads are consistently positive, with average sell prices exceeding \$40/MWh in many months but the curve is flattening

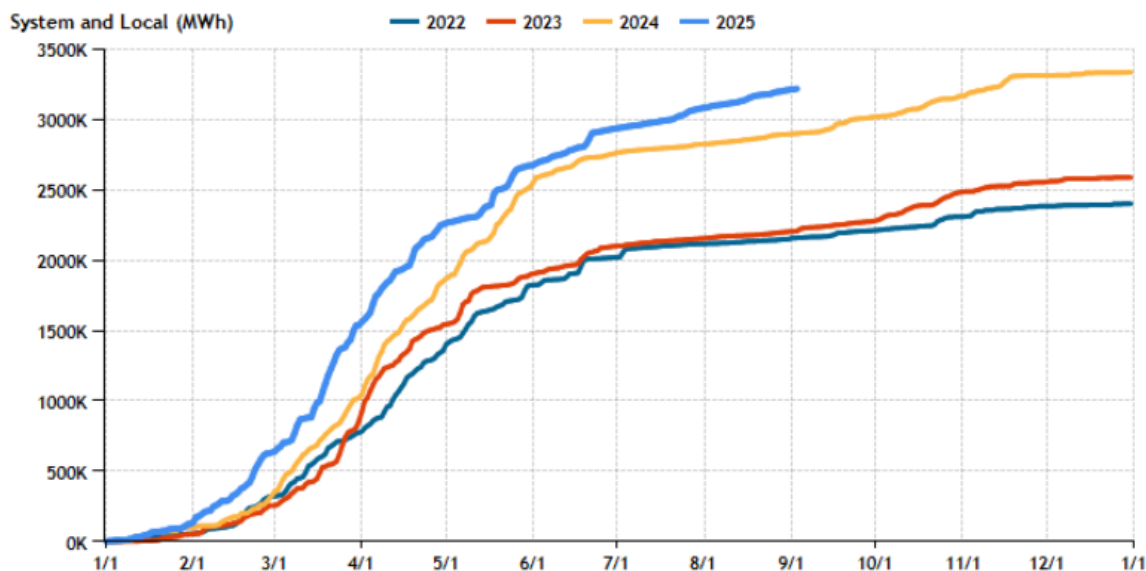
The 8-hour battery, by contrast, expands into shoulder periods, reducing the renewable fraction of charging energy to around 60–70%. Average buy prices are therefore slightly higher, typically in the \$10–15/MWh range, but the extended discharge can capture both the evening ramp value along with what presents itself during the light load hours. While the arbitrage spread narrows relative to the 4-hour case, the 8-hour strategy delivers a larger total volume of discharge energy—often 30–40% more in each month—and offsets a greater share of imports and thermal resources during peak hours.

The tradeoff is clear: the 4-hour battery is the superior tool for pure solar shifting and economic arbitrage, while the 8-hour battery offers greater system reliability and capacity by covering longer peaks. The former has enjoyed volatility around the REC and natural gas prices over the past three years while the latter is set to take on the reduced spread value by capturing more hours within a given day. Load growth projections and the added solar will play into conversation in the coming years as the percentages of battery charge compared to the non-carbon threshold cannot go much higher while the other months of the year will be an active part of the discussion going forward.

Conclusions

This analysis underscores the extent to which renewables are reshaping CAISO's supply stack. In peak months, renewable penetration regularly exceeds half of total generation, a structural shift that intensifies the need for balancing resources. The shoulder months (Q2/Oct-Nov) have a much higher penetration of renewables which allows the midday block pricing to settle in negative territory. The renewable penetration is reflected in the CAISO curtailment volumes as the battery charging has yet to displace the solar capacity growth.

Figure 11 | CAISO Curtailment Cumulative Volume



Each year, curtailment volume moves to the left (earlier in the year), which reflects the non-carbon penetration and the need for the battery fleet capacity to continue as it serves as demand that can absorb the less expensive prices. The complication sits on the charging side as the current market construction is seeing lower implied heat rates during the evening ramp block of hours. In summary, the evolution of the market fundamentals will continue to present the balance between economics tied to a specific technology, such as batteries, and the reliability benefits of the short and long-duration storage fleet.

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Attachment 5

Section 4, Alternatives - Redline Version

4 Alternatives

4.1 Introduction

This section discusses alternatives to the proposed 1,150-megawatt (MW) up to 9,200-megawatt-hour (MWh) Prairie Song Reliability Project (Project) in Los Angeles County. These include the No Project Alternative, the Reduced Project Alternative, and an Alternative Project Site. This discussion focuses on alternatives that could feasibly accomplish most of the basic objectives of the Project and could avoid or substantially lessen one or more of the potential impacts. This section also describes the site selection criteria used in determining the proposed location of the Project and alternatives that were considered but rejected from further review.

The California Environmental Quality Act (CEQA) requires consideration of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project and evaluate the comparative merits of the alternatives” (Title 14, California Code of Regulations [CCR] 15126.6[a]).

Thus, the focus of an alternatives analysis should be on alternatives that “could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects” (Title 14, CCR 15126.6[c]). The CEQA Guidelines further provide that “among the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.”

The Energy Facilities Siting Regulations (Title 20, CCR, Appendix B) guidelines titled Information Requirements for an Application require the following:

A discussion of the range of reasonable alternatives to the project, or to the location of the project, including the no project alternative, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and an evaluation of the comparative merits of the alternatives. In accordance with Public Resources Code section 25540.6(b), a discussion of the applicant’s site selection criteria, any alternative sites considered for the project, and the reasons why the applicant chose the proposed site.

The data adequacy regulations also require the following:

A description of how the site and related facilities were selected, and the consideration given to engineering constraints, site geology, environmental impacts, water, waste and fuel constraints, electric transmission constraints, and any other factors considered by the applicant.

Further, the CEQA Guidelines, Section 15126.6(d) provides in pertinent part, “If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed. (County of Inyo v. City of Los Angeles (1981) 124 Cal.App.3d 1).”

4.2 Project Objectives

One of the primary purposes of the Project is to assist the State of California in meeting its goal of reducing statewide annual greenhouse gas emissions from the electric sector to 25 million metric tons by 2035. The Project would help balance electricity generation from renewable sources, such as wind and solar, with electricity demand by storing excess generation from emissions free power sources and delivering it back to the grid when demand exceeds real-time generation supply. The Project may displace the need for additional fossil fuel based generating stations needed to serve peak demand periods when renewable sources may be inadequate or unavailable.

The principle Basic Project Objectives include the following:

- Construct and operate an up to 1,150MW BESS facility in Los Angeles County with an interconnection utilizing available system capacity at the existing Southern California Edison (SCE) Vincent Substation to balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability.
- Provide new energy storage capacity to assist California electric utilities in meeting obligations under California's Renewable Portfolio Standard Program and Senate Bills 100 and 1020, which require renewable energy sources and zero-carbon resources to supply 60% of all retail sales of electricity to California end-use customers by December 31, 2030, 90% of all retail sales of electricity to California end-use customers by December 31, 2035, 95% of all retail sales of electricity to California end-use customers by December 31, 2040, and 100% of all retail sales of electricity to California end-use customers by December 31, 2045.
- Provide new energy storage capacity to assist the State of California in meeting its goal of reducing statewide annual greenhouse gas emissions from the electric sector to 25 million metric tons by 2035.
- Provide storage capacity to help balance electricity generation from renewable sources, such as wind and solar, with electricity demand by storing excess generation predominately from emissions free power sources and deliver it back to the grid when demand exceeds real-time generation supply.
- Offer energy storage to curtail dispatch and displace the need for additional fossil fuel based generating stations needed to serve peak demand periods when intermittent renewable sources may be inadequate or unavailable. The additional storage capacity may allow for the deferral or avoidance of regional transmission facilities.
- Provide energy storage of sufficient size, power, capacity, scale, and location to assist California utilities in meeting obligations under the California Public Utilities Commission's (CPUC's) Mid-Term Reliability Procurement and upcoming Clean Power Procurement Program Requirements.
- Develop an electricity storage facility in close proximity to a utility grid-connected substation with existing capacity available for interconnection for charging and discharging and the ability to deliver capacity to the load to minimize environmental impacts.
- Secure a location to allow the stored energy to relieve grid congestion, and enhance electricity reliability, without requiring the construction of substantial new regional transmission infrastructure or network upgrades.
- Construct and operate a battery energy storage facility in Los Angeles County, resulting in economic benefits to the County, creating prevailing wage construction jobs, and facilitating local community benefits.
- Locate and gain site control of site large enough and well-suited to support development of the Project's 1,150MW and up to 9,200MWh battery energy storage.

- Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts from long 500 kilovolt (kV) gen-tie lines.
- Locate a site to accommodate a gen-tie line of reasonable length to the Point of Interconnection and the ability to deliver power to the Los Angeles (LA) Basin local reliability area during peak demand.
- Locate near existing roadways and related infrastructure where available and feasible for construction and operations and maintenance (O&M) access.

4.3 Project Overview

Prairie Song Reliability Project LLC (Applicant), a subsidiary of Coval Infrastructure DevCo LLC, proposes to construct, operate, and eventually repower or decommission the up to 1,150MW Prairie Song Reliability Project (Project) located on up to approximately 107 acres in unincorporated Los Angeles County. The primary components of the Project include a containerized battery energy storage system (BESS) facility utilizing lithium-iron phosphate cells, or similar technology, O&M buildings, an on-site Project substation, a 500kV overhead generation interconnection (gen-tie) transmission line, and interconnection facilities within the existing SCE owned and operated Vincent Substation. The BESS Facility site will be approximately 71 acres in size and the gen-tie line will be up to approximately 36 acres.

Electrical energy will be transferred from the existing power grid to the Project for storage and from the Project to the power grid when additional electricity is needed. The Project will provide additional capacity to the electrical grid to assist with serving load during periods of peak demand by charging when demand is low and discharging when demand is high. This operating principle increases the integration of additional intermittent renewable energy, such as wind and solar, in California's energy mix and reduces the need to operate natural gas power plants. The Project will also serve as an additional local/regional capacity resource that will enhance grid reliability, particularly to the LA Basin local reliability area and may allow for the deferral or avoidance of regional transmission facilities.

The Project will be remotely operated and monitored year-round as well as supported by on-site O&M staff 7 days a week. The Project will be available to receive or deliver energy 24 hours a day and 365 days a year. During the operational life of the Project, qualified technicians will inspect the Project facilities and conduct necessary maintenance to ensure reliable and safe operational readiness.

4.4 Rationale for Alternatives Selection

The following discussion covers a reasonable range of feasible alternatives that would avoid or substantially lessen one or more significant effects of the Project while attaining most of the Project objectives. In accordance with the CEQA Guidelines, many factors may be taken into account when addressing the feasibility of alternatives, such as environmental impacts, site suitability as it pertains to various land use designations or zoning, economic viability, availability of infrastructure, regulatory limitations, and jurisdictional boundaries (CEQA Guidelines, 15126.6[f][1]).

In determining an appropriate range of Project alternatives to be evaluated, a broad range of alternatives were reviewed. Based on initial review and consideration, it was determined that some of these preliminary alternatives did not accomplish most of the objectives, as listed above, or would result in greater impacts than the Project. Thus, these alternatives were rejected and were not fully analyzed. The alternatives that were considered and rejected are discussed in Section 4.5 below.

~~Two (2) alternatives~~The alternatives would meet most of the Project objectives, are potentially feasible, and would avoid or minimize some potential impacts as compared to the Project. ~~These alternatives are the Reduced Project Alternative and the Alternative Project Site.~~ Additionally, a No Project Alternative is required to be included in the range of alternatives.

The ~~three (3)~~ alternatives, as listed below, are more fully analyzed than the rejected alternatives discussed in Section 4.5. For each of these alternatives, the analysis includes a description of the alternative and a comparison of the environmental effects relative to the Project. These Project alternatives are addressed in Sections 4.6, ~~4.7 through 4.12~~4.12 in this section as follows:

- Alternative 1: No Project Alternative
- Alternative 2: Peaceful Valley Alternative Site
- Alternative 3: Reduced Project Alternative
- Alternative 4: Crown Valley Alternative Site
- Alternative 5: Tierra Subida Alternative Site
- Alternative 6: Pearblossom Alternative Site
- Alternative 7: Barrel Springs Alternative Site

- ~~Alternative 1: No Project Alternative~~
- ~~Alternative 2: Alternative Project Site (Peaceful Valley Alternative Site)~~
- ~~Alternative 3: Reduced Project Alternative~~

The alternatives studied constitute a reasonable range because they contain enough variation to facilitate informed decision making that leads to a reasoned choice. Also, the discussion of each alternative is sufficient to allow meaningful evaluation, analysis, and comparison with the Project. Therefore, the significant effects of each alternative are discussed in less detail than those of the Project, but in enough detail to provide the CEC with perspective and a reasoned choice among alternatives to the Project.

The Project would not result in any significant and unavoidable adverse impacts for which feasible mitigation measures could not reduce the impacts to below significance. Implementation of feasible mitigation measures would reduce potentially significant impacts to the following issue areas to less than significant: Air Quality, Biological Resources, Cultural Resources, Hazardous Materials Handling, Noise, Paleontological Resources, Traffic and Transportation, and Wildfire.

Potential impacts to the following issue areas were determined not to be significant after further evaluation and would not require mitigation: Geological Hazards and Resources, Land Use, Public Health, Socioeconomics, Soils, Waste Management, Visual Resources, Water Resources, and Worker Health and Safety.

Sections 4.6, ~~4.7, and 4.8 through 4.12~~ compare the impacts of the No Project Alternative, the individual impacts of the Peaceful Valley five (5) Alternative Sites, and the Reduced Project Alternative to the impacts of the Project. A summary of how these alternatives compare to the Project Objectives is provided in Table 4-1, Alternatives Summary Relative to Project Objectives.

Table 4-1. Alternatives Summary Relative to Project Objectives

	Project Objective	Project	No Project Alternative	Peaceful Valley Alternative Site	Reduced Project Alternative	Crown Valley Alternative Site	Tierra Subida Alternative Site	Pearblossom Alternative Site	Barrel Springs Alternative Site
1	Construct and operate an up to 1,150MW BESS facility in Los Angeles County with an interconnection utilizing available system capacity at the existing SCE Vincent Substation to balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability.	Yes	No	Yes	No	No	Yes	Yes	Yes
2	Provide new energy storage capacity to assist California electric utilities in meeting obligations under California's Renewable Portfolio Standard Program and Senate Bills 100 and 1020, which require renewable energy sources and zero-carbon resources to supply 60% of all retail sales of electricity to California end-use customers by December 31, 2030, 90% of all retail sales of electricity to California end-use customers by December 31, 2035, 95% of all retail sales of electricity to California end-use customers by December 31, 2040, and 100% of all retail sales of electricity to California end-use customers by December 31, 2045.	Yes	No	Yes	Yes*	Yes*	Yes	Yes	Yes
3	Provide new energy storage capacity to assist the State of California in meeting its goal of reducing	Yes	No	Yes	Yes*	Yes*	Yes	Yes	Yes

Table 4-1. Alternatives Summary Relative to Project Objectives

	Project Objective	Project	No Project Alternative	Peaceful Valley Alternative Site	Reduced Project Alternative	Crown Valley Alternative Site	Tierra Subida Alternative Site	Pearblossom Alternative Site	Barrel Springs Alternative Site
	statewide annual greenhouse gas emissions from the electric sector to 25 million metric tons by 2035.								
4	Provide storage capacity to help balance electricity generation from renewable sources, such as wind and solar, with electricity demand by storing excess generation predominately from emissions free power sources and deliver it back to the grid when demand exceeds real-time generation supply.	Yes	No	Yes	Yes*	<u>Yes*</u>	<u>Yes</u>	<u>Yes</u>	<u>Yes</u>
5	Offer energy storage to curtail dispatch and displace the need for additional fossil fuel based generating stations needed to serve peak demand periods when intermittent renewable sources may be inadequate or unavailable. The additional storage capacity may allow for the deferral or avoidance of regional transmission facilities.	Yes	No	Yes	Yes*	<u>Yes*</u>	<u>Yes</u>	<u>Yes</u>	<u>Yes</u>
6	Provide energy storage of sufficient size, scale, and location to assist California utilities in meeting obligations under the CPUC's Mid-Term Reliability Procurement and upcoming Clean Power Procurement Program Requirements	Yes	No	Yes	No	<u>No</u>	<u>Yes</u>	<u>Yes</u>	<u>Yes</u>
7	Develop an electricity storage facility in close proximity to a utility grid-connected substation with existing	Yes	No	No	Yes	<u>No</u>	<u>No</u>	<u>No</u>	<u>No</u>

Table 4-1. Alternatives Summary Relative to Project Objectives

	Project Objective	Project	No Project Alternative	Peaceful Valley Alternative Site	Reduced Project Alternative	Crown Valley Alternative Site	Tierra Subida Alternative Site	Pearblossom Alternative Site	Barrel Springs Alternative Site
	capacity available for interconnection for charging and discharging and the ability to deliver capacity to the load to minimize environmental impacts.								
8	Secure a location to allow the stored energy to relieve grid congestion, and enhance electricity reliability, without requiring the construction of substantial new regional transmission infrastructure or network upgrades.	Yes	No	No	Yes	<u>No</u>	<u>No</u>	<u>No</u>	<u>No</u>
9	Construct and operate a battery energy storage facility in Los Angeles County, resulting in economic benefits to the County, creating prevailing wage construction jobs, and facilitating local community benefits.	Yes	No	Yes	Yes*	<u>Yes</u>	<u>Yes</u>	<u>Yes</u>	<u>Yes</u>
10	Locate and gain site control of site large enough and well-suited to support development of the Project's 1,150MW and up to 9,200MWh battery energy storage.	Yes	No	Ability to gain site control is unknown	No	<u>Ability to gain site control is unknown</u>	<u>Ability to gain site control is unknown</u>	<u>Ability to gain site control is unknown</u>	<u>Ability to gain site control is unknown</u>
11	Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts from long 500kV gen-tie lines.	Yes	No	Yes*	Yes	<u>Yes*</u>	<u>Yes*</u>	<u>Yes*</u>	<u>Yes*</u>
12	Locate a site to accommodate a gen-tie line of reasonable length to	Yes	No	Yes	Yes	<u>Yes*</u>	<u>Yes*</u>	<u>Yes*</u>	<u>Yes*</u>

Table 4-1. Alternatives Summary Relative to Project Objectives

	Project Objective	Project	No Project Alternative	Peaceful Valley Alternative Site	Reduced Project Alternative	<u>Crown Valley Alternative Site</u>	<u>Tierra Subida Alternative Site</u>	<u>Pearblossom Alternative Site</u>	<u>Barrel Springs Alternative Site</u>
	the POI and the ability to deliver power to the Los Angeles Basin local reliability area during peak demand.								
13	Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.	Yes	No	No	Yes	<u>No</u>	<u>No</u>	<u>No</u>	<u>No</u>

Notes: MW = megawatt; SCE = Southern California Edison; CPUC = California Public Utilities Commission; MWh = megawatt hours; kV = kilovolt; POI = Point of Interconnection; O&M = operations and maintenance.

* Indicates that while an alternative may meet a project objective, it only partially achieves the project objective as the proposed project would achieve the objective to a greater degree.

4.5 Alternatives Considered but Eliminated from Further Analyses

The purpose of an alternatives analysis is to develop alternatives to the Project that avoid potentially significant environmental effects identified as a result of the Project, while still feasibly meeting most of the basic project objectives. Several alternatives were considered but subsequently eliminated from further analyses because of “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (Title 14, CCR 15126.6[c]).

4.5.1 Alternative Site Locations Analyzed

The Project proponent completed an extensive site planning process to identify and avoid constraints, which included analysis of numerous potential sites for the Project. This site planning process was intended to create a project that optimizes reliable, dispatchable energy generation, while being sensitive to environmental constraints, and ultimately resulted in the Project. Several alternative site locations were considered but subsequently rejected from further analysis because they would result in greater impacts than the Project, primarily due to the construction of a longer gen-tie line from the alternative site to the Vincent Substation and sloped terrain.

All alternative locations must be centered around an interconnection to the Vincent Substation. The Vincent substation is located at a key point in the grid, Service Path 26, that is able to deliver energy from renewable resources outside of the LA Basin Resource Area to meet LA Basin Local Capacity Requirements (LCR), with tie lines into the Western and Eastern LA Basin. LCR refers to the minimum amount of local generation capacity needed within specific areas to meet reliability criteria, particularly in areas where transmission constraints limit the ability to import power and is a critical metric for understanding energy needs necessary to meet future grid demand.

The LA Basin LCR is increasing, primarily due to load growth. The 2024-2025 Transmission Plan shows that peak load in the SCE Main area is forecasted to grow from 25,265MW in 2026 to 27,929MW in 2034 (CAISO 2025a), representing a 9.5% increase over 8 years. The 2026 LCR Tech Study also shows that the local capacity needed in the LA Basin is expected to increase from 5,812MW in 2026 to 7,226MW in 2030, which is an approximate 20% increase in required capacity in 4 years. Compared with the 2025 LCR study, demand for the LA Basin is 429MW higher than last year's forecast and the forecasted LCR needs have increased by 1,689MW due to load forecast increase (CAISO 2025b). The 2026 LCR Tech Study estimates an annual LCR increase in the LA Basin of 364.25MW between 2026 and 2030. In addition, the California Independent System Operator is projecting that there will be a total potential curtailment of 1,300-gigawatt hours of wind and solar from the SCE North area in 2034, absent storage availability (CAISO 2025a).

Locating this important energy storage Project with efficient and environmentally sound access to the Vincent Substation provides the Project with the ability to help reduce wind and solar curtailment while also supporting the growing LCR needs in the LA Basin, allowing stored resources to be dispatched when needed.

Alternative Location Criterion

Alternative site locations were evaluated to determine if a 1,150MW, 9,200MWh, battery energy storage system with supporting improvements could be reasonably and feasibly placed in another location. The Project developed a robust set of criteria, based on the project objectives, to evaluate potential Alternative Sites. The evaluation criteria stratify sites based on the project objectives. Sites that do not meet most of the basic project objectives

were analyzed but ultimately eliminated from further consideration. The alternatives analyses comprised the following principle criteria:

Areas within a 2-mile radius of the Vincent Substation were reviewed as potential Alternative Sites.

- Potential sites outside of the 2-mile radius were eliminated due to physical siting constraints. Specifically, the mountainous terrain to the south, east, and north does not contain sites of sufficient acreage and slope that are constructable. Similarly, the lands to the west are predominately developed with residential and commercial land uses. A project developed in these land uses would inherently generate more potential impacts and use conflicts than the Project location. In addition, sites farther than 2 miles from the Vincent Substation would result in a lengthier gen-tie line which would contribute to greater potential acreages used and impacts than the Project.

Exclude areas that contain over 50% area of greater than 5-degree slopes.

- As noted above, most of the lands within a 2-mile radius are mountainous or already developed with other uses.
- Significantly, slopes over 5° require substantial grading and earthwork such as retaining walls and other structural improvements and would accordingly generate impacts that are avoided or minimized at the Project site.

Exclude Protected Areas Database of the United States (PAD-US) areas¹.

- Protected areas were excluded to avoid environmental impacts and potential land use conflicts in areas likely to invite recreationalists.

Exclude areas within the 100-year floodplain.

- Potential Alternative Sites within the 100-year floodplain were excluded because constructing a BESS and incorporating flood-proofing construction requirements within a 100-year floodplain would result in additional environmental impacts, and pose constructability issues and flood and hazard insurance risks.

Exclude areas with non-riverine wetlands and wetland complexes.

- Non-riverine wetland areas were excluded to avoid environmental impacts.
- Wetland complexes create a functional ecological unit through interconnection of wetland features and provide habitat, biodiversity, as well as water filtration and purification.

¹ PAD-US is America's official national inventory of U.S. terrestrial and marine protected areas that are dedicated to the preservation of biological diversity and to other natural, recreation and cultural uses, managed for these purposes through legal or other effective means (USGS 2022). <https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-overview>.

Areas with parcel groupings that were at least 60 contiguous acres in size were carried forward for evaluation as Alternative Sites.

- A total of 60 contiguous acres was used to identify the minimum viable project size that would be necessary to support a 1,150MW, 9,200MWh project.

After applying the alternative site criteria listed above, two (2) potential Alternative Site areas were identified as shown in Figure 4-1, Expanded Alternative Site Reviews.

Alternative Site 1 (herein referred to as the Mountain Springs Alternative Site) does not meet the project objective to ***“Locate and gain site control of site large enough and well-suited to support development of the Project’s 1,150-MW and up to 9,200MWh battery energy storage.”*** The Mountain Springs Alternative Site is bisected by the Sierra Highway, partially comprised of commercially unavailable Southern California Edison owned parcels, and much of the area is currently under option by another developer, making site control infeasible. The Mountain Springs Alternative Site is therefore excluded from further analysis.

Alternative Site 2 (the Peaceful Valley Alternative Site) meets the alternative site criterion, partially meets the project objectives, and is therefore further discussed in Section 4.7.

4.5.2 Alternative Site Locations Analyzed – Expanded

In response to Data Request ALT-1(a), the following expanded alternative location analysis is provided. The expanded alternatives analysis is two-pronged as it looks at (1) alternative locations that are within a larger radius of the Vincent Substation (6 miles as opposed to 2 miles) and (2) alternative locations that could support a smaller 45-acre reduced project alternative.

To evaluate alternative locations within a larger 6-mile radius of Vincent Substation, the same principle criteria discussed above in Section 4.5.1 (and iterated below), was applied:

- Exclude areas that contain over 50% area of greater than 5-degree slopes
- Exclude Protected Areas Database of the United States (PAD-US) areas²
- Exclude areas within the 100-year floodplain
- Exclude areas with non-riverine wetlands and wetland complexes

Once the initial criteria were applied, a secondary set of criteria was applied:

- Exclude areas within a 0.5-mile radius of schools, libraries, and churches
- Exclude areas designated by Los Angeles County as Significant Ecological Areas (SEAs)

Once the above criteria was applied, areas with parcel groupings that were at least 60 contiguous acres in size were carried forward for evaluation. Parcel groupings that were approximately 45 acres in size were carried forward to analyze sites for the reduced footprint alternative site.

² PAD-US is America’s official national inventory of U.S. terrestrial and marine protected areas that are dedicated to the preservation of biological diversity and to other natural, recreation, and cultural uses, managed for these purposes through legal or other effective means (USGS 2022).

The above criteria resulted in a subset of additional potential alternative sites that were further reviewed as described below (Table 4-2). These potential alternative sites are shown in Figure 4-1, Alternative Site Review.

Table 4-2. Additional Potential Alternative Sites

Potential Alternative Site	Size (acres)	Carried Forward or Dismissed
<u>PAS-1</u>	<u>79</u>	<u>Dismissed. The site is located approximately 0.6 miles from Vasquez High School and High Desert School. In comparison, the nearest school to the Project site is the Meadowlark Elementary School, approximately 2 miles west of the proposed BESS facility. The site is also adjacent to approximately 22 residences, compared to the Project site, which is adjacent to 11 residences when including residences across Soledad Canyon Road.</u>
<u>PAS-2</u>	<u>40</u>	<u>Dismissed. The site is located approximately 0.6 miles from Vasquez High School and High Desert School. In comparison, the nearest school to the Project site is the Meadowlark Elementary School, approximately 2 miles west of the proposed BESS facility. The site also consists of nine (9) residences, which would result in the displacement of nine (9) residences, compared to the Project site, which will displace one (1) residence.</u>
<u>PAS-3</u>	<u>101</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-4</u>	<u>45</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-5</u>	<u>67</u>	<u>Dismissed. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project. However, due to the site's close proximity to the proposed Project, this site was dismissed from further review as potential impacts would be similar to the proposed Project.</u>
<u>PAS-6</u>	<u>66</u>	<u>Dismissed. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project. However, due to the site's close proximity to the proposed Project, this site was dismissed from further review as potential impacts would be similar to the proposed Project.</u>
<u>PAS-7</u>	<u>48</u>	<u>Dismissed. The site consists of a similar number of residences as the Project; however, the site is located directly adjacent to more residences than the proposed Project site.</u>
<u>PAS-8</u>	<u>58</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-9</u>	<u>118</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-10</u>	<u>125</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>

Table 4-2. Additional Potential Alternative Sites

<u>Potential Alternative Site</u>	<u>Size (acres)</u>	<u>Carried Forward or Dismissed</u>
<u>PAS-11</u>	<u>56</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-12</u>	<u>540</u>	<u>Carried Forward. The site consists of no residences and is located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-13</u>	<u>142</u>	<u>Dismissed. While the site does not consist of any existing residences, approximately half the site is encumbered by existing high-voltage transmission lines, the easements of which make the site too small to support the Project.</u>
<u>PAS-14</u>	<u>65</u>	<u>Carried Forward. The site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project.</u>
<u>PAS-15</u>	<u>80</u>	<u>Dismissed. While the site consists of a similar number of residences as the Project and is also located directly adjacent to a similar number of residences as the Project, approximately half the site is encumbered by existing high-voltage transmission lines, the easements of which make the site too small for use.</u>
<u>PAS-16</u>	<u>46</u>	<u>Dismissed. The site consists of 14 residences, which would result in the displacement of 14 residences, compared to the Project site, which will displace one (1) residence. The site is also directly adjacent to more residences than the proposed Project site.</u>
<u>PAS-17</u>	<u>64</u>	<u>Dismissed. The site consists of a similar number of residences as the Project; however, the site is located directly adjacent to more residences.</u>
<u>PAS-18</u>	<u>73</u>	<u>Carried Forward. The site consists of no residences. While the site is located directly adjacent to several more residences than the proposed Project site, the site is carried forward due to its location in a High Fire Hazard Severity Zone, which contrasts with the proposed Project, which is in a Very High Fire Hazard Severity Zone.</u>
<u>PAS-19</u>	<u>74</u>	<u>Carried Forward. The site consists of no residences. While the site is located directly adjacent to several more residences than the proposed Project site, the site is carried forward due to its location in a High Fire Hazard Severity Zone, which contrasts with the proposed Project, which is in a Very High Fire Hazard Severity Zone.</u>
<u>PAS-20</u>	<u>71</u>	<u>Dismissed. The site consists of approximately 30 residences, which would result in the displacement of 30 residences, compared to the Project site, which will displace one (1) residence.</u>
<u>PAS-21</u>	<u>56</u>	<u>Dismissed. The site consists of approximately 30 residences, which would result in the displacement of 30 residences, compared to the Project site, which will displace one (1) residence.</u>

Note: PAS = Potential Alternative Site; BESS = battery energy storage system.

After applying the expanded alternative site criteria listed above and grouping alternative sites located near one another,³ four (4) additional potential Alternative Sites were identified. These additional alternative sites meet the

³ For example, PAS-8, -9, -10, and -11 are in close proximity to one another; therefore, the site closest to the Vincent Substation was carried forward for analysis (i.e., PAS-8).

alternative site criteria, partially meet the Project objectives, and are therefore further discussed in Sections 4.9 through 4.12. The additional alternative sites listed below and the previously identified alternative site (Peaceful Valley Alternative Site) are shown in Figure 4-2, Alternative Sites.

- Alternative Site 3 (herein referred to as the Crown Valley Alternative Site)
 - PAS-4
- Alternative Site 4 (herein referred to as the Tierra Subida Alternative Site)
 - PAS-8
- Alternative Site 5 (herein referred to as Pearblossom Alternative Site)
 - PAS-18
- Alternative Site 6 (herein referred to as the Barrel Springs Alternative Site)
 - PAS-12

The Crown Valley Alternative Site is approximately 45 acres in size and could support a reduced Project footprint. This alternative could not support the Project as proposed. The other three (3) additional potential alternative sites (Tierra Subida, Pearblossom, and Barrel Springs) are of sufficient size to support the Project as proposed.

4.5.3 Alternative Gen-Tie Line

In response to Data Request ALT-1(b) and (c), the following alternative gen-tie analysis is provided to describe an alternative gen-tie line route that avoids the Santa Clara River SEA. Due to constraints imposed by SCE on where the Project must enter the Vincent Substation (see Appendix 4A), the location of the SEA, and constructability requirements for tensioning and pulling conductors between towers, an alternative gen-tie route (underground or overhead) that avoids the SEA is not feasible. The information below provides an analysis of each constraint surrounding the Vincent Substation.

Discussion of Entry into the Vincent Substation and the Significant Ecological Area

An alternative gen-tie route (underground or overhead) that avoids the SEA is not feasible due to constraints imposed by SCE on where the Project must enter the substation (see SCE email provided in Appendix 4A). As background, it is important to understand SCE requirements relating to interconnection facilities. Per Section 4.15 of the SCE Interconnection Handbook, “Currently there is no equipment that allows a below ground POCO [Point of Change of Ownership] for interconnections at 66 kV and above. Any POCO at these voltage levels will need to be installed above ground to ensure clear distinction between SCE’s equipment and the Interconnection Customer’s equipment” (see Appendix 4A, The Interconnection Handbook Southern California Edison Company Rev. 15, January 31, 2024). This means that SCE requires that the Project install an aboveground pole outside of SCE property to accommodate a change of ownership facilities. This is true for both underground and overhead gen-tie options. The installation of an aboveground POCO is a limiting factor in the Project’s ability to identify an alternative gen-tie route that avoids the SEA. The following discussion reviews each border (east, north, west, south) of the Vincent Substation and describes constraints specific to each border relative to the SEA.

East: The SEA directly borders an existing road (Angeles Forest Highway) and the Vincent Substation to the east. SCE owns the parcels within the SEA along the eastern border of the Vincent Substation (APNs 3056015803, 3056014813). These parcels, and the SEA, extend north and south beyond the eastern boundary of the Vincent

Substation, effectively blocking any entry to the Vincent Substation from the east that does not impact the SEA. Because SCE owns the parcels within the SEA along the eastern boundary of the Vincent Substation, the pole cannot be placed east of the substation without being constructed on SCE land or impacting the SEA. As stated above, SCE requires that the POCO pole be constructed on non-SCE owned land. Therefore, the pole cannot be placed east of the Vincent Substation without violating SCE's requirements regarding construction of the pole on SCE-owned land or impacting the SEA.

North: The Vincent Substation is bordered on the north by parcels owned primarily by SCE (APNs 3056014814, 3056014813, 3056014810, 3056014812). These parcels contain eight (8) high-voltage transmission lines, as well as two (2) low-voltage lines. These lines fully encumber the southern portion of the parcels that are closest to the Vincent Substation, making it technically impossible to enter the Vincent Substation from the north. If the Project attempted to cross farther north (approximately 2,300 feet), near Carson Mesa Road, the lines disperse and the gen-tie would only need to cross five (5) high-voltage transmission lines before heading back south into the Vincent Substation. It is extremely difficult to build a line over or under the group of five (5) aligned high-voltage lines on the western edge of APN 3056014810. If the Project could build towers tall enough to span the approximately 1,000-foot right-of-way created by the existing transmission corridor, it would then have to cross back over six (6) high-voltage transmission lines in a constrained area to get to an open bay position on the western side of the Vincent Substation. Therefore, while a gen-tie route that entered the Vincent Substation on the north could avoid the SEA, it is infeasible because the gen-tie could not reach the northern portion of the Vincent Substation from the Project's eastern location. There is one potential route onto SCE property in the northwestern corner of the substation that is discussed below.

West: The Vincent Substation is bordered on the west by a residential neighborhood. The residential neighborhood consists of two (2) rows of 14 parcels. Purchasing 14 residential parcels to enter directly from the west of the Vincent Substation is unlikely. The residential neighborhood effectively blocks the proposed gen-tie line from entering the Vincent Substation from a western route.

South: Similar to the eastern side of the Vincent Substation, the southern side of the Vincent Substation is surrounded by the SEA. The SEA boundary is located between approximately 115 feet and 160 feet from the southern border of the Vincent Substation. An alternative path that enters Vincent Substation from the south would need to be located within the 115-to-160-foot space between the SEA and Vincent Substation, which has the potential to cause permanent and/or temporary impacts to the SEA due to the required right-of-way width and temporary laydown and workspace needed to construct and operate the line. There is no alternative path that can enter Vincent Substation from the south that extends farther than 160 feet south of Vincent Substation because of the location of the SEA.

Due to the proximity of the SEA boundary to the east and south, existing infrastructure to the north, restrictions on construction of the interconnection facilities on SCE-owned property to the east and north, and the neighboring community to the west, there is only one potential route to connect the Project to the Vincent Substation that avoids permanent impacts the SEA (see Figure 4-3, Alternative Gen-Tie). This route would utilize two (2) privately owned parcels (APNs 3056014046, 3056014042) along the northwestern border of the SCE-owned parcels surrounding the Vincent Substation that would allow for potential access. In this alternative gen-tie scenario, starting from the Vincent Substation, SCE would place the first tower (Conceptual Pole [CP] 3) outside the southern border of the Vincent Substation in a similar location to the routes proposed by the Project. The route would then head west to just outside the southwestern corner of the Vincent Substation where a tower (CP-2) would be placed to turn the route 90 degrees to the north. The route would then run north between the Vincent Substation to the east and the residential community to the west. Due to the presence of an existing 230 kV monopole outside the southwestern

corner of the Vincent Substation, the CP-2 tower would need to be placed closer to the residential community than as currently proposed (approximately 150 feet away from the property line). The route would then run north and place a third tower (CP-1) outside the northeastern corner of the Vincent Substation, where it would exit the SCE property into privately owned APN 3056014046.

While conceptually possible, this route has two fatal flaws that render it infeasible. One, the route would effectively ring fence the Vincent Substation to the south and west and eliminate the potential for future projects to access the substation from these directions. SCE has stated that the Project cannot change its entry point into the substation (see SCE email provided in Appendix 4A) and does not allow projects to block future access to the substation. Two, it is not feasible to string and tension the conductors between the towers south of the Vincent Substation (CP-2 and CP-3). The steep terrain south of the towers and constraints imposed by existing structures do not provide adequate space to string and tension the conductors. In addition, if it were possible to overcome terrain restrictions to the south, the stringing and tensioning area would generate temporary impacts in the SEA.

Finally, the applicant also does not have site control or rights-of-way over the parcels between the site and the Vincent Substation for a route that avoids the SEA. Obtaining the additional site control necessary to construct this line (seven [7] landowners over nine [9] unique parcels) would be an additional feasibility concern.

A summary table of alternative gen-tie constraints is provided below (Table 4-3).

Table 4-3. Alternative Gen-Tie Constraints

Direction	Limitation(s)	SEA Impact
East	SEA boundary SCE requirement for POCO on private property	POCO must be aboveground. Permanent impacts to the SEA would be necessary.
North	Existing high-voltage transmission lines SCE requirement to maintain current Point of Interconnection location	No impact, but not technically possible to enter from the north due to multiple high-voltage line crossings in a constrained space.
West	Residential development containing 28 parcels	No impact, but impact to residential neighborhood is likely and site control is unlikely.
South	SEA borders Vincent Substation to the south	Permanent impacts to the SEA for any line extending more than 160 feet to the south.
Northwestern Corner	SEA borders Vincent Substation to the south Residential neighborhood to the west Topography does not allow for tensioning and pulling lines	If possible, there would be temporary impacts to the SEA from tensioning and pulling requirements.

Note: gen-tie = generation interconnection; SEA = Significant Ecological Area; SCE = Southern California Edison; POCO = Point of Change of Ownership.

4.5.42 Alternative Technologies

The Project proponent conducted an analysis to identify alternative technologies to the lithium-iron phosphate battery energy storage technology proposed for the Project. Several alternative technologies were considered but were subsequently rejected from further analysis because they did not accomplish most of the Project objectives

or would result in greater impacts than the Project. A discussion of the alternative technologies considered and rejected is provided below:

Compressed Air Energy Storage

Traditional compressed air energy storage uses a compressor to convert electrical energy into high pressure compressed air that is stored in this increased energy state, typically by injecting the compressed air into existing, deep salt caverns or depleted gas reservoirs that can store compressed air and retain it in the formation for long periods. When electricity is required, the compressed air is expanded through a turbine generator, converting the stored energy back into electricity. Because the expansion process results in significant cooling of the expanding air stream, heat is added back into the compressed air before to avoid unacceptably low temperatures for continuing operation of the turbine. The addition of heat to the expansion process generally requires the combustion of significant quantities of fossil fuel with associated emissions including criteria and toxic air contaminants as well as significant emissions of greenhouse gases (GHGs). Compressing air and the subsequent reheating results in round trip efficiencies ranging from 46% to 80% (DOE 2023). Since this technology produces GHG emissions, the traditional compressed air technology would not meet basic project objectives and was rejected in favor of battery energy storage technology.

Pumped Hydro Storage

Pumped hydro storage uses water released by gravity from an upper reservoir through turbine generating equipment into a lower reservoir separated by at least several hundred to more than a thousand feet or more of elevation to generate electricity. Typically, power is generated during peak power demand periods or when needed to address system reliability with an efficiency typically around 70% to 87% (NREL 2024a). During off-peak periods, water from the lower reservoir is pumped back up into the upper reservoir to “recharge” the system. Pumped hydro storage has many positive characteristics including a long lifespan (50+ years), long storage durations, and the provision of synchronous generation (including rotational inertia) to the grid. However, pumped hydro storage would require much larger reservoirs and surface elevation differentials than are required for battery energy storage technology. The creation of large reservoirs would require inundation of a much larger area than the Project and may result in much greater land use, biological and visual resources impacts than the Project. Viable sites are not located near the Vincent Substation. In addition, the technology is also much more capital intensive per installed MW than the battery energy storage technology. Finally, pumped hydro would not meet a basic project objective of deploying a utility scale battery energy storage system. For these reasons, this alternative was rejected as not meeting key project objectives.

Flywheel Energy Storage

Flywheels store energy mechanically by spinning a mass at high speed. This stored kinetic energy can be converted back into electricity when needed, making the flywheels a potential alternative to batteries for energy storage. Excess electricity is used to spin a flywheel rotor (a heavy, spinning mass) to a high speed. When electricity is needed, the flywheel's rotational energy is converted back into electricity by a generator with a round trip efficiency between 70% to 95% (EESI 2019). Flywheels can deliver high power output quickly and can have a long lifespan with minimal maintenance; however, flywheels typically have lower energy density compared to batteries, making them more suited for short-duration, high-power applications. In addition, the cost of flywheel systems can be higher than batteries, though they may have lower maintenance costs over their lifetime. Finally, flywheel energy storage would not meet a basic project objective of deploying a utility scale battery energy storage system. Flywheel

energy technology was rejected from further analysis because it is not a proven technology at the scale of the Project and has energy output issues and would not substantially reduce the impacts associated with the Project.

Hydrogen Energy Storage

Hydrogen energy storage for electricity involves using electrolysis to convert surplus electricity into hydrogen, storing the hydrogen for later use, and then converting the stored hydrogen back into electricity through fuel cells or combustion. This process offers a way to store excess energy from renewable sources like solar; however, there are many challenges with hydrogen energy storage technology. The main challenge stems from hydrogen's low energy density, flammability, low round trip efficiency between 20% to 45% (EESI 2019), and potential for leakage. Efficiently storing and transporting hydrogen requires specialized infrastructure and can lead to energy losses or safety concerns. Materials used for storage can be susceptible to hydrogen embrittlement. Hydrogen has a much lower energy density per unit volume compared to traditional fuels, meaning more space is needed to store the same amount of energy. This necessitates larger storage tanks or more complex storage systems. To achieve higher storage density, hydrogen can be compressed to high pressures or liquefied at very low temperatures, requiring significant energy input and specialized infrastructure. The processes of compressing or liquefying hydrogen can lead to energy losses, reducing the overall efficiency of the storage system. In addition, hydrogen is a highly flammable gas that can ignite easily and burn with a nearly invisible flame, posing safety risks during storage, transportation, and use, and hydrogen's small molecular size makes it prone to leakage through porous materials or even through previously impermeable materials, raising concerns about containment. Developing materials that are both strong, lightweight, and resistant to hydrogen embrittlement while being cost-effective is a significant challenge, and building and maintaining the infrastructure for hydrogen production, storage, and transportation can be expensive to manufacture and maintain. The overall efficiency of hydrogen storage and use (including production, storage, and utilization) can also be low. Hydrogen energy storage was rejected from further analysis because it is not a proven technology at the scale of the Project and has its own energy, fire and safety issues and would not substantially reduce the impacts associated with potential fire and safety hazards.

Flow Battery Energy Storage

Redox flow batteries operate on the principle of redox reactions, where oxidation and reduction processes occur in a fluid electrolyte. The main components of a flow battery include two (2) tanks of electrolyte solutions, one for the catholyte (positive side) and one for the anolyte (negative side), and a cell stack where the electrochemical reactions take place. Redox flow batteries store energy in liquid electrolytes, which are pumped from external reservoirs into the cell stack during charging and discharging cycles. Vanadium is currently employed in most flow batteries; however, several flow battery technologies that do not contain vanadium are emerging such as zinc-bromine, iron, organic based, and sodium-based flow batteries (EPRI 2024).

Since the active electrolytic material is separated from the reactive electrodes in the battery, redox flow batteries have a much higher level of safety relative to other electrochemical energy storage technologies. Additional advantages include long life cycle, low fire risk due to low flammability of battery and electrolyte material, and easy maintenance. However, compared to lithium-ion batteries, redox flow batteries have lower energy and power densities and typically involve more space-intensive system infrastructure, which limits them for large-scale stationary applications. Redox flow batteries also tend to have lower round-trip efficiencies (60% to 85% [EESI 2019]) compared to lithium-ion batteries and have higher costs due in part to a lack of large-scale manufacturing capacity and the need for pumps, sensors and other power and flow management systems (NREL 2024b). Redox flow battery technology was rejected from further analysis because it has lower energy and power densities requiring more space and additional equipment compared to lithium-ion batteries and is not a proven technology at the scale of the Project.

Sodium Ion Battery Energy Storage

Sodium-sulfur batteries are a type of high-temperature battery that relies on a reversible redox reaction between molten sodium and sulfur to charge and discharge electricity. Sodium-sulfur batteries have high energy densities, which can make them advantageous for areas with space constraints. Sodium-sulfur batteries are in the initial commercialization phase, marked by high energy density, low levels of self-discharge (which correspond to higher efficiencies), and relatively long cycle life. These storage systems rely on common, abundant, and cheap materials, which may help drive down costs relative to storage systems reliant on scarce minerals (NREL 2024b).

In addition, sodium-sulfur batteries have high reliability and can be easily installed, relocated, and maintained; however, these batteries operate at high temperatures, which presents certain safety issues that could limit applications. Several notable safety failures of deployed sodium-sulfur systems, which caused fires, combined with declining lithium-ion costs, have led to declining deployments (NREL 2024b). Sodium-Sulfur batteries have similar round trip efficiencies to lithium iron phosphate BESS. Sodium-sulfur battery technology was rejected from further analysis because it is not a proven technology at the scale of the Project and has its own fire and safety issues and would not substantially reduce the impacts associated with potential fire hazards.

4.5.53 Distributed Storage Alternative

An additional potential alternative to the Project would be the combination of many, smaller distributed storage projects across the local area. This would require mass scaling to reach an energy storage potential similar to the Project on the residential and commercial level, with individual homeowners and companies installing these systems at rates currently not experienced or expected, given market, economic and other factors. A typical home battery storage system installed in a garage holds 13.5 kilowatt-hours (kWh) of energy⁴ as compared to the up to 9,200,000kWh that the Project would hold. This would mean that approximately 681,000 homes would need to install home storage systems to reach the level of energy storage the Project proposes, though those systems would be operated independently behind the meter by homeowners, foregoing the system reliability benefits of a utility-scale resource like the Project. This would require financial outlay and the decision of thousands of homeowners or business owners, which is an infeasible option considering there could not be any type of coordinated commitment to complete these installations.

4.5.64 Alternatives Carried Forward

Based on the foregoing, ~~seventeen (17)~~ three (3) alternatives are carried forward for further analysis.

- **Alternative 1:** No Project Alternative
- **Alternative 2:** ~~Alternative Project Site (Peaceful Valley Alternative Site)~~
- **Alternative 3:** Reduced Project Alternative
- **Alternative 4:** Crown Valley Alternative Site
- **Alternative 5:** Tierra Subida Alternative Site
- **Alternative 6:** Pearblossom Alternative Site
- **Alternative 7:** Barrel Springs Alternative Site

⁴ <https://www.tesla.com/powerwall>.

4.6 Analysis of the No Project Alternative

4.6.1 No Project Alternative Description and Setting

The No Project Alternative is required so that the California Energy Commission (CEC) can compare the impacts of approving the Project with the impacts of not approving the Project. The No Project Alternative must discuss the existing conditions as well as what would be reasonably expected to occur in the foreseeable future if the Project was not approved, based on current plans and available infrastructure and community services. The No Project Alternative is the circumstance under which the Project does not proceed, the project site remains in its existing condition, and potential impacts associated with the Project would be avoided and Project benefits foregone.

4.6.2 Summary of the No Project Alternative

Under the No Project Alternative, the Project would not be implemented, and the site would remain in its current condition. Under this alternative, none of the potential direct or indirect environmental impacts associated with construction, operation and decommissioning of the Project would occur.

As discussed above, all of the Project's potential effects can be avoided, minimized, or mitigated to a level of less than significant under CEQA. Moreover, for each subject matter discussed in this Application, the Project can demonstrate compliance with Applicable Laws, Ordinances, Regulations, and Standards. Therefore while it would have no effects, because the Project will have no significant effects, the No Project Alternative will not "avoid or substantially lessen any of the significant effects of the project." (14 CCR 15126.6[a].)

If the No Project Alternative results in the Project not being constructed, none of the Applicant's basic project Objectives would be realized. The No Project Alternative would forego the electric system and greenhouse gas policy benefits associated with up to 1,150MW of energy storage utilizing available system capacity at the existing SCE Vincent Substation. The No Project Alternative would mean that the Project's energy storage would not be available to balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability.

The No Project Alternative foregoes the new energy storage capacity to assist California electric utilities with their Renewable Portfolio Standard renewable energy sources and zero-carbon resources goals for the retail sales of electricity to California end-use customers. The No Project Alternative also fails to provide new energy storage capacity to assist the State of California in meeting its goal of reducing statewide annual greenhouse gas emissions from the electric sector to 25 million metric tons by 2035.

The No Project Alternative would result in foregoing energy storage capacity to help balance electricity generation from renewable sources, such as wind and solar, with electricity demand by storing excess generation predominately from emissions free power sources and deliver it back to the grid when demand exceeds real-time generation supply. The No Project Alternative eliminates the ability to offer energy storage to curtail dispatch and displace the need for additional fossil fuel based generating stations needed to serve peak demand periods when intermittent renewable sources may be inadequate or unavailable. It also foregoes the additional storage capacity may allow for the deferral or avoidance of regional transmission facilities.

Without the Project, the No Project Alternative foregoes energy storage of sufficient size, power, capacity, scale, and location to assist California utilities in meeting obligations under the CPUC's Mid-Term Reliability Procurement and upcoming Clean Power Procurement Program Requirements.

The No Project Alternative means that there will be no development of an electricity storage facility in close proximity to a utility grid-connected substation with existing capacity available for interconnection for charging and discharging and the ability to deliver capacity to the load to minimize environmental impacts. It foregoes the addition of stored energy to relieve grid congestion, and enhance electricity reliability, without requiring the construction of substantial new regional transmission infrastructure or network upgrades. In terms of economic development, the No Project Alternative eliminates the construction and operation of a battery energy storage facility in Los Angeles County and its resulting in economic benefits to the County, creating prevailing wage construction jobs, and facilitating local community benefits.

The No Project Alternative also foregoes an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation with a gen-tie line of reasonable length, delivering power to the LA Basin local reliability area during peak demand while utilizing existing roadways and related infrastructure where available and feasible for construction and O&M access.

If those basic project objectives would not be met, and the grid reliability, and environmental and policy benefits from the Project would not be realized. The Project would provide a significant contribution to the State's ambitious renewable energy and storage needs, and the No Project Alternative would deprive the State and the area of this significant contribution. The No Project Alternative would also not be consistent with California's environmental policy goals of encouraging development and deployment of energy storage resources, such as the Project, as articulated in CPUC Decision 21-06-035.

The No Project Alternative could result in inadequate system reliability (more blackouts), greater fuel consumption, greenhouse gas emissions, air pollution, climate change and other environmental impacts in the state because less efficient energy storage than the Project would be employed. The No Project Alternative would also deprive the area of a significant construction employment opportunity with associated purchases of local goods and services, as well as jobs associated with the construction, operation and maintenance of the facility, and ongoing property tax revenue, and other community benefits. Therefore, because no development would not satisfactorily meet the project objectives specified above, the No Project Alternative was rejected in favor of the Project.

4.7 Analysis of the Peaceful Valley Alternative Site

4.7.1 Peaceful Valley Alternative Site Description and Setting

As shown on Figures 4-1 and 4-2, the Peaceful Valley Alternative Site is located at the edge of the 2-mile radius, north of the Project site and north of Highway 14 off of Peacefull Valley Road. The Peaceful Valley Alternative Site is an approximately 113-acre block of land consisting of 13 parcels. 10 of the 13 parcels contain residential land uses with the other three (3) parcels being undeveloped. The site is generally flat but does contain some topography around two (2) riverine features that cross the site. It is surrounded by mountainous terrain and similar to the project site it is in a Very High Fire Hazard Severity Zone and is not served by any water or sewer utilities.

4.7.2 Peaceful Valley Alternative Site Comparison

All of the potential impacts at the current project site are less than significant with or without mitigation. Therefore, the Peaceful Valley Alternative Site could not generate fewer potentially significant impacts than the project as discussed above. CEQA requires consideration of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project” (Title 14, CCR 15126.6[a]). To stratify the project and the Peaceful Valley Alternative by noting differences, the following analysis focuses on how the project locations differ in their ability to meet the project objectives and the potential for the Peaceful Valley Alternative Site to result in potentially significant impacts that are not present for the Project.

The two (2) primary project objectives that stratify the Project site and the Peaceful Valley Alternative Site are:

Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts.

The Project would entail an approximately 1.1-mile-long Gen-Tie (Northern Gen-Tie Route) or an approximately 1.8-mile-long Gen-Tie (Southern Gen-Tie Route), and Peaceful Valley Alternative Site would entail a minimum 1.8-mile-long Gen-Tie. Regardless, if the Northern Gen-Tie Route or the Southern Gen-Tie Route is selected, the Project Gen-Tie would be routed through semi-developed land (existing dirt roads) to the Vincent Substation resulting in potential Land Use and Transportation impacts. The Project Gen-Tie would not cross other transmission lines (until entering the Vincent Substation) or highways. Cultural Resources records searches do not show the Project Gen-Tie approaching any recorded cultural resources sites.

The Peaceful Valley Alternative Site Gen-Tie would need to cross the Sierra Highway as well as the Antelope Valley Freeway. Depending on the specific route, Peaceful Valley Alternative Site Gen-Tie would need to cross between one (1) and five (5) high voltage (>220kV) transmission lines. The Peaceful Valley Alternative Site Gen-Tie route would also have to parallel significantly sloped terrain or travel near existing homes generating potential impacts to homeowners and disturbing significantly more land for access roads due to cross slope stability requirements. Finally, the Peaceful Valley Alternative Site Gen-Tie route would cross an area of land where numerous Cultural Resources sites are located thus increasing the potential for cultural resource impacts.

Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.

The Project Site is located adjacent to an existing access and exit point for the Antelope Valley Freeway. The Freeway access becomes Soledad Canyon Road, which parallels the site. Access to the Project Gen-Tie line is supported by the following existing roads: Carson Mesa, Foreston, and Kentucky Springs. Carson Mesa Road and Foreston Road are not expected to require upgrades for Gen-Tie access and construction. Kentucky Springs Road would need to be extended by approximately 0.6 miles to facilitate construction and operational access to the Gen-Tie.

Access to Peaceful Valley Alternative Site would require use of the Sierra Highway as well as approximately 0.8 miles along Peaceful Valley Road, a local dirt road. This road is used for residential access by many of the local homeowners, and it is expected that there would be associated construction traffic impacts to residents. The Peaceful Valley Alternative Site Gen-Tie would have to create approximately 0.6 miles of new roads for construction and operational access to the Gen-Tie, resulting in potential Land Use and Transportation impacts.

In addition to these two (2) objectives, the following considerations were reviewed to compare the project site to Peaceful Valley Alternative Site.

- **Gen-Tie Landowner Agreements:** The Peaceful Valley Alternative Site Gen-Tie Route requires site control or easement agreements from nine (9) to 10 landowners, depending on the chosen route. These landowner counts represent preferred Gen-Tie routes that are either the most direct or limit development on steep terrain. The involvement of a larger number of landowners introduces considerable risk to the development process as well as the potential to increase the length and potential impacts of the Gen-Tie line could result in potentially significant effects on Land Use. If landowners decline an easement option, the Gen-Tie Route will have to go around those properties, either increasing the length of the Gen-Tie, forcing it on-to steep terrain, or both. In any of these situations, the potential for ground disturbance and Visual Resource impacts would be higher due to the increased number of towers necessary to complete the Gen-Tie route and the increased length of access roads necessary to build and maintain the line, resulting in potential Feasibility issues under CEQA.
- **Existing Transmission Line Conflicts:** The Peaceful Valley Alternative Site Gen-Tie Route must run parallel to five (5) existing transmission lines leading to the Vincent Substation. While this may facilitate access to the transmission right-of-way, the required entry point into the Vincent Substation requires crossing over the Midway-Vincent 500kV line as specified in the Large Generator Interconnection Agreement. This routing may necessitate traversing more densely populated residential areas, potentially making it infeasible and potential Land Use and Transportation impacts.
- **Residential Displacement:** Peaceful Valley Alternative Site identified during the 2-mile search consists of 13 parcels, 10 of which contain permanent residences. This represents a threefold increase in the number of homeowners who may be displaced by the project and would increase the potential for significant impacts to Socioeconomics. Additionally, the alternative site has a comparable number of adjacent homeowners, resulting in potential Land Use and Transportation impacts.
- **Crossings:** The Peaceful Valley Alternative Site presents significantly higher crossing risks, particularly due to required crossings over the Antelope Valley Freeway and Sierra Highway. Furthermore, it does not eliminate many crossings associated with the current layout, including those over railroad tracks and Carson Mesa Road. The Gen-Tie for Peaceful Valley Alternative Site would have to use a helicopter to string line across the Sierra Highway and Antelope Valley Freeway and would necessitate closure of both routes during stringing and would increase the potential for temporary traffic and Transportation impacts.
- **Site Topography:** The topography of Peaceful Valley Alternative Site is predominantly flat, but contains several steep ridges present in areas required for construction. This condition will necessitate more extensive grading and earthwork compared to the Project and would increase the potential for significant impacts to air quality and Paleontological and Cultural Resources impacts due additional earthwork, resulting in potential Feasibility issues under CEQA.
- **Gen-Tie Terrain Considerations:** Due to the existing transmission corridor located on a mountainside, constructing the Peaceful Valley Alternative Site Gen-Tie Route will require navigating highly sloped terrain to minimize unnecessary crossings of transmission lines, in addition to potential grid reliability issues associated with existing facilities. This presents significant engineering challenges and raises concerns about the feasibility of any proposed route, resulting in potential Feasibility issues under CEQA.
- **Distance to Services:** The Peaceful Valley Alternative Site is located approximately 0.8 miles down Peaceful Valley Road, a dirt road. The site is approximately 2.6 miles away from LA County Fire Station 80. This is an increase of 1.9 miles over the distance to the current project location. In addition, any emergency service to the Peaceful Valley Alternative Site would potentially have to make an unprotected left hand turn from

Mountain Springs Road on to Forest View Road then travel 0.8 miles up the Peaceful Valley Road, resulting in potential Traffic impacts. The increased distance to the Peaceful Valley Alternative Site and the use and/or potential improvement of Peaceful Valley Road would represent an increased potential for significant impacts to County Services, Air Quality, and Public Health versus the project.

- **Access Road Expansion:** The Peaceful Valley Alternative Site Gen-Tie Route would require enhancements to the existing access road infrastructure used for servicing transmission lines, leading to additional Visual Resources and Soils ground disturbance impacts and potential Traffic impacts
- **Visual Resources Impact from Gen-Tie Line:** If crossing agreements are secured for Antelope Valley Freeway and Sierra Freeway, the Peaceful Valley Alternative Site Gen-Tie Route would further increase Visual Resources impacts for drivers on these roadways. In contrast, the Project Site utilizes a Gen-Tie Route that avoids heavily trafficked automotive corridors.

4.7.3 Summary of the Peaceful Valley Alternative Site Analysis

As shown in the analysis above, the alternative site cannot avoid or substantially lessen any of the potential significant effects of the Project, because the project does not possess any potentially significant impacts. The Peaceful Valley Alternative Site contains the potential for significant impacts and only partially meets the project objectives. The Peaceful Valley Alternative Site is not located near the Vincent Substation in a way that minimizes impacts nor is it located near existing roadways and infrastructure suitable for construction of the project. In conclusion, the Peaceful Valley Alternative Site is less desirable than the project because of its “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (Title 14, CCR 15126.6[c]). In addition, there is little potential to obtain site control of these areas as the parcels are not currently for sale.

4.8 Analysis of the Reduced Project Alternative

4.8.1 Reduced Project Alternative Description and Setting

Under the Reduced Project Alternative, the Project capacity would be reduced from using an 8-hour battery to a 4-hour battery thereby reducing the total capacity from 9,200MWh to 4,600MWh. Under this alternative, the project footprint would be a total of approximately 89 acres, which is a reduction of approximately 18 acres or approximately 17% compared to the Project. The reduction of battery size from an 8-hour battery to a 4-hour battery would specifically reduce the BESS facility size from 70.9 acres to 44.8 acres. The Project site would be reduced mainly in the area north of Soledad Canyon Road on the northwest end. The Reduced Project Alternative would reduce the footprint of the site north of Soledad Canyon Road, but would not eliminate the need for the project to be on both sides of the road. Under the alternative, the 23.1-acre Project substation would remain the same size as the Project and the stormwater detention facilities and other components (as noted in Table 2-2, Preliminary Footprint of the BESS Facility) would be reduced by 1 acre and 2 acres respectively. All other Project components (Project substation, access roads, laydown yard, and the gen-tie) would be the same as the Project. The length of construction would be reduced under this Alternative to approximately 13 months, thus reducing the number of construction workers required and haul truck trips. However, the phases of construction would remain the same as the Project. Grading and installation activities would be reduced due to the smaller Project footprint. The gen-tie line would remain unchanged under the Reduced Project Alternative as there would still be the need to connect the BESS Facility to the Vincent Substation via the Northern or Southern Gen-Tie Route.

4.8.2 Comparison of the Effects of the Reduced Project Alternative to the Project

Air Quality/Greenhouse Gas Emissions

The Reduced Project Alternative would require less construction activities than the Project, which would reduce air quality emissions during construction. The reduction of the development footprint by about 18 acres (17%) under the Reduced Project Alternative would reduce diesel emissions, as the construction efforts would be reduced and would reduce any potential health risks relative to the Project. While the reduction in the development footprint would reduce overall emissions, the criteria pollutant emission thresholds are based on a daily emission rate. The duration of construction would be slightly reduced under this Reduced Project Alternative relative to the Project (13 months vs. 20 months), but the per day activities are expected to be similar to the Project. Thus, it is expected that the Reduced Project Alternative's potential impacts related to daily criteria pollutant emissions would be similar to the Project. The Reduced Project Alternative could implement mitigation measures to reduce potential air quality impacts to less than significant, similar to the Project.

The GHG emissions generated by the Reduced Project Alternative would be lower than the GHG emissions generated from construction of the Project because the Reduced Project scenario would generate GHG emissions from the construction of a 17% smaller facility. However, this alternative would deprive the area of some of the Project's beneficial impacts, including adding a larger BESS project to the grid that would store additional excess energy produced during periods of high generation and dispatching more clean energy to the grid when renewable resources are unavailable. This alternative would reduce the total capacity of electricity stored from 9,200MWh to 4,600MWh; therefore, while it would help bridge the gaps during peak demand periods or times when solar and wind output is low, but not to the same extent as the proposed Project because of its reduced total capacity. Thus, all GHG emission impacts, including the beneficial impacts identified for the Project, would be reduced under the Reduced Project Alternative, resulting in potential GHG and Air Quality impacts

This Reduced Project Alternative also would forego Project benefits. The Reduced Project Alternative would reduce project benefits in the following ways:

- Would not be able to support California's new goals for resource adequacy that is greater than 4 hours;
- Would reduce daily renewable energy grid integration by half (4,600MWh), or would reduce increase daily renewable curtailment by 4,600MWh compared to the project; and
- Would increase the reliance on traditional, GHG emitting, power plants to serve load for 4 hours each day.

Biological Resources

The Reduced Project Alternative would include a reduction in impact area of 18 acres when compared to the Project. However, given that the area being reduced would be located north of Soledad Canyon Road where sensitive vegetation communities occur, and that all other Project components (substation, access roads, laydown yard, and the gen-tie) would be the same as the proposed Project, the total mitigation requirements would not be significantly reduced under the Reduced Project Alternative. The Reduced Project Alternative would reduce the acreages of permanent and temporary direct impacts to special-status plants and wildlife during construction, direct impacts to vegetation communities and land covers, and direct impacts to potential jurisdictional waters. All other potential indirect impacts of the Reduced Project Alternative would be similar to the Project.

Overall, the Reduced Project Alternative would slightly reduce potential biological resource impacts relative to the Project. The Reduced Project Alternative would still require mitigation measures such as demarcation of disturbance limits, biological monitoring, worker education awareness programs, Crotch's bumble bee (*Bombus crotchii*) avoidance and minimization measures, on-site preservation, a habitat mitigation and monitoring plan, a special-status relocation plan, nesting bird avoidance, an invasive species prevention plan, jurisdictional waters compensation, and mitigation measures for site restoration that could include reduce potential impacts to less than significant, similar to the Project.

Cultural Resources

Under the Reduced Project Alternative, the impact area would be reduced by 18 acres (17%). The Reduced Project Alternative would reduce potential impacts to undiscovered cultural resources and undiscovered human remains considering the potential impact area would be reduced. This alternative would reduce potential impacts by 18 acres, or 17% relative to the Project. Thus, the Reduced Project Alternative's impacts to undiscovered cultural resources and undiscovered human remains would be less than the Project.

The Reduced Project Alternative could implement mitigation measures such as a worker's environmental awareness program, a management of inadvertent discovery program, and procedure for handling human remains, similar to the Project.

Geological Hazards and Resources

The Reduced Project Alternative would reduce the impact area by 18 acres. As the impact area would be reduced by 17%, the Reduced Project Alternative may substantially reduce the project's less than significant geologic impacts related to ground shaking, liquefaction, landslides, and subsidence and no impacts related to earthquake faults and mineral resources during construction, operation and decommissioning activities. However, the Reduced Project Alternative's geologic potential impacts would remain less than significant, similar to the Project.

Hazardous Materials Handling

The potential impacts from hazards and hazardous materials would be reduced because the development footprint would be reduced by 18 acres and the construction period would be reduced from 20 months to 13 months; however, the Reduced Project Alternative would continue to have hazardous materials impacts similar to that of the Project. Potential impacts related to handling and storing hazardous materials during construction- and operation-related activities would still occur under this alternative. The Reduced Project Alternative would be required to implement the mitigation measures such as railroad soil and ballast management, similar to the Project. Thus, hazards and hazardous materials impacts due to the Reduced Project Alternative would be less than significant with implementation of mitigation, similar to the Project.

Land Use

Like the Project, the Reduced Project Alternative is anticipated to have less than significant potential impacts related to land use and planning because it will comply and/or be consistent with all applicable land use and planning documents. Overall, potential land use impacts would be the same under the Reduced Project Alternative as the Project.

Noise

The Reduced Project Alternative would reduce the development footprint in the site by 18 acres (17%). The construction period would also be shorter under the Reduced Project Alternative when compared to the Project (13 months vs. 20 months). Thus, the potential construction and operational noise impacts under the Reduced Project Alternative would be slightly less than that of the Project, including potential impacts associated with construction-related noise and cumulative exceedances of noise standards. The Reduced Project Alternative could implement mitigation measures such as locating stationary noise sources as far as feasible from sensitive receptors, equipping all construction equipment with properly operating and maintained mufflers, and the implementation of temporary noise barriers to ensure that noise generation from construction and decommissioning activities would not exceed County standards and noise ordinances prior to work commencing. These mitigation measures could reduce these potential impacts to less than significant, similar to the Project.

Paleontological Resources

The Reduced Project Alternative would reduce the impact area by 18 acres (17%), which would also reduce the potential impacts to paleontological resources as a result of grading. This alternative would reduce potential impacts to areas underlain by late Pleistocene-age older dissected surficial sediments. Considering a reduction would occur to these areas, the Reduced Project Alternative reduction would reduce the paleontological resource potential impact relative to the Project. Nonetheless, the Reduced Project Alternative would still require conventional grading throughout the site requiring approximately 143,836 cubic yards of cut and approximately 512,578 cubic yards of fill and would therefore result in a potential impact to paleontological resources. The Reduced Project Alternative could implement monitoring mitigation measures such as monitoring and having a paleontologist prepare a Paleontological Resources Impact Mitigation Program to reduce the potential impact to less than significant, similar to the Project.

Public Health

The Reduced Project Alternative would reduce the development footprint by 18 acres (17%). Thus, the Reduced Project Alternative would slightly reduce the potential public health impacts during construction and operation. The Project's potential cancer risk and non-cancer health impacts would continue to be below a level of significance with implementation of mitigation measures such the use of Tier 4 or better engines, similar to the Project. Thus, all potential public health impacts identified for the Project would be reduced under the Reduced Project Alternative.

Socioeconomics

The Reduced Project Alternative would reduce the project's footprint by 18 acres (17%) and would reduce the construction period from 20 months to 13 months. Thus, the Reduced Project Alternative would have fewer socioeconomic impacts related to population growth, housing and environmental justice. The Reduced Project Alternative would also lessen some of the beneficial impacts that would be derived because there would be fewer tax benefits from the capital expenditure, fewer construction employment opportunities with associated purchases of local goods and services when compared to the Project, as well as fewer jobs associated with the operation and maintenance of the facility. Also, the ongoing property tax revenue from the site would be reduced. Thus, all socioeconomic impacts, including the loss or reduction of the beneficial impacts identified for the Project under the Reduced Project Alternative.

Soils

The Reduced Project Alternative would reduce the development footprint by 18 acres (17%), which would also reduce the amount of grading that would be required during construction. The Reduced Project Alternative would still require conventional grading throughout the site, but grading would be limited to approximately 143,836 cubic yards of cut and approximately 512,578 cubic yards of fill. Therefore, the Reduced Project Alternative would result in a fewer potential impacts to soils from soil erosion, loss of topsoil, and risks associated with expansive soils. Thus, fewer soil potential impacts would occur under this alternative than those identified for the Project.

Traffic and Transportation

The peak day period of construction for the Project would generate approximately 1,862 trips and operation of the Project would require 32 daily trips. Therefore, the construction traffic for the Project would require mitigation measures in the form of a transportation demand management plan and a traffic control plan. Operation of the Project would not generate a significant number of trips and thereby would not cause a substantial amount of vehicle miles traveled, and traffic impacts from operation would be less than significant. The Reduced Project Alternative would generate a reduced vehicle miles traveled during construction and operations as compared to the Project and would still require the same type of mitigation measures. As such, less than significant potential transportation impacts under this alternative would be less than that of the Project.

Visual Resources

Under the Reduced Project Alternative, the project would be reduced by approximately 18 acres. This reduction represents a reduction of 17% of the Project's development footprint north of Soledad Canyon Road, which would reduce the scale and acreage of the facility. Thus, the less than significant impacts related to certain key observation points north of the project site would be somewhat reduced. Nonetheless, the Reduced Project Alternative would continue to result in a potential impact to visual quality and the character similar to the Project. This alternative would be designed with the same project design features as the proposed project, including the construction of a tan perimeter block wall, targeted installation of site perimeter landscaping, and colorization of BESS enclosures, substation buildings, and substation H-frame structures. With these design features, potential aesthetic impacts from the Reduced Project Alternative would remain less than significant, similar to the project. Also, similar to the Project, potential impacts from light and glare would remain less significant under this alternative.

Waste Management

The Reduced Project Alternative would reduce the development footprint by 18 acres (17%). Thus, the Reduced Project Alternative would lessen the Project's potential waste management impacts related to having waste disposal needs beyond the capacity of appropriate landfills during construction, operation and decommissioning. While the Project's impacts would continue to be below a level of significance with no mitigation measures required, the Reduced Project Alternative would lessen these potential impacts considering less development would occur on the Project site. Thus, potential impacts from waste management identified for the Project would be slightly reduced under the Reduced Project Alternative.

Water Resources

The Reduced Project Alternative would reduce the impact area by 18 acres. Similar to the Project, potential hydrology and water quality impacts related to issues such as violating water quality standards, decreasing groundwater supplies and recharge, altering existing drainage patterns, increasing stormwater runoff or releasing pollutants due to flood, tsunami or seiche would still occur under this alternative. The Project's potential water resources impacts would remain below a level of significance with no mitigation measures required; however, these impacts would occur to a lesser extent. The Reduced Project Alternative would also generate fewer demands for water, wastewater and stormwater service systems. With the development of a slightly smaller footprint and facility, this alternative would result in a decrease in water demand because less irrigation and operation water would be required. Overall, the Reduced Project Alternative would have fewer potential impacts on water resources compared to the Project.

Wildfire

The Project is located on State Responsibility Area lands that are classified as a high fire hazard severity zone. While potential wildfire impacts would be slightly reduced because the development footprint would be reduced by 18 acres, the Reduced Project Alternative would continue to have potential wildfire impacts similar to that of the Project. Potential impacts related to construction-related wildfire risk, operation-related wildfire risk, and the installation of infrastructure that may exacerbate fire risk would still occur. Similar to the Project, the Reduced Project Alternative would be required to implement mitigation measures such as ignition avoidance and fire patrols during extreme fire days, pre-construction requirements, construction requirements and operational vegetation management requirements to lessen potential wildfire impacts to below a level of significance. Thus, potential wildfire impacts due to the Reduced Project Alternative would be less than significant with implementation of mitigation, similar to the Project.

Worker Health and Safety

While the Reduced Project Alternative would reduce the project footprint by 18 acres (17%), this alternative would still produce the Project's potential worker health and safety impacts related to construction and operation safety hazards. Under this alternative, the potential health and safety impacts would remain and would require implementation of construction training and safety programs, operations health and safety programs, safety training, fire protection training, and water quality procedures, the same as the Project. Thus, all potential worker health and safety impacts identified for the Project would be the same under the Reduced Project Alternative.

4.8.3 Summary of the Reduced Project Alternative Analysis

The Reduced Project Alternative would reduce the development footprint by 18 acres. The reduction of the development footprint by 17% would reduce impacts to the following environmental resources areas: air quality/GHG emissions, biological resources, cultural resources, noise, paleontological resources, public health, socioeconomics, soils, traffic and transportation, visual resources, waste management, and water resources.

This alternative would meet some but not all of the basic project objectives.

If the Reduced Project Alternative were built instead of the Project, the State would forego the electric system and greenhouse gas policy benefits associated with up to 4,600MWh of energy storage utilizing available system capacity at the existing SCE Vincent Substation. The Reduced Project Alternative would mean that half of the

Project's energy storage capacity would not be available to balance intermittent renewable generation and serve as an additional capacity resource that is over 4 hours in duration.

The Reduced Project Alternative reduces the new greater than 4-hour energy storage capacity to assist California electric utilities with their Renewable Portfolio Standard renewable energy sources and zero-carbon resources goals for the retail sales of electricity to California end-use customers. The Reduced Project Alternative also reduces the flexibility of the Project to provide new energy storage capacity (either 4 hours or greater than 4 hours) to assist the State of California in meeting its goal of reducing statewide annual greenhouse gas emissions from the electric sector to 25 million metric tons by 2035.

The Reduced Project Alternative would result in halving the daily energy storage capacity (4,600MWh) to help balance electricity generation from renewable sources, such as wind and solar, with electricity demand by storing excess generation predominately from emissions free power sources and deliver it back to the grid when demand exceeds real-time generation supply. The Reduced Project Alternative significantly reduces the ability to offer energy storage to curtail dispatch and displace the need for additional fossil fuel based generating stations needed to serve peak demand periods when intermittent renewable sources may be inadequate or unavailable. It also reduces the additional storage capacity that may allow for the deferral or avoidance of regional transmission facilities.

The Reduced Project Alternative has reduced ability, compared to the Project, to provide energy storage of sufficient size, power, capacity, scale, and location to assist California utilities in meeting some of its obligations under the CPUC's Mid-Term Reliability Procurement and upcoming Clean Power Procurement Program Requirements.

The Reduced Project Alternative means that there will less capacity developed at an electricity storage facility in close proximity to a utility grid-connected substation with existing capacity available for interconnection for charging and discharging and the ability to deliver capacity to the load to minimize environmental impacts. It reduces the addition of stored energy capacity to relieve grid congestion, and enhance electricity reliability, without requiring the construction of substantial new regional transmission infrastructure or network upgrades.

In terms of economic development, the Reduced Project Alternative reduces the economic benefits associated with the construction and operation of a battery energy storage facility in Los Angeles County, resulting in, fewer prevailing wage construction jobs, and reduced local community benefits.

The Reduced Project Alternative also reduces the benefits of developing an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation with a gen-tie line of reasonable length, delivering power to the LA Basin local reliability area during peak demand while utilizing existing roadways and related infrastructure where available and feasible for construction and O&M access. If lost capacity from the Reduced Project Alternative, compared to the Project, were to be replaced at the Vincent substation, there would be inherently more impacts due to the need for additional redundant facilities (i.e., project substation, gen-tie line, O&M buildings, and set-backs) and the potential for additional upgrades at the Vincent substation or along transmission lines to provide similar services to the grid.

A 2024 report from the CEC that evaluates the value of long-duration energy storage states that "Today's lithium batteries (about 7 GW) are providing very useful services to the grid, but the 4-hr duration will not be adequate for getting through each night as the state transitions away from natural gas. This project found that an 8-hr battery is well-suited for supporting California as solar electricity becomes dominant. The 8-hr batteries will be charged while the sun is up, discharge quickly during peak demand in the early evening, and then discharge more slowly for the lower demand experienced during the night. Approximately 70 GW of 8-hr storage will be beneficial and may be

cycled more than 300 times per year.”(CEC 2024). The Reduced Project Alternative would not be able to meet this potential 70-gigawatt need.

4.9 Analysis of the Crown Valley Alternative Site

4.9.1 Crown Valley Alternative Site Description and Setting

As shown on Figures 4-1 and 4-2, the Crown Valley Alternative Site is located toward the western edge of the 6-mile radius, north and west of the Project site and north of Highway 14 off of Crown Valley Road. The Crown Valley Alternative Site is a 45-acre block of land consisting of five parcels (APNs 3217-026-051, 3217-026-052, 3217-026-025, 3217-026-026, 3217-026-027). Three (3) of the five (5) parcels contain residential land uses, while the other two (2) parcels are undeveloped. The site is generally flat but does contain some topography around riverine features that bisect the site. The site is surrounded by mountainous terrain and, similar to the Project site, is in a Very High Fire Hazard Severity Zone.

4.9.2 Crown Valley Alternative Site Comparison

All the potential impacts at the current Project site are less than significant with or without mitigation. Therefore, the Crown Valley Alternative Site could not generate fewer potentially significant impacts than the Project as discussed above. To differentiate the Project and the Crown Valley Alternative, the following analysis focuses on how the locations differ in their ability to meet the Project objectives and the potential for the Crown Valley Alternative Site to result in potentially significant impacts that are not present for the Project.

The three (3) primary Project objectives that stratify the Project site and the Crown Valley Alternative Site are as follows:

Construct and operate an up to 1,150 MW BESS facility in Los Angeles County with an interconnection utilizing available system capacity at the existing SCE Vincent Substation to balance intermittent renewable generation and serve as an additional capacity resource that will enhance grid reliability.

Under this alternative, the Project capacity would be reduced from using an 8-hour battery to a 4-hour battery, thereby reducing the total capacity from 9,200 MWh to 4,600 MWh. Implementation of this alternative would mean that half of the Project’s energy storage capacity would not be available to balance intermittent renewable generation and serve as an additional capacity resource that is over 4 hours in duration. This would also reduce the Project’s energy storage capacity available to support grid reliability and would reduce the capacity available to assist California electric utilities with their Renewable Portfolio Standard and zero-carbon resources goals for the retail sales of electricity to California end-use customers. For additional discussion applicable to this alternative, please refer to Section 4.8, Analysis of the Reduced Project Alternative.

Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts.

The Project would entail an approximately 1.1-mile-long gen-tie (Northern Gen-Tie Route) or an approximately 1.8-mile-long gen-tie (Southern Gen-Tie Route). The Crown Valley Alternative Site would entail a minimum 4-mile-long gen-tie. It is assumed that the Crown Valley Alternative Site Gen-Tie would travel south on Acton Canyon Road to

Sierra Highway and parallel Sierra Highway before crossing the Antelope Valley Freeway and into Vincent Substation. The Crown Valley Alternative Site Gen-Tie would require land agreements with approximately 20 parcels, which is in contrast to the proposed project that traverses six (6) parcels.

The Crown Valley Alternative Site Gen-Tie would need to parallel Sierra Highway and cross the Antelope Valley Freeway. The Crown Valley Alternative Site Gen-Tie route would also have to parallel significantly sloped terrain or travel near existing homes, generating potential impacts to homeowners and disturbing significantly more land for access roads due to cross slope stability requirements.

While the Crown Valley Alternative Site is located near existing electrical infrastructure (a 115 kV transmission line) and the existing SCE Acton Substation, these facilities are not of sufficient size or capacity to support the Project objectives and/or would require several upgrades to support Project connection to the grid. In addition, the Project's interconnection documents require the Project interconnect to the SCE Vincent Substation. The Crown Valley Alternative Site would not meet this important Project objective.

Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.

The Project site is located adjacent to an existing access and exit point for the Antelope Valley Freeway. The freeway access becomes Soledad Canyon Road, which parallels the site. Access to the Project gen-tie line is supported by the following existing roads: Carson Mesa, Foreston, and Kentucky Springs. Carson Mesa Road and Foreston Road are not expected to require upgrades for gen-tie access and construction. Kentucky Springs Road would need to be extended by approximately 0.6 miles to facilitate construction and operational access to the gen-tie.

Access to the Crown Valley Alternative Site would require use of the Sierra Highway as well as approximately 0.6 miles along Acton Canyon Road, a local dirt road. This road is used for residential access by many of the local homeowners, and it is expected that there would be associated construction traffic impacts to residents to construct the Crown Valley Alternative Site Gen-Tie. The Crown Valley Alternative Site Gen-Tie would likely require fewer spur roads for construction and operational access to the gen-tie due to its proximity to existing roads but would have more tower pads and short connecting roads than the Project.

In addition to these two (2) objectives, the following considerations were reviewed to compare the Project site to Crown Valley Alternative Site.

- **Gen-Tie Landowner Agreements:** The Crown Valley Alternative Site Gen-Tie Route requires site control or easement agreements from about 20 landowners, depending on the chosen route (as a comparison, the Project requires site control or easement agreements from six [6] landowners). These landowner counts represent preferred gen-tie routes that are either the most direct or limit development on steep terrain. The involvement of a larger number of landowners introduces considerable risk to the development process that renders the alternative infeasible, as well as the potential to increase the length and potential impacts of the gen-tie line, which could result in potentially significant effects on land use. If landowners decline an easement option, the gen-tie route will have to go around those properties, either increasing the length of the gen-tie, forcing it onto steep terrain, or both. In any of these situations, the potential for ground disturbance and visual resource impacts would be higher due to the increased number of towers necessary to complete the gen-tie route and the increased length of access roads necessary to build and maintain the line, resulting in potential feasibility issues under CEQA.

- **Existing Transmission Line Conflicts:** The Crown Valley Alternative Site Gen-Tie Route would not require crossing any existing transmission lines to reach the point of interconnection at the Vincent Substation. However, the routing would necessitate traversing more densely populated residential areas than the Project, potentially making it infeasible and creating potential land use and transportation impacts.
- **Residential Displacement:** The Crown Valley Alternative Site consists of five (5) parcels, three (3) of which contain permanent residences. This represents an increase in the number of homeowners who may be displaced compared to the Project and would increase potential impacts to socioeconomics. The alternative site has a comparable number of adjacent homeowners compared the Project, resulting in similar potential land use and transportation impacts.
- **Crossings:** The Crown Valley Alternative Site presents significantly higher crossing risks, particularly due to the required crossing over the Antelope Valley Freeway and paralleling Sierra Highway. Furthermore, it does not eliminate crossings associated with the current layout, including those over railroad tracks and Carson Mesa Road. The gen-tie for Crown Valley Alternative Site would have to use a helicopter to string line across the Antelope Valley Freeway, would necessitate closure of both routes during stringing, and would increase the potential for temporary traffic and transportation impacts.
- **Site Topography:** The topography of the Crown Valley Alternative Site is predominantly flat but contains several steep ridges present in areas required for construction. This condition will necessitate more extensive grading and earthwork compared to the Project and would increase the potential for significant impacts to air quality and paleontological and cultural resources due to additional earthwork, resulting in potential feasibility issues under CEQA.
- **Gen-Tie Terrain Considerations:** The Crown Valley Alternative Site Gen-Tie Route will require navigating around more existing residences and established land uses than the Project. This presents significant engineering challenges and raises concerns about the feasibility of any proposed route, resulting in potential feasibility issues under CEQA.
- **Distance to Services:** The Crown Valley Alternative Site is located approximately 0.6 miles down Acton Canyon Road. The site is approximately 2.0 miles away from LA County Fire Station 80. This is an increase of 1.3 miles over the distance to the current Project location. The increased distance to the Crown Valley Alternative Site and the use and/or potential improvement of Peaceful Valley Road would represent an increased potential for significant impacts to County services, air quality, and public health versus the Project.
- **Access Road Expansion:** The Crown Valley Alternative Site Gen-Tie Route would require enhancements to the existing access road infrastructure used for servicing transmission lines, leading to additional visual resources and soils ground disturbance impacts and potential traffic impacts.
- **Visual Resources Impact from Gen-Tie Line:** If crossing agreements are secured for Antelope Valley Freeway, the Crown Valley Alternative Site Gen-Tie Route would further increase visual resources impacts for drivers on these roadways. In contrast, the Project site utilizes a gen-tie route that avoids heavily trafficked automotive corridors.

4.9.3 Summary of the Crown Valley Alternative Site Analysis

As shown in the analysis above, the alternative site cannot avoid or substantially lessen any of the potential significant effects of the Project, because the Project does not possess any potentially significant impacts. The Crown Valley Alternative Site contains the potential for significant impacts and only partially meets the Project objectives. The Crown Valley Alternative Site is not located near the Vincent Substation in a way that minimizes

impacts, nor is it located farther from existing roadways and infrastructure suitable for construction of the Project. In conclusion, the Crown Valley Alternative Site is less desirable than the Project because of its “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (14 CCR 15126.6[c]). In addition, there is little potential to obtain site control of these areas as the parcels are not currently for sale.

4.10 Analysis of the Tierra Subida Alternative Site

4.10.1 Tierra Subida Alternative Site Description and Setting

As shown on Figures 4-1 and 4-2, the Tierra Subida Alternative Site is located near the northern edge of the 6-mile radius, north of the Project site and east of Highway 14 off West Avenue S near the City of Palmdale. The Tierra Subida Alternative Site is a 58-acre block of land consisting of 13 parcels (APNs 3054-020-020, 3054-020-021, 3054-020-022, 3054-020-023, 3054-020-029, 3054-020-030, 3054-020-031, 3054-020-032, 3054-020-033, 3054-020-034, 3054-020-035, 3054-020-036, 3054-020-901). One of the 13 parcels contains residential land uses, 11 parcels are undeveloped, and one (1) parcel consists of a park-and-ride. The site is generally flat and, based on desktop review, does not appear to contain riverine features. The site is not surrounded by mountainous terrain and is similar to the Project site as it is in a Very High Fire Hazard Severity Zone. The site is within the San Andreas Fault Zone, a Holocene-active fault, which has the potential to result in increased geological hazard impacts compared to the Project.

4.10.2 Tierra Subida Alternative Site Comparison

All the potential impacts at the current Project site are less than significant with or without mitigation. Therefore, the Tierra Subida Alternative Site could not generate fewer potentially significant impacts than the Project. As discussed above, CEQA requires consideration of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project” (14 CCR 15126.6[a]). To differentiate the Project and the Tierra Subida Alternative, the following analysis focuses on how the locations differ in their ability to meet the Project objectives and the potential for the Tierra Subida Alternative Site to result in potentially significant impacts that are not present for the Project.

The two (2) primary Project objectives that stratify the Project site and the Tierra Subida Alternative Site are as follows:

Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts.

The Project would entail an approximately 1.1-mile-long gen-tie (Northern Gen-Tie Route) or an approximately 1.8-mile-long gen-tie (Southern Gen-Tie Route), and the Tierra Subida Alternative Site would entail a minimum 5.0-mile-long gen-tie. Regardless, if the Northern Gen-Tie Route or the Southern Gen-Tie Route is selected, the Project gen-tie would be routed through semi-developed land (existing dirt roads) to the Vincent Substation, resulting in potential land use and transportation impacts. The Project gen-tie would not cross other transmission lines (until entering the Vincent Substation) or highways.

It is assumed that the Tierra Subida Alternative Site Gen-Tie would travel south on Tierra Subida Avenue for approximately 2 miles then align with the existing high-voltage transmission corridor for approximately 3 miles, which would include two (2) high-voltage transmission line crossings, before crossing five (5) additional high-voltage transmission lines, then crossing the Antelope Valley Freeway and Sierra Highway, crossing another high-voltage transmission line, and finally entering into Vincent Substation. The Tierra Subida Alternative Site Gen-Tie would need to cross the Sierra Highway as well as the Antelope Valley Freeway in addition to the State Water Project. Depending on the specific route, the Tierra Subida Alternative Site Gen-Tie would need to cross eight (8) high-voltage (220 kV and 500 kV) transmission lines. The Tierra Subida Alternative Site Gen-Tie route would also have to parallel significantly sloped terrain and the Antelope Valley Freeway, generating additional visual resources impacts and disturbing significantly more land for access roads due to cross slope stability requirements.

Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.

The Project site is located adjacent to an existing access and exit point for the Antelope Valley Freeway. The freeway access becomes Soledad Canyon Road, which parallels the site. Access to the Project gen-tie line is supported by the following existing roads: Carson Mesa, Foreston, and Kentucky Springs. Carson Mesa Road and Foreston Road are not expected to require upgrades for gen-tie access and construction. Kentucky Springs Road would need to be extended by approximately 0.6 miles to facilitate construction and operational access to the gen-tie.

Access to Tierra Subida Alternative Site would require use of the Antelope Valley Freeway and existing paved roads, similar to the Project and resulting in similar transportation impacts as the Project. However, the Tierra Subida Alternative Site is located near more existing residences than the Project, and its gen-tie would need to pass by many (potentially 24) more existing residences, resulting in a potential land use impact.

In addition to these two (2) objectives, the following considerations were reviewed to compare the Project site to the Tierra Subida Alternative Site.

- **Gen-Tie Landowner Agreements:** The Tierra Subida Alternative Site Gen-Tie Route requires site control or easement agreements from around 30 or more landowners, depending on the chosen route (as a comparison, the Project requires site control or easement agreements from six [6] landowners). These landowner counts represent preferred gen-tie routes that are either the most direct or limit development on steep terrain. The involvement of a larger number of landowners introduces considerable risk to the development process as well, rendering the alternative infeasible, as well as the potential to increase the length and potential impacts of the gen-tie line, which could result in potentially significant effects on land use. If landowners decline an easement option, the gen-tie route will have to go around those properties, either increasing the length of the gen-tie, forcing it onto steep terrain, or both. In any of these situations, the potential for ground disturbance and visual resource impacts would be higher due to the increased number of towers necessary to complete the gen-tie route and the increased length of access roads necessary to build and maintain the line, resulting in potential feasibility issues under CEQA.
- **Existing Transmission Line Conflicts:** The Tierra Subida Alternative Site Gen-Tie Route must run parallel and eventually cross eight (8) existing transmission lines, owned by two different power providers (SCE and Los Angeles Department of Water and Power [LADWP]) leading to the Vincent Substation.
- **Residential Displacement:** The Tierra Subida Alternative Site consists of 13 parcels, none of which contain permanent residences. This represents a decrease in the number of homeowners who may be displaced and would reduce potential impacts to socioeconomics. However, the alternative site has more adjacent

homeowners and is in an area that has a denser population than the Project site, resulting in potential land use and transportation impacts.

- **Crossings:** The Tierra Subida Alternative Site presents significantly higher crossing risks, particularly due to required crossings over the eight (8) high-voltage transmission lines, Antelope Valley Freeway, Sierra Highway, and State Water Project. Furthermore, it does not eliminate many crossings associated with the current layout, including those over railroad tracks and Carson Mesa Road. The gen-tie for the Tierra Subida Alternative Site would have to use a helicopter to string line across the Sierra Highway and Antelope Valley Freeway, would necessitate closure of both routes during stringing, and would increase the potential for temporary traffic and transportation impacts.
- **Site Topography:** The topography of the Tierra Subida Alternative Site is predominantly flat. This condition will necessitate less extensive grading and earthwork compared to the Project and decrease the potential for significant impacts to air quality and paleontological and cultural resources due to less earthwork.
- **Gen-Tie Terrain Considerations:** Due to the existing transmission corridor located on a mountainside, constructing the Tierra Subida Alternative Site Gen-Tie Route will require navigating highly sloped terrain. This presents significant engineering challenges regarding tower placement, tower design, and access road installation, and raises concerns about the feasibility of any proposed route, resulting in potential feasibility issues under CEQA.
- **Distance to Services:** The Tierra Subida Alternative Site is located a similar distance to the existing fire response services as the Project because the alternative site is located near existing services in the City of Palmdale. This represents similar potential for significant impacts to County services, air quality, and public health as the Project.
- **Access Road Expansion:** The Tierra Subida Alternative Site Gen-Tie Route would require enhancements to the existing access road infrastructure used for servicing transmission lines, leading to additional visual resources and soils ground disturbance impacts and potential traffic impacts.
- **Visual Resources Impact from Gen-Tie Line:** If crossing agreements are secured for Antelope Valley Freeway and Sierra Freeway, the Tierra Subida Alternative Site Gen-Tie Route would further increase visual resources impacts for drivers on these roadways. In contrast, the Project site utilizes a gen-tie route that avoids heavily trafficked automotive corridors.

4.10.3 Summary of the Tierra Subida Alternative Site Analysis

As shown in the analysis above, the alternative site cannot avoid or substantially lessen any of the potential significant effects of the Project because the Project does not possess any potentially significant impacts. The Tierra Subida Alternative Site contains the potential for significant impacts and only partially meets the Project objectives. The Tierra Subida Alternative Site is not located near the Vincent Substation in a way that minimizes impacts, nor is it located near existing roadways and infrastructure suitable for construction of the Project. In conclusion, the Tierra Subida Alternative Site is less desirable than the Project because of its “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (14 CCR 15126.6[c]). In addition, there is little potential to obtain site control of these areas as the parcels are not currently for sale.

4.11 Analysis of the Pearblossom Alternative Site

4.11.1 Pearblossom Alternative Site Description and Setting

As shown on Figures 4-1 and 4-2, the Pearblossom Alternative Site is located at the northeastern edge of the 6-mile radius, northeast of the Project site, near the intersection of Peablossom Highway and 47th Street East, near the City of Palmdale. The Pearblossom Alternative Site is a 73-acre block of land consisting of two (2) parcels (APNs 3052-027-027, 3052-027-028). None of the parcels contain existing residences. The site is generally flat and, based on desktop review, appears to contain riverine features. The site itself is not surrounded by mountainous terrain. Unlike the Project site, the Pearblossom Alternative Site is designated as a High Fire Hazard Severity Zone, as opposed to a Very High Fire Hazard Severity Zone, which is the same designation for the other alternative sites analyzed herein and the Project site. The site is adjacent to the San Andreas Fault Zone, a Holocene-active fault, which has the potential to result in increased geological hazard impacts compared to the Project.

4.11.2 Pearblossom Alternative Site Comparison

All the potential impacts at the current Project site are less than significant with or without mitigation. Therefore, the Pearblossom Alternative Site could not generate fewer potentially significant impacts than the Project. To differentiate the Project and the Pearblossom Alternative, the following analysis focuses on how the locations differ in their ability to meet the Project objectives and the potential for the Pearblossom Alternative Site to result in potentially significant impacts that are not present for the Project.

The two (2) primary Project objectives that stratify the Project site and the Pearblossom Alternative Site are as follows:

Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts.

The Project would entail an approximately 1.1-mile-long gen-tie (Northern Gen-Tie Route) or an approximately 1.8-mile-long gen-tie (Southern Gen-Tie Route), and the Pearblossom Alternative Site would entail a minimum 7-mile-long gen-tie. Regardless, if the Northern Gen-Tie Route or the Southern Gen-Tie Route is selected, the Project gen-tie would be routed through semi-developed land (existing dirt roads) to the Vincent Substation resulting in potential land use and transportation impacts. The Project gen-tie would not cross other high-voltage transmission lines (until entering the Vincent Substation) or highways.

It is assumed that the Pearblossom Alternative Site Gen-Tie would travel south on 47th Street East for approximately 2 miles then align with the existing high-voltage transmission corridor for approximately 5 miles, while crossing two (2) high-voltage transmission lines owned by LADWP, before reaching the Vincent Substation. The Pearblossom Alternative Site Gen-Tie would not need to cross the Sierra Highway or the Antelope Valley Freeway. The Pearblossom Alternative Site Gen-Tie would need to cross eight (8) high-voltage transmission lines. The Pearblossom Alternative Site Gen-Tie route would also have to parallel significantly sloped terrain and would travel near a comparable number of existing homes as the Project, generating similar potential impacts to homeowners but disturbing significantly more land for access roads due to cross slope stability requirements. Based on desktop review, the Pearblossom Alternative Site appears to contain western Joshua tree (*Yucca brevifolia*), a species of ecological and cultural importance that is currently being considered by the state for listing as a threatened species.

Under this alternative, impacts to western Joshua tree could occur. In comparison, the Project site does not contain western Joshua tree.

Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.

The Project site is located adjacent to an existing access and exit point for the Antelope Valley Freeway. The freeway access becomes Soledad Canyon Road, which parallels the site. Access to the Project gen-tie line is supported by the following existing roads: Carson Mesa, Foreston, and Kentucky Springs. Carson Mesa Road and Foreston Road are not expected to require upgrades for gen-tie access and construction. Kentucky Springs Road would need to be extended by approximately 0.6 miles to facilitate construction and operational access to the gen-tie.

Access to the Pearblossom Alternative Site would require use of the State Route 138 and Pearblossom Highway and existing paved roads, similar to the Project and resulting in similar transportation impacts as the Project. However, the Pearblossom Alternative Site is located near more existing residences than the Project, resulting in a potential land use impact.

In addition to these two (2) objectives, the following considerations were reviewed to compare the Project site to the Pearblossom Alternative Site.

- **Gen-Tie Landowner Agreements:** The Pearblossom Alternative Site Gen-Tie Route requires site control or easement agreements from 30 or more landowners, depending on the chosen route (as a comparison, the Project requires site control or easement agreements from six [6] landowners). These landowner counts represent preferred gen-tie routes that are either the most direct or limit development on steep terrain. The involvement of a larger number of landowners introduces considerable risk to the development process that renders the alternative infeasible, as well as the potential to increase the length and potential impacts of the gen-tie line, which could result in potentially significant effects on land use. If landowners decline an easement option, the gen-tie route will have to go around those properties, either increasing the length of the gen-tie, forcing it onto steep terrain, or both. In any of these situations, the potential for ground disturbance and visual resource impacts would be higher due to the increased number of towers necessary to complete the gen-tie route and the increased length of access roads necessary to build and maintain the line, resulting in potential feasibility issues under CEQA.
- **Existing Transmission Line Conflicts:** The Pearblossom Alternative Site Gen-Tie Route must run parallel to five (5) existing transmission lines leading to the Vincent Substation. It will cross two (2) LADWP high-voltage lines and six (6) SCE high-voltage lines, totaling eight (8) high-voltage crossings, before entering the Vincent Substation.
- **Residential Displacement:** The Pearblossom Alternative Site consists of two (2) parcels, neither of which contain permanent residences. This represents a decrease in the number of homeowners who may be displaced and would reduce potential impacts to socioeconomics. However, the alternative site has more adjacent homeowners and is in an area that has a denser population than the Project site, resulting in potential land use and transportation impacts.
- **Crossings:** The Pearblossom Alternative Site presents increased crossing risks because the alternative, unlike the Project, would need to cross eight (8) high-voltage transmission lines. The Pearblossom Alternative, like the Project, would not need to cross the Antelope Valley Freeway and Sierra Highway like the other alternative sites. In addition, the alternative site would eliminate the crossings associated with the current layout, including those over railroad tracks and Carson Mesa Road. However, the

Pearblossom site would need to cross the State Water Project. The gen-tie for the Pearblossom Alternative Site would decrease the potential for temporary traffic and transportation impacts.

- **Site Topography:** The topography of the Pearblossom Alternative Site is predominantly flat. This condition will necessitate less extensive grading and earthwork compared to the Project and decrease the potential for significant impacts to air quality and paleontological and cultural resources impacts due to less earthwork.
- **Gen-Tie Terrain Considerations:** Due to the existing transmission corridor located on a mountainside, constructing the Pearblossom Alternative Site Gen-Tie Route will require navigating highly sloped terrain to minimize unnecessary crossings of transmission lines, in addition to potential grid reliability issues associated with existing facilities. This presents significant engineering challenges and raises concerns about the feasibility of any proposed route, resulting in potential feasibility issues under CEQA.
- **Distance to Services:** The Pearblossom Alternative Site is located a similar distance to the existing fire response services as the Project because the alternative site is located near existing services in the City of Palmdale. This represents similar potential for significant impacts to County services, air quality, and public health as the Project.
- **Access Road Expansion:** The Pearblossom Alternative Site Gen-Tie Route would require enhancements to the existing access road infrastructure used for servicing transmission lines, leading to additional visual resources and soils ground disturbance impacts and potential traffic impacts.
- **Visual Resources Impact from Gen-Tie Line:** Both the Pearblossom Alternative Site and the Project site would utilize a gen-tie route that avoids heavily trafficked automotive corridors. Impacts would be similar because neither project would require crossing the Antelope Valley Freeway or Sierra Highway. However, the Pearblossom gen-tie would be significantly longer than the Project gen-tie, which has the potential to result in additional visual resource impacts.

4.11.3 Summary of the Pearblossom Alternative Site Analysis

As shown in the analysis above, the alternative site cannot avoid or substantially lessen any of the potential significant effects of the Project, because the Project will not have any potentially significant impacts. The Pearblossom Alternative Site contains the potential for significant impacts and only partially meets the Project objectives. The Pearblossom Alternative Site is not located near the Vincent Substation in a way that minimizes impacts, nor is it located near existing roadways and infrastructure suitable for construction of the Project. In conclusion, the Pearblossom Alternative Site is less desirable than the project because of its “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (14 CCR 15126.6[c]). In addition, there is little potential to obtain site control of these areas as the parcels are not currently for sale.

4.12 Analysis of the Barrel Springs Alternative Site

4.12.1 Barrel Springs Alternative Site Description and Setting

As shown on Figures 4-1 and 4-2, the Barrel Springs Alternative Site is located at the northeastern edge of the 6-mile radius, northeast of the Project site, near the intersection of Barrel Springs Road and 47th Street East, near the City of Palmdale. The Barrel Springs Alternative Site is a 540-acre block of land consisting of one (1) large parcel (APN 3048-008-003). The parcel does not contain existing residences. The site is generally flat but does contain

some topography around riverine features that cross the site. It is surrounded by mountainous terrain, and, similar to the Project site, it is in a Very High Fire Hazard Severity Zone and is not served by any water or sewer utilities. The site is within the San Andreas Fault Zone, a Holocene-active fault, which has the potential to result in increased geological hazard impacts compared to the Project.

4.12.2 Barrel Springs Alternative Site Comparison

All the potential impacts at the current Project site are less than significant with or without mitigation. Therefore, the Barrel Springs Alternative Site could not generate fewer potentially significant impacts than the Project. As discussed above CEQA requires consideration of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project” (14 CCR 15126.6[a]). To differentiate the Project and the Barrel Springs Alternative, the following analysis focuses on how the locations differ in their ability to meet the Project objectives and the potential for the Barrel Springs Alternative Site to result in potentially significant impacts that are not present for the Project.

The two (2) primary Project objectives that stratify the Project site and the Barrel Springs Alternative Site are as follows:

Develop an energy storage project that is in close proximity to existing electrical infrastructure and the Vincent Substation, to avoid and minimize potential impacts.

The Project would entail an approximately 1.1-mile-long gen-tie (Northern Gen-Tie Route) or an approximately 1.8-mile-long gen-tie (Southern Gen-Tie Route), and the Barrel Springs Alternative Site would entail a minimum 5.0-mile-long gen-tie. Regardless, if the Northern Gen-Tie Route or the Southern Gen-Tie Route is selected, the Project gen-tie would be routed through semi-developed land (existing dirt roads) to the Vincent Substation, resulting in potential land use and transportation impacts. The Project gen-tie would not cross other transmission lines (until entering the Vincent Substation) or highways.

It is assumed that the Barrel Springs Alternative Site Gen-Tie would travel south for approximately 1 mile then align with the existing high-voltage transmission corridor for approximately 4 miles before reaching the Vincent Substation. The Barrel Springs Alternative Site Gen-Tie would not need to cross the Sierra Highway or the Antelope Valley Freeway. The Barrel Springs Alternative Site Gen-Tie would need to cross eight (8) high-voltage transmission lines. The Barrel Springs Alternative Site Gen-Tie route would also have to parallel significantly sloped terrain and would travel near a comparable number of existing homes as the Project, generating similar potential impacts to homeowners but disturbing significantly more land for access roads due to cross slope stability requirements. Based on desktop review, the Barrel Springs Alternative Site appears to contain western Joshua tree, a species of ecological and cultural importance that is currently being considered by the state for listing as a threatened species. However, the large size of the alternative site parcel provides flexibility, so it is assumed that impacts to western Joshua tree could be avoided.

Locate near existing roadways and related infrastructure where available and feasible for construction and O&M access.

The Project site is located adjacent to an existing access and exit point for the Antelope Valley Freeway. The freeway access becomes Soledad Canyon Road, which parallels the site. Access to the Project gen-tie line is supported by the following existing roads: Carson Mesa, Foreston, and Kentucky Springs. Carson Mesa Road and Foreston Road

are not expected to require upgrades for gen-tie access and construction. Kentucky Springs Road would need to be extended by approximately 0.6 miles to facilitate construction and operational access to the gen-tie.

Access to the Barrel Springs Alternative Site would require use of the State Route 138 and Pearblossom Highway and existing paved roads, similar to the Project and resulting in similar transportation impacts as the Project. The Barrel Springs Alternative Site is located near a similar number of existing residences as the Project, resulting in similar potential land use impacts.

In addition to these two (2) objectives, the following considerations were reviewed to compare the Project site to the Barrel Springs Alternative Site.

- **Gen-Tie Landowner Agreements:** The Barrel Springs Alternative Site Gen-Tie Route requires site control or easement agreements from around 20 or more landowners, depending on the chosen route (as a comparison, the Project requires site control or easement agreements from six [6] landowners). These landowner counts represent preferred gen-tie routes that are either the most direct or limit development on steep terrain. The involvement of a larger number of landowners introduces considerable risk to the development process that renders the alternative infeasible, as well as the potential to increase the length and potential impacts of the gen-tie line, which could result in potentially significant effects on land use. If landowners decline an easement option, the gen-tie route will have to go around those properties, either increasing the length of the gen-tie, forcing it onto steep terrain, or both. In any of these situations, the potential for ground disturbance and visual resource impacts would be higher due to the increased number of towers necessary to complete the gen-tie route and the increased length of access roads necessary to build and maintain the line, resulting in potential feasibility issues under CEQA.
- **Existing Transmission Line Conflicts:** The Barrel Springs Alternative Site Gen-Tie Route must run parallel to five (5) existing transmission lines leading to the Vincent Substation. It will cross two (2) LADWP high-voltage lines and six (6) SCE high-voltage lines, totaling eight (8) high-voltage crossings, before entering the Vincent substation.
- **Residential Displacement:** The Barrel Springs Alternative Site consists of one (1) parcel, which does not contain permanent residences. This represents a decrease in the number of homeowners who may be displaced and would reduce potential impacts to socioeconomics.
- **Crossings:** The Barrel Springs Alternative Site presents increased crossing risks because the alternative, unlike the Project, would need to cross eight (8) high-voltage transmission lines. The Barrel Springs Alternative, like the Project, would not need to cross the Antelope Valley Freeway and Sierra Highway like the other alternative sites. In addition, the alternative site would eliminate the crossings associated with the current layout, including those over railroad tracks and Carson Mesa Road. However, the Barrel Springs site would need to cross the State Water Project. The gen-tie for the Barrel Springs Alternative Site would decrease the potential for temporary traffic and transportation impacts.
- **Site Topography:** The topography of the Barrel Springs Alternative Site is predominantly flat. This condition will necessitate similar amounts of extensive grading and earthwork as the Project and have similar potential for significant impacts to air quality and paleontological and cultural resources. The large size of the site may provide flexibility in siting to avoid topography constraints.
- **Gen-Tie Terrain Considerations:** Due to the existing transmission corridor located on a mountainside, constructing the Barrel Springs Alternative Site Gen-Tie Route will require navigating highly sloped terrain to minimize unnecessary crossings of transmission lines, in addition to potential grid reliability issues

associated with existing facilities. This presents significant engineering challenges and raises concerns about the feasibility of any proposed route, resulting in potential feasibility issues under CEQA.

- **Distance to Services:** The Barrel Springs Alternative Site is located a similar distance to the existing fire response services as the Project because the alternative site is located near existing services in the City of Palmdale. This represents similar potential for significant impacts to County services, air quality, and public health as the Project.
- **Access Road Expansion:** The Barrel Springs Alternative Site Gen-Tie Route would require enhancements to the existing access road infrastructure used for servicing transmission lines, leading to additional visual resources and soils ground disturbance impacts and potential traffic impacts.
- **Visual Resources Impact from Gen-Tie Line:** Both the Barrel Springs Alternative Site and the Project site would utilize a gen-tie route that avoids heavily trafficked automotive corridors. Impacts would be similar because neither project would require crossing the Antelope Valley Freeway or Sierra Highway. However, the Barrel Springs gen-tie would be significantly longer than the Project gen-tie, which has the potential to result in additional visual resource impacts.

4.12.3 Summary of the Barrel Springs Alternative Site Analysis

As shown in the analysis above, the alternative site cannot avoid or substantially lessen any of the potential significant effects of the Project, because the Project will have not any potentially significant impacts. The Barrel Springs Alternative Site contains the potential for significant impacts and only partially meets the Project objectives. The Barrel Springs Alternative Site is not located near the Vincent Substation in a way that minimizes impacts, nor is it located near existing roadways and infrastructure suitable for construction of the Project. In conclusion, the Barrel Springs Alternative Site is less desirable than the Project because of its “(i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.” (14 CCR 15126.6[c]). In addition, there is little potential to obtain site control of these areas as the parcels are not currently for sale.

4.13 Summary of Alternatives

A summary of the alternatives compared to the Project-by-Project Objective is provided in Table 4-1 below. The asterisks provided in the ~~Reduced Project Alternative~~ column indicate that while an the Peaceful Valley Alternative Site or Reduced Project alternative may meet a project objective, it only partially achieves the project objective as the proposed project would achieve the objective to a greater degree.

A summary of potential impacts of the Alternatives compared to the Project by resource topic is included in Table 4-4 below.

Table 4-4. Summary of Potentially Significant Effects for the Project and Project Alternatives

Issue Area	Proposed Project (Prairie Song)	No Project Alternative ¹	Peaceful Valley Alternative Site ¹	Reduced Project Alternative ¹	Crown Valley Alternative Site	Pearblossom Alternative Site	Tierra Subida Alternative Site	Barrel Springs Alternative Site
Air Quality	LTS	NA	LTS	Potentially Significant (Reduced GHG benefits)	Potentially Significant (Reduced GHG benefits)	LTS	LTS	LTS
Biological Resources	LTS	NA	LTS	LTS	LTS	LTS	LTS	LTS
Cultural Resources	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant
Geological Hazards and Resources	LTS	NA	LTS	LTS	LTS	LTS	LTS	LTS
Land Use	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant
Noise	LTS	NA	LTS	LTS	LTS	LTS	LTS	LTS
Paleontological Resources	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant
Public Health	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant
Socioeconomics	LTS	NA	LTS	LTS (Reduced tax and other project benefits)	LTS (Reduced tax and other project benefits)	LTS	LTS	LTS
Soils	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant
Traffic and Transportation	LTS	NA	Potentially Significant	LTS	LTS	Potentially Significant	Potentially Significant	Potentially Significant

Table 4-4. Summary of Potentially Significant Effects for the Project and Project Alternatives

Issue Area	Proposed Project (Prairie Song)	No Project Alternative ¹	Peaceful Valley Alternative Site ¹	Reduced Project Alternative ¹	Crown Valley Alternative Site	Pearblossom Alternative Site	Tierra Subida Alternative Site	Barrel Springs Alternative Site
Visual Resources	LTS	NA	Potentially Significant	LTS	<u>LTS</u>	<u>Potentially Significant</u>	<u>Potentially Significant</u>	<u>Potentially Significant</u>
Waste Management	LTS	NA	LTS	LTS	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>
Water Resources	LTS	NA	LTS	LTS	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>
Wildfire	LTS	NA	LTS	LTS	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>
Worker Health and Safety	LTS	LTS	LTS	LTS	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>	<u>LTS</u>

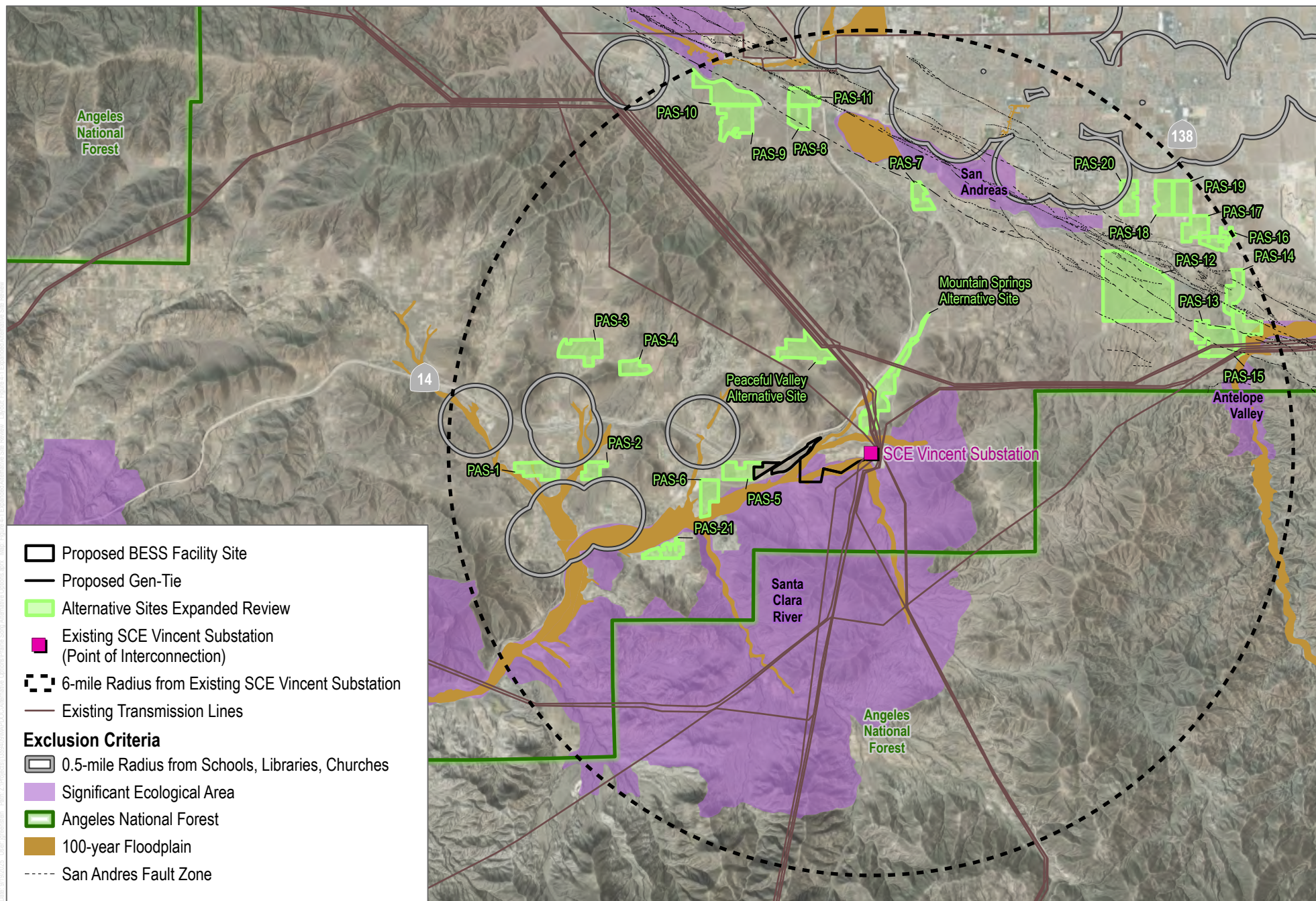
Notes: LTS = less than significant; NA = not applicable; GHG = greenhouse gas.
Potentially Significant = potentially significant and unavoidable impact.

¹ See Sections 4.6 through 4.128 for discussions of potential effects.

4.140 References

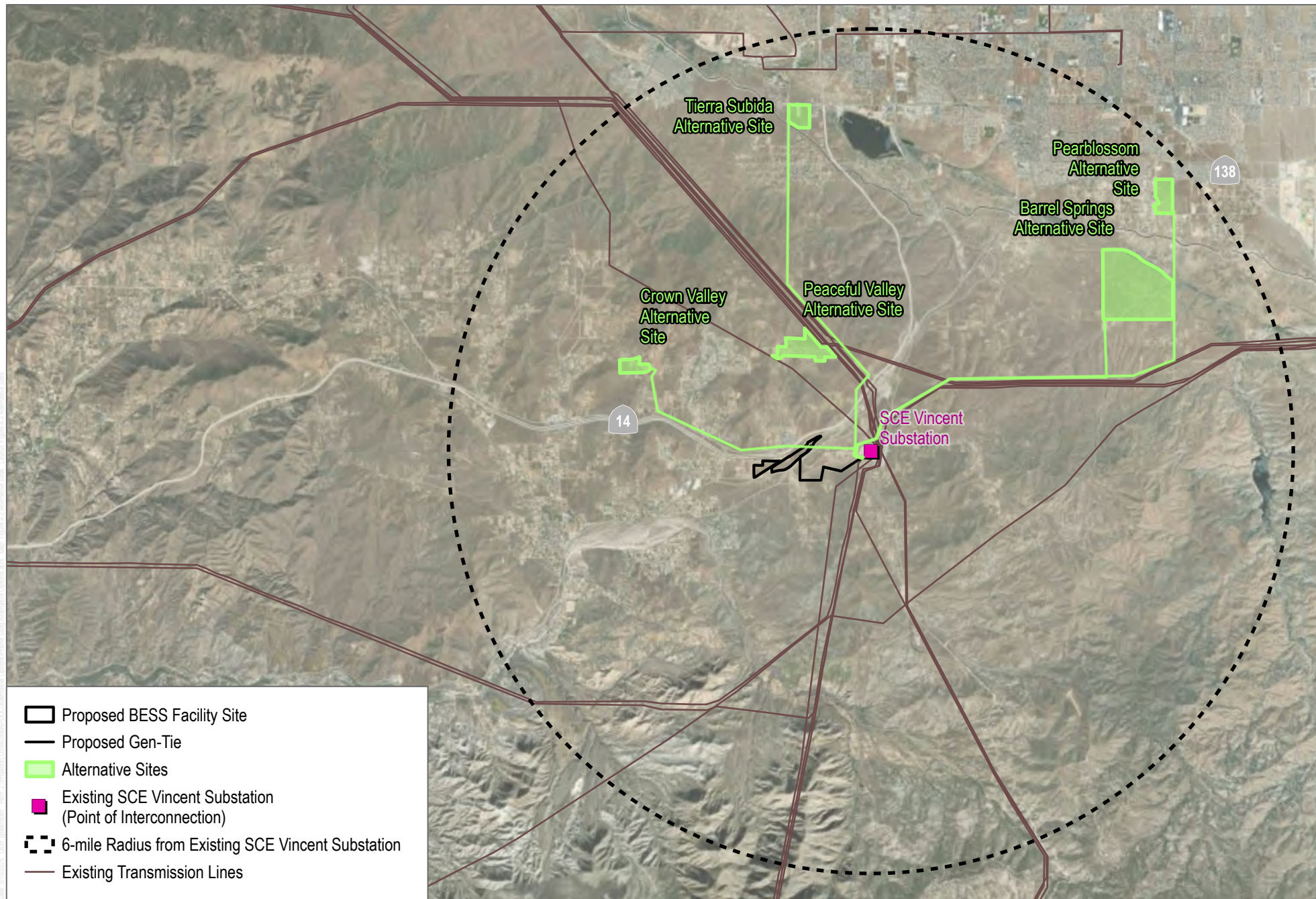
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SOURCE: World Imagery; Esri 2025; Los Angeles County 2025; Hitachi Energy 2025; FEMA 2025; USFS 2025; USGS 2025

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SOURCE: World Imagery; Los Angeles County 2025; Hitachi Energy 2025

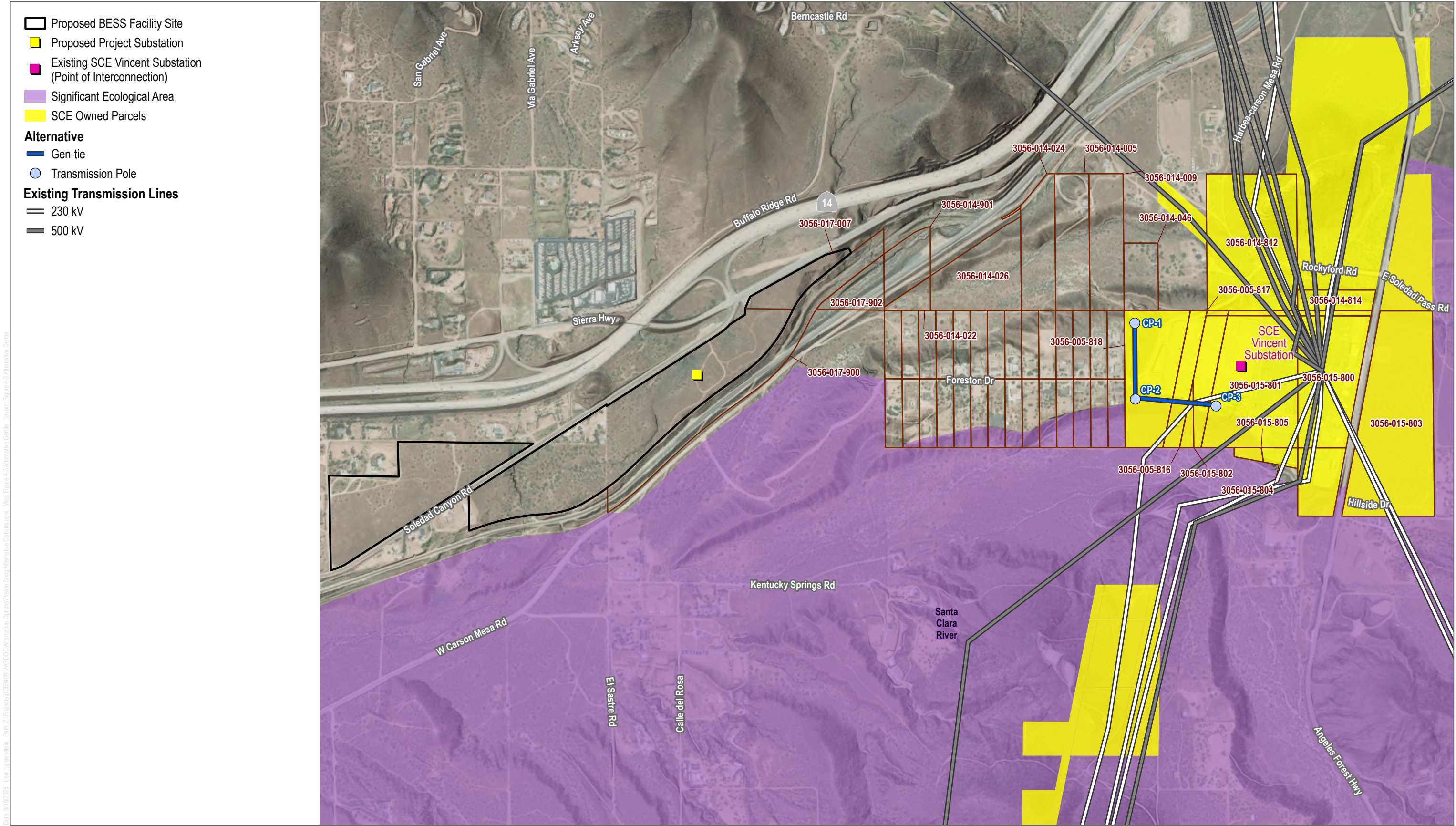
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0 1 2 Miles

FIGURE 4-2
Alternative Sites
Prairie Song Reliability Project

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Date: 9/19/2025 User: jprosser Path: Z:\Projects\113594\09\MAPDOC\Alternative Options\Prane Song Alternative Options.aprx Map: Figure 4-3 Alternative Gen-tie Layout: Figure 4-3 Alternative Gen-tie

SOURCE: World Imagery; County of Los Angeles 2025; Hitachi Energy 2025; USGS 2025

FIGURE 4-3
Alternative Gen-tie
Prairie Song Reliability Project

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Attachment 6

Expanded Alternatives Analysis Support Documentation



Re: (External):Q1625 - CEQA Alternatives Analysis Substation Entry Information Request

From Garrett Lehman [REDACTED]
Date Thu 8/21/2025 2:26 PM
To [REDACTED]@sce.com>; [REDACTED]@sce.com>
Cc Grace Bouziden [REDACTED]

Thank you Rodney. We appreciate the response

Garrett Lehman

Director
[REDACTED]

From: [REDACTED]@sce.com>
Sent: Thursday, August 21, 2025 12:43 PM
To: Garrett Lehman [REDACTED] [REDACTED]@sce.com>
Cc: Grace Bouziden [REDACTED]
Subject: Re: (External):Q1625 - CEQA Alternatives Analysis Substation Entry Information Request

Garrett, please see attached and let me know if that works for you. See below for responses to the questions in [blue](#).

Best regards,
[REDACTED]

From: Garrett Lehman [REDACTED]
Sent: Friday, August 8, 2025 10:30
To: [REDACTED]@sce.com>; [REDACTED]@sce.com>
Cc: Grace Bouziden [REDACTED]
Subject: (External):Q1625 - CEQA Alternatives Analysis Substation Entry Information Request

Hi Ari and Rodney,

The CEC has asked us to evaluate other possible Gen-Tie routes for the purposes of a CEQA Alternative evaluation. To that end, we have the following questions:

- Would SCE allow us to underground the 500kV line up to the Vincent substation? If so, could we daylight on SCE property, or would we have to daylight on private property?
 - [A customer could underground their portion of the gentie line but would need to rise up outside of SCE property for an overhead transition to SCE's portion of the gentie. SCE does not allow customer assets within SCE property.](#)

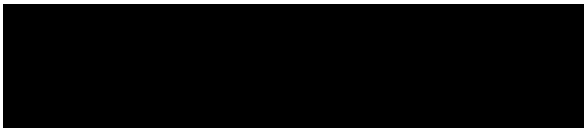
- Would we be allowed to enter Vincent on the West or North side of the substation, or do we need to keep our entry located on the South side of Vincent?
 - [There are no alternative routes for the project gentie to enter into Vincent Substation.](#)

If you have any questions, please call so I can provide additional context.

Thanks, and have a good weekend.

Garrett Lehman

Director





The Interconnection Handbook

Southern California Edison Company

Rev. 15

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		Version No.	15
	INTERCONNECTION HANDBOOK	Effective Date	1/31/2024

Approved by:

Original signed by

Patricia Arons

Principal Manager Resiliency & Subtransmission Planning

01/31/2024

Date

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INTRODUCTION AND SUMMARY OF TECHNICAL REQUIREMENTS

Southern California Edison Company's (SCE) Interconnection Handbook (Handbook) is broken up into three distinct parts based on the customer project type that are being connected, planned to be connected, or facility additions and modifications to existing customer facilities interconnected to the SCE's electric system.

The three parts of the handbook address:

- Generator Interconnections;
- End-User Facility Interconnections; and
- Transmission Interconnections

Collectively these types of interconnections are referred to in the Handbook as "Interconnected Facility (INTFAC)."

There is a fourth section in the Interconnection Handbook that addresses how SCE will work towards a solution to mitigate any adverse impact on affected systems using the California Independent System Operator (CAISO) tariff.

The Handbook specifies what is necessary for facilities to interconnect to SCE's electric system (Requirements), or locations where SCE is the operating agent, which shall be referred to as "SCE's electric system". These Requirements provide for safe and reliable operation of SCE's electric system.

As a Transmission Owner (TO), SCE is required to provide and maintain a Handbook to guide entities that need to interconnect to SCE's electric system. Please note that generators directly connecting to SCE's transmission facilities must also adhere to the CAISO generation interconnection procedures. This is because these facilities are under CASIO operational control and they perform the Transmission Operator (TOP) function for them.

Link to CAISO Fifth Replacement Federal Energy Regulatory Commission (FERC) Electric Tariff: <http://www.caiso.com/rules/Pages/Regulatory/Default.aspx>

1.1 Introduction

1.1.1 Purpose of Interconnection Handbook

The Handbook was written to provide SCE's customers an overview of the Requirements to address interconnection requests, and to support compliance with North American Electric Reliability Corporation (NERC) Reliability Standard, FAC-001-3, and Facility Connection Requirements. It also provides a means to facilitate communication of technical information to SCE regarding the INTFAC, and are **not meant to be used as a design specification** for the INTFAC.

SCE's Requirements do not cover all aspects of the necessary technical criteria applicable to an INTFAC project, and the final design of facility connections to SCE's electric system will be subject to SCE review and approval on a case-by-case basis.

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The Handbook considers the following general items that need to be addressed by customers in their interconnection request to SCE:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions
- Cybersecurity Measures

Please note some of the items in the list above do not apply to all applicable entities – and some applicable entities may have requirements that are not included in the list. SCE has compiled a list of additional technical standards and criteria that the INTFAC must adhere to, as referenced in the Requirements, and is provided in Appendix A.

Once the initial facility information has been provided SCE will determine and communicate any additional project-specific technical requirements necessary from the INTFAC. It is in the customer's best interest to discuss their project plans with SCE prior to making any major financial commitment such as the purchasing or installation of equipment.

SCE will follow notification procedures for new or modified facilities in the [Transmission Control Agreement \(TCA\) per Section 4.2.3](#), with respect to the CAISO Register.

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In addition, customers may also inquire about SCE’s interconnection procedures and for notification of new or modified generation, transmission, and end-user facilities from the following contact:

Contact	Mailing Address
Manager, Grid Contracts Management	Manager, Grid Contracts Management P.O. Box 800 2244 Walnut Grove Avenue Rosemead, California 91770

1.1.2 Conformity

The INTFAC shall comply with all applicable NERC Reliability Standards, Western Electricity Coordinating Council (WECC) Reliability Criteria and Guidelines, along with any WECC, SCE and CAISO system planning and performance guidelines for its facilities. SCE will not assume any responsibility for complying with mandatory reliability standards for such facilities and offers no opinion whether the Interconnection Customer must register with NERC pursuant to Section 215 of the Federal Power Act. If required to register with NERC, the INTFAC shall be responsible for complying with all Applicable Reliability Standards for its facilities.

The INTFAC is responsible for conforming to applicable:

- FERC Rules, Regulations, and Orders
- NERC Standards
- WECC Regional Criteria, Policies, and Guidelines
- CAISO Planning Standards
- SCE Reliability Criteria, as well as good engineering and utility practice.

1.1.3 Requirements are Subject to Change

These Requirements are subject to change. INTFACs have the responsibility to ensure that they comply with the most recent version of the Interconnection Requirements. The current version may be accessed at SCE's internet site, <https://www.sce.com/>. Each page of the Handbook displays its effective date in the upper right-hand corner.

1.1.4 Applicability

Upon execution of an Interconnection Agreement per the appropriate tariff, the INTFAC should make reference to this document in its entirety during the construction process.

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PART 1

Generator Interconnection Requirements

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SECTION 1 GENERATOR INTERCONNECTION OVERVIEW

The Generator Interconnection Section specifies what is necessary for generation facilities to interconnect to SCE's electric system and gives customers an overview of the requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the generation facilities interconnecting to SCE's electric system.

Throughout this section the term “Producer” shall refer to the owner, its agents, or the operator of facilities being interconnected to SCE’s electric system that includes performing the functions of supplying energy and a service (exclusive of basic energy and transmission services) to support the reliable operation of the transmission system.

All Producers with generation connected to SCE’s electrical system, regardless of voltage or classification, are required to adhere to SCE’s Generation Modeling Data Requirements.

SCE’s Generation Modeling Requirements can be found in the [CAISO and SCE Joint Transmission Planning Base Case Preparation Process](#) and in [Section 10 of the CAISO Business Practice Manual for Transmission Planning Process](#).

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SECTION 2 PARALLEL SYSTEMS

These requirements apply to interconnecting generating facilities that intend to operate in parallel with SCE's electric system, and, in some instances, ultimately deliver power to the CAISO grid (directly to the transmission system, or via SCE's Distribution system).

Subject to FERC, California Public Utilities Commission (CPUC) regulations, and SCE approval, a Producer may elect to operate a generator facility in parallel with SCE or as a separate system with the capability of non-parallel load transfer between the two independent electrical systems. Induction generators, and some systems using inverter devices, must be operated in parallel to produce energy. Synchronous generators may be operated either in parallel or as a separate system. However, please note that the requirements provided in this document are applicable to interconnecting generators intending to operate in parallel.

2.1 Parallel Operation

A parallel operation is one in which the Producer's generating facilities operate connected to SCE's electric system. A consequence of such parallel operation is that the parallel generator becomes a part of SCE's electric system, and must, therefore, be considered in planning the protection of SCE's electric system. To be allowed to operate in parallel with the electric grid, the generating facility must meet Southern California Edison Transmission Planning Criteria and the technical specification as outlined in the relevant section of this document.

2.2 Need for Protective Devices

Prudent electrical practices require that certain protective devices (relays, circuit breakers, etc.) must be installed at any location where a Producer desires to operate its generating facilities in parallel with the SCE system. The purpose of these devices is to isolate faults from the Electrical Grid and promptly disconnect the Producer's generating equipment from the SCE system when faults or abnormal operation jeopardize the reliable operation of equipment or the safety of personnel. Other modifications to electrical system configuration or protective relays may also be required to accommodate parallel generation. SCE assumes no responsibility for determining protective equipment needed to protect Producer's facilities.

2.3 Hazards

SCE's transmission and distribution lines are subject to a variety of natural and man-made hazards. Among these are lightning, earthquakes, wind, animals, automobiles, mischief, fire, and human error. Producer's electric systems are subject to these same hazards but not nearly to the same degree because SCE's electric system has greater exposure to these hazards.

The electric problems that can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that damaged equipment be de-energized as soon as possible to ensure public safety and continued operation of the remainder of SCE's electric system.

Where SCE controls the only source of supply to a given transmission or distribution line, it has the sole responsibility to install protective equipment to detect faulted equipment or other operating abnormalities and to isolate the problem from the remainder of SCE's electric system. A non-SCE generating facility

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connected to and operated in parallel with an SCE line represents another source of power to energize the line. Accordingly, SCE requires that such facilities also have adequate protective devices installed to react to abnormal electric system conditions and isolate from SCE's electric system.

2.4 Islanding

Generating facilities operating in parallel with SCE's electric system must also be equipped to detect another condition referred to as "unintentional islanding." Islanding is the abnormal operating condition where a portion of SCE's electric system and loads become isolated from the remainder of SCE's electric system while still connected to and receiving energy from generating facilities within an electrical island. When unintentional islanding occurs, all generating facilities within the electrical island must be disconnected to prevent continued operation.

The protective devices and other requirements identified in Section 3 are intended to provide protection against hazards, such as those noted above, by ensuring that parallel generating facilities are disconnected when abnormal operating conditions occur. The following sections reflect the fact that these requirements are typically minimal for small installations but increase in scope and/or complexity as the size of the generation installation increases. SCE may require voltage and frequency protective functions or relays to detect islanding and shut down generation during periods of islanding.

2.5 UPS

Uninterruptible Power Supply (UPS) systems will be classified as either a separate or a parallel system depending on the following criteria. If such UPS systems are not capable of transfer of electric power from the emergency source to SCE's electric system, they will be classified as a separate system generating facility. If such UPS systems are capable of transfer of power, they must meet the requirements for parallel generation.

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SECTION 3 PROTECTION REQUIREMENTS

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE's electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE's electric system. For instance, a manual disconnecting device must be provided by the Producer, but the form of this device will vary with the service voltage and generating facility capacity.

While some protection requirements can be standardized, the detailed protection design highly depends on the Producer's generator size, type and characteristics, number of generators, interconnection line characteristics (i.e., voltage, impedance, and ampacity), as well as the existing protection equipment and configuration of SCE's surrounding electric system. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical generation facilities connected at different locations in SCE's electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements (See Section 8.)

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic maintenance/replacement. Typically, the frequency of transmission line relay replacement does not exceed once every fifteen (15) years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule. If equipment does fail, that may impact the reliability of the electric system and it shall be replaced according to the Interconnection Agreement.

For Generation interconnections utilizing a sub-transmission line interconnection at voltage 66 and 115 kV or transmission line at 161 kV, 220 kV and 500 kV, Producers shall utilize Protection Requirements as defined in this Interconnection Handbook Part 3 Transmission Interconnection Requirements Section 2.

Applicability: SCE's requirements identify three different categories for Producer generating facilities connecting to the SCE electric system each with distinctive protection requirements. These categories are:

1. Interconnection voltage above 34.5 kV
2. 200 kVA and above capacity, interconnection voltage 34.5 kV or below
3. Less than 200 kVA capacity, interconnection voltage 34.5 kV or below

Aggregation: Where multiple generating facilities (with a single owner) are allowed to connect to SCE's electric system through a single point of interconnection, the interconnection is said to have aggregated generating facilities. The appropriate category of aggregated generating facilities is calculated by summing the kVA ratings of the multiple generators.

Disclaimer: The categories above have been established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the specific requirements for

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each installation will be made by SCE depending on several factors that could include Producer load magnitude, the magnitude of other load connected to that circuit/system, available short circuit duty contribution, and other conditions SCE deems prudent.

The Protection Requirements of the above three categories are described in Sections 3.1 to 3.3. These sections include Figures 3a through 3i which illustrate typical installations for protection equipment. The following is a legend of device numbers referred to in these figures:

Legend

Protective Device Numbers and Description

4	Master Contactor
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
50	Breaker Failure
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Over-current
59	Over-voltage
59G	Over-voltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Over-current
78	Loss of Synchronism (Out-of-Step)
79	Reclosing Relay
81O	Over-frequency
81U	Under-frequency
87	Current Differential
87L	Transmission Line Differential

NOTE: For additional information on device numbers, refer to ANSI C37.2.

3.1 Category 1: Voltage Over 34.5 kV

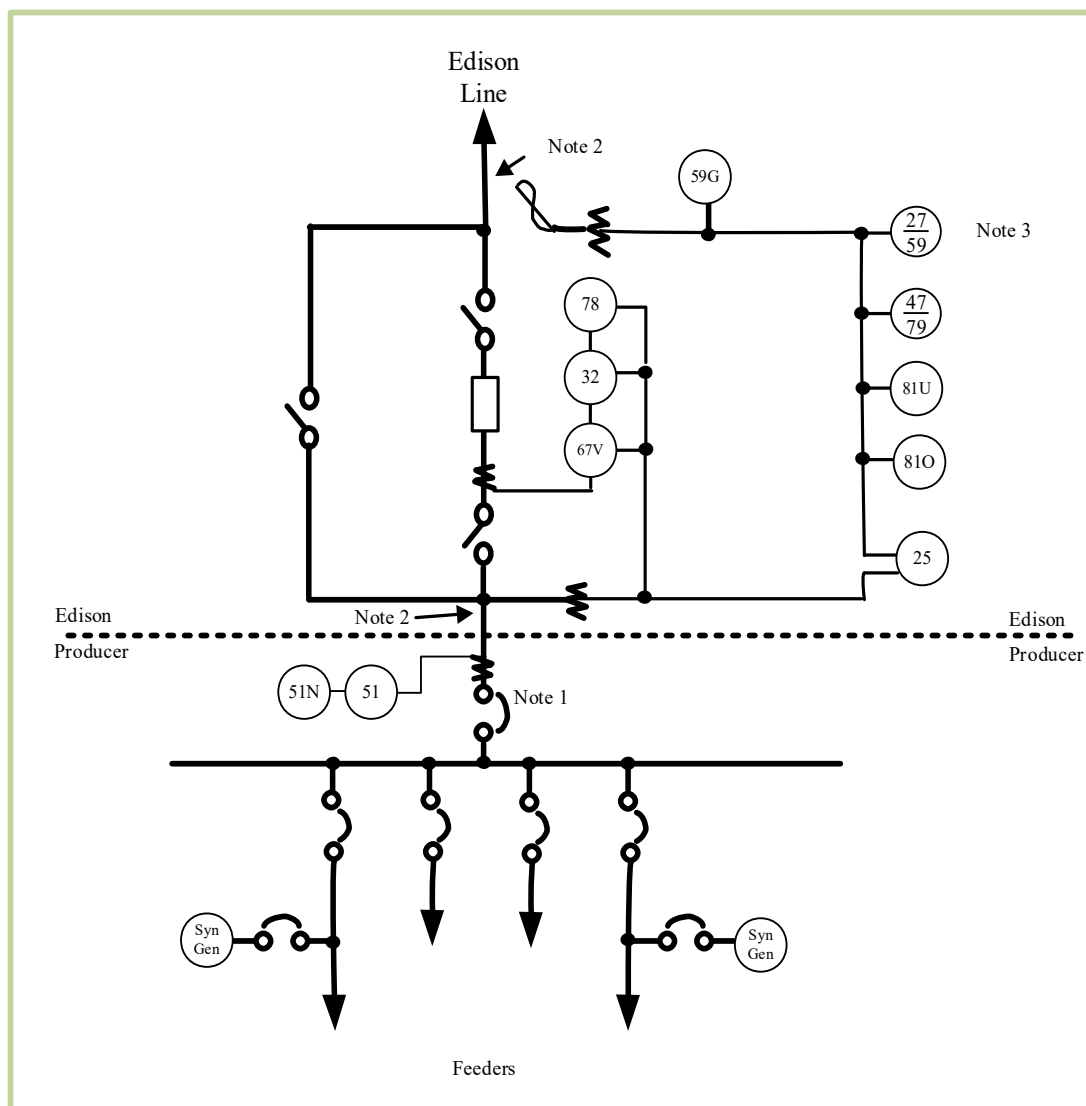
This Category is limited to generating facilities interconnecting at a single point with interconnection voltage above 34.5 kV. This requirement applies to all interconnections to the CAISO Controlled Grid, and to interconnections to SCE owned and operated facilities above 34.5 kV.

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Typical Installations

Figures 3a, 3b, and 3c show typical installations with the SCE interface.

Figure 3a: Typical Synchronous Parallel Generation with Assumed SCE Owned Protection (> 34.5 kV)

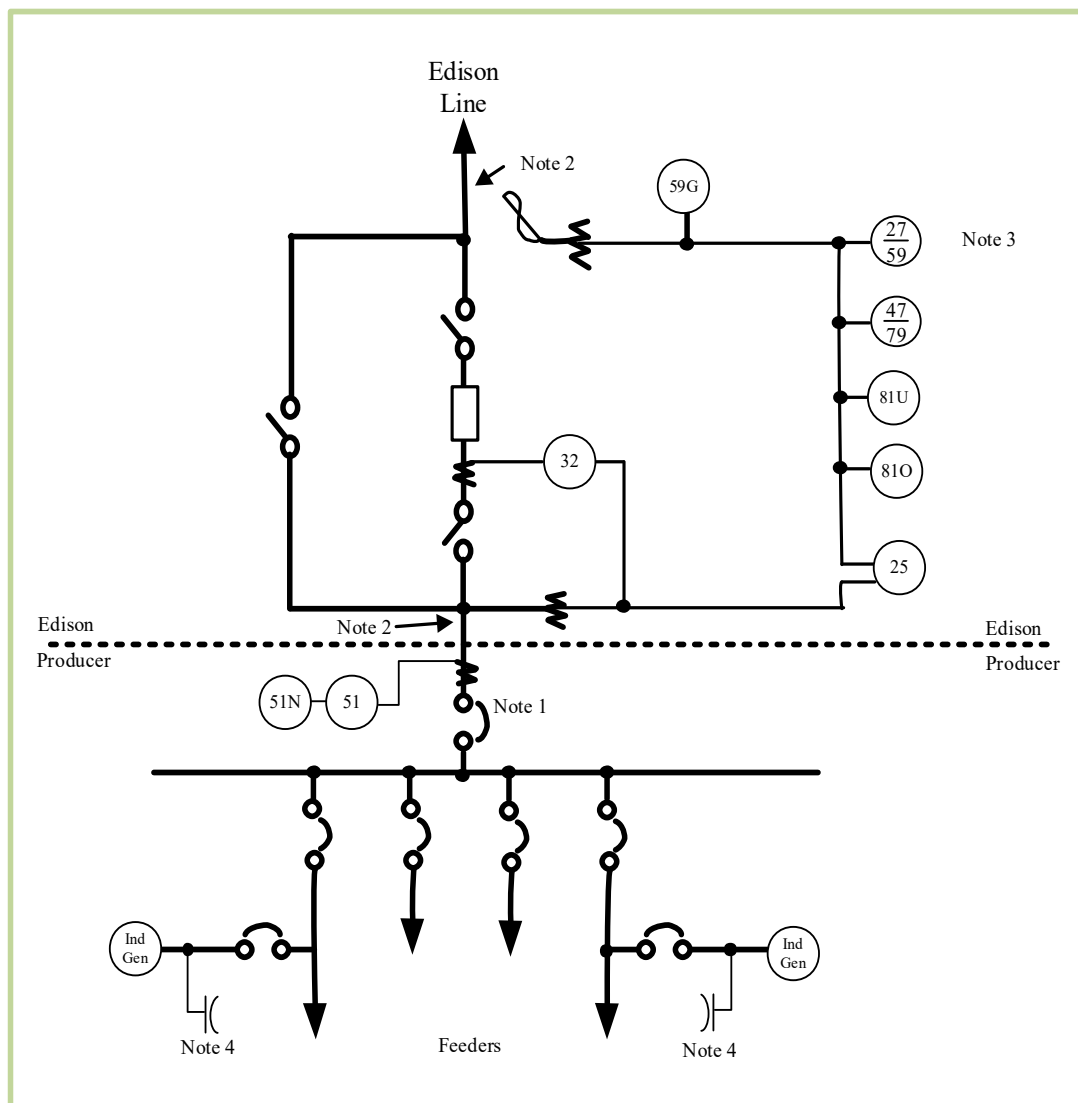


- Notes:**
1. Producer's main breaker or switch.
 2. Transformation, if required, may be by SCE or the Producer.
 3. Relay operates on two different phase-to-phase voltages.

Not all Producer-side protective relaying is shown.

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Figure 3b: Typical Induction Parallel Generation with Assumed SCE Owned Protection (>34.5 kV)



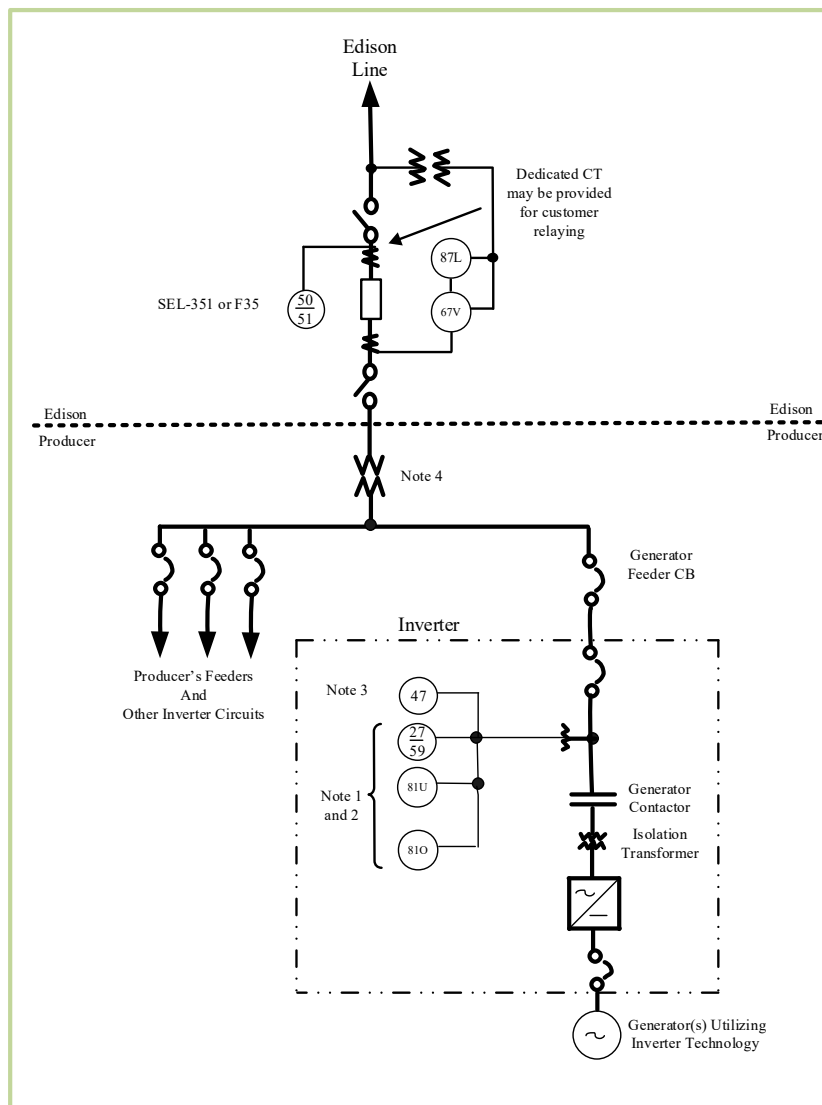
- Notes:**
1. Producer's main breaker or switch.
 2. Transformation, if required, may be by SCE or the Producer.
 3. Relay operates on two different phase-to-phase voltages.
 4. See Section 5.8.

Not all Producer-side protective relaying is shown.

For induction generation interconnection facilities, the Producer is responsible for installing the appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

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**Figure 3c: Typical Parallel Generation Utilizing Inverter Technology
Assumed SCE Owned Protection (>34.5 kV)**



- Notes:**
1. Producer's main breaker or switch.
 2. Transformation, if required, may be by SCE or the Producer.
 3. Relay operates on two different phase-to-phase voltages.
Not all Producer-side protective relaying is shown.
 4. Grounding transformer or ground detector (by Edison or the Producer.) Required unless main transformer is wye-grounded-delta
 5. Protective and synchronizing relays required if the Producer desires to serve isolated load during Edison outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.

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3.1.1 Specific Requirements for Category 1

- a) Typically, an SCE-owned and controlled circuit breaker is relied upon -to isolate generation facilities during SCE's electric system disturbances.
- b) Producer-owned and controlled circuit breaker(s) or disconnect switch(es)- (as required – refer to Section 5.14 Isolating Equipment Requirements and Switching and Tagging Rules) are required at the main to disconnect for Producer system trouble. If desired, SCE may permit the Producer to trip and/or close the SCE breaker by remote control. If synchronizing is to be done with SCE, SCE will install synchronizing supervision relays and telecommunications as required.
- c) Producer to provide synchronizing relays or equipment at the main, generator, and other breakers as appropriate. Either induction starting, automatic synchronizing, or manual synchronizing supervised by a synchronizing relay must be provided by the Producer.
- d) Induction starting will be permitted only where the inrush will not exceed SCE prescribed limits. Producer shall never attempt to parallel its system with SCE's electric system when the Producer's synchronizing facilities are malfunctioning or inoperative. Manual synchronizing without a supervising relay is not permitted. Automatic synchronizing may be required for synchronous generators which contribute short circuit current exceeding 5 (%) percent of the pre-existing short circuit current at the point of interconnection with SCE's distribution system.
- e) Protection related telecommunications may be required as determined by SCE Protection Engineering.

3.1.2 Protective relays which perform the following functions

- a) Short Circuit Protection (Devices 51V or 67V, 51N or 59G)
The designated relays will detect faults on the SCE electric system to which the Producer's generating facility is connected. Generally, the phase relays are voltage restrained overcurrent type or impedance torque-controlled overcurrent type. Occasionally, pilot relays or transferred tripping relays may be required. In ground fault protection, a directional overcurrent relay or ground fault voltage detector may be used. A grounding transformer may be required to avoid dangerous overvoltages which could occur during accidental isolation of the line from the main system while the generator is in operation. Adequate grounding can be provided either by the use of a wye-grounded-delta main power transformer or by installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. Devices 51V or 67V are normally omitted for induction or inverter-based generator installations because of the absence of sustained fault currents from these generators.
- b) Islanding Protection (Devices 27/59, 81-O, 81-U)
During the course of fault clearing or due to accident, equipment malfunction, or malicious mischief, it is possible for a SCE circuit/system to become separated from the main system, leaving customers on the circuit supplied from the Producer's generator. To protect customers

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from abnormal voltage or frequency excursions under these conditions, and to facilitate rapid restoration of normal service, relays for islanding protection are required. Generally, these relays will provide over and under frequency functions and three phase over- and under-voltage functions with instantaneous overvoltage tripping. For generating facilities aggregating 10 MW and greater, SCE may elect to use a voltage phase comparison system (Telesync) for islanding protection while retaining the voltage and frequency relays for backup.

c) Breaker Closing/Reclosing Control (Devices 25, 47/79)

It is important that the closing of the SCE circuit breaker be controlled so that it can only be closed when it is safe to do so. Inadvertent closing of the circuit breaker could result in paralleling out of synchronism or energizing of de-energized facilities, and hazardous conditions could result. The required logic for manual closing of the SCE breaker is:

- The line side of the breaker is energized with proper voltage and phase sequence, the load side of the breaker is de-energized and the Producer's main breaker (or generator breaker) is open, or
- Synchronism check across the breaker is satisfactory which, in most cases, indicates that either the breaker bypass switch is closed or interconnection with the Producer already exists elsewhere.

To provide the best continuity of service to the Producer, automatic reclosing of the SCE breaker subsequent to fault clearing is engineered into the control circuitry. If the trouble is permanent, the breaker will trip again and lockout. No further reclosing will take place until the breaker has been reclosed manually. The required conditions for automatic reclosing are the same as for manual closing. Where provision is made for closing of the SCE circuit breaker by the Producer, the required conditions for closing will be the same as for manual closing by SCE. The Producer's closing control will enable SCE's synchronizing relay to close the breaker.

d) Loss of Synchronism (Device 78)

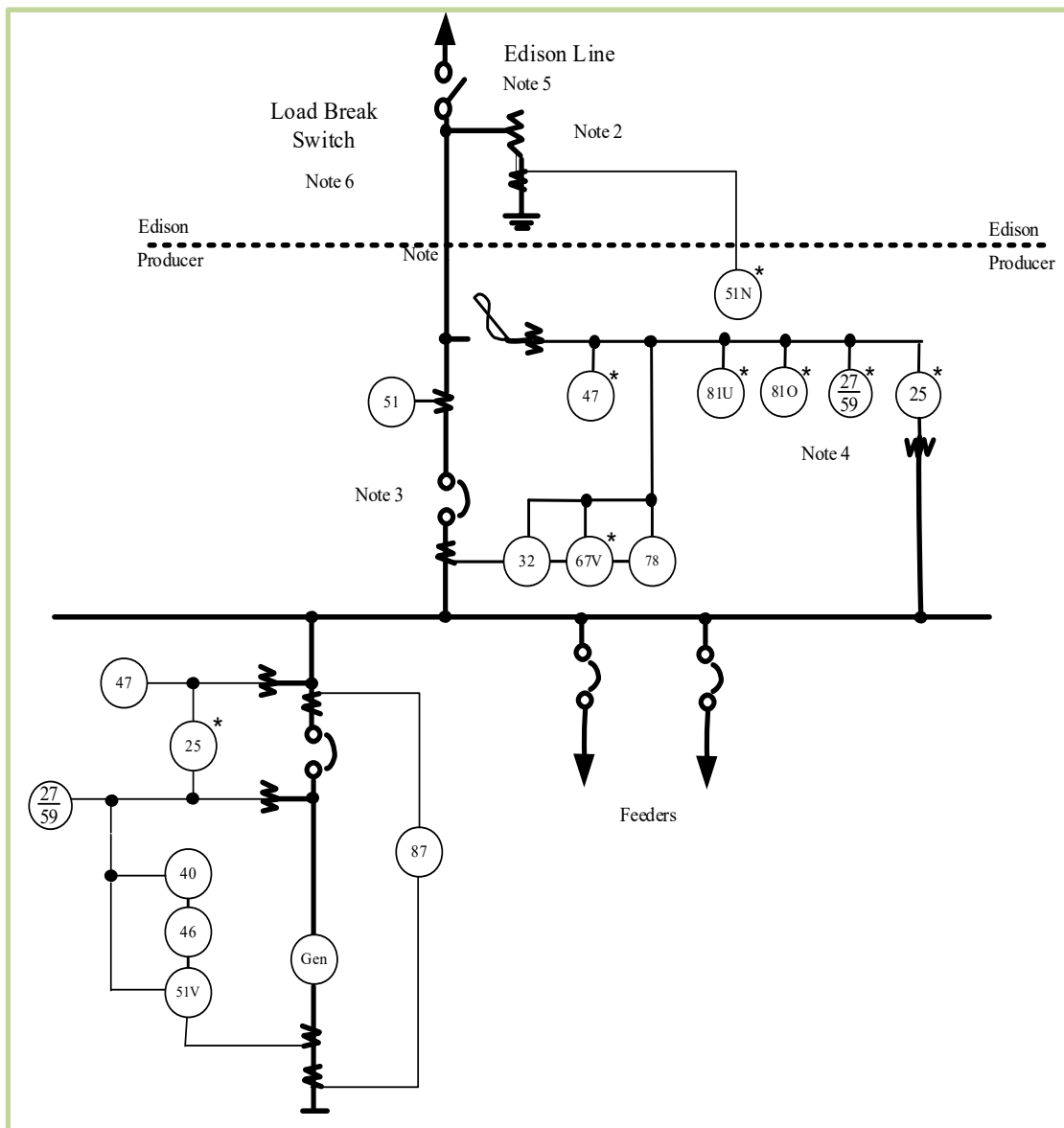
Operation of the Producer's synchronous generator out of synchronism with SCE may cause large voltage fluctuations to SCE's customers and may cause severe damage to the generator. If SCE determines that the relative capacities of its system and of the Producer's generating facility are such that this situation is likely to occur or for those installations which have experienced such voltage fluctuations, specific relays for detection of loss of synchronism (out of step) will be required.

3.2 Category 2: Total Generation 200 kVA and Above, Voltage at 34.5 kV or Below

All installations in this Category require SCE review of the protective functions to be provided by the Producer. Refer to Figures 3d, 3e, and 3f for typical installations. Producers must ensure their compliance to SCE's Telemetry Requirements as stated in Section 7 of these Requirements.

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Figure 3d: Typical Synchronous Parallel Generation with Assumed Producer Owned Protection ($> 200 \text{ kVA}, \leq 34.5 \text{ kV}$)

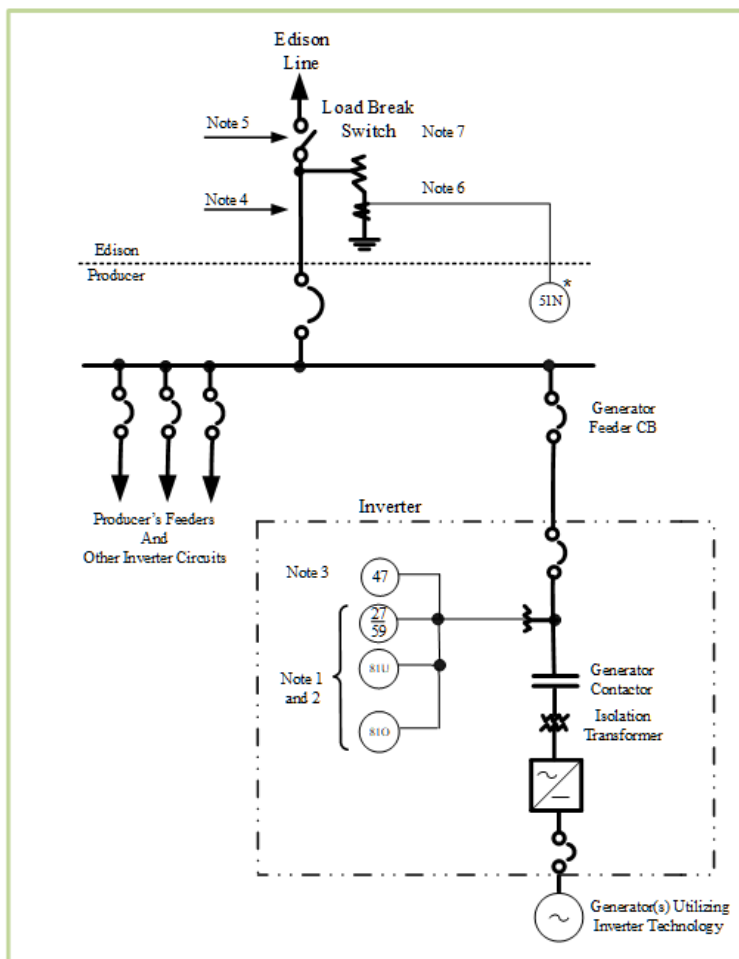


- Notes:**
1. Transformation (as required) by SCE or the Producer.
 2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye-grounded-delta. (See 3.2.3.d for requirements)
 3. Protective and synchronizing relays required if the Producer desires to serve isolated load during SCE outage. If not provided at main circuit breaker, these functions should be provided at generator breaker.
 4. Two phase-to-phase connected or three phase-to-neutral connected relays required.
 5. Load break switch to be installed when required by SCE's Distribution Design Standards.
 6. Projects exporting 1MW and larger will require an automated device as required by SCE's Distribution Design Standards. (See Section 4.14 for details)
- *** Indicates devices required by SCE. Others are shown as conventional practice.

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appropriate VAR supporting equipment at its facility to maintain unity power factor at the point of interconnection.

**Figure 3f: Typical Parallel Generation Utilizing Inverter Technology
With Assumed Producer Owned Protection (≥ 200 KVA, ≤ 34.5 kV)**



- Notes:**
- Protective devices required by SCE for all installations.** $\frac{27}{59}$ shall be a 3Ø unit or two 1Ø units.
 - UL1741 certified inverters meet noted protection requirements without additional relays provided all inverters are UL1741 compliant.
 - Recommended for three phase generators.
 - Transformation as required by SCE or the Producer.
 - Load break switch to be installed when required by SCE's Distribution Design Standards.
 - Grounding transformer or ground detector may be required to be supplied by SCE unless the main transformer is zwye-grounded-delta. (See 3.2.3.D for requirements)
 - Projects exporting 1MW and larger will require an automated device as required by SCE's Distribution Design Standards. (See Section 4.14 for details)
 - Producer is responsible for other protective devices not shown on the diagram because of large variations with type of inverter.
 - Drawing does not show metering requirements.
- "*" Indicates devices required by SCE. Others are shown as conventional practice.

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3.2.1 The Producer shall provide adequate protective devices

- a) Detect and clear the generator(s) from short circuits or grounds on SCE's electric system serving the Producer.
- b) Detect the voltage and frequency changes that can occur if the SCE electric system serving the Producer is disconnected from the main system and clear the Producer's generating facilities from the islanded system.
- c) Prevent re-paralleling the Producer's generation, after an incident of trouble, unless the SCE service voltage has been of normal magnitude and frequency continuously for a pre-determined period of time (typically five minutes).

3.2.2 Protection devices which may be required to satisfy the above Requirement

- a) Phase over-current trip devices (Device 51, 51V, or 67V)
In most cases these will have to be voltage-restrained or voltage-controlled over-current relays to provide coordination with SCE relays. Devices 51V or 67V are normally omitted for induction or inverter-based generator installations because of the absence of sustained fault currents from these generators.
- b) Residual over-current or over-voltage relays to trip for ground faults on the SCE electric system (Devices 51N or 59G)
In ground fault protection, a directional overcurrent relay or ground fault voltage detector may be used. A grounding transformer may be required to avoid dangerous overvoltages which could occur during accidental isolation of the line from the main system while the generator is in operation. Adequate grounding can be provided either by using a wye-grounded-delta main power transformer or installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. The required type of device (51N or 59G) depends on the characteristic of SCE's interconnecting system. Contact SCE for information for a specific location.
- c) Over/under voltage relays (Device 59/27)
Two over/under voltage relays measuring different phase-to-phase voltages or three over/under voltage relays each measuring a phase-to-neutral voltage is required. A single multiphase over/under voltage relay is acceptable if it has separate voltage measurement elements for each phase or phase pair. Under voltage relays should be adjustable from 75-90% of nominal voltage and have time delay to prevent unnecessary tripping on external faults. Over voltage relays should be adjustable from 110-120% of nominal voltage and be instantaneous or a combination of instantaneous and time delayed. Setting changes with temperature variation should not exceed +2 volts over the expected temperature range.

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- d) Over/under frequency relays (Device 81-O or 81-U)
The over/under-frequency relay should be adjustable per the applicable standards (e.g. CAISO, NERC, and IEEE) requirements and regional requirements (WECC). Setting change with temperature variation over the expected range, or voltage variation over +10%, should not exceed +0.05 Hz.
- e) Phase sequence under-voltage relay (Device 47/27)
To permit paralleling only when SCE voltage and phase sequence are normal.
- f) Automatic Separation: In some cases, protective devices supplied with the generating equipment will meet some or all of these requirements, provided that it is acceptable to trip the generator whenever the SCE source is lost. If the Producer desires to automatically separate from SCE and commence isolated operation upon loss of the SCE source, additional devices will be necessary to affect the separation.
- g) Loss of Synchronism (Device 78)
In specific installations, particularly with large generators (over 10,000 kVA), SCE may require specific additional protection functions such as loss of excitation, loss of synchronism and over-excitation protection, if these conditions would have an impact on SCE's electric system.
- h) Potential for exports greater than contractual allowances: Generating Facility whose net MW output is less than the gross nameplate MW value of the generation unit(s) may require additional protection facilities for the unlikely event that the facility generates more than the allowable contractual amount.

3.2.3 Other protection devices for Category 2 Generation

- a) **Utility Quality Relays:** Depending on the size of the generating facility and the size of the distribution or subtransmission system to which it is connected, SCE may require the Producer to utilize "utility quality" protective relays. Such relays have more stringent tolerances and more widely published characteristics than "industrial quality" relays and have the ability to coordinate protective settings with utility settings. This Requirement will be invoked only if the generating facility is large enough to require close coordination with SCE relays. In general, installations aggregating less than 1,000 kVA will not be subject to this Requirement.
- b) **Relay Operation Recorders:** All protective devices supplied to satisfy the requirements in Category 2 generating facilities shall be equipped with operation indicators (targets) or shall be connected to an annunciator or event recorder so that it will be possible to determine, after the fact, which devices caused a particular trip.
- c) **Relay Testing:** All protective devices supplied to satisfy the requirements in this Category shall be tested by qualified personnel prior to SCE approving parallel operation, and at intervals at least as frequent as those used by SCE for the relays protecting the line(s) serving the Producer. Special tests may also be requested by SCE to investigate apparent missed operations. Each routine or special test shall include both a calibration check and an actual trip

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of the circuit breaker from the device being tested. For each test, a report shall be prepared and sent to SCE listing the tests made and the "as found" and "as left" settings/calibration values.

- d) **Four-wire Multi-grounded Neutral versus three-wire Distribution Circuits:** In projects where the Producer is served from an SCE four-wire multi-grounded neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system. This is necessary to avoid dangerous over-voltages on other customers served from phase-to-neutral connected distribution transformers. Adequate grounding can be provided either by the use of a wye-delta main power transformer or by installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. For three-wire distribution circuits, installation of a ground detector will be required, to provide detection of ground faults in SCE's three-wire distribution circuit. This requirement will not apply if the generating facility passes the applicable Rule 21/WDAT technical evaluation criteria.

3.2.4 Exemption for Installing Phase Over-Current Protective Devices

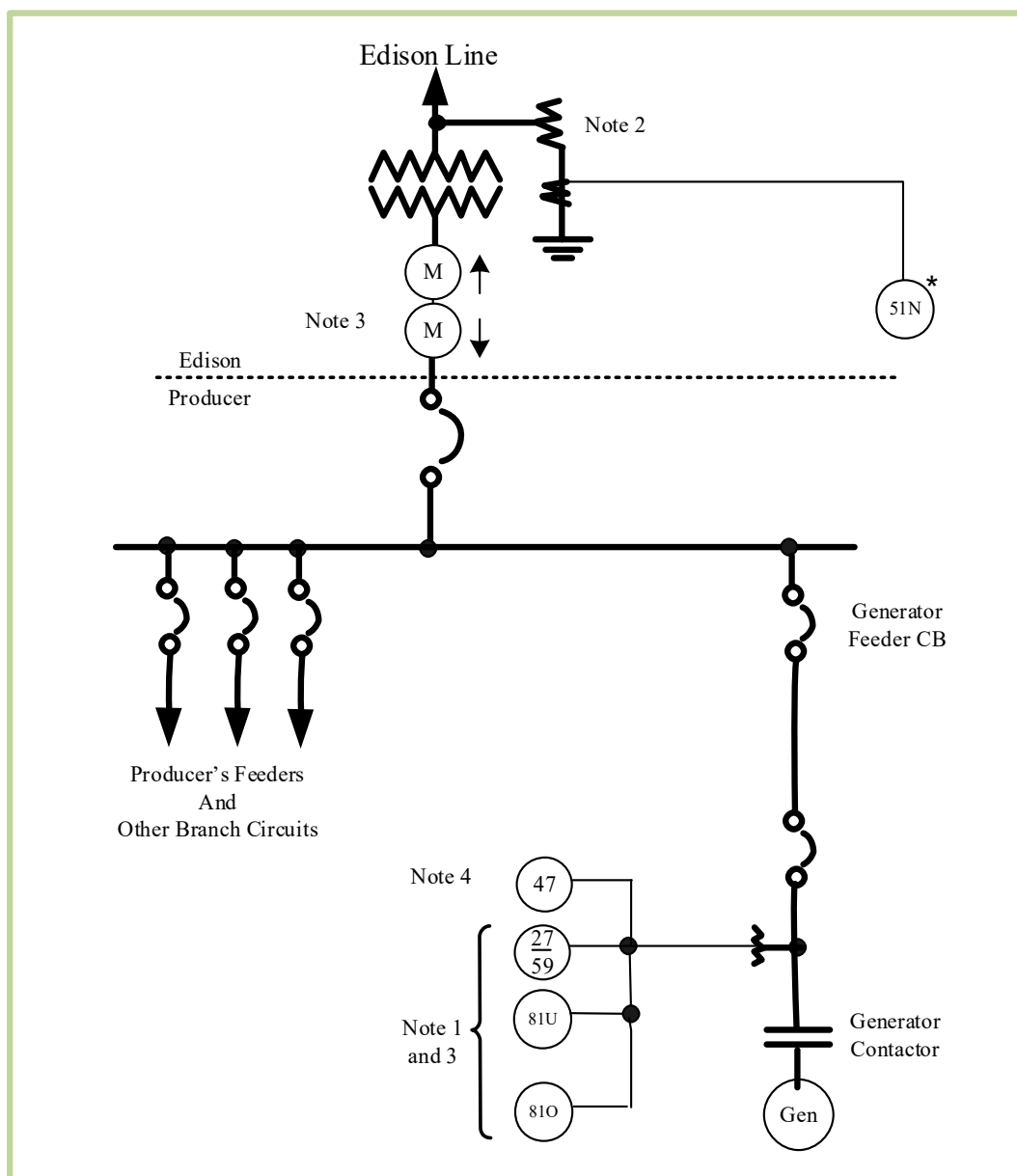
Where induction or inverter-based generators are employed rather than synchronous machines, the phase over-current protective devices required by SCE generally will be waived since these generation sources will not deliver sustained over-currents. All other specified protective devices are required.

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3.3 Category 3: Total Generation Less Than 200 kVA, in Voltage at 34.5kV & Below

The following requirements for small generating facilities are based on an assumed low density of parallel generation on the serving circuit. Other requirements may be imposed should the density exceed a tolerable limit. Refer to Figure 3g and Figure 3h.

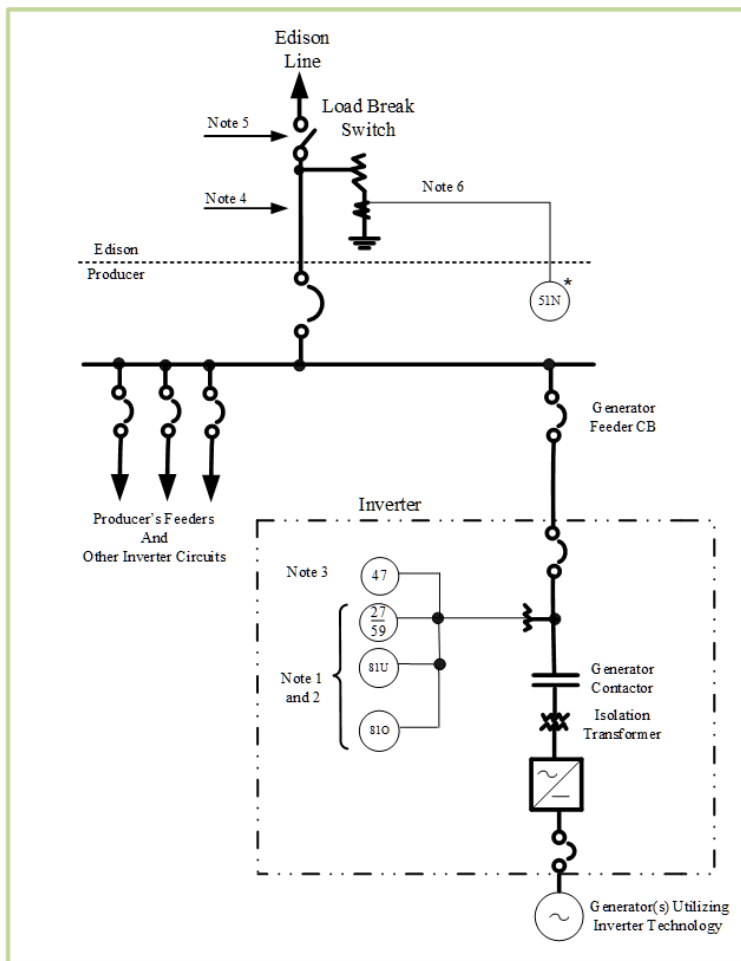
Figure 3g: Typical Parallel Generation Under 200 kVA



- Notes:**
1. Protective devices required by SCE for all installations. Other protective devices for generator not shown because of large variations with type of generator.
 2. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye-grounded-delta. (See 3.2.3.d for requirements)
 3. Self-contained metering is typical.
 4. Required for three phase generators.

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**Figure 3h: Typical Parallel Generation Utilizing Inverter Technology
With Assumed Producer Owned Protection (< 200 KVA, ≤ 34.5 kV)**



- Notes:**
1. Protective devices required by SCE for all installations. $\frac{27}{59}$ shall be a 3Ø unit or two 1Ø units.
 2. UL1741 certified inverters meet noted protection requirements without additional relays provided all inverters are UL1741 compliant.
 3. Recommended for three phase generators.
 4. Transformation as required by SCE or the Producer.
 5. Load break switch to be installed when required by SCE's Distribution Design Standards.
 6. Grounding transformer or ground detector is required to be supplied by SCE unless the main transformer is wye-grounded-delta. (See 3.3.D for requirements)
 7. Design Standards. (See Section 4.14 for details)
 8. Producer is responsible for other protective devices not shown on the diagram because of large $\frac{V_{LL}}{V_{LL}}$ variations with type of inverter.
 9. Drawing does not show metering requirements.
- "*" Indicates devices required by SCE. Others are shown as conventional practice.

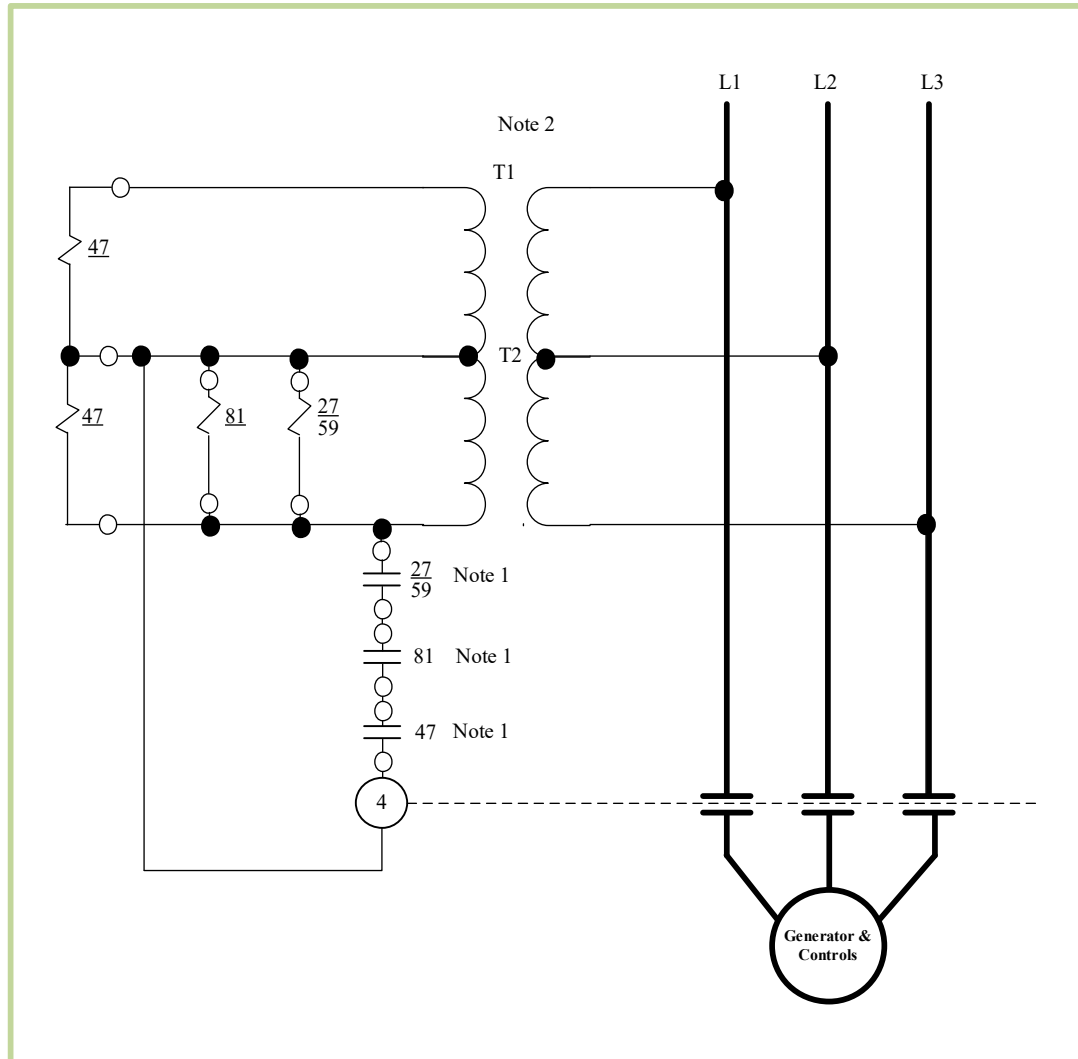
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- a) **Line Voltage Relay or Contactor:** Producer generator controls are to be equipped with a line voltage relay or contactor which will prevent the generator from being connected to a de-energized or single-phased (if normally three phase) source. This relay is to disconnect the generator from a de-energized utility line and prevent its reconnection until the line has been re-energized by SCE and has maintained nominal voltage and frequency continuously for a pre-determined period of time (typically five minutes).
- b) **Relays to Detect Islanding:** Producer generators are to be equipped with over/under frequency and over/under voltage relays for islanding detection. These relays must meet the specifications listed in Section 3.2.2, paragraphs (c) and (d). The relays may be arranged to deenergize the contactor as shown in Figure 3f. The Producer generator islanding protection must be able to detect an islanded condition and cease to energize SCE's distribution system within two seconds. Other requirements may be imposed on those installations unable to meet this requirement.
- c) **Fault Detection:** The Producer shall provide adequate protective relays to detect and clear the generator(s) from short circuits or grounds on SCE's electric system serving the Producer.
- d) **Four-wire Multi-grounded Neutral versus three-wire Distribution Circuits:** In projects where the Producer is served from an SCE four wire multi grounded neutral distribution circuit, adequate grounding must be provided to ensure neutral stability during accidental isolation of the line from the main system. This is necessary to avoid dangerous over-voltages on other customers served from phase to neutral connected distribution transformers. Adequate grounding can be provided either by the use of a wye delta main power transformer or by installing an appropriate grounding transformer. To limit the effects of such grounding on SCE's ground relay sensitivity, SCE may require that the grounding impedance be limited to the highest value suitable for neutral stabilization. For three-wire distribution circuits, installation of a ground detector will be required, to provide detection of ground faults in SCE's three-wire distribution circuit. This requirement will not apply if the generating facility passes the applicable Rule 21/WDAT technical evaluation criteria.

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Figure 3i: Typical Relay/Contactor Arrangement Under 200 kVA

This drawing is intended to show the relay/contactor arrangement only. Other over-current or switching devices may be required by local authorities.



- Notes:**
1. Contacts closed with normal voltage, frequency and phase sequence.
 2. Control transformers as required to match relay/contacter voltage to supply voltage. Arrangement shown is for three phase system. For single phase omit L3, T1, Dev. 47.

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- a) **Dedicated Distribution Transformer:** SCE may require the Producer to be served through a dedicated distribution transformer which serves no other customers. The purpose of the dedicated transformer is to confine any voltage fluctuations or harmonics produced by the generators to the Producer's own system.
- b) **Harmonic Requirements for Inverters:** See "Voltage Imbalance and Abnormal Voltage or Current Waveforms" Section 5.10.
- c) **SCE Telecommunications:** Typically not required for protective purposes in Category 3 generating facilities except as required to coordinate with SCE's protective relays.
- d) **Exception to Protection Devices:** Producers generating facilities may, as an alternative to the requirements specified in this Category 3 generating facility section above, utilize an approved inverter/interface device meeting applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers ("IEEE"), and accredited testing laboratories such as Underwriters Laboratories ("UL"). These requirements include, but are not limited to, the provisions of IEEE Standard 929, IEEE Standard 1547, and UL Standard 1741.

3.4 Breaker Duty and Surge Protection

3.4.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review breaker duty and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing breakers, consideration should be given to the following factors:

- a) Methods of limiting duty to the circuit breaker capability, or less:
 - 1. De-looping or rearranging transmission lines at substations;
 - 2. Split bus arrangements.
- b) Magnitude of short circuit duty.
- c) The effect of future projects on the duty.
- d) Increasing the interrupting capability of equipment.
- e) The ability of a particular breaker to interrupt short circuits considering applicable operating experience and prior test data.

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Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility breakers.

3.4.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the requirements of SCE's Interconnection Handbook, the Producer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the generation facility to any short circuit occurring on SCE's electric system not otherwise isolated by SCE's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE's electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the generation facility and the SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The Producer shall be responsible for protection of the generation facility and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The Producer shall be solely responsible to disconnect their facility if conditions on SCE's electric system are impacted by the generation facility.

3.5 Underfrequency Relays

For voltage classes 161 kV and above, it is essential that the underfrequency protection of generating units and any other manual or automatic actions are coordinated with underfrequency load shedding relay settings. For further information, please refer to Section 3.2.2.d.

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, CAISO/SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

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SECTION 4 MISCELLANEOUS REQUIREMENTS:

4.1 Power System Stabilizers (PSS)

All new Producers' synchronous generators, larger than 30 MVA and interconnecting at a voltage 60 kV or higher are required to install PSS with a suitable excitation system, unless an exemption has been obtained from WECC. Suitable excitation systems are defined in the WECC report; "Criteria to Determine Excitation System Suitability for PSS," dated December 1992.

Unless an exemption has been received from the WECC, all new generators are assumed suitable for PSS, and must abide by the following requirements:

- The generator excitation system must be equipped with a PSS. The PSS improves stability in the electrical system when system power disturbances occur.
- The PSS equipment must be approved by SCE prior to installation and operation.
- The PSS must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of PSS equipment.
- Calibration and test reports must be submitted to SCE for review and approval. The generating facility shall not be considered operational until calibration of the PSS has been performed to SCE's satisfaction.
- The PSS shall be properly maintained and in service when the generator is online for power production.

In addition to the foregoing requirements, Producers must conform to all applicable current or future WECC Criteria. Specific to PSS, these Criteria currently include "WECC Power System Stabilizer Design and Performance Criteria," approved by the Technical Operations Subcommittee, September 15, 2003.

4.2 Governor Droop Setting

All new Producers' generators having suitable systems must comply with the WECC Criterion PRC-001-WECC-CRT-2.1 for governor droop setting.

These requirements are necessary to provide an equitable and coordinated system response to load/generation imbalances. Governor droop shall be set to be greater than or equal to 3% but less than or equal to 5%. Governors shall not be operated with excessive dead-bands, and governors shall not be blocked unless required by regulatory mandates.

4.3 Wind Turbine Generating Facilities

4.3.1 Wind Turbine Set-Back Criteria

- The Producer shall locate its wind-driven generating unit such that it does not encroach onto SCE transmission right of way or edge of any electric operating property.
- The Producer shall be responsible for performing its appropriate grounding requirements for its wind-driven generating units.

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4.3.2 Generator Electric Grid Fault Ride-Through Capability and Power Factor Criteria

SCE currently supports a Low Voltage Ride-Through¹ Criterion that the WECC has adopted to ensure continued reliable service. The Criteria are summarized as follows:

- a) Generator is to remain in-service during system faults (three phase faults with normal clearing and single-line-to-ground with delayed clearing) unless clearing the fault effectively disconnects the generator from the system.
- b) During the transient period, the generator is required to remain in-service for the low voltage and frequency excursions specified in WECC Disturbance-Performance Table of “Allowable Effects on Other Systems” as applied to load bus constraint. These performance criteria are applied to the generator interconnection point, not the generator terminals.
- c) Generators may be tripped after the fault period if this action is intended as part of a Remedial Action Scheme.
- d) This Standard will not apply to individual units or to a site where the sum of the installed capabilities of all machines is less than 10MVA, unless it can be proven that reliability concerns exist.
- e) The performance criterion of this Standard may be satisfied with performance of the generators or by installing equipment to satisfy the performance criteria.
- f) The performance criterion of this Standard applies to any generation independent of the interconnected voltage level.

No exemption from this Standard will be given because of minor impact to the interconnected system. This criterion also applies to existing generators that go through any refurbishments or any replacements.

4.4 Reclosing Circuit Breakers and Hot Line Reclose Blocking

Because most short circuits on overhead lines are of a temporary nature, it is SCE's practice to reclose the circuit breakers on such lines within a few seconds after they have automatically tripped. This practice improves continuity of service to all SCE's customers. The protective relays specified by SCE for parallel generation interfaces are intended to disconnect the generating facilities from faulty or isolated lines before reclosing occurs. Should the Producer desire additional protection against the possibility that reclosing might occur with his generator still connected to the line (a potentially damaging occurrence for synchronous generators), SCE can provide, at the Producer's expense, "Hot Line Reclose Blocking" at the necessary points on its system. Transfer trip protection may be required to facilitate restoration of service to SCE's customers. SCE's preference is to avoid such equipment because of the possible adverse effects on service continuity and the problems of moving or rearranging the equipment to accommodate system changes. Costs for installing, maintaining, and/or rearranging such equipment will be borne by the Producer(s) requesting the equipment.

¹ Ride-through - A generating plant remaining connected and continuing to generate current after a voltage or frequency disturbance.

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4.5 Unbalanced Currents

Producers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the Producer to protect its equipment from excessive negative sequence currents.

4.6 Sub-Synchronous Interaction Evaluations

Generators interconnected within electrical proximity of series capacitor banks on the transmission system or Flexible Current Transmission Systems (FACTS) are susceptible to Subsynchronous Interaction (SSI) conditions which must be evaluated. Sub-Synchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter-based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

A study must be performed to evaluate the SSI between generating facilities and the transmission system for projects interconnecting in close electrical proximity of series capacitor banks on the transmission system or FACTS devices to ensure that the Generator Project does not damage SCE's control systems. The SSI study may require that the INTFAC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the INTFAC.

The Interconnection Customer is 100% responsible for the cost associated with SSI studies and mitigations. It is the INTFAC's responsibility to select, purchase, and install turbine/inverter-based generators that are compatible with the series compensation in the area and the FACTS devices.

4.6.1 Sub-Synchronous Resonance Studies

SSR occurs when the network natural frequencies (below fundamental frequencies) coincide with the turbine-generator torsional-mode frequencies causing the turbine-generator to stress that may result in shaft failure. The turbine-generator and the system may interact with SSR into two main ways: Torsional Interaction (TI) and Torque Amplification (TA). To evaluate a potential SSR condition on a new generator installation near series compensated lines or FACTS devices a screening study needs to be conducted to identify any TA or TI impact on the series compensation level or FACTS devices controls. If a case is identified by the initial screening process (Frequency Scanning Study) a more detailed time domain study is required to quantify the potential damage and provide with mitigation measures.

4.6.2 Sub-Synchronous Control Interaction Studies

SSCI risk occurs on zero-crossing reactance when going from negative (capacitive) to positive (inductive) reactance. To evaluate a potential SSCI condition on a new generator installation near series compensated lines or FACTS devices a screening is performed through impedance scans looking out into the system from the inverter-based plant, with the plant disconnected. If a case is identified by the initial screening process, a more detailed study is required to quantify the potential damage and provide with mitigation measures.

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4.7 Voltage Control

Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the Transmission Operator. The control mode of generating units shall be accurately represented in operating studies.

All new Producers' synchronous generators, regardless of size and interconnecting at a voltage 55kV or higher, must abide by the following requirements:

- The synchronous generator shall have an excitation system with a continuously acting Voltage Control equipment.
- The Voltage Control equipment must be approved by SCE prior to installation and operation.
- The Voltage Control equipment must be calibrated and operated in accordance with WECC standard procedures for calibration, testing, and operation of Voltage Control equipment.
- Calibration and test reports must be submitted to SCE for review and approval. The generating facility shall not be considered operational until calibration of the Voltage Control has been performed to SCE's satisfaction.
- The Voltage Control equipment shall be properly maintained and in service when the generator is online for power production.

Automatic voltage control equipment on generating units, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by either the

- CAISO for generators directly connected to SCE owned portions of the Bulk Electric System; or
- SCE for generators connected to SCE's Local Distribution System, which are facilities not under CASIO operational control.

4.8 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive overvoltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The Producer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on the generating facility's equipment. In addition, the Producer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing, and gap application, substation and

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transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

4.9 Ratings

4.9.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to current NERC Reliability Standard governing Facility Ratings.

4.9.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE's electric system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases, the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

4.9.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

4.9.4 Ambient Conditions

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

4.9.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor/cable, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, the allowable current that will not cause the cables to operate above the designed temperature limit, and the termination equipment.

4.9.6 Overhead Conductors

The transmission line conductor ratings are calculated in accordance with the latest applicable version of the ANSI/IEEE 738 For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C, and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors, SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

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4.9.7 Underground Cable

The transmission line cable ratings are calculated in accordance with IEC 60287. For cross-linked polyethylene (XLPE) insulated cable, the normal cable rating allows a total temperature of 90°C and the emergency rating allows 105°C for 4 hours. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification and/or component tested data.

4.9.8 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

4.9.9 Terminal Equipment

Terminal equipment comprises: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

4.9.10 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component.

4.9.11 Transformer Normal Ratings

The "normal" rating is the transformer's highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special "load capability study" has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

4.9.12 Transformer Emergency Rating

A transformer's emergency rating is arrived at by one of two methods. First, if no "load capability study" is available, then a 10% overload is allowed. Second, if a "load capability study" has been performed, then the Long-Term Emergency Loading Limits (LTELL) and Short-Term Emergency Loading Limits (STELL) indicated in the "load capability study" shall be used.

4.9.13 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

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4.9.14 Relays Protective Devices

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., “limited to 725 A by relay setting.”

4.9.15 Path Ratings

As stated in WECC’s Project Coordination, Path Rating, and Progress Report Processes, Section 2.2 (Policies): “New facilities and facility modifications should not adversely affect Accepted or Existing Ratings, regardless of whether an Accepted Rating for the path associated with the new facility or modification is being sought. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations, remedial action schemes, or any other facilities affecting the capacity or use of the Western Interconnection.”

4.10 Synchronizing of Facilities

Testing and synchronizing of a generation facility may be required depending on SCE’s electric system conditions, ownership, or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE’s transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The Producer is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the Producer shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to the SCE’s electric system and upon which trial operation begins.

For additional technical information regarding the synchronizing of generators refer to Section 3 Protection Requirements.

4.11 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the generation facility and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

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4.12 Abnormal Frequency and Voltages

4.12.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

4.12.2 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and Emergency Conditions. All operating entities shall assist with the CAISO's coordination efforts.

4.12.3 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

4.13 Communications and Procedures

4.13.1 Use of Communication System

It is essential to establish and maintain communications with the SCE GCC, the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

4.13.2 Remedial Action Schemes Communication Equipment Requirements

Generation facilities will require the necessary communication equipment for the implementation of Remedial Action Schemes (RAS). This equipment provides line monitoring and high-speed communications between the Generation Facility breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to generators that may be required to trip to relieve congestion on SCE's electric system. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the WECC Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria for RAS redundancy. *"Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection, arming, power, supplies, telecommunications facilities and equipment, logic controllers (when applicable), and RAS trip/close circuits."* Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

4.13.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

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4.14 Remote Control Equipment

The installation of Remote Control Equipment, as applicable for voltage, is required for any generating facility with a requested export greater than or equal to 1 MW. The Producer is responsible for cost. Please see the SCE Unit Cost Guide for reference to equipment cost in accordance with Attachment A to Decision D.16-06-052.

Remote Control Equipment can include the installation of a new switch or automation of an existing switch or recloser depending on voltage, location, and space condition.

4.15 Point of Change of Ownership (POCO)

Currently there is no equipment that allows a below ground POCO for interconnections at 66 kV and above. Any POCO at these voltage levels will need to be installed above ground to ensure clear distinction between SCE's equipment and the Interconnection Customer's equipment.

4.16 Looping High Voltage Transmission Lines

Due to system complexities, SCE does not allow 500 kV and 220 kV transmission lines nor radial gen-tie lines connecting to SCE facilities to be tapped by load or generation interconnection projects. Instead, load or generation interconnection projects wishing to interconnect on these types of SCE-owned lines must do so via a looping substation that is owned, operated, and maintained by SCE. Generation interconnection projects wishing to interconnect to a customer-owned, radial, generation tie-line must do so via a looping substation that would be owned, operated, maintained by the Interconnection Customer and/or owner of the generation tie-line. Existing taps connected to SCE's 500 kV and 220 kV transmission lines will continue to be allowed.

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SECTION 5 GENERAL OPERATING REQUIREMENTS:

- a) **System Operating Bulletins:** Generator facilities connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating requirements are discussed in the sections below. SCE may also require additional operating requirements specific to a generator facility. If so, these requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to a generator facility, and any subsequent revisions, will be provided by SCE to the Producer as they are made available.
- b) **Producer's Responsibility:** It is the Producer's responsibility to comply with applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore, it is advisable for the Producer to regularly monitor operating procedures that apply to its generating facilities. The CAISO publishes its operating procedures on its internet site, but it is prudent for the Producer to contact the CAISO for specific requirements.
- c) **Quality of Service:** The interconnection of the generator facility's equipment with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the generator facility, such equipment shall be disconnected until the problem is resolved.
- d) **SCE Circuits:** Generator facilities are not permitted to energize any de-energized SCE circuit.
- e) **Operate Prudently:** The Producer will be required to operate its facility in accordance with prudent electrical practices.
- f) **Protection in Service:** The generating facility shall be operated with all of the required protective apparatus in service whenever the generating facility is connected to, or is operated in parallel with, the SCE electric system. Redundant protective devices may be provided at the Producer's expense if the generator is to be operated in parallel during routine testing of or failure of a protective device. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.
- g) **Added Facilities Documentation:** The Producer may not commence parallel operation of generator(s) until final written approval has been given by SCE. As part of the approval process, the Producer shall provide, prior to the commencement of parallel operation, all documents required by SCE to establish the value of any facilities installed by the Producer and deeded to SCE for use as added facilities. SCE reserves the right to inspect the Producer's facility and witness testing of any equipment or devices associated with the interconnection.

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5.1 Generating Facility Records and Data

SCE requires generating facility operating records and data from the Producer in order for SCE to plan and reliably operate its electrical system. Some Producers may be subject to similar record and data obligations from the CAISO. If so, the Producer may satisfy many of SCE's operating record and data requirements by giving SCE permission to access the Producer's information held by the CAISO.

Table 5.1 illustrates typical sizes of generating facilities and typical means of communicating generating facility operating records and data to SCE. Typically, medium, and large sized generating facilities are required to install real-time telemetering, but small generating facilities may be excluded from many record and data requirements. Section 7 of this document describes the real-time telemetering² hardware requirements. The following two sub-sections describe generating facility operating records and data Producers are required to submit to SCE by real-time telemetering, voice communication or equivalent means.

SCE will require submission of additional records if such records are necessary for SCE to reliably operate and plan its electrical system.

Table 5.1: Typical Communication Requirements Per Generating Facility Size

Aggregate Generation Facility Size	Real Time Telemetering	Voice
Gen. ≥ 1 MW but < 10 MW	*	X
Gen. ≥ 10 MW but < 20 MW	X	X
Gen. ≥ 20 MW	X	X

*Centralized RTU or its equivalent successor

5.2 Operating Records and Data the Producer Must Provide to SCE

- a) SCE requires some Producers to maintain operating communications with an SCE designated switching center. These communications provide SCE operating records and data about the Producer's generating facilities for SCE to reliably operate its electric system. Generally, Producers with generating facility capacity of 1 MW or greater will have these requirements, but it may be necessary for SCE to receive generating facility records for smaller generators if needed for reliability. Table 5.2 illustrates typical required generating facility records and data. SCE may require Producers to provide additional records than those shown in Table 5.2.

² Generation up to 10 MW may rely on the Public Switched Telephone Network (PSTN) as the primary means of maintaining operating communications. Generation greater than 10 MW should provide an alternate means of communication in addition to the PSTN to insure availability in the event of unplanned outage or emergency.

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Table 5.2: Typical Required Generating Facility Records and Data

	Generation Facility Record	Typical Size of Aggregate Generation³ Facility	Delivery Date or Primary Communication Mode	Delivery Location
1	System Parallel Operation or Separation	> 200 kW	Timely by Voice	Designated SCE Switching Center
2	Scheduled and Unscheduled Outages	> 200 kW	<u>Scheduled Outages</u> Outage Duration Adv. Notice < 1 day 24 Hours 1 day or more 1 Week Major overhaul 6 Months <u>Unscheduled Outages</u> Timely <u>Communication Mode</u> <u>Voice</u>	Designated SCE Switching Center
3	Levels Of Real And Reactive Power	³ 1 MW	Real-time Telemetry	SCADA
4	Equipment Clearance	³ 10 MW	Timely by Voice	Designated SCE Switching Center
5	Interruption event	> 200 kW	Timely after event by Voice	Designated SCE Switching Center
6	Gen. Circuit Breaker Status	³ 10 MW	Real-time Telemetry	SCADA
7	Gen. on/off Status	³ 10 MW	Real-time Telemetry	SCADA
8	Generator Terminal Voltage	³ 10 MW	Real-time Telemetry	SCADA
9	BESS State of Charge	> 1 MW	Real-time Telemetry	SCADA

b) An interruption event is said to occur on an interconnection circuit when its closed energized circuit breaker has opened or trips and interrupts powerflow to/from SCE facilities. After experiencing an event, the Producer is required to submit the following event information to their Designated Switching Center in order for SCE to assess relay operations and system integrity.

- Date and time of trips by the interconnection circuit breaker
- Generation facility status at time of incident (real & reactive power generation)
- Relay operation indicator (target) operations
- Oscillograph or Sequence of Event recorder records.

³ Aggregate generation is the total nameplate capacity of generating facilities at the generation site being interconnected or the total generation under one SCE account.

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5.3 Operating Data and Records the Producer Must Provide SCE Upon Request

- a) The Producer will be required to keep a daily operations log (records) for the generating facility which must include levels of operating voltage, relay operations, information on maintenance outages, maintenance performed, availability, and circuit breaker trip operations requiring a manual reset. Producers with the necessary metering will be required to log fuel consumption, cogeneration fuel efficiency kilowatts, kilovars, and kilowatt-hours generated and settings or adjustments of the generator control equipment and protective devices, and any significant events related to the operation of the generating facility, including but not limited to real and reactive power production; changes in operating status and protective apparatus operations; and any unusual conditions found during inspections. Changes in settings shall also be logged for Producer's generator(s) if it is "block-loaded" to a specific kW capacity.
- b) SCE, after giving written notice to the Producer, shall have the right to review and obtain copies of metering records and operations and maintenance logs of the generating facility.
- c) If a Producer's generating facility has a Nameplate Rating greater than one (1) megawatt, SCE may require the Producer to report to a designated SCE Switching Center twice a day at agreed upon times for:
 - the current day's operation,
 - the hourly readings in kW of capacity delivered, and
 - the energy in kWh delivered since the last report.

5.4 Calibration of Producer Owned Protective Apparatus

The Producer must test the protective apparatus it owns on a routine basis to provide correct calibration and operation of the devices. Required test intervals of these protective apparatus have been established as shown in Table 5.3.

These test intervals are based on the nominal system voltage at the point of interconnection to SCE. SCE may require the Producer, at the Producer's expense, to demonstrate to SCE's satisfaction the correct calibration and operation of the Producer's protective apparatus at any time SCE reasonably believes that the Producer's protective apparatus may impair the SCE electric system integrity.

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Table 5.3: Required Test Intervals for Protective Devices

Interconnection Voltage (Applies For All Voltage Levels)		Test Interval	Delivery Location
1	Microprocessor Protective Relay with Monitoring Microprocessor Protective Relay without monitoring Electromechanical & Solid-State Protective Relays	Every twelve years ¹ Every six years ² Every six years ²	mail to: Manager, Grid Contracts Management, P.O. Box 800, 2244 Walnut Grove Avenue, Rosemead, California 91770
1 For Microprocessor relays with self-monitoring (all voltages) if they meet the following: - Internal self-diagnosis and alarming. - Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. - Alarming for power supply failure - Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. 2 For any unmonitored protective relay not having all the attributes indicated above, including Sudden Pressure relays.			

5.5 Disconnecting Service to a Generation Facility

Applicable agreements and tariffs may state criteria for disconnection of generating facilities which are interconnected to SCE's electric system. In general, generating facilities may be curtailed or disconnected if SCE determines that their operation creates a threat to personnel or the electric system.

5.6 Voltage Variations

- a) **Voltage Regulation:** Operation of the Producer's generating facility shall not adversely affect the voltage regulation of that portion of SCE's electric system to which it is connected. Adequate voltage control shall be provided by the Producer to minimize voltage regulation on SCE's electric system caused by changing generator-loading conditions. The step-up transformer ratio must be chosen such that the Producer can meet its voltage regulation obligations over the expected range of SCE system voltages. Step-up transformers must be equipped with no-load taps which provide +5% adjustment of the transformer ratio in 2.5% steps.
- b) **Exception:** The tap Requirement will be waived if the Producer submits a study to SCE which demonstrates to SCE's satisfaction that the Producer can meet its voltage regulation obligations over the expected range of system voltages specified by SCE. Generator voltage schedule and transformer tap settings will be specified by SCE, as necessary, or the CAISO to ensure proper coordination of voltages and regulator action. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. Table 5.4 below identifies whether SCE or the CAISO specifies these schedules.

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Table 5.4: Electric System Jurisdiction and Tap-setting Specification

Generating Facility Connected to:	CAISO Controlled Transmission System	SCE Controlled Subtransmission or Distribution
Voltage Schedule	Specified by CAISO	Specified by SCE, as needed
Transformer Tap Settings	Specified by SCE ±5% in 2.5% steps	Specified by SCE ±5% in 2.5% steps

- c) **Transmission Voltages:** Expected transmission system operating voltages range from 160 to 164 kV for 161 kV nominal voltage, 220 to 242 kV for 220 kV nominal voltage, and 520 to 540 kV for 500 kV nominal voltage. Voltage regulation at a given location on the transmission system must follow the CAISO and SCE voltage schedules.
- d) **Distribution and Subtransmission Voltages:** In order to supply and maintain proper voltages for SCE's customers as required by the CPUC, SCE's primary distribution voltages (2.4 to 34.5 kV) and subtransmission voltages (55 to 115 kV) may fluctuate by as much as +5% from the nominal values (e.g., 12.47 kV +5%; 34.5 kV +5%; etc.). SCE uses various voltage regulation techniques to raise or lower primary distribution and subtransmission voltages to maintain the customer's service voltage at the desired level. Producers interconnected at primary distribution or subtransmission voltage levels must be able to withstand such voltage changes and to respond with proper power factor adjustment not to oppose or interfere with SCE's or the CAISO's voltage regulation processes.

5.7 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

5.7.1 Interconnection

SCE shall not be obligated to supply or absorb reactive power for the generator facility when it interferes with operation of SCE's electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

5.7.2 Subtransmission System

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five-year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

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5.8 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers, and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the Producer at the facility, or by SCE at SCE's facilities at the Producer's expense.

Generator VAR schedules, as needed, will be specified by SCE or the CAISO to ensure proper coordination of voltages. It is the Producer's responsibility to ensure voltage-VAR schedule compliance. If power factor correction equipment is necessary, it must be installed by the Producer at its facility at the Producer's expense to ensure the power factor at the point of interconnection meets the criteria in Table 5.5.

Note that the generator power factor capability for Wholesale Distribution Access Tariff (WDAT) service is likely to require equipment capable of operating over the range of 0.9 lag to 0.95 lead to meet the Tariff Point of Delivery requirements.

Table 5.5: Power Factor Criteria

Generating Facility Connected to:	CAISO Controlled Transmission System	SCE Controlled Distribution System*
Power Factor	Synchronous: Generator has the capability of 0.90 lagging to 0.95 leading	Synchronous: Generator has the capability of 0.90 lagging to 0.95 leading at POI
	Asynchronous (FERC Order 827): 0.95 lagging to 0.95 leading at high side of generating station	Asynchronous (FERC Order 827): 0.95 lagging to 0.95 leading at high side of generating station

* For Rule 21 projects, reference the Rule 21 tariff for power factor requirements.

5.8.1 Reactive Power Equipment – Induction Generators (in aggregate)

5.8.1.1 Facility Reactive Power Equipment Design

Producers shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits as they relate to their generator facilities.

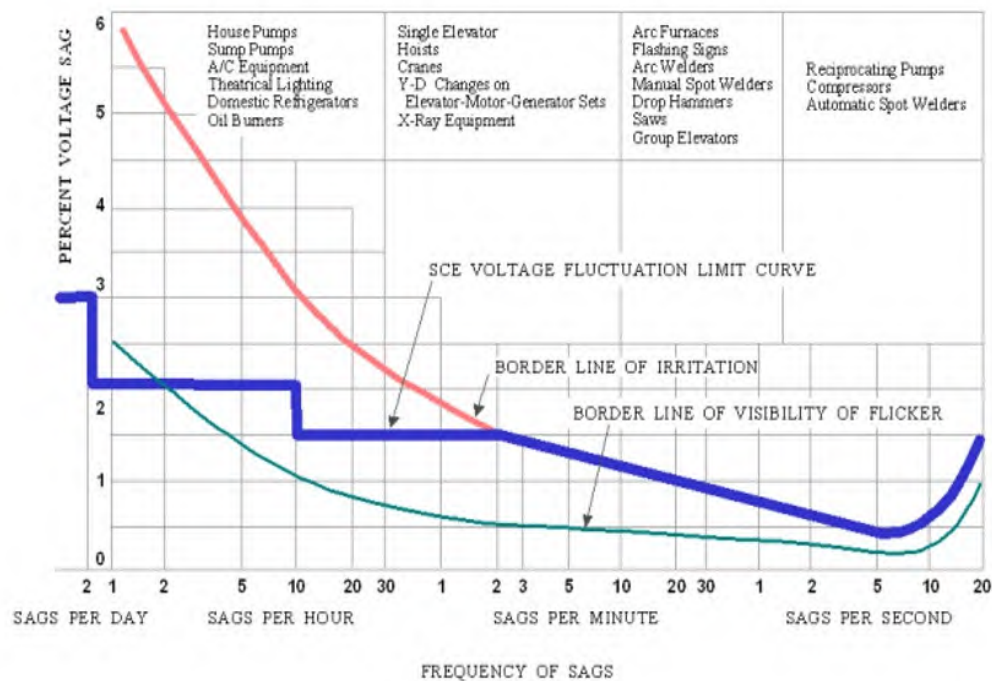
Reactive power equipment utilized at a generator facility to meet SCE's requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system,

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and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

- severe overvoltages that could result from self-excitation of induction generators,
- transients that result from switching of shunt capacitors,
- voltage regulation problems associated with switching of inductive and capacitive devices.
- unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and
- Voltage flicker exceeding SCE Voltage Flicker limits (See Figure 5a).

Figure 5a: Voltage Fluctuation Design Limits



5.8.1.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized at a generator facility to meet SCE's requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

- the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE's electric system) associated with a step change in the output of a generator facility's reactive power equipment must be less than or equal to 1%; and

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- b) the maximum allowable deviation from a generator facility's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the generator facility's maximum (boost) reactive capability.

5.8.2 Reactive Power Supply Requirements - Synchronous Generators

Producers connected to SCE's electric system and utilizing synchronous generators are required to generate or supply reactive power so that the generating facility does not impose any additional reactive power demand upon SCE other than the demand of loads within the facility. The Producer will not be permitted to deliver excess reactive power to SCE under normal operating conditions unless otherwise agreed to by SCE. Under emergency operating conditions, the Producer is permitted to deliver excess reactive power to SCE to ensure voltage schedule compliance.

Producers connected to the subtransmission system or bulk power system (above 34.5 kV) must have the voltage regulation equipment and generator reactive power capability to maintain a voltage schedule or reactive power schedule prescribed by SCE or, if applicable, the CAISO. Generators must be capable of operation over the power factor ranges designated in Table 5.5.

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5.8.3 Reactive Power Supply Requirements - Inverter Systems

Forced commutated inverters must meet SCE's reactive power supply requirements of synchronous generators in 5.8.2. Line commutated inverters must be corrected to satisfy SCE's reactive power supply requirements of induction generators in 5.8.1.

Inverters must also meet SCE's harmonic load limits based on the latest IEEE Standard 519. For further information on the assessment and mitigation of harmonics due to inverters, refer to "SCE Subtransmission Planning Criteria and Guidelines, Appendix C, HARMONIC LOAD LIMITS, APPLICATION OF IEEE STANDARD 519-1992 TO SUBTRANSMISSION PLANNING".

5.8.3.1 IEEE and UL Standards for Inverter Systems 200 kVA or Less

Inverter systems which conform to the recommended practices in IEEE Standard 929-19 and which have been tested and approved for conformance to UL Subject 1741, are considered to have met all SCE's reactive power supply requirements.

5.8.4 Voltage and Reactive Control

5.8.4.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

5.8.4.2 Transmission Lines

Not Applicable to Generation.

5.8.4.3 Switchable Devices

Not Applicable to Generation.

5.9 Ride Through Requirements

The CAISO is responsible for frequency control and therefore SCE can assume no responsibility for damage that occurs due to off nominal frequency operation. It is possible that the electrical network including SCE's electric system may operate outside of the limits stated above. It is the responsibility of all Producers connected to SCE's electric system to install equipment to protect against damage to Producer owned equipment from off-nominal frequency operation.

Generators that are required to use under-frequency detection for islanding must coordinate frequency threshold settings to ensure conformance with SCE's abnormal frequency operation plan.

SCE's requirements identify three different categories for Producer generating facilities connecting to the SCE electric system each with distinctive protection requirements. These categories are:

5.10 Off Nominal Frequency and Voltage Ride Through

- Category 1: Voltage class 34.5 kV and below
- Category 2: All BES voltage classes
- Category 3: class every other generator not covered by IEEE 1547 or PRC-024-3

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5.11 Off Nominal Frequency

5.11.1 Category 1

Producer's generating facilities connecting at 34.5 kV and below are required to comply with IEEE 1547 and/or Rule 21 frequency ride through requirements as applicable.

5.11.2 Category 2

Producer's generating facilities interconnecting to SCE's Bulk Electric System shall set off nominal Frequency Protective Relay settings to meet the NERC Reliability Standard PRC-024-3

5.11.3 Category 3

Producer's generating facilities that protect for off-nominal frequency operation shall set off nominal Frequency Protective Relay settings to meet at a minimum the time frames in Table 5.6.

Table 5.6: Off Nominal Frequency Limits

Under Frequency Limit	Over Frequency Limit	Minimum Time
> 59.4 Hz	< 60.6 Hz	continuous operating range
≤ 59.4 Hz	≥ 60.6 Hz	3 minutes
≤ 58.4 Hz	≥ 61.6 Hz	30 seconds
≤ 57.8 Hz	N/A	7.5 seconds
≤ 57.3 Hz	N/A	45 cycles
≤ 57.0 Hz	≥ 61.7 Hz	may trip instantaneously if required to protect equipment from damage

Frequency relay settings must not allow less stringent operation of the generating facility than specified in the shown in Table 5.6, unless agreed to in writing by SCE and coordinated with SCE's abnormal frequency operation plan.

5.11.4 Inverter-Based Category 2 and 3

Category 2 and 3 Producers with inverter-based generating facilities interconnecting at 55 kV and above shall comply with the IEEE Standard 2800-2022 frequency ride-through requirements.

5.12 Voltage Ride-Through

5.12.1 Category 1

Producer's generating facilities connecting at 34.5 kV and below are required to comply with IEEE 1547 and/or Rule 21 voltage ride through requirements as applicable.

5.12.2 Category 2

Producer's generating facilities interconnecting to SCE's Bulk Electric System shall set voltage Protective Relay settings to meet the NERC Reliability Standard PRC-024-3.

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5.12.3 Category 3

Producer's generating facilities shall set voltage Protective Relay settings to meet at a minimum the time frames in Table 5.7.

Table 5.7: Generator Voltage Protective Relay Settings

Low Voltage	High Voltage	Time
$\geq .90$ (pu)	< 1.10 (pu)	continuous operating range
$< .90$ (pu)	≥ 1.10 (pu)	3 seconds/1 second
$< .75$ (pu)	≥ 1.15 (pu)	2 seconds/.5 seconds
$< .65$ (pu)	≥ 1.175 (pu)	.3 seconds/.2 seconds
$< .45$ (pu)	N/A	.15 seconds
N/A	≥ 1.20 (pu)	may trip instantaneously if required to protect equipment from damage

5.12.4 Inverter-Based Category 2 and 3

Category 2 and 3 Producers with inverter-based generating facilities interconnecting at 55 kV and above shall comply with the IEEE Standard 2800-2022 voltage ride-through requirements.

Producers with inverter-based resources interconnecting to SCE's system shall design and operate their settings to eliminate the use of momentary cessation (i.e., where the power electronic firing commands are blocked such that the inverter ceases to inject both active and reactive current resulting in no active or reactive power output). Inverter-based resources shall continue to inject current during a fault if the high-side voltage remains within the voltage ride-through thresholds defined in IEEE Std. 2800-2022.

5.13 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if a generator facility's output degrades power quality to SCE's facilities, other generator or customer facilities, SCE may require the installation of equipment to eliminate the power quality problem.

5.13.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a generator facility to be connected at the transmission or subtransmission system level, may not exceed 1% at the Point of Common Connection⁴ (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by a generator facility shall not exceed 1.5%.

⁴ The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Producer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Producer and SCE.

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It is the responsibility of Producers, with a generator facility connected to SCE's electric system to install adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

5.13.2 Harmonics

Generator facilities are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance with good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

5.13.3 Disconnection

SCE may disconnect any generator facility until the requirements within this section of the Interconnection Handbook are met.

5.13.4 Photovoltaic Inverter Systems

Photovoltaic inverter systems which conform to the recommended practices in IEEE Standard 929-2000 and which have been tested and approved for conformance to UL Subject 1741 are considered to have met SCE's requirements for voltage imbalance and abnormal waveforms.

5.14 Isolating Equipment Requirements and Switching & Tagging Rules

5.14.1 Applicable to Generation Facilities connecting to voltages > 34.5KV

An isolating device must be installed, and specific inter-company rules must be in place to ensure the safety of SCE personnel. The isolating device isolates the Generation Facility from the SCE Electric System and prevents inadvertent energization of the generation tie-line while personnel are performing maintenance and/or repair work on the Interconnection Facilities.

5.14.1.1 Manual Disconnects

The isolating disconnect shall be placed in the LINE disconnect position on the high side of the Producer's generation tie-line. A separate GROUND disconnect shall also be incorporated and placed in the line position on the high side of the Producer's generation tie-line.

For 220 kV and below, the disconnects must be 3-phase, gang-operated disconnects with a common operating handle. For 500 kV, each phase must be equipped with a disconnect having its own operating handle.

The operating handle of the LINE disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the open positions. The operating handle of the GROUND disconnect/disconnects must include a provision for locking the disconnect control handle/handles in the closed positions.

For manual LINE disconnects, the device must:

1. Provide unrestricted, 24-hour access to SCE personnel.

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2. Allow visible⁵ verification that separation has been accomplished.
3. Be capable of being locked in the open position.
4. Be clearly labeled with permanent signage.

5.14.1.2 Switching and Tagging Rules

SCE and Producer shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. In accordance with SCE's switching and tagging rules, the Producer shall allow SCE to place its locks on the Producer's Interconnection Facilities, as may be required (specifically disconnect switches and/or circuit breakers on the Producer's terminus of the generation tie-line). The locking feature of disconnects may be utilized by either party when inter-company clearances are issued on the generation tie-line.

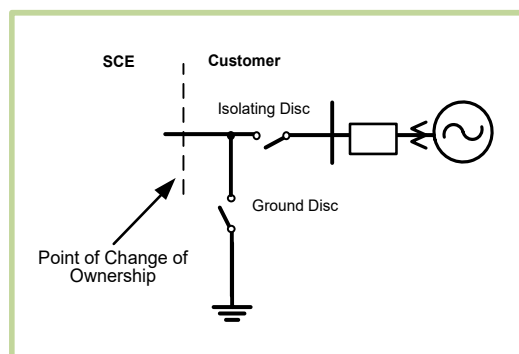
5.14.2 Applicable to Generation Facilities connecting to voltages $\leq 34.5\text{KV}$

The producer shall furnish and install a ganged, manually operated isolating device near the Point Of Change of Ownership (POCO) (when SCE and applicant electrical systems connect also referred to as the Point of Common Coupling (PCC)) to isolate the Generating Facility from SCE's Electric System. See Figure 5a.

The device must:

1. Allow visible⁶ verification that separation has been accomplished.
2. Include marking or signage that clearly indicates open and closed positions.
3. Be capable of being reached quickly and conveniently 24 hours a day by SCE personnel.
4. Be capable of being locked in the open position.
5. Be clearly labeled with permanent signage.

Figure 5b: Typical Isolating Disconnect Device Configuration



⁵ Visible means a visible break when the disconnect is in the open position. Here, visible verification should allow for visual inspection of the device. Typically, this switch should not be enclosed inside of a building or structure.

⁶ Visible means a visible break; when the disconnect is in the open position, there is a visible separation between the contacts, and the separation may be observed without disassembling the device. Typically, this switch contains visible blades inside an enclosure.

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5.15 Grounding Circuits and Substations

The Producers shall follow practices outlined in IEEE 80 “IEEE Guide for Safety in AC Substation Grounding.” Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

Reason for Substation Grounding

Substation grounding practices are outlined in IEEE 80 “IEEE Guide for Safety in AC Substation Grounding.”

According to IEEE 80 – 2013 a safe ground grid design has the following two objectives:

- “To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.”
- “To reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of critical electric shock.”

“People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design.” (IEEE 80 – 2013)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

5.15.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4, 12.47 and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Common subtransmission voltages are nominally 66 kV to 115 kV. Common transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4, 12.47, and 16 kV circuits are effectively grounded, but some are operated with high impedance or resonant grounding. A substantial number of the effectively grounded circuits are used for four wire distribution (phase to neutral connected loads). The system grounding may change over time, such as when high impedance grounding is replaced with solid grounding to accommodate four-wire load or solid grounding is replaced with resonant grounding to reduce wildfire risk. SCE will provide the Producer necessary information on the specific circuit serving their generator facility for proper grounding.

5.15.2 Grounding Grid Studies shall be conducted in the following situations

Grounding calculations will be required for each new substation, and at existing substations, when

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the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

- **Short Circuit Duty Changes**
 1. Circuit breaker replacement for short-circuit duty reasons if a grounding study has not been performed in the last eight years
 2. Addition of transmission or subtransmission line to a substation
 3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty
 4. Addition or replacement of a transformer at a substation. other than a like for like replacement. The replacement of a transformer bank with the same base MVA is considered a like for like replacement. Replacement transformer banks with a lower base MVA than existing will not require a grounding study.
 - a. Like for like transformer replacements require a review of the ground grid if a grounding study has not been performed in the last eight years.
 5. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty
- **System Protection Changes**
 1. Changes in system protection that significantly increases the clearing time for ground faults.
- **Grounding Source Changes**
 1. Grounding of ungrounded or impedance grounded winding of a transformer
 2. Addition or major change of ground source at a substation
- **Substation Changes**
 1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
 2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
 3. Sale or lease of substation property for other uses.
- A grounding review should be conducted any time a grounding problem is reasonably suspected.

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5.15.3 Ground Mats

If the generator facility and SCE substation ground mats are tied together, all cables may be landed without any protection. However, if the generator facility and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All generator facility ground mats shall be designed in accordance with good engineering practice and judgment. Presently the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All Producers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard for their generator facilities interconnected to SCE's electric system. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the Producer's facility or changes on the SCE system, the Producer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the Producer.

The Producer is responsible to ensure that the Ground Potential Rise (GPR) of the generator facility's or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the Producer. Generator facility and SCE ground grids are typically tied together when they are in close proximity to each other. If it is elected to install separate ground grids for SCE and the generation facility, the Producer shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the generation facility.

Any ground grid design, which results in a GPR that exceeds 3,000 volts RMS for the worst-case fault or has a calculated or measured ground grid resistance in excess of 3 ohm, will require special approval by SCE.

5.15.4 Substation Grounding

The Producer shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

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5.16 Non-SCE Pole Grounding

The Producer shall follow SCE Construction, Operation, and Maintenance requirements. The last Producer -owned structure before the point of interconnection which connects the Producer's generation facility to SCE's electric system shall be designed and constructed to meet SCE grounding requirements.

Generation facilities that will require SCE's crews to climb in order to construct, operate, or maintain SCE facilities shall be built to meet SCE all standards and specifications. Constructing to SCE specifications will ensure that SCE crews can perform work in accordance with internal safety practices identified within SCE's Accident Prevention Manual. This manual stipulates the proper training and equipment to safely climb and work. Examples of safety related requirements that:

- Climbing Steps
- Belt-Off Locations
- Grounding Locations
- Required PPE
- Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If SCE personnel will be or could be performing work on a non-SCE owned pole connecting a generator facility directly to SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required on that line in close proximity to the generation facility.

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

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SECTION 6 REVENUE METERING REQUIREMENTS

6.1 General Information

Revenue metering is required to measure the energy, charging capacity, and charging demand consumed, delivered, or stored for later redelivery by a customer. While functionally similar, there are varying metering requirements for customers depending on the nature and purpose of their proposed generating facility along with varying rules established by the authorities having jurisdiction over both SCE and the customer. Metering requirements for customers taking service under a FERC tariff and retail service under CPUC regulations are set forth in Sections 6.2 and 6.3.

For Battery Energy Storage Systems (BESS), FERC mandated that loads associated with these resources are “wholesale” when they are operating (charging or discharging), but “retail” when the BESS resource is in idle mode (not charging or discharging). The CPUC’s Station Power for Energy Storage Devices Tariff (“SPESD Tariff”) approach is similar. However, it also stipulates that a BESS resource’s load is also “wholesale” when a BESS resource is under contract in idle mode waiting for a signal from the CAISO to provide Ancillary Services.⁷

In general, all CAISO revenue metering and associated equipment used to measure load shall be provided, owned, and maintained at the Producer's expense.

6.2 Retail Service

The retail metering requirements for retail service will be owned, operated, and maintained by SCE under SCE’s [Electrical Service Requirements](#) (ESR) and in accordance with SCE approved tariffs.

Retail Service pertains to the energy metered at the delivery point to meet all customer’s energy requirements, minus the wholesale energy, considering the customer’s statutory, contractual, and/ or other right or obligation to be served.

Energy used for purposes that do not directly support the charge or discharge of a BESS resource should be considered Retail Energy. If a BESS resource is in idle mode, and not waiting for a signal from the CAISO to provide Ancillary Services, the energy consumed by the Generating Facility during this idle period is Retail Energy.

Below is a list of equipment and/ or conditions used to satisfy the Station Power and Auxiliary Load energy needs as they relate to Retail Service provided by SCE:

Auxiliary Load⁸: Energy for operating electric equipment, or portions thereof, located on the BESS resource site owned by the same entity that owns the BESS unit, which electrical equipment is used exclusively for the storage, charge, or discharge of the BESS resources energy.

⁷ Ancillary Services are defined within the CAISO Fifth Replacement FERC Electric Tariff.

⁸ In situations where the Auxiliary Load cannot easily be distinguished, the customer must clearly identify its different elements and the associated rated load for SCE retail billing purposes.

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Examples:

- *Switchgear loads (heater, lights, relays and meters)*
- *SCE communications container (HVAC, SCE communication equipment, lights, data/IT equipment)*
- *BESS container HVAC (temperature sensitive), fire suppression system, container lights, battery controls (Energy Management System (EMS) and Battery Management System (BMS))*
- *Battery Controls (EMS and BMS), which might be used during charging, discharging, or when the BESS is idle.*

Station Power: *Incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the BESS resource; located on BESS or hybrid collocated site; and used exclusively in relation to the storage, charge, or discharge of the BESS energy.*

Examples:

- *Outdoor lighting*
- *Sprinkler systems or pumps for outdoors (landscaping irrigation)*
- *Alarm system for safety of the property*
- *Internal lighting for office /cubicle*
- *Any load required for secondary loads not required to service the battery while it is either idle or charging or discharging.*
- *General Ventilation for containers or other equipment not required for charging or discharging the BESS resource*

Examples of Losses that should be taken into consideration:

- *Losses (line losses, heat losses, & transformer losses)*
- *Capacitor bank losses*
- *Other losses on equipment installed between metered point and the Point of Delivery (“POD”)*

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6.3 Approach to Retail Meter Customer Projects

6.3.1 Prior to initiating the Cluster Phase II Study or Facilities Study, the customer must clearly articulate to SCE its metering configuration from one of the following three approaches:

6.3.2 The Retail Service meter shall, to the extent practicable, reasonably capture all Retail Service loads, which includes Station Power. Any Station Power loads not captured should be documented on Form 14-979 and reported to SCE prior to SCE issuing the Permission to Operate (PTO).

6.3.2.1 All electric charging service may be separately metered via a sub-metering arrangement. The Station Power service sub-meter shall to the extent practicable capture all Station Power loads. Any Station Power load not captured should be documented on Form 14-979 and be reported to SCE prior to SCE issuing the PTO letter.

6.3.2.2 SCE will at its discretion accept alternative metering and measurement arrangements to the extent that the metering and measuring arrangement captures all Station Power loads and does not impose an administrative burden on SCE.

6.4 SCE Metering Requirements for Customers Taking Interconnection and Distribution Service

6.4.1 Customer Metering Arrangement Data

It is the responsibility of the customer to provide detailed one-line diagrams and documentation that clearly shows its proposed generating facility's (or facilities') metering arrangement as early in the interconnection study process as possible, but no later than ten (10) business days following:

- Cluster Study Phase 1 Results Meeting; or
- System Impact Study Results Meeting.

SCE must be able to approve the metering one-line diagram no later than ten (10) business days prior to the start of the Cluster Phase II or a Facilities Study, if required by tariff.

From this documentation SCE must be able to, by way of proper metering, determine the wholesale and retail loads and generating facility characteristics (generator output, charging demand or charging capacity, etc.).

Failure of the customer to provide this information may delay the development of the applicable interconnection agreement and the customer's requested in-service and commercial operation date.

6.4.2 Customer station light and power, auxiliary loads, cap banks, and all metering must be clearly shown on the one-line diagrams. The customer must also provide documentation detailing the load profiles, along with their losses, for these elements.

6.4.3 Non-Battery Storage Generating Facility

6.4.3.1 Non-battery storage generating facilities must be metered in a manner acceptable to SCE.

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- 6.4.3.2 Station light and power and auxiliary loads associated with non-battery storage generation projects are considered retail loads and must be metered in a manner acceptable to SCE.
- 6.4.3.3 If the station light and power and auxiliary loads associated with non-battery storage generation facilities are located behind the meter solely associated with the non-battery storage generation facility, additional meters may not be required. Reference Figure 6a, Option A or B in Appendix A, Meter Single-line Examples, below.
- 6.4.3.4 CAISO Resource ID
 - 6.4.3.4.1 Any non-battery storage generating facility with a CAISO resource ID must be metered separately from other generating facilities that are connected that have a different CAISO resource ID. Reference Figure 6b, 6C in Appendix A, Meter Single-line Examples, below.
 - 6.4.3.4.2 If the generating facility has a CAISO resource ID and the customer desires to add additional non-battery storage generation or a new non-battery storage generating facility under the same resource ID, additional metering may not be required. However, the metering arrangement must be reviewed and approved by SCE.
 - 6.4.3.4.3 If the customer has a generating facility with a CAISO resource ID and desires to add additional non-battery storage generation or a new non-battery storage generation facility under a different CAISO resource ID, alteration of existing metering and/or additional metering may be required.
- 6.4.3.5 Generating operating characteristics (generator output, etc.) must be metered.
- 6.4.3.6 If the customer is an SCE retail customer with an SCE retail customer ID and another generator (a different SCE retail customer) desires to interconnect and share interconnection facilities, additional metering may be required. Reference Figure 6b, 6C, & 6D in Appendix A, Meter Single-line Examples, below.

6.4.4 Battery Energy Storage System (BESS) Generating Facility – Stand Alone Systems

- 6.4.4.1 A BESS generating facility must be metered in a manner acceptable to SCE.
- 6.4.4.2 Station light and power and auxiliary loads associated with BESS generating facilities are wholesale loads when the BESSs are operating (charging or discharging). When the BESSs are idle (not charging or discharging), and not waiting for a signal from the CAISO to provide Ancillary Services, Station Power and Auxiliary Loads are retail loads.
- 6.4.4.3 If the Station Power and Auxiliary Loads associated with a BESS generating facility are located behind the meter solely associated with the BESS generation facility, additional meters may not be required. Reference Figure 6a, Option A or B in Appendix A, Meter Single-line Examples, below.
 - 6.4.4.3.1 If a customer elects to install BESS wholesale/retail load

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downstream of a meter associated with retail load, all load downstream of the retail meter will be billed as retail load.

6.4.4.4 CAISO Resource ID

6.4.4.4.1 Any BESS generating facility with a CAISO resource ID must be metered separately from other generating facilities that are connected that have a different CAISO resource ID. Reference Figure 6b, 6c & 6d in Appendix A, Meter Single-line Examples, below.

6.4.4.4.2 If the generating facility has a CAISO resource ID and the customer desires to add additional BESSs or a new BESS generating facility under the same resource ID, additional metering may not be required. However, the metering arrangement must be reviewed and approved by SCE.

6.4.4.4.3 If the customer has a generating facility with a CAISO resource ID and desires to add additional BESSs or a new BESS generating facility under a different CAISO resource ID, alteration of existing metering and/or additional metering may be required.

6.4.4.5 BESS generating facility operating characteristics (generator output and generator charging, etc.) must be metered.

6.4.4.6 If the customer is an SCE retail customer with an SCE retail customer ID and another generator (a different SCE retail customer) desires to interconnect and share interconnection facilities, additional metering may be required (see example 2 (Figure 6b) one-line below).

6.4.5 Battery Energy Storage System (BESS) Generating Facility – Paired Storage

6.4.5.1 CAISO Resource ID

6.4.5.1.1 Any generating facility with a CAISO resource ID must be metered separately from other generating facilities that are connected that have a different CAISO resource ID. See example 2 (Figure 6b) one-line below.

6.4.5.1.2 If the generating facility has a CAISO resource ID and the customer desires to add additional generation or a new generating facility under the same resource ID, additional metering may not be required. However, the metering arrangement must be reviewed and approved by SCE.

6.4.5.1.3 If the customer has a generating facility with a CAISO resource ID and desires to add additional generation or a new generating facility under a different CAISO resource ID, alteration of existing metering and/or additional metering may be required (see example 2 (Figure 6b) one-line below).

6.4.5.2 SCE Retail Customer

6.4.5.2.1 Any generating facility that is an SCE retail customer must be metered separately from any other generating facility that is or intends to be a different SCE retail customer. See example 2 (Figure 6b) one-line below.

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6.5 Metering Instrument Transformers

6.5.1 Revenue metering instrument transformers shall be utilized for revenue metering only, which includes metering by SCE meter(s) and CAISO meter(s). No devices other than SCE and CAISO meters are permitted to be connected to revenue metering instruments.

6.5.2 The revenue metering dedicated PT voltage coils shall be utilized for revenue metering only, which includes metering by SCE meter(s) and CAISO meter(s). If the metering PT has a second set of coils it may be used for protection, monitoring, and/or synching purposes.

6.5.3 Revenue metering PTs and CTs must meet rated voltage, marked ratios, and Basic Impulse Level (BIL) specified in ANSI C12.11 (Standard for Instrument Transformers for Revenue Metering).

6.5.4 The metering PTs shall be 0.3 ANSI accuracy class, or higher, metering devices. The metering CTs shall be 0.15S special extended range ANSI accuracy class metering devices (IEEE C57.13.6 IEEE Standard for High-Accuracy Instrument Transformers). CTs must be guaranteed and tested to accurately measure current down to at least 0.5% of CT rating.

6.5.5 The metering CTs shall be sized in accordance with good metering practices and shall always be within meter accuracy class range during generation cycles and/or auxiliary load cycles. The CTs' preferred rating factor is 4.0 and preferred accuracy range is 0.05% to 400% of rated current.

6.5.6 Metering CTs' and PTs' specifications must be submitted for SCE review and acceptance before ordering. If customer makes metering design change in the future, customer must resubmit proposed changes to SCE for review and acceptance before ordering.

6.6 SCE Meter Panels

6.6.1 Interconnecting customers shall install and wire up meter panels for SCE meters per SCE specifications.

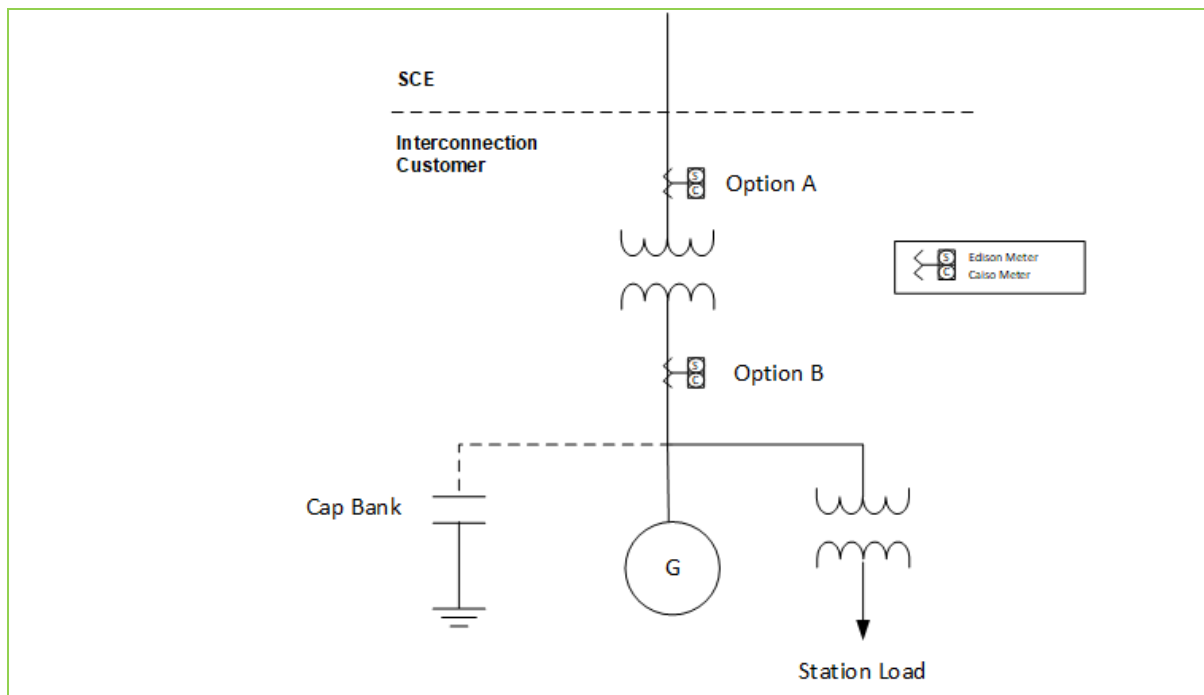
6.6.2 SCE meter panel design and location shall meet the SCE Electrical Service Requirements (ESR). The SCE meter panel must be located at the fence line of the customer's property, outside and fenced from the switchyard; have separate lockable gate with 24-hour access for SCE personnel to the meter without entering the customer substation (with drive up access); and have a safety working area with a minimum of 3 X 3 feet in front of the meter panel. Refer to examples shown in Figures 6e, 6f, and 6g.

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Example 1:

Figure 6a: Typical Metering Installation for a single resource Generating Facility

Typical metering configuration for single resource generators taking service under the CAISO Tariff with CAISO metering installed on Producer's side of the interconnection



Option A- Metering on the high side of transformer

Option B- Metering on the low side of transformer compensated with transformer losses to the high side

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6.7 Location/Ownership of CAISO Metering Equipment

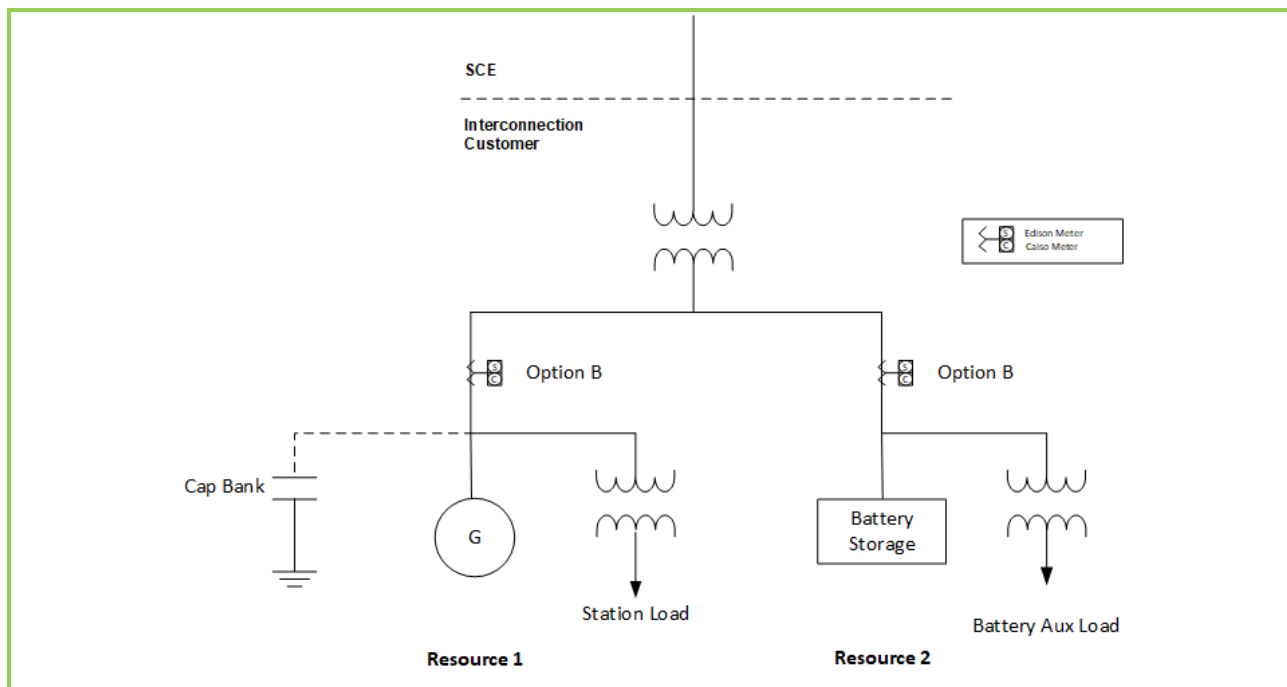
Applicable to Metering Installed on a Producer's Side of Interconnection

A Producer shall, at its expense, install, own, and maintain all CAISO metering equipment, including metering CTs/PTs, meters, routers, and telecommunication's equipment providing such equipment is installed on its assets and located on its side of the point of interconnection with SCE (Figure 6b).

Example 2:

Figure 6b: Typical Metering Installation for multiple resource Generating Facility

Typical metering configuration for multiple resource generators taking service under the CAISO Tariff with CAISO metering installed on Producer's side of the interconnection

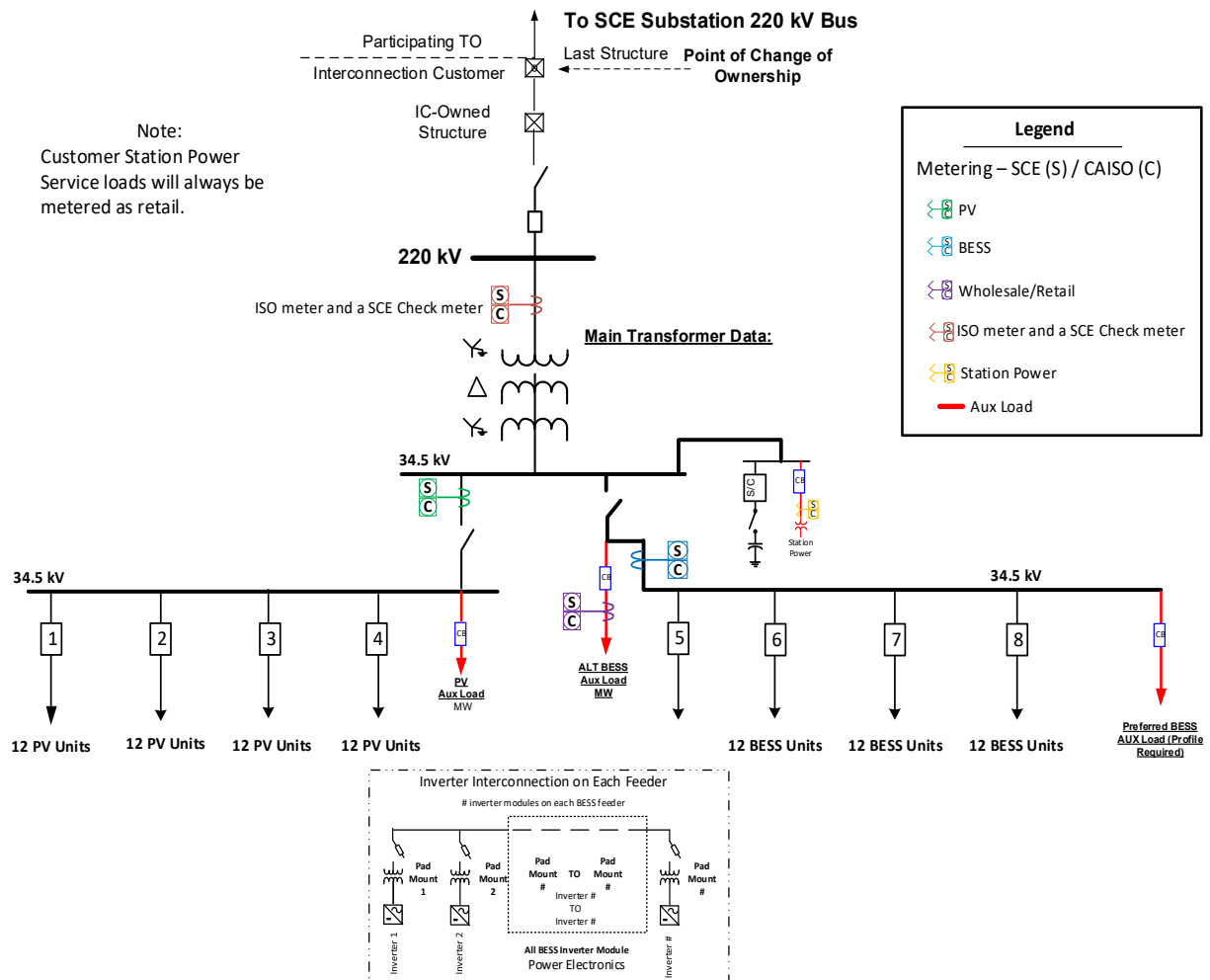


Note: Metering installed on the low side of the transformer is compensated with transformer losses to the high side.

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Figure 6c: Example of a more complex metering installation connecting a Generating Facility with multiple resources to SCE's Transmission System.

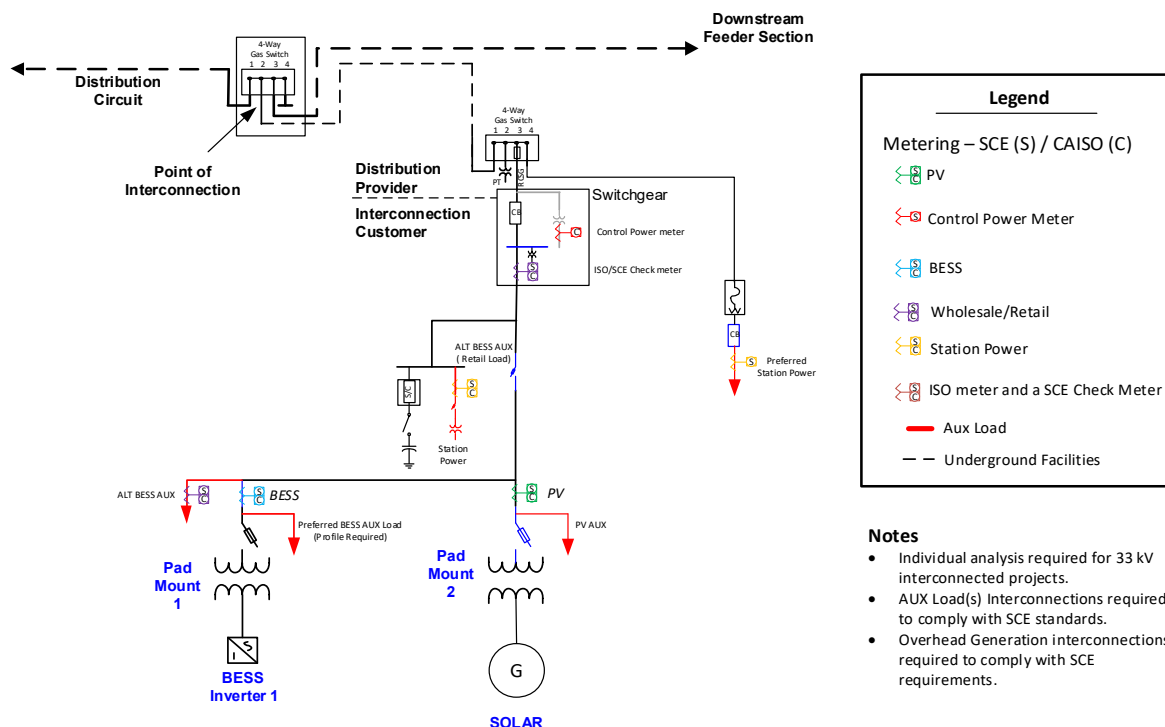
The single line depicts a metering configuration for multiple resource generators with CAISO metering installed on Producer's side of the interconnection taking service under the CAISO Tariff.



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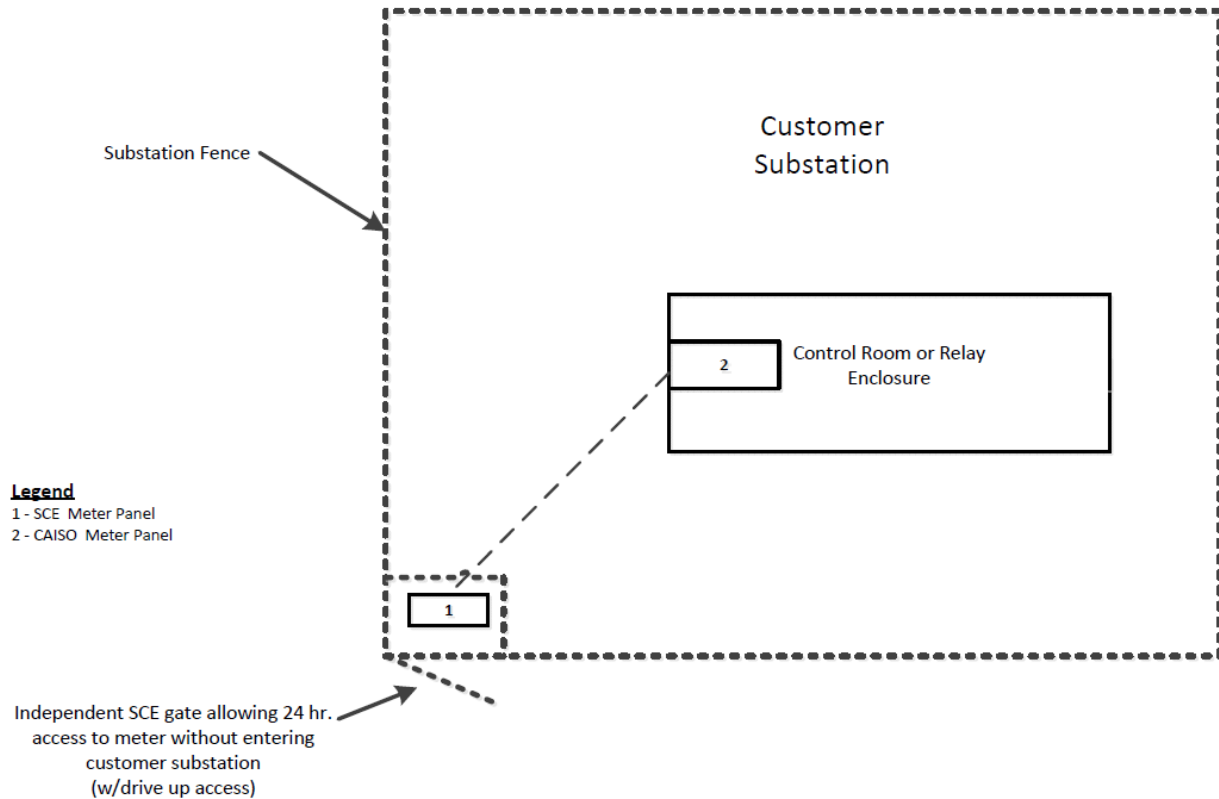
Figure 6d: Example of a more complex metering installation connecting a Generating Facility with multiple resources to SCE's Local Distribution System (i.e., 12, 16 and 33 kV)

The single line depicts a metering configuration for multiple resource generators with CAISO metering installed on Producer's side of the interconnection taking service under the CAISO Tariff.



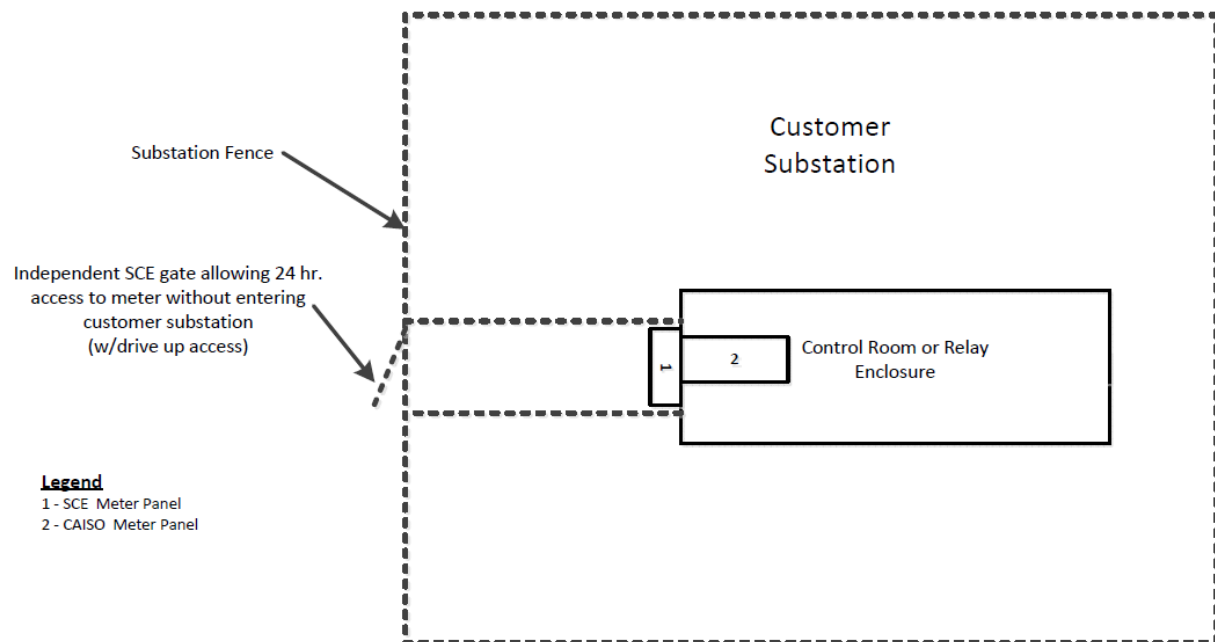
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Figure 6e: Example of SCE metering panel location for a Customer Substation with Customer owned PTs and CTs shared with CAISO Circuit. One (1) combined panel for SCE/CAISO allowed as long as access requirements are met



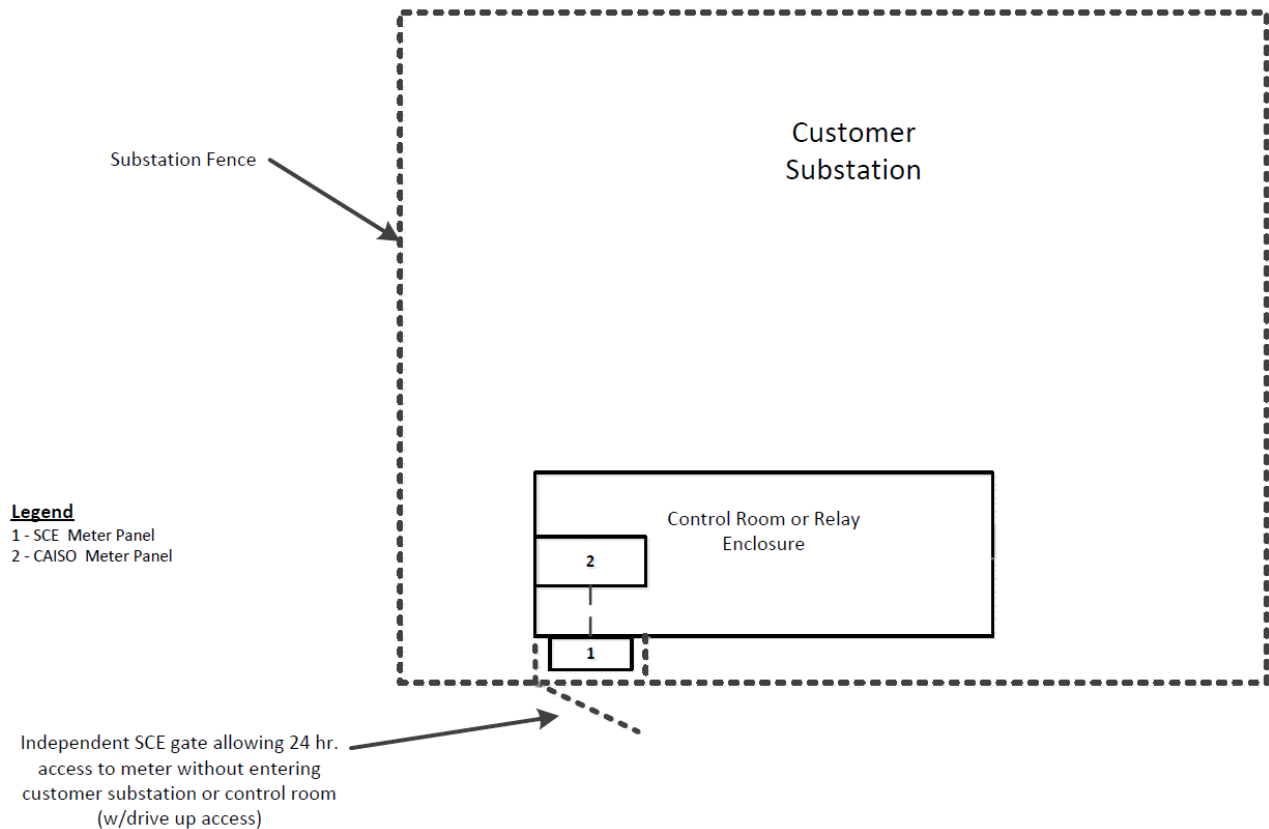
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Figure 6f: Example of SCE metering panel location for a Customer Substation with Customer owned PTs and CTs shared with CAISO Circuit. One (1) combined panel for SCE/CAISO allowed as long as access requirements are met



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Figure 6g: Example of SCE metering panel location for a Customer Substation with Customer owned PTs and CTs shared with CAISO Circuit. One (1) combined panel for SCE/CAISO allowed as long as access requirements are met



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SECTION 7 TELEMETERING REQUIREMENTS (HARDWARE)

7.1 Telemetry Requirements

Applicable to Generation, Transmission, and End-User Facilities

For a high degree of service reliability under normal and emergency operation, it is essential that the INTFAC have adequate and reliable telecommunication facilities.

The INTFAC shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

Applicable to Generation Facilities

Producers with generating facilities 1 MVA nameplate or larger will require telemetrying equipment and telecommunications at Producer's expense. For projects equal to or greater than 1 MVA but less than 10 MVA, real time SCADA telemetry of watts and vars only are required for total generation and customer load. For projects 10 MVA and greater, the telemetrying equipment must transmit at minimum generator unit gross MW and MVAR, generator status, generator circuit breaker status, and generator terminal voltage. In addition, real time telemetrying of project net MW and MVAR is required.

Wind generation facilities equal to or greater than 1 MVA nameplate will require real-time monitoring in most cases. It is the Producer's responsibility to comply with any CAISO telemetry requirements. These telemetry requirements apply to non-exporting-for-sale as well as exporting-for-sale generating facilities; refer to SCE System Operating Bulletin 510 for exemptions to certain non-exporting-for-sale generating facilities.

For generating facilities utilizing photovoltaic inverter-based technology, the nameplate rating is the total aggregate AC nameplate rating of the inverter unit(s). For generating facilities utilizing non-photovoltaic inverter-based technology (i.e., Fuel Cell, Energy Storage, etc.), the total aggregate nameplate rating is either the AC nameplate rating of the inverter unit(s) or the total aggregate nameplate rating of the generator/generating unit(s), as determined by SCE to be the limiting component.

7.2 Total Generation 1 MVA Nameplate or More

Applicable to Generation Facilities

The following is a list of requirements for the installation of Real-Time telemetry at the Producers generating facility. Unless otherwise specified, all the facilities listed below are to be provided by the Producer.

7.2.1 The following specifications are to be used as informational guidelines to facilitate the Centralized Telemetry Method installation at the Generation Facility:

The following apply to a generating facility with $1 \text{ MVA} \leq \text{Total Generation} < 10 \text{ MVA}$ interconnected to an SCE (34.5 kV or below) Distribution Circuit. Customer will purchase and install equipment for the Centralized Telemetry Method (CTM) (See Figure 8 for typical installation configuration). The purpose of the CTM is to collect customer facility and generation information for use on the SCE SCADA system to determine system loading, assist in Grid

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operation, and collect historical data. SCE will provide/approve acceptable solutions for connection to the CTM and program the CTM equipment as necessary. Customer will own, maintain, repair, replace, and upgrade and bring all required telemetry to the CTM.

- a) A NEMA 4 enclosure or equivalent for the CTM equipment is required. Other enclosures or mounting shall be evaluated on a case-by-case basis. The location should be reasonably close to the origin of telemetering signals or data concentrator. A control room or relay house is acceptable as long as the temperature range is within 0° C to 70° C.
- b) Provide a 120 VAC 15 Amp power source to the CTM cabinet for CTM power.
- c) Provide data communication cables for virtual I/O points directly to the CTM cabinet for termination. Typical data communication cables will be Industrial RS-485 Cables such as Belden 3108A or equivalent. A 4-foot coil is to be left at the CTM location and will be terminated by SCE inside the CTM cabinet.
- d) Communication between the producer's Data Concentrator and the CTM shall be ModBus RTU, 16-bit integer, 9600 baud, 8 bits, 1 stop, no parity.
- e) Provide Broadband internet service with a Static IP address.
- f) Local Network configuration and ISP must support an IPsec VPN connection between the CTM and SCE.
- g) Specific Network requirements shall be evaluated on a case-by-case basis.

7.2.2 The following specifications are to be used as informational guidelines to facilitate the RTU installation at the Generation Facility:

The following apply to a generating facility with $1 \text{ MVA} \leq \text{Total Generation} < 10 \text{ MVA}$ interconnected to an SCE Substation or $\text{Total Generation} \geq 10 \text{ MVA}$. The following is a list of requirements for the installation of a Real-Time Remote Terminal Unit (RTU) or equivalent device at the Producer's generating facility. See Figure 7a and Figure 7b for installation configuration. Unless otherwise specified, all the facilities listed below are to be provided by the Producer.

At the customer's expense, SCE will purchase, configure, install, and commission the RTU. The size and point count of the RTU is determined based on the generation nameplate capacity as well as the number of data points to be monitored. SCE will own, operate, maintain, repair, control, alter, replace, and upgrade the RTU. The purpose of the RTU is to collect and concentrate customer facility and generation information for use on the SCE SCADA system to determine system loading, assist in Grid operation, and collect historical data.

- a) An interior location suitable for floor or wall mounting the RTU is required. The location should be reasonably close to the origin of telemetering signals or data concentrator. A control room or relay house is acceptable as long as the temperature range is within 0° C to 70° C. The Heating Ventilation and Air Conditioning (HVAC) requirements for fiber optic terminal equipment are more stringent than what is required for RTU equipment. Therefore, the requirements in this Section 7 will match those of Section 8: Telecommunications Requirements, whenever line protection or RAS specifies the use of fiber optic communications and its terminal equipment.

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- Cable access can be either through the top or bottom of the RTU cabinet.
 - Floor space for standard 8-foot tall, 19” free-standing rack (PREFERRED).
 - Wall space for a single door cabinet 24 inches wide by 20 inches deep by 30 inches high. The wall mount cabinet weighs 125 pounds and is mounted with a ½ inch bolt through mounting tabs at each corner.
- b) Provide a 120 VAC, 15 Amp convenience power source to the RTU cabinet. This source will utilize a dedicated breaker labeled “SCE-RTU”. A 4-foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.
 - c) Station DC power 10 A @ 48 VDC or 5 Amp @ 125 VDC (not shared with other equipment) run to the RTU cabinet for RTU power. The voltage to be supplied to the RTU shall be communicated to SCE PSC in order for SCE to procure the appropriate RTU. The circuit breaker shall label “SCE-RTU”. If DC power is not available, a 120 VAC circuit may be used as long as this circuit is sourced from an Uninterruptible Power System with a minimum of 4-hour backup.
 - d) One stranded AWG #8 conductor will be connected to station ground and run to the RTU cabinet by the customer.
 - e) The customer will run all data signal cables for physical I/O points to the RTU cabinet or to a near-by (6 feet or less) interface cabinet for termination. Data cables must be shielded with shield grounded at RTU end only. Twisted-pair stranded wire between AWG #16 and AWG #22 or twisted-pair solid wire between AWG #18 and AWG #24 may be used. Cables containing 6, 12, 25 and 32 pairs are typical. A 10-foot coil is to be left at the RTU location and will be terminated by SCE inside the RTU cabinet.
 - f) All analog quantities will be represented by a + / – 1 milli-Amp or a 4 to 20 milli-Amp current loop. The current loop may be shared as long as there are no grounds, and it is not driven beyond the manufacturers specified limits. Physical status points will be presented by a dry contact available at the interface cabinet. All status points will utilize the Normally Open contacts of the customer provided isolation relay. The RTU will provide the contact wetting voltage.
 - g) The customer shall provide data communication cables for virtual I/O points directly to the RTU cabinet for termination. Typical data communication cables include standard CAT V (Ethernet) cables, Industrial Ethernet Cable, or Industrial RS-485 Cables such as Belden 3108A or equivalent.
 - h) Communication between the customer data concentrator and the Edison RTU shall be ModBus RTU, 9600 baud, 8 bits, 1 stop, no parity. Other data communication protocols shall be evaluated on a case-by-case basis.
 - i) Specific Telemetry Requirements identified in Table 7.1.

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Table 7.1: Telemetry Requirements

GENERATOR SIZE AND TYPE	DATA ACQUISITION REQUIREMENT
GF with aggregate generation < 1 MVA	No remote telemetry is required
Non-Wind GF interconnected at ≤ 33 kV with 1 MVA ≤ aggregate generation < 10 MVA	Real-time (SCADA) telemetry required for total generation. Customer load data may be required and shall be evaluated on a case by case basis - Watts - VARs - State of Charge (BESS only) - Voltage
Wind GF ≥ 1 MVA	Real-time (SCADA) telemetry required for total project - Watts - VARs - Voltage - Entire Project CB Status⁹
GF with an aggregate plant ≥ 10 MVA	Real-time (SCADA) telemetry required for 2 of the following 3 parameters: - Total Gross Generation - Customer Load - Net flow to/from utility interface Plus the following: - Watts - VARs - Amps - Volts (Generator Bus) - Interface CB Status¹⁰ - State of charge (BESS only) - AVR status and control mode
Any single generating unit ≥ 10 MVA	Real-time (SCADA) telemetry required for each individual generating unit: - Watts - VARs - Amps - Volts (Generator Bus) - Unit CB Status¹¹ - State of charge (BESS only) - AVR status and control mode
Switchyards ≥ 55 kV	Real-time (SCADA) telemetry required for: - Bus Voltage - Line MW - Line MVARs - Switchyard CB Status¹²

- j) SCE's GCC on a site-to-site basis may deem other status, protection alarms, or controls necessary. All ratings are based on the Gross Nameplate Rating.
- k) ITBI ITS Network & Telecom Services Grid Projects will determine communications from the RTU to EMS.
- l) The RTU cabinet can be delivered to the customer premises for mounting and conveniences to the customer.

⁹ All CB statuses contained in the entire projects

¹⁰ The customer's high side main breaker status

¹¹ Individual Generating Unit CB Status

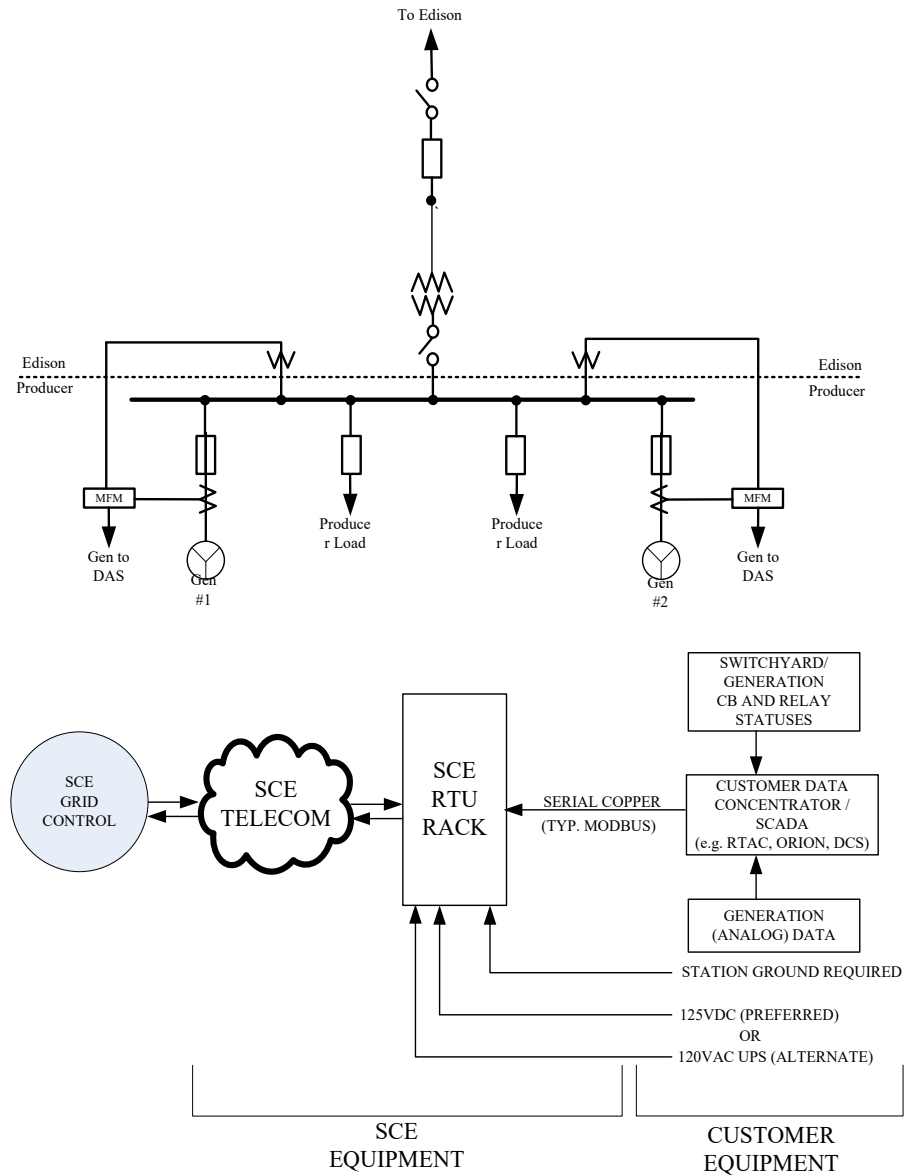
¹² Entire switchyard CB status

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m) 24-hour access to the RTU for maintenance by SCE's Power System Controls technicians.

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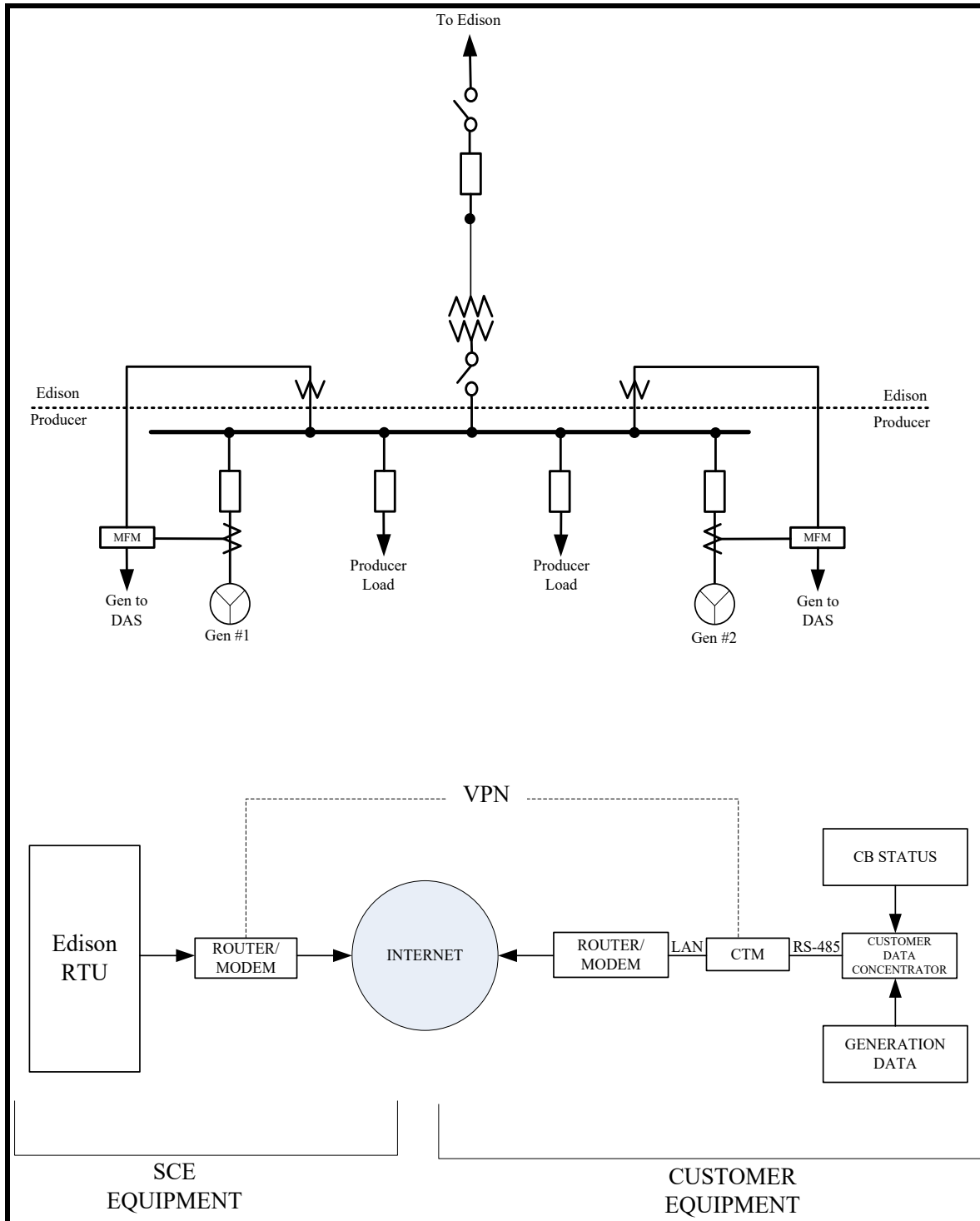
Figure 7a: Typical Remote Terminal Unit (RTU) Installation
1 MVA ≤ Total Generation ≤ 10 MVA interconnected to an SCE Substation or Total Generation ≥ 10 MVA



*For generation 1 MVA or more.

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Figure 7b: Typical Centralized Telemetry Method (CTM) Installation
1 MVA ≤ Total Generation < 10 MVA interconnected to an SCE (34.5 kV or below) Distribution Circuit



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7.3 Exemption for Cold-Iron and Emergency-Backup Generators

Note: These types of generators are not operated in parallel to SCE’s electric system except for short times (*typically only several minutes or less*) while performing a “soft-transfer” of customer load between the generator and SCE’s electric system. As such, the telemetry requirements of this section **do not apply** to Cold-Iron or Emergency-Backup generators that have selected “Isolated Operation” or “Momentary Parallel” operation.

7.3.1 Cold-Ironing is the action of providing shore-side electrical power to a ship at berth while its on-board generator(s) are shut down.

- a) Cold-Iron generator is a generator on board a ship which has the capability of Cold- Ironing.
- b) The initial process of Cold-Ironing involves paralleling the ship's electrical system to SCE’s electric system for a short duration while the ship's electrical load is transferred between the ship's generator and shore power. A Cold-Iron generator does not parallel to SCE’s electric system beyond the initial transferring process.

7.3.2 Emergency-Backup Generation (EBG) is customer-owned generation utilized when disruption of utility power has occurred or is imminent.

- a) When utilized, following a disruption, the customer would first disconnect from SCE’s electric system prior to starting up the EBG.
- b) When utilized prior to a disruption of utility power, the EBG would be started and loaded to carry the entire customer load, and then the customer would disconnect from SCE’s electric system.
- c) Upon resumption of utility power, the customer would first connect to SCE’s electric system and then unload the EBG.

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SECTION 8 TELECOMMUNICATIONS REQUIREMENTS

8.1 General Description

The following requirements are to be used as guidelines for typical Telecommunications equipment installation at an Interconnection Facility (INTFAC). Specific design and installation details are addressed during final engineering for each specific INTFAC.

SCE's telecommunications facilities support line clearing in the event of faults in the INTFAC's gen-tie, Supervisory Control and Data Acquisition (SCADA) at the INTFAC's generator (See Section 7), and, if required, a Remedial Action Scheme. As noted in [Section 3](#), the selection of protection devices depends on the INTFAC's generator size and type, number of generators, the composition of the existing protection equipment and the power line characteristics (i.e., voltage, impedance, and ampacity) of its gen-tie and the surrounding area. Identical INTFAC's connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. For INTFAC's connecting at ≥ 200 kV and above, the primary protection relays are designed to isolate the faulted transmission line within six (6) cycles. Voltage classes as low as 66 kV may have similar time clearing requirement if studies show an electrically faulted transmission line will have severe network impacts if not electrically separated from the grid as quickly as possible. SCE selects high speed relays for these situations.

SCE uses fiber optic (FO) cable for communications between these relays because it is:

1. Fast (speed of light);
2. Resilient (not subject to atmospheric or other interference);
3. Reliable (consistent latency);
4. Available as carrier grade terminal equipment (integral redundancies, design margins, maintenance support); and
5. A best utility practice.
6. Non-conductive (when using All-Dielectric Self-Supporting cable)

SCE does not allow the use of Intermittent and indeterminate communications methods, such as a leased circuits, radios using unlicensed frequencies, and cellular or satellite paths, which defeat the purpose of line current differential relays.

In cases where a second FO telecommunication is required, for protection relay coordination or to support a RAS, the second FO path must comply with WECC guidelines governing diverse routing. The customer will construct the communications path(s) between its end user Facility and the point of interconnection. Primary path can be provided with a FO cable at the end user Facility or as OPGW (fiber Optical Ground Wire). Diverse routing will be required for secondary path. Telemetry data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or RAS, a leased circuit may be used for telemetry (SCADA). See Section 8.6.

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8.2 Fiber Optic Cable and Communications Paths:

The INTFAC will install the main and diverse FO cables (if needed) from its facility to SCE designated points just outside of the SCE interconnection substation, from which SCE will extend the FO cables into the substation. A minimum of eight (8) strands within each FO cable will be provided to SCE for its exclusive use. SCE follows the WECC Applicable Reliability Standards for space diversity between the -C's main and diverse FO cables. SCE's implementation is the following:

1. Main and a diverse FO cables (i.e., redundant) on two separate paths (i.e., diverse) and spaced such that a single credible event cannot sever both cables. Equipment redundancy is also required. Options within the right-of-way include:
 - a) Main path: OPGW or underbuilt FO cable on the gen-tie poles and for the Diverse path: Underground FO cable in the right-of-way; or
 - b) Main and diverse (two) direct buried FO cables separated by ≥ 25 feet; or
 - c) Main and diverse (two) FO cables in conduits separated by ≥ 10 feet and fully encased in concrete.

Protection and Telecom Engineering has final approval for fiber architecture.

Fiber Optic Cable at Aggregation (Collector) Substations

If the -C will be connecting to a non-SCE aggregation substation (commonly known as a collector substation) that in turn is connected to an SCE substation, the -C is responsible for providing the telecommunication equipment and communications paths between the collector sub and the -C necessary for line protection and RAS participation. The -C is responsible for confirming its telecommunications plan of service meets the WECC Applicable Reliability Standards. An -C that interconnects to a collector substation:

- d) Is responsible for the telecom for its line protection between the -C and its collector substation, including any lightwave, channel banks, or related terminal equipment.
- e) Is responsible for transport of any RTU data from the -C to the SCE terminal equipment at the collector substation.
- f) May elect to install FO cables and equipment that meet WECC's diversity requirement. Sufficient space and facilities must also be provided at both locations (collector substation and -C) to install appropriate equipment to support the RAS.

The provisions of this Handbook for space diversity apply on the -C's side of the collector sub.

8.3 Space Requirements

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the INTFAC to support line protection, telemetering (SCADA), equipment protection, and RAS/CRAS communications applicable to the project. Refer to the respective sections for Protection and Telemetering for their space requirements.

The INTFAC shall provide sufficient floor space within a secure building to install one communication equipment cabinet or 19" EIA/TIA Telecommunication rack for each of the fiber

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optic cables (corresponding to the Protection requirements in order to support WECC diversity).

The INTFAC shall procure and install the communication equipment cabinet(s) or rack(s) per SCE's current Telecom Standards. These cabinet(s) or rack(s) shall be secured per current **California Seismic requirements**.

The INTFAC shall provide a working clearance of 36" in front and behind the communication equipment cabinet(s) or rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36" unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment cabinet(s) or rack(s) to contain "live electrical equipment," which is consistent with the 36" working clearance specified in the **National Electric Code**.

8.4 HVAC Requirements

The INTFAC shall provide and maintain suitable environmental controls in the equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic lightwave, transport or data equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or RAS specifies the use of fiber optic communications and its lightwave, transport or data equipment, the requirements of Section 7: Telemetry Requirements (Hardware) will match those in this Section 8.

8.5 Power and Grounding Requirements

The INTFAC shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment cabinet(s) to the designated station ground termination to protect the communications equipment and service personnel.

The INTFAC shall provide two dedicated branch circuits (20 Amp each) from the 125 VDC station power to support each required telecommunications equipment rack. The dedicated source breakers shall be labeled "SCE-Telecom A" and "SCE-Telecom B." If DC power is not available, two 20 Amp, 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System (UPS) with a minimum of a 4-hour backup. The 4-hour backup source shall be maintained by INTFAC. The power source shall not be shared with other equipment. AC Power is not applicable when line protection is required.

The INTFAC shall provide a 120 VAC, 15 Amp convenience power source adjacent to the telecommunications equipment cabinet(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The INTFAC shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 7.

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8.6 Telemetry and Leased Circuit:

If the INTFAC requires a dedicated RTU but is not required to construct fiber optic cables for line protection or RAS (typical for INTFACs ≥ 10 MW but < 20 MW), the INTFAC shall:

1. Arrange with the local service provided to deliver a 20 Mb or greater Ethernet circuit from the INTFAC location to a SCE designated SCE service center or similar facility.
2. Technical specifications for circuit are as follows:
 - a. Latency Max 20 ms (one-way)
 - b. MTU Max 9126 (on Telco side)
 - c. CIR Min 25 Mbps
 - d. PDR 99.9% (PDR=Packet Delivery Rate)
 - e. Availability 99.99% (network availability)
 - f. Sync None (We will have to provide our own)
 - g. Interface GigE (Multimode preferred)
3. Designate to the service provided that SCE shall be authorized to report trouble and to initiate inquires, troubleshooting and repairs with the service provider on the INTFAC's behalf in the event of an interruption of service on the communication circuit.
4. Incur all make ready and recurring costs of the leased circuit.
5. Provide high-voltage protection for the service providers communications, if necessary.
6. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment described in Item 6 below. The SCE equipment cabinet(s) shall be no more than 100 feet from the MPOE.
7. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary to extend a communications circuit from the RTU to communications equipment and the leased communications circuit in the event the SCE RTU is not located within the same facility as the communications equipment, SCE's RTU and communications equipment shall be no further apart than 100 feet.
8. Provide (1) communications cabinet described in Section 8.3 above.

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8.7 Miscellaneous:

1. While SCE may discuss telecommunication connection preferences of the customer's facility, ultimately, SCE has final decision regarding the selection of telecommunication connection equipment. The telecommunication connection equipment must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.
2. Use of SCE telecommunications infrastructure (including microwave facilities and fiber optic cables) by a customer is not an option.
3. Leased circuits, radio using unlicensed frequencies, cellular, and satellite are not acceptable options at SCE for high-speed protective line relays or C/RAS supporting transmissions lines.
4. SCE telecommunications terminal equipment, being electronic devices, will be periodically refreshed, i.e. replaced, sometime after installation. The time until refresh depends on a number of factors, including its operating environment, repair history, and manufacturer support. A refresh typically occurs around 10 years and could be as early as 5 years or as long as 15 years after installation. The interconnection customer should anticipate for these refreshes to be considered Capital Additions under the terms of the interconnection agreement, with the associated cost being the responsibility of the interconnection customer.
5. The customer shall provide access for SCE employees and approved contractors for planned maintenance and service restoration 24 hours a day, 7 days a week after the communication equipment is installed and in operation.

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SECTION 9 PROPERTY REQUIREMENTS

9.1 Right of Way Requirements

The Producer must acquire the necessary Right of Way requirements for its interconnection or transmission line, along with the access requirements to the point of interconnection with SCE's facilities. The use of SCE's Right of Way and/or fee owned property shall not be included in any interconnection proposals.

9.2 Transmission Line Crossing Policy

A "proposed" interconnection transmission line, or Right of Way access, crossing SCE transmission line or access easements or fee owned property must be submitted to SCE's Vegetation & Land Management (V&LM) organization for a separate review by several internal departments for approval/denial. For your reference, below are SCE's Transmission Crossing Policy guidelines:

- A new non-SCE owned transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE facilities and/or the new facilities proposed prior to the new line, including facilities needed for queued-or-clustered--ahead generation.
- A new non-SCE owned transmission line, triggered by a generator facility, with higher voltage may be allowed the superior position than an SCE line if it adheres to G.O. 9510F¹³ Grade "A" self-supporting Dead-end construction and has a minimum of double insulator strings on both sides. SCE will regain the superior position if its lower voltage facilities are upgraded and are of equal or higher voltage than the non-SCE owned transmission line. Note: This will apply to all voltages.
- A new non-SCE owned transmission line of higher voltage may be allowed the superior position if it crosses a multiple SCE circuit corridor (two circuits or more). However, this type of crossing needs to be reviewed, and approved by SCE, on a case-by-case basis. All costs incurred by SCE for mitigation measures that are required to accommodate a proposed crossing of SCE facilities shall be at the customer's expense.
- A new non-SCE owned transmission line, regardless of voltage, shall not be allowed the superior position if it crosses a circuit which terminates at a current or former nuclear power plant switchyard.

¹³ **General Order No. 95. (G.O. 95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases, SCE Practices and Standards may be more stringent. The INTFAC must adhere to the appropriate requirements.

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9.3 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- 66 kV Tap: 80 ft. by 94 ft.
- 66 kV Loop: 135 ft. by 105 ft.
- 115 kV Tap: 112 ft. by 110 ft.
- 115 kV Loop: 170 ft. by 140 ft.

These land requirements assume the customer is installing/owning the transformer and gen-tie line.

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer, other facilities; and the land needed for the incoming line(s) is not included.

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SECTION 10 GENERATOR SHARING BREAKER AND A HALF

10.1 Summary

Generation¹⁴ projects may request interconnection directly to a bus position on any of SCE's 500 kV, 220 kV, 115 kV, and 66 kV switchracks. The guidelines for generation interconnection bus positions are as follows:

10.1.1 SCE Project¹⁵

Bus positions reserved for future SCE transformers will not be assigned to generation interconnection projects. Bus positions reserved for any other SCE project with a proposed operating date within 10 years of the execution of the generation project's Generation Interconnection Agreement (GIA), will not be assigned to generation interconnection projects.

10.1.2 Generator Sharing Breaker and a Half

Generation interconnections to SCE's 500 kV, 220 kV, 115 kV, and 66 kV switchracks may share the same breaker-and-a-half (BAAH) position under the following conditions:

- The remaining switchrack facilities are not overloaded when a bus side breaker is lost
- Loss of generation projects sharing the breaker and a half position do not exceed the CAISO's 1,150 MW N-1 and 1,400 N-2 tripping limitations
- No system performance issues result from generation projects sharing the same BAAH position
- No SCE load is part of the configuration when both bus side breakers are lost

10.1.3 Generator Bus Assignments

Typically, generation projects requesting interconnection to SCE's 500 kV, 220 kV, 115 kV, and 66 kV switchracks are assigned a bus position on a first come first served basis (i.e. the first customer ready to begin construction will be assigned the position). If multiple eligible generation customers are concurrently ready to begin construction and request the same bus position at a substation where available bus positions are limited, the following guidelines will apply:

10.1.3.1 Generator Bus Position Eligibility Requirements

- Generation customer must have a signed GIA/Engineering, Procurement & Construction Letter Agreement.
- Generation project must be active (not parked/suspended).
- Generation project construction must start within 15-18 months.

¹⁴ Generation refers to Generators or Energy Storage Projects and/or Hybrid projects.

¹⁵ SCE Project in this context can be defined as any SCE-built project requiring a bus position, not supporting an SCE/EIX-owned generator.

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10.1.3.2 Generator Bus Position Priority Determination

In the event that multiple generation projects have met all above eligibility requirements and are scheduled to begin construction simultaneously, the following criteria will determine which generator will be assigned the bus position. The generation project that meets the most criteria will be assigned the bus position.

1. Queue Position – The generation project with the earlier queue position will satisfy this criterion.
2. Generation tie-line routing – The generation project with the generation tie-line route that has less transmission line crossing, a shorter route length, less environmental impact, and/or has fewer licensing challenges will satisfy this criterion.
3. Power Purchase Agreement (PPA) – The generation project that can provide proof of having an executed and regulator-approved PPA will satisfy this criterion.
4. Shortlist Status – The generation project that can provide proof that it is currently included on an active short list, or other commercially recognized method of preferential ranking of power providers by a prospective purchasing Load Serving Entity, will satisfy this criterion.
5. Permitting Status – The generation project that is farther along in the environmental permitting process, will satisfy this criterion.
6. Land Acquisition Status - The generation project that can demonstrate a present legal right to begin construction of the Generating Facility on one hundred percent (100%) of the real property footprint necessary for the entire Generating facility, will satisfy this criterion.

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SECTION 11 INVERTER-BASED RESOURCE PERFORMANCE REQUIREMENTS

Generators interconnecting below 50 kV shall follow the Rule 21 requirements for Autonomous Functionalities listed below:

- a) Anti-Islanding Protection
- b) Low/High Voltage Ride Through (L/HVRT)
- c) Low/High Frequency Ride Through (L/HFRT)
- d) Dynamic Volt/Var Operations
- e) Ramp Rates
- f) Fixed Power Factor
- g) Reconnect by “Soft-Start” Methods
- h) I-DER System Parameters and Monitored Points

Inverter-based resources interconnecting at 55 kV and above shall comply with the IEEE Standard 2800-2022, “IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems.”¹⁶ The requirements for the parameter settings may differ from the recommended default values specified in the IEEE Standard 2800-2022 depending on the resource location. As such, Producers shall consult with the SCE GCC and Transmission System Planning & Strategy to ensure that the parameter settings are set appropriately. Producers shall also consult with SCE’s Power Quality and Protection Engineering to ensure all applicable IEEE Standard 2800-2022 requirements are implemented appropriately.

¹⁶ IEEE is currently drafting a new standard that will define recommended practices for test and verification procedures to demonstrate compliance with the IEEE Standard 2800; therefore, at this time, Producers are not required to comply with Clause 12, “Test and Verification Requirements” of the IEEE Standard 2800. Clause 12 will be required once this new standard is published and approved (IEEE P2800.2, “Test and Verification of BPS Connected Inverter-based Resources”).

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SECTION 12 CYBERSECURITY MEASURES

The INTFAC shall implement reasonable administrative, technical, and physical safeguards, including any specific safeguards specified from time to time by SCE, to protect the security and integrity of SCE’s systems.

A “Cybersecurity Incident” is: (a) unless expressly authorized, any use, reproduction, distribution, transfer, disposition, disclosure, possession, memory input, alteration, erasure, damage, breach in the security, or other activity by a person or party other than SCE of (i) Interconnection Customer’s computing systems or equipment, including those that contain information about SCE’s systems or provide information to SCE’s systems, or (ii) SCE’s computing systems or equipment, if caused by the action or inaction of Interconnection Customer; or (b) any unauthorized access to, interception of, disclosure or acquisition of such information.

The Interconnection Customer shall immediately notify SCE at cybersecurity@sce.com of any reasonably suspected or confirmed Cybersecurity Incident immediately upon Interconnection Customer’s awareness of the event. Such notification to SCE by the Interconnection Customer shall include the nature of the event, date and time of the event, suspected amount and type of information exposed and steps being taken to investigate the circumstances of the exposure. The Interconnection Customer shall cooperate and assist SCE in the investigation, analysis and resolution of Cybersecurity Incidents affecting SCE’s systems. The Interconnection Customer shall provide SCE with details of the investigation and final disposition of the Cybersecurity Incident relating to SCE’s services or systems or which may impact the confidentiality, integrity, or availability of those services or systems or of SCE’s information.

In addition to the above, Interconnection Customer shall: (i) regularly scan its systems for vulnerabilities, (ii) rank all vulnerabilities and promptly remediate detected vulnerabilities ranked as critical, high or moderate, and (iii) use commercially reasonable efforts to identify any critical, high, or moderate vulnerabilities, risks, or threats that could potentially impact SCE, and shall notify SCE in writing at cybersecurity@sce.com within one (1) Business Day after such identification. If Interconnection Customer determines that it cannot remediate any such potential or detected vulnerabilities, risk or threats within thirty (30) Calendar Days after identifying any such potential or detected vulnerabilities, risks, or threats, it shall promptly notify SCE in writing. Interconnection Customer’s notification shall provide detailed information describing the controls used to mitigate these vulnerabilities, risks or threats.

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PART 2

Method of Service/End User Facility Interconnection Requirements

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SECTION 1 METHOD OF SERVICE / END USER FACILITY INTERCONNECTION OVERVIEW

The Method of Service (MOS) study specifies what is necessary to interconnect a customer end user Facility to SCE's electric system and provides these customers with an overview of the requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the end user Facilities interconnecting to SCE's electric system.

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SECTION 2 PROTECTION REQUIREMENTS

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE's electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE's electric system.

While some protection requirements can be standardized, the detailed protection design highly depends on the type and characteristics of the customer's end user Facility (i.e., voltage, impedance, and ampacity), as well as the existing protection equipment and configuration of SCE's surrounding electric system. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical end user Facilities connected at different locations in SCE's electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements, (See Section 7.)

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic replacement. Typically, the frequency of transmission line relay replacement does not exceed once every fifteen (15) years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule. If equipment does fail, it shall be replaced according to the Interconnection Agreement.

For MOS interconnections utilizing a sub-transmission line interconnection at voltage 66 kV and 115 kV or transmission line at 220 kV and 500 kV, customers shall utilize Protection Requirements as defined in this Interconnection Handbook, Part 3 Transmission Interconnection Requirements Section 2.

2.1 Circuit Breaker Short Circuit Duty and Surge Protection

2.1.1 SCE Short Circuit Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review circuit breaker short circuit duty capabilities and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short-circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing circuit breakers, consideration should be given to the following factors:

- a) Methods of limiting duty to below the circuit breaker capability:

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1. De-looping or rearranging transmission lines at substations;
 2. Split bus arrangements.
- b) Magnitude of short circuit duty.
 - c) The effect of future projects on the short circuit duty.
 - d) Increasing the interrupting capability of equipment.
 - e) The ability of a particular circuit breaker to interrupt short circuit currents considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include reevaluation of the facility circuit breakers.

2.1.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the requirements of SCE's Interconnection Handbook, the owner shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of its end-user Facilities to any short circuit occurring on SCE's electric system not otherwise isolated by SCE's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE's electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the customer's end-user Facilities and the SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The owner shall be responsible for protection of the end-user Facilities and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The owner shall be solely responsible to disconnect their facility if conditions on SCE's electric system are impacted by the customer's end-user Facilities.

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SECTION 3 MISCELLANEOUS REQUIREMENTS:

3.1 Overhead & Underground Facilities Requirements

The customer shall ensure that its overhead facilities are constructed to a minimum of General Order 95 Rules for Overhead Electric Line Construction standards when facilities are built within California and to National Electric Safety Code standards when facilities are built outside of California. The customer shall ensure that its underground facilities are constructed to a minimum of General Order 128 Rules for Construction of Underground Electric Supply and Communication Systems when facilities are built within California and to National Electric Safety Code standards when facilities are built outside of California. Where facilities are intended to be owned by SCE, additional design requirements apply and must be consistent with SCE's design standards.

3.2 Automatic Voltage Regulators (AVR)

Automatic voltage control equipment on end user Facilities, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the balancing authority operator which is the CAISO.

3.3 Underfrequency Relays

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, the CAISO and SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one-second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping shall not be implemented.

3.4 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive over-voltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The customer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on the end user Facilities equipment. In addition, the customer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

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3.5 Ratings

3.5.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to NERC Standard governing Facility Ratings.

3.5.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE's electric system is rated according to the manufacturer's nameplate or certifications, and ANSI/IEEE standards. The manufacturer's nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases, the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE's determination indicates that a reduced rating is prudent or an increase rating is justified.

3.5.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

3.5.4 Ambient Conditions

Since SCE's territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

3.5.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This comprises of the transmission line conductor/cable, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, the allowable current that will not cause the cables to operate above the designed temperature limit, and the termination equipment.

3.5.6 Overhead Conductors

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor rating allows a total temperature of 90°C and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors, SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification.

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3.5.7 Underground Cable

The transmission line cable ratings are calculated in accordance with IEC 60287. For cross-linked polyethylene (XLPE) insulated cable, the normal cable rating allows a total temperature of 90°C and the emergency rating allows 105°C for 4 hours. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification and/or component tested data.

3.5.8 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow, so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

3.5.9 Terminal Equipment

Terminal equipment comprises of the following: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

3.5.10 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All the above ratings are reported to the CAISO Transmission Register.

3.5.11 Transformer Normal Ratings

The "normal" rating is the transformer's highest continuous nameplate rating with all its cooling equipment operating. The only exception is when a special "load capability study" has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

3.5.12 Transformer Emergency Ratings

A transformer's emergency rating is arrived at by one of two methods. First, if no overload tests are available then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal as revealed by the test. For transformers on the transmission system, i.e., primary voltage of 500 kV, the allowed duration of the emergency loading is 24-hours. For transformers with primary voltage of 161 kV to 220 kV, the allowed duration is 30 days.

3.5.13 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

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3.5.14 Relay Protective Setting Limits

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., “limited to 725 A by relay setting.”

3.5.15 Path Ratings

As stated in Section 2 of the WECC Procedures for Project Rating Review, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, end user Facilities, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

3.6 Synchronizing of Facilities

Testing and synchronizing of a customer’s end user Facility may be required depending on SCE’s electric system conditions, ownership, or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE’s transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The owner of the end user Facilities is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of their facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the owner of the end user Facility shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to the SCE transmission system and upon which trial operation begins.

3.7 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the customer’s end user Facilities and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

3.8 Abnormal Frequency and Voltages

3.8.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

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3.8.2 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions on the CAISO controlled system. All operating entities shall assist with the CAISO's coordination efforts.

3.8.3 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3.9 Communications and Procedures

3.9.1 Use of Communication System

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

3.9.2 Remedial Action Schemes Communication Equipment Requirements

Customer end use Facilities will require the necessary communication equipment for the implementation of Remedial Action Schemes (RAS). This equipment provides line monitoring and high-speed communications between customer's breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to end user Facilities that may be required to trip in order to relieve congestion on transmission facilities. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the WECC Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria for RAS redundancy.

“Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection, arming, power, supplies, telecommunications facilities and equipment, logic controllers (when applicable), and RAS trip/close circuits.” Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

3.9.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

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3.10 Point of Change of Ownership (POCO)

Currently there is no equipment that allows a below ground POCO for interconnections at 66 kV and above. Any POCO at these voltage levels will need to be installed above ground to ensure clear distinction between SCE's equipment and the Interconnection Customer's equipment.

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SECTION 4 GENERAL OPERATING REQUIREMENTS:

- a) **System Operating Bulletins:** An end user Facility connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating requirements are discussed in the sections below. SCE may also require additional operating requirements specific to an end user Facility. If so, these requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOB's and/or SSIs specific to the end user Facility and any subsequent revisions will be provided by SCE to the customer as they are made available.
- b) **Responsibility for the Owner of an end user Facility:** The owner of an end user Facility is responsible for complying with all applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore, it is advisable for the customer to regularly monitor operating procedures that apply to its end user Facility. The CAISO publishes its operating procedures on its internet site, but it is prudent for the customer to contact the CAISO for specific requirements.
- c) **Quality of Service:** The interconnection of the customer's equipment with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the customer's end use Facility, such equipment shall be disconnected until the problem is resolved.
- d) **SCE Circuits:** Only SCE is permitted to energize any de-energized SCE circuit.
- e) **Operate Prudently:** The owner of an end user Facility will be required to operate its facility in accordance with prudent electrical practices.
- f) **Protection in Service:** An end user Facility shall be operated with all of required protective apparatus in service whenever the end user Facility is connected to, or is operated in parallel with, the SCE electric system. Redundant protective devices may be provided at the customer's discretion. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.
- g) **Added Facilities Documentation:** The customer may not commence parallel operation of its end user Facility until final written approval has been given by SCE. As part of the approval process, the customer shall provide, prior to the commencement of parallel operation, all documents required by SCE to establish the value of any facilities installed by the customer and deeded to SCE for use as added facilities. SCE reserves the right to inspect the customer's end user Facility and witness testing of any equipment or devices associated with the interconnection.

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4.1 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

4.1.1 Interconnection

Interconnection with other utilities will normally be designed with the capability of maintaining near-zero VAR exchange between systems. Entities interconnecting their electric system with SCE's electric system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. SCE shall not be obligated to supply or absorb reactive power for the customer's end user Facility when it interferes with operation of the SCE electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

4.1.2 Subtransmission System

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five-year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

4.2 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers, and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the customer at its end use Facility, or by SCE at SCE's facilities at the customer's expense.

4.2.1 Facility Reactive Power Equipment Design

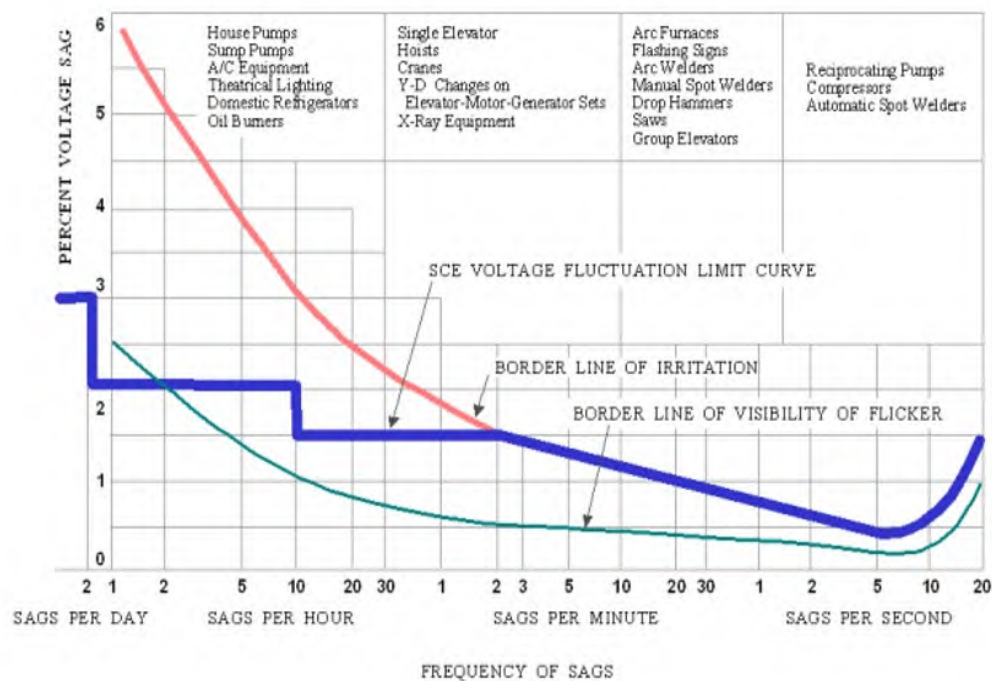
Customers shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

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The reactive power equipment utilized by the interconnecting customer to meet SCE's requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

- severe over-voltages that could result from self-excitation- of induction generators,
- transients that result from switching of shunt capacitors,
- voltage regulation problems associated with switching of inductive and capacitive devices.
- unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and
- Voltage flicker exceeding SCE Voltage Flicker limits (See Figure 4a).

Figure 4a: Voltage Fluctuation Design Limits



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4.2.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized by the interconnecting customer to meet SCE's requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

- a) the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE's electric system) associated with a step change in the output of the customer's reactive power equipment must be less than or equal to 1%; and
- b) the maximum allowable deviation from the customer's reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the customer's maximum (boost) reactive capability.

4.2.3 Voltage and Reactive Control

4.2.3.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4.2.3.2 Transmission Lines

Although transmission lines should be kept in service as much as possible, during over-voltage system conditions a customer's transmission line(s) may be subject to removal from operation as a means to mitigate voltage problems in the local area. SCE will notify CAISO when removing such facilities from and returning them back to service.

4.2.3.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

4.3 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if an end user Facility degrades power quality to other SCE customer facilities or SCE's own facilities, SCE may require the owner of that end user Facility to install equipment to eliminate the power quality problem.

4.3.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a customer's end use Facility connected to SCE at the transmission or subtransmission system level, may not exceed 1% at the

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Point of Common Connection¹ (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by a customer's end use Facility shall not exceed 1.5%.

It is the responsibility of the owner of an end use Facility, connected to SCE's electric system, to install the adequate mitigation devices to protect their own equipment from damage that maybe caused by voltage imbalance condition.

4.3.2 Harmonics

Customers interconnecting to SCE's electric system are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

4.3.3 Disconnection

SCE may disconnect any Facility connected to its system until the above requirements are met.

4.3.4 Photovoltaic Inverter Systems

Photovoltaic inverter systems which conform to the recommended practices in the latest IEEE Standard 929 "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems" and which have been tested and approved for conformance to UL Subject 1741 are considered to have met SCE's requirements for voltage imbalance and abnormal waveforms.

4.4 Grounding Circuits and Substations

A customer interconnecting its end user Facility to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

Reason for Substation Grounding

Substation grounding practices are outlined in the latest IEEE 80 "IEEE Guide for Safety in AC Substation Grounding."

According to IEEE 80 – 2013 a safe ground grid design has the following two objectives:

- "To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service."

¹ The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Producer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Producer and SCE.

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- “To reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of critical electric shock.”

“People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design.” (IEEE 80 –2013)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

4.4.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4 kV, 12.47 kV and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Common subtransmission voltages are nominally 66 kV to 115 kV. Common transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4, 12.47, and 16 kV circuits are effectively grounded, but some are operated with high impedance or resonant grounding. A substantial number of the effectively grounded circuits are used for four-wire- distribution (phase to neutral connected loads). The system grounding may change over time, such as when high impedance grounding is replaced with solid grounding to accommodate four-wire load or solid grounding is replaced with resonant grounding to reduce wildfire risk. SCE will provide the customer necessary information on the specific circuit serving its end user Facility for proper grounding.

4.4.2 Grounding Grid Studies shall be conducted in the following situations:

Grounding calculations will be required for each new substation, and at existing substations, when the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

- Short Circuit Duty Changes
 1. Circuit breaker replacement for short-circuit duty reasons if a grounding study has not been performed in the last eight years
 2. Addition of a transmission or subtransmission line to a substation
 3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty
 1. Addition or replacement of a transformer at a substation other than a like for like replacement. The replacement of a transformer bank with the same base MVA is considered a like for like replacement. Replacement transformer banks with a lower base MVA than existing will not require a grounding study.
 - a. Like for like transformer replacements require a review of the ground grid if a grounding study has not been performed in the last eight years.
 2. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty

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- System Protection Changes
 1. Changes in system protection that significantly increases the clearing time for ground faults.
- Grounding Source Changes
 2. Grounding of ungrounded or impedance grounded winding of a transformer
 3. Addition or major change of ground source at a substation
- Substation Changes
 1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
 2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
 3. Sale or lease of substation property for other uses.
- A grounding review should be conducted any time a grounding problem is reasonably suspected.

4.4.3 Ground Mats

If the customer's end user Facility and SCE substation ground mats are tied together, all cables may be landed without any protection. If the customer's end user Facility and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All ground mats shall be designed in accordance with good engineering practice and judgment. Presently, the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All customers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the customer's end user Facility or changes on the SCE system, the customer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the customer.

The customer is responsible to ensure that the Ground Potential Rise (GPR) of its or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the customer. End user

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facility and SCE ground grids are typically tied together when they are in close proximity to each other. If it is elected to install separate ground grids for SCE and the customer, the facility shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the customer's end user Facility.

Any ground grid design, which results in a GPR that exceeds 3,000 Volts (RMS) for the worst-case fault or has a calculated or measured ground grid resistance in excess of 3 ohm, will require special approval by SCE.

4.4.4 Substation Grounding

A customer connecting and end user Facility to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

4.5 Non-SCE Pole Grounding

A customer connecting its end user Facility to SCE's system shall follow SCE Construction, Operation, and Maintenance requirements. The last customer-owned structure shall be designed and constructed to meet SCE grounding requirements.

Customer facilities that will require SCE's crews to climb in order to construct, operate, or maintain SCE facilities shall be constructed so as to meet SCE standards and specifications. Constructing to SCE specifications will ensure that SCE crews can safely perform and complete the jobs at hand in accordance with SCE's Accident Prevention Manual that stipulate the proper training and equipment to safely climb and work. Examples of safety related requirements that:

- Climbing Steps
- Belt-Off Locations
- Grounding Locations
- Required PPE
- Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If there is the potential need to have SCE personnel work on non-SCE owned poles connecting the customer's end user Facility directly to SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

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SECTION 5 REVENUE METERING REQUIREMENTS

5.1 General Information

Revenue metering is required to measure the energy and capacity delivered and consumed by a customer. While functionally similar, there are varying requirements for customers depending on the nature and purpose of their end user Facility along with varying rules established by the authorities having jurisdiction over both SCE and the customer. Metering Requirements for customers taking service under a FERC tariff, and retail service under CPUC regulations are set forth in Section 6.2.

In general, all CAISO revenue metering and associated equipment used to measure load shall be provided, owned, and maintained at the customer's expense.

5.1.1 Retail Service

The retail metering requirements for retail service will be owned, operated, and maintained by SCE under SCE's Electrical Service Requirements (ESR) and in accordance with SCE approved tariffs.

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SECTION 6 TELEMETERING REQUIREMENTS (HARDWARE)

6.1 Telemetry Requirements

For a high degree of service reliability under normal and emergency operation, it is essential that the customer's end user Facility have adequate and reliable telecommunication facilities.

The customer shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

6.2 Exemption for Cold-Iron and Emergency-Backup Generators

Note: These types of generators are not operated in parallel to SCE's electric system except for short times (*typically only several minutes*) while performing a "soft-transfer" of customer load between the generator and SCE's electric system. As such, the telemetry requirements of this section **do not apply** to Cold-Iron or Emergency-Backup generators.

6.2.1 Cold-Ironing is the action of providing shore-side electrical power to a ship at berth while its on-board generator(s) are shut down.

- Cold-Iron generator is a generator on board a ship which has the capability of Cold-Ironing.
- The initial process of Cold-Ironing involves paralleling the ship's electrical system to SCE's electric system for a short duration while the ship's electrical load is transferred between the ship's generator and shore power. A Cold-Iron generator does not parallel to SCE's electric system beyond the initial transferring process.

6.2.2 Emergency-Backup Generation (EBG) is customer-owned generation utilized when disruption of utility power has occurred or is imminent.

- When utilized, **following** a disruption, the customer would first disconnect from SCE's electric system prior to starting up the EBG.
- When utilized **prior to** a disruption of utility power, the EBG would be started and loaded to carry the entire customer load, and then the customer would disconnect from SCE's electric system.
- Upon resumption of utility power, the customer would first connect to SCE's electric system and then unload the EBG.

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SECTION 7 TELECOMMUNICATIONS REQUIREMENTS

7.1 General Description

The following requirements are to be used as guidelines for typical Telecommunications equipment installation at an INTFAC. Specific design and installation details are addressed during final engineering for each specific INTFAC.

SCE's telecommunications facilities support line clearing in the event of faults in the INTFAC's customer tie line, Supervisory Control and Data Acquisition (SCADA) at the INTFAC's end user Facility (See Section 6), and, if required, a Remedial Action Scheme. As noted in Section 2, the selection of protection devices depends on the INTFAC's end user Facility size and type, number of end user Facilities, the composition of the existing protection equipment and the power line characteristics (i.e., voltage, impedance, and ampacity) of its customer tie line and the surrounding area. Identical INTFACs connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. For INTFACs connecting at ≥ 200 kV and above, the primary protection relays are designed to isolate the faulted transmission line within six (6) cycles. Voltage classes as low as 66 kV may have similar time clearing requirement if studies show an electrically faulted transmission line will have severe network impacts if not electrically separated from the grid as quickly as possible. SCE selects high speed relays for these situations.

SCE uses fiber optic (FO) cable for communications between these relays because it is:

1. Fast;
2. Resilient (not subject to atmospheric or other interference);
3. Reliable (consistent latency);
4. Available as carrier grade terminal equipment (integral redundancies, design margins, maintenance support); and
5. A best utility practice.
6. Non-conductive (when using All-Dielectric Self-Supporting cable)

SCE does not allow the use of Intermittent and indeterminate communications methods, such as a leased circuits, radios using unlicensed frequencies, and cellular or satellite paths, which defeat the purpose of line current differential relays.

In cases where a second FO telecommunication is required, for protection relay coordination or to support a RAS, the second FO path must comply with WECC guidelines governing diverse routing. The customer will construct the communications path(s) between its end user Facility and the point of interconnection. Primary path can be provided with a FO cable at the end user Facility or as OPGW (fiber Optical Ground Wire). Diverse routing will be required for secondary path. Telemetry data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or RAS, a leased circuit may be used for telemetry (SCADA). See Section 7.6.

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7.2 Fiber Optic Communications Paths:

The INTFAC will install the main and diverse FO cables (if needed) from its facility to SCE designated points just outside of the SCE interconnection substation, from which SCE will extend the FO cables into the substation. A minimum of twelve (12) strands within each FO cable will be provided to SCE for its exclusive use. SCE follows the WECC Applicable Reliability Standards for space diversity between the INTFAC's main and diverse FO cables. SCE's implementation is the following:

Main and a diverse FO cables (i.e. redundant) on two separate paths (i.e. diverse) and spaced such that a single credible event cannot sever both cables. Equipment redundancy is also required. Options within the right-of-way include:

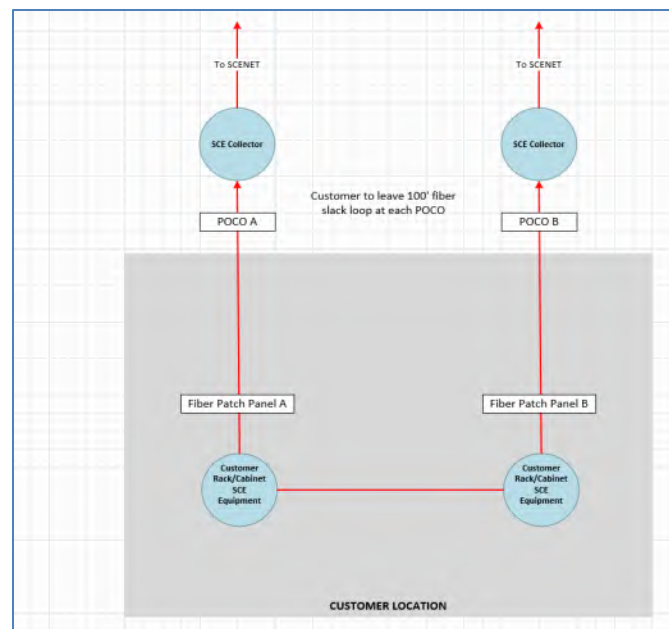
- Main path: OPGW or underbuilt FO cable on the gen-tie poles and for the Diverse path: Underground FO cable in the right-of-way; or
- Main and diverse (two) direct buried FO cables separated by ≥ 25 feet; or
- Main and diverse (two) FO cables in conduits separated by ≥ 10 feet and fully encased in concrete.

Customer to provide diversely routed Single-mode fiber cable with 100' slack loop to each POCO.

Customer will terminate each cable in one of their racks/cabinets and provide a duplex single-mode jumper to each SCE racks/cabinet, 1 from each fiber patch panel. The jumpers will have LC connectors at the SCE end.

For the relays: Customer to provide diversely routed multi-mode duplex jumpers from SCE racks/cabinets to each relay with ST Connectors.

Figure 7a: Telecommunications Block Diagram



SCE Protection and Telecom Engineering has final approval for fiber architecture.

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Fiber Optic Cable at Aggregation (Collector) Substations

If the INTFAC will be connecting to a non-SCE aggregation substation (commonly known as a collector substation) that in turn is connected to an SCE substation, the INTFAC is responsible for providing the telecommunication equipment and communications paths between the collector sub and the INTFAC necessary for line protection and RAS participation. The INTFAC is responsible for confirming its telecommunications plan of service meets the WECC Applicable Reliability Standards. An INTFAC that interconnects to a collector substation:

- a) Is responsible for the telecom for its line protection between the INTFAC and its collector substation, including any lightwave, channel banks, or related terminal equipment.
- b) Is responsible for transport of any RTU data from the INTFAC to the SCE terminal equipment at the collector substation.
- c) May elect to install FO cables and equipment that meet WECC's diversity requirement. Sufficient space and facilities must also be provided at both locations (collector substation and INTFAC) to install appropriate equipment to support the RAS.

The provisions of this Handbook for space diversity apply on the INTFAC's side of the collector sub.

7.3 Space Requirements

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the INTFAC to support line protection, telemetering (SCADA), equipment protection, and RAS communications applicable to the project. Refer to the respective sections for Protection and Telemetering for their space requirements.

The INTFAC shall provide sufficient floor space within a secure building to install one communication equipment cabinet or 19" EIA/TIA Telecommunication rack for each of the fiber optic cables (corresponding to the Protection requirements in order to support WECC diversity).

The INTFAC shall procure and install the communication equipment cabinet(s) or rack(s) per SCE's current Telecom Standards. These cabinet(s) or rack(s) shall be secured per current **California Seismic requirements**.

The INTFAC shall provide a working clearance of 36" in front and behind the communication equipment cabinet(s) or rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36" unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment cabinet(s) or rack(s) to contain "live electrical equipment," which is consistent with the 36" working clearance specified in the **National Electric Code**.

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7.4 HVAC Requirements

The INTFAC shall provide and maintain suitable environmental controls in the equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic lightwave, transport or data equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or C/RAS specifies the use of fiber optic communications and its lightwave, transport or data equipment, the requirements of Section 6: Telemetry Requirements (Hardware) will match those in this Section 7.

7.5 Power and Grounding Requirements

The INTFAC shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment cabinet(s) to the designated station ground termination to protect the communications equipment and service personnel.

The INTFAC shall provide two 15 Amp dedicated branch circuits from the 125 VDC station power to support each required telecommunications equipment rack. The dedicated source breakers shall be labeled “SCE-Telecom A” and “SCE-Telecom B.” If DC power is not available, two 15 Amp, 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System (UPS) with a minimum of a 4-hour backup. The 4-hour backup source shall be maintained by INTFAC. The power source shall not be shared with other equipment.

The INTFAC shall provide a 120 VAC, 15 Amp convenience power source adjacent to the telecommunications equipment cabinet(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The INTFAC shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 6

7.6 Telemetry and Leased Circuit:

If the INTFAC requires a dedicated RTU but is not required to construct fiber optic cables for line protection or C/RAS (typical for INTFACs ≥ 10 MW but < 20 MW), the INTFAC shall:

7. Arrange with the local service provided to deliver a 25Mb or greater Ethernet circuit from the INTFAC location to a SCE designated SCE service center or similar facility.
8. Technical specifications for circuit are as follows:
 - a. Latency Max 20 ms (one-way)
 - b. MTU Max 9126 (on Telco side)
 - c. CIR Min 20 Mbps
 - d. PDR 99.9% (PDR=Packet Delivery Rate)
 - e. Availability 99.99% (network availability)
 - f. Sync None (We will have to provide our own)

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g. Interface GigE (Multimode preferred)

9. Designate to the service provided that SCE shall be authorized to report trouble and to initiate inquires, troubleshooting and repairs with the service provider on the INTFAC's behalf in the event of an interruption of service on the communication circuit;
10. Incur all make ready and reoccurring costs of the leased circuit;
11. Provide high-voltage protection for the service provider communications, if necessary.
12. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment described in Item 6 below. The SCE equipment cabinet(s) shall be no more than 100 feet from the MPOE;
13. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary to extend a communications circuit from the RTU to communications equipment and the leased communications circuit in the event the SCE RTU is not located within the same facility as the communications equipment, SCE's RTU and communications equipment shall be no further apart than 100 feet.
14. Provide (1) communications cabinet described in Section 7.3 above.

7.7 Miscellaneous:

1. While SCE may discuss telecommunication connection preferences of the customer's facility, ultimately, SCE has final discretion regarding the selection of telecommunication connection equipment. The telecommunication connection must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.
2. Use of SCE telecommunications infrastructure (including microwave facilities and fiber optic cables) by a customer is not an option.
3. Leased circuits, radio using unlicensed frequencies, cellular, and satellite are not acceptable options at SCE for high speed protective line relays or C/RAS supporting transmissions lines.
4. SCE telecommunications terminal equipment, being electronic devices, will be periodically refreshed, i.e. replaced, sometime after installation. The time until refresh depends on a number of factors, including its operating environment, repair history, and manufacturer support. A refresh typically occurs around 10 years and could be as early as 5 years or as long as 15 years after installation. The interconnection customer should anticipate for these refreshes to be considered Capital Additions under the terms of the interconnection agreement, with the associated cost being the responsibility of the interconnection customer.
5. The customer shall provide access for SCE employees and approved contractors for planned maintenance and service restoration 24 hours a day, 7 days a week after the communication equipment is installed and in operation.

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SECTION 8 PROPERTY REQUIREMENTS

The customer must acquire the necessary Right of Way requirements for their end use Facility along with the access requirements to the point of interconnection with SCE's facilities. The use of SCE Right of Way and/or fee owned property shall not be included in any interconnection proposals.

8.1 Transmission Line Crossing Policy

The Interconnection Transmission line or access Right of Way that are proposed to cross SCE transmission line or access easements or fee owned property must be submitted to SCE's Vegetation & Land Management (V&LM) organization for a separate review request for approval/denial. For your reference, below are SCE's Transmission Crossing Policy guidelines:

- A new customer transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE facilities and/or the new facilities proposed prior to the new line.
- A new customer transmission line, triggered by a customer's end user Facility, with higher voltage may be allowed the superior position with G.O. 95² Grade "A" self-supporting Dead-end construction with minimum of double insulator strings on both sides. This will apply to all voltages. SCE will regain the superior position should SCE lower voltage facilities be upgraded in the future of equal or higher voltage than the customer's end user facilities.
- A new customer transmission line of higher voltage may be allowed the superior position if it is crossing a SCE multiple circuits corridor (two circuits or more), but this type of crossing will need to be reviewed on a case-by-case basis.
- A new customer transmission line, regardless of voltage, shall not be allowed the superior position if it is crossing a circuit which terminates at the switchyard for a nuclear power plant.

8.2 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

- SCE owned Transformers:
 - 66 kV Tap: 105 ft. by 115 ft.
 - 66 kV Loop: 135 ft. by 160 ft.
 - 115 kV Tap: 115 ft. by 130 ft.
 - 115 kV Loop: 170 ft. by 205 ft.

² **General Order No. 95. (G.O. 95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases, SCE Practices and Standards may be more stringent. The interconnecting customer must adhere to the appropriate requirements.

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- Customer owned Transformers:
 - 66 kV Tap: 80 ft. by 80 ft.
 - 66 kV Loop: 135 ft. by 105 ft.
 - 115 kV Tap: 115 ft. by 110 ft.
 - 115 kV Loop: 170 ft. by 140 ft.

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer, other facilities; and the land needed for the incoming line(s) is not included.

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SECTION 9 CYBERSECURITY MEASURES

The INTFAC shall implement reasonable administrative, technical, and physical safeguards, including any specific safeguards specified from time to time by SCE, to protect the security and integrity of SCE's systems.

A "Cybersecurity Incident" is: (a) unless expressly authorized, any use, reproduction, distribution, transfer, disposition, disclosure, possession, memory input, alteration, erasure, damage, breach in the security, or other activity by a person or party other than SCE of (i) Interconnection Customer's computing systems or equipment, including those that contain information about SCE's systems or provide information to SCE's systems, or (ii) SCE's computing systems or equipment, if caused by the action or inaction of Interconnection Customer; or (b) any unauthorized access to, interception of, disclosure or acquisition of such information.

The Interconnection Customer shall immediately notify SCE at cybersecurity@sce.com of any reasonably suspected or confirmed Cybersecurity Incident immediately upon Interconnection Customer's awareness of the event. Such notification to SCE by the Interconnection Customer shall include the nature of the event, date and time of the event, suspected amount and type of information exposed and steps being taken to investigate the circumstances of the exposure. The Interconnection Customer shall cooperate and assist SCE in the investigation, analysis and resolution of Cybersecurity Incidents affecting SCE's systems. The Interconnection Customer shall provide SCE with details of the investigation and final disposition of the Cybersecurity Incident relating to SCE's services or systems or which may impact the confidentiality, integrity, or availability of those services or systems or of SCE's information.

In addition to the above, Interconnection Customer shall: (i) regularly scan its systems for vulnerabilities, (ii) rank all vulnerabilities and promptly remediate detected vulnerabilities ranked as critical, high or moderate, and (iii) use commercially reasonable efforts to identify any critical, high, or moderate vulnerabilities, risks, or threats that could potentially impact SCE, and shall notify SCE in writing at cybersecurity@sce.com within one (1) Business Day after such identification. If Interconnection Customer determines that it cannot remediate any such potential or detected vulnerabilities, risk or threats within thirty (30) Calendar Days after identifying any such potential or detected vulnerabilities, risks, or threats, it shall promptly notify SCE in writing. Interconnection Customer's notification shall provide detailed information describing the controls used to mitigate these vulnerabilities, risks or threats.

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PART 3

Transmission Interconnection Requirements

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SECTION 1 TRANSMISSION INTERCONNECTION OVERVIEW

The Transmission Interconnection Section specifies what is necessary to interconnect non-SCE owned Transmission Facilities to SCE's electric system and provides these customers with an overview of the Requirements to address interconnection requests. It also provides a means to facilitate the communication of technical information to SCE regarding the generation facilities interconnecting to SCE's electric system.

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SECTION 2 PROTECTION REQUIREMENTS

Protective devices (relays, circuit breakers, synchronizing equipment, etc.) must be installed for the protection of SCE’s electric system as required by SCE. Generally, the protective devices may differ with the relative electrical capacity of the installation. The larger the installation, the greater the effect it may have on SCE’s electric system.

While some protection requirements can be standardized, the detailed protection design highly depends on the type and characteristics of the interconnecting Transmission Facilities, (i.e., voltage, impedance, and ampacity), and the existing protection equipment and configuration of SCE’s electric system in the vicinity of the point of interconnection. Fault duty, existing relay schemes, stability requirements, and other considerations may impact the selection of protection systems. Consequently, identical transmission interconnection customers connected at different locations in SCE’s electric system can have widely varying protection requirements and costs. The varying protection requirements will be used to define the corresponding Telecommunications requirements, (See Section 6 Telecommunications Requirements.)

For voltage classes 200 kV and above, primary relay protection for network transmission circuits will be designed to clear transmission line faults within a maximum of 6 cycles. Project stability studies may indicate that faster clearing times are necessary. To ensure the reliability of the electric system, protective relays, and associated equipment require periodic replacement. Typically, the frequency of transmission line relay replacement does not exceed once every 15 years, but equipment failure, availability of replacement parts, system changes, or other factors may alter the relay system replacement schedule.

Protection Categories: SCE classifies Transmission Facilities connecting to SCE electric system into three distinct categories each having their own distinctive protection requirements.

The categories are:

1. Interconnection voltage 66 kV and 115 kV
2. Interconnection voltage 220 kV
3. Interconnection voltage 500 kV (Protection requirements of these categories are described in Sections 2.1 to 2.3.)

Disclaimer: These Protection Categories were established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the specific requirements for each installation will be made by SCE.

The following is a legend of device numbers referred to in Sections 2.1 through 2.3:

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Legend

Protective Device Numbers and Description

4	Master Contactor
21	Distance/Impedance
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
50	Breaker Failure
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Over-current
59	Over-voltage
59G	Over-voltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Over-current
78	Loss of Synchronism (Out-of-Step)
79	Reclosing Relay
810	Over-frequency
81U	Under-frequency
87	Current Differential

NOTE: For additional information on device numbers, refer to ANSI C37.2.

2.1 Category 1: Voltage 66 kV and 115 kV

2-terminal or 3-terminal lines: Dual pilot

Source substation (SCE):

(1) Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1) Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication path

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Interconnection substation: (looking towards the line)

(1) Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1) Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication path

2.2 Category 2: Voltage 220 kV

2-terminal line: Dual pilot

Source substation (SCE):

(1) Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1) Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication paths

Interconnection substation: (looking towards the line)

(1) Primary relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-311L

(1) Duplicate relay that provides communication based high-speed protection (87L); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90

(2) Fiber interface and two redundant and diverse digital communication paths

2.3 Category 3: Voltage 500 kV

Source substation (SCE):

(2) Communication based high-speed relays that provides high-speed protection (87L or POTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90, SEL-411L

(1) Communication based high speed relay that provides Permissive Over-Reaching Transfer Trip Scheme (POTT) and Direct Transfer Trip (DTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-421

(2) Direct Transfer Trip Relays. Example RFL-9745's

(3) Fiber interfaces and two redundant and diverse digital communication paths.

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Interconnection substation: (looking towards the line)

(2) Communication based high-speed relays that provides high-speed protection (87L or POTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example L90, SEL-411L

(1) Communication based high speed relay that provides Permissive Over-Reaching Transfer Trip Scheme (POTT) and Direct Transfer Trip (DTT); backup Phase distance (21) or directional phase overcurrent (67) and directional ground overcurrent (67G) protection. Example SEL-421

(2) Direct Transfer Trip Relays. Example RFL-9745's

(3) Fiber interfaces and two redundant and diverse digital communication paths.

2.4 Circuit Breaker Short Circuit Duty Ratings and Surge Protection

2.4.1 SCE Duty Analysis

The recognized standard for circuit breakers rated on a symmetrical current basis is IEEE Standard C37.010-1999(R2005), "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and ANSI/IEEE Standard C37.5 for circuit breakers rated on a total current basis. SCE will review circuit breaker short circuit duty ratings and surge protection to identify any additions required to maintain an acceptable level of SCE system availability, reliability, equipment insulation margins, and safety. Also, the management of increasing short circuit duty of the transmission system involves selecting the alternative that provides the best balance between cost and capability. System arrangements must be designed so that the interrupting capability of available equipment is not exceeded.

When studies of planned future system arrangements indicate that the short-circuit duty will reach the capability of existing circuit breakers, consideration should be given to the following factors:

Methods of limiting short circuit duty to under the circuit breaker capability, or less:

1. De-looping or rearranging transmission lines at substations;
2. Split bus arrangements.
 - Magnitude of short circuit duty.
 - The effect of future projects on the short circuit duty.
 - Increasing the interrupting capability of equipment.
 - The ability of a particular circuit breaker to interrupt short circuit currents considering applicable operating experience and prior test data.

Please note that SCE performs an annual short circuit duty analysis, which may include re-evaluation of the facility circuit breakers.

2.4.2 Customer Owned Duty/Surge Protection Equipment

In compliance with Good Utility Practice and, if applicable, the Requirements within the Handbook, the owner of the Transmission Facilities being interconnected shall provide, install, own, and

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maintain relays, circuit breakers and all other devices necessary to remove any fault contribution those facilities may have related to any short circuit occurring on SCE’s electric system, not otherwise isolated by SCE’s equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of SCE’s electric system. Such protective equipment shall include, but not limited to, a disconnecting device and a fault current-interrupting device located between the customer’s Transmission Facilities and SCE electric system at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The owner of the Transmission Facilities shall be responsible for protection of their equipment and other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The interconnecting Transmission Facilities owner shall be solely responsible to disconnect their facility if conditions on SCE’s electric system are impacted by them.

2.5 RAS and CRAS

A RAS (Remedial Action Scheme) is an automatic system designed to 1) detect predetermined system conditions by RAS monitoring relays; 2) take corrective actions by logic processors and mitigation relays for the grid to meet requirements identified in the NERC Reliability Standards. A CRAS (Centralized Remedial Action Scheme) has the same functionality as a standalone RAS but offers a Centralized platform which coordinates & optimizes the various RASs. CRAS platform has been specified as the standard moving forward.

A RAS/CRAS has three basic components:

1. Line or Bank outage monitor relay (“Line Monitor” or “Bank Monitor”): typically installed at SCE substations, occasionally installed also at the Interconnection substations as required.
2. Mitigation/Tripping relay: typically installed at both SCE and Interconnection substations.
3. Logic Processor and arming program: SCE substations and/or centralized locations.

A typical RAS/CRAS has two redundant systems (system A and system B) with full diverse digital communications paths. The two systems are typically identical.

CRAS is the standard for all new RAS installations.

- Exception for the use of CRAS would be in areas where anticipated Generation-interconnection growth is slow to minimal

For existing standalone RASs with new generation being added, the RAS-to-CRAS Scoring Matrix (maintained by Protection Engineering) is to be utilized to determine when RAS should be transitioned to CRAS.

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SECTION 3 MISCELLANEOUS REQUIREMENTS:

3.1 Transmission Facilities Requirements

The customer shall ensure that its transmission facilities are constructed to a minimum of General Order 95 **Rules for Overhead Electric Line Construction** standards when facilities are built within California and to **National Electric Safety Code** standards when facilities are built outside of California. The customer shall ensure that its underground transmission facilities are constructed to a minimum of General Order 128 **Rules for Construction of Underground Electric Supply and Communication Systems** when facilities are built within California and to **National Electric Safety Code** standards when facilities are built outside of California. Where facilities are intended to be owned by SCE, additional design requirements apply and must be consistent with SCE's design standards

3.2 Sub-Synchronous Interaction Evaluations

Transmission lines with series capacitors or Flexible Alternating Current Transmission Systems (FACTS) interconnected within electrical proximity of generating facilities are susceptible to Subsynchronous Interaction (SSI) conditions which must be evaluated. Sub-Synchronous Interaction evaluations include Sub-Synchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter-based generators using power electronic devices (e.g., Solar PV and Wind Turbines).

A study must be performed to evaluate the SSI between transmission lines with series capacitor banks and/or FACTS devices projects interconnecting in close electrical proximity of generating facilities to ensure that the transmission projects does not damage SCE's control systems. The SSI study may require that the INTFAC provide a detailed PSCAD model of its series capacitor banks and/or FACTS and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required prior to initial energization of the transmission project. The study and the proposed mitigation(s) shall be at the expense of the INTFAC.

The Interconnection Customer is 100% responsible for the cost associated with SSI studies and mitigations. It is the INTFAC's responsibility to select, purchase, and install equipment that are compatible with the existing system.

3.2.1 Sub-Synchronous Resonance Studies

SSR occurs when the network natural frequencies (below fundamental frequencies) coincide with the turbine-generator torsional-mode frequencies causing the turbine-generator to stress that may result in shaft failure. The turbine-generator and the system may interact with SSR into two main ways: Torsional Interaction (TI) and Torque Amplification (TA). In order to evaluate a potential SSR condition on a new series capacitors and / or FACTS devices installation near generation facilities a screening study needs to be conducted to identify any TA or TI impact on the series compensation level or FACTS devices controls. If a case is identified by the initial screening process (Frequency Scanning Study) a more detailed time domain study is required to quantify the potential damage and provide with mitigation measures.

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3.2.2 Sub-Synchronous Control Interaction Studies

SSCI risk occurs on zero-crossing reactance when going from negative (capacitive) to positive (inductive) reactance. In order to evaluate a potential SSCI condition on a new series capacitors and / or FACTS devices installation near generation facilities a screening is performed through impedance scans looking out into the system from the inverter-based plant, with the plant disconnected. If a case is identified by the initial screening process, a more detailed study is required to quantify the potential damage and provide with mitigation measures.

3.3 Automatic Voltage Regulators (AVR)

Automatic voltage control equipment, synchronous condensers, and Flexible Alternating Current Transmission System (FACTS) shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the CAISO.

3.4 Underfrequency Relays

Since the facilities of SCE's electric system may be vital to the secure operation of the Interconnection, CAISO and SCE shall make every effort to remain connected to the Interconnection. However, if the system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect the system.

Intentional tripping of tie lines due to underfrequency is permitted at the discretion of SCE's electric system, providing that the separation frequency is no higher than 57.9 Hz with a one-second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping shall not be implemented.

3.5 Insulation Coordination

Insulation coordination is the selection of insulation strength and practice of correlating insulation levels of equipment and circuits with the characteristics of surge-protective devices such that the insulation is protected from excessive over-voltages. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety.

The customer shall be responsible for an insulation coordination study to determine appropriate surge arrester class and rating on their Transmission Facilities interconnecting into SCE's system. In addition, the customer is responsible for the proper selection of substation equipment and their arrangements from an insulation coordination standpoint.

Basic Surge Level (BSLs), surge arrester, conductor spacing, and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan.

3.6 Ratings

3.6.1 Facility Ratings

The ratings of facilities are the responsibility of the owner of those facilities. Ratings of facilities must conform to the current NERC Reliability Standard governing Facility Ratings.

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3.6.2 Ratings Provided by Equipment Manufacturers

Equipment installed on SCE’s electric system is rated according to the manufacturer’s nameplate or certifications, and ANSI/IEEE standards. The manufacturer’s nameplate rating is the normal rating of the equipment. ANSI/IEEE standards may allow for emergency overloads above the normal rating under specified conditions and often according to an engineering calculation. Emergency loading may impact the service life of the equipment. In some cases, the manufacturer has certified equipment for operation at different normal or emergency loads based on site-specific operation conditions. Older technology equipment is rated according to the standards under which it was built unless the manufacturer, ANSI/IEEE standards, or SCE’s determination indicates that a reduced rating is prudent, or an increase rating is justified.

3.6.3 Rating Practice

The normal and emergency ratings of transmission lines or the transformation facilities shall equal the least rated component in the path of power flow.

3.6.4 Ambient Conditions

Since SCE’s territory is in a year-round moderate climate, SCE does not establish equipment ratings based on seasonal temperatures. That is, SCE standard ratings for normal and emergency ratings are the same throughout the year and reflect summer ambient temperatures coincident with ANSI/IEEE standards, i.e., 40°C (104°F). However, in some cases SCE may calculate site-specific ratings that consider the local ambient conditions based on ANSI/IEEE rating methods.

3.6.5 Transmission Lines

The transmission circuit rating is determined according to the least rated component in the path of power flow. This is comprised of the transmission line conductor/cable, the series devices in the line, the allowable current that will not cause the conductors to sag below allowable clearance limits, the allowable current that will not cause the cables to operate above the designed temperature limit, and the termination equipment.

3.6.6 Overhead Conductors

The transmission line conductor ratings are calculated in accordance with ANSI/IEEE 738-1993. For Aluminum Conductor Steel Reinforced (ACSR) conductor the normal conductor, rating allows a total temperature of 90°C, and the emergency rating allows 135°C. Similarly, for aluminum and copper conductors, SCE permits 85°C and 130°C. For Aluminum Conductor Steel Supported (ACSS), SCE base the normal rating at 120°C, and 200°C for the emergency rating. Higher or lower temperature limits may be permitted as appropriate, depending on engineering justification.

3.6.7 Underground Cable

The transmission line cable ratings are calculated in accordance with IEC 60287. For XLPE insulated cable, the normal cable rating allows a total temperature of 90° C, and the emergency rating allows 105° C for 4 hours. Higher or lower temperature limits may be permitted as appropriate depending on engineering justification and/or component tested data.

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3.6.8 Series and Shunt Compensation Devices

Series capacitor and reactors are only permitted to be loaded to ANSI/IEEE limits or as specified by the manufacturer. VAR compensators shall be rated according to the ANSI/IEEE standards where applicable and according to the manufacturer's limitations. These ratings are reported to CAISO Transmission Register. Shunt capacitors and reactors are not in the path of power flow, so they are not directly a "limiting component." However, their reactive power capacity is reported to CAISO Transmission Register.

3.6.9 Terminal Equipment

Terminal equipment are comprised of the following components: circuit breakers, disconnect switches, jumpers, drops, conductors, buses, and wave-traps, i.e., all equipment in the path of power flow that might limit the capacity of the transmission line or transformer bank to which it is connected. The normal and emergency ampere rating for each termination device is reported to CAISO in its Transmission Register.

3.6.10 Transformer Bays

The rating of a transformer bay is determined by the least rated device in the path of power flow. This comprises ratings of the transformer, the transformer leads, the termination equipment, and reduced parallel capacity where applicable. The transformer rating is compared to the termination equipment ratings and lead conductors to establish the final transformation rating based on the least rated component. All the above ratings are reported to the CAISO Transmission Register.

3.6.11 Transformer Normal Ratings

The "normal" rating is the transformer's highest continuous nameplate rating with all of its cooling equipment operating. The only exception is when a special "load capability study" has been performed showing that a specific transformer is capable of higher than nameplate loading and for which the test data or calculations are available.

3.6.12 Transformer Emergency Ratings

A transformer's emergency rating is arrived at by one of two methods. First, if no overload tests are available, then a 10% overload is allowed. Second, if a factory heat-run or a load capability study has been performed, the emergency rating may be as high as 20% above normal, as revealed by the test. For transformers on the transmission system, (i.e., primary voltage of 500 kV), the allowed duration of the emergency loading is 24-hours. For transformers with a primary voltage of 161 kV to 220 kV, the allowed duration is 30 days.

3.6.13 Parallel Operation of Transformers

When two or more transformers are operated in parallel, consideration is given to load split due to their relative impedances such that full parallel capacity is not usually realized. The permissible parallel loading is calculated according to ANSI/IEEE standards.

3.6.14 Relays Protective Devices

In cases where protection systems constitute a loading limit on a facility, this limit is the rating for that facility. These limiting factors are reported to the CAISO Transmission Register and are so noted as to the specific reason, e.g., "limited to 725 A by relay setting."

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3.6.15 Path Ratings

As stated in Section 2.2.2 of the Path Rating Process of the Project Coordination and Path Rating Processes¹, new facilities and facility modifications should not adversely impact accepted or existing ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations, remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system.

3.7 Synchronizing of Facilities

Testing and synchronizing of a customer's Transmission Facilities may be required depending on SCE's electric system conditions, ownership, or policy, and will be determined based on facility operating parameters. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect synchronization.

Appropriate operating procedures and equipment designs are needed to guard against out-of-sync closure or uncontrolled energization. (Note: SCE's transmission lines utilize ACB phase rotation, which is different than the national standard phase rotation). The owner of the Transmission Facilities is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

Synchronizing locations shall be determined ahead of time; required procedures shall be in place and be coordinated with SCE. SCE and the owner of the Transmission Facilities shall mutually agree and select the initial synchronization date. The initial synchronization date shall mean the date upon which a facility is initially synchronized to SCE's electric system and upon which trial operation begins.

3.8 Maintenance Coordination and Inspection

The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of the customer's Transmission Facilities and associated equipment, including but not limited to control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities shall follow CAISO procedures and are responsible for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

3.9 Abnormal Frequency and Voltages

3.9.1 Joint Reliability Procedures

Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3.9.2 Voltage and Reactive Flows

CAISO shall coordinate the control of voltage levels and reactive flows during normal and Emergency Conditions. All operating entities shall assist with the CAISO's coordination efforts.

¹ https://www.wecc.org/Reliability/Project_Coordination_Path_Rating_and_Progress_Report_Processes_20170316.pdf

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3.9.3 Transfer Limits Under Outage and Abnormal System Conditions

In addition to establishing total transfer capability limits under normal system conditions, transmission providers and balancing authority shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3.10 Communications and Procedures

3.10.1 Use of Communication System

It is essential to establish and maintain communications with the SCE Grid Control Center (GCC), the Alternate Grid Control Center (AGCC) or a jurisdictional Switching Center should a temporarily attended station or area of jurisdiction become involved in a case of system trouble. It is equally important that communication services be kept clear of nonessential use during times of system trouble to facilitate system restoration or other emergency operations.

3.10.2 Remedial Action Schemes Communication Equipment Requirements

Customer Transmission Facilities will require the necessary communication equipment for the implementation of RAS. This equipment provides line monitoring and high-speed communications between the customer's breaker and the central control facility, utilizing applicable protocols. RASs may also be applied to individual transmission lines to relieve congestion on much larger portion of SCE's electric system. Thus, allowing a RAS to incorporate disconnection into automatic control algorithms under contingency conditions, as needed.

RASs are fully redundant systems. The following paragraph is an excerpt from the "WECC Remedial Action Scheme Design Guide that specifies the Philosophy and General Design Criteria" for RAS redundancy. *"Redundancy is intended to allow removing one scheme following a failure or for maintenance while keeping full scheme capability in service with a separate scheme. Redundancy requirements cover all aspects of the scheme design including detection, arming, power, supplies, telecommunications facilities and equipment, logic controllers (when applicable), and RAS trip/close circuits.* Excerpt from: WECC Remedial Action Scheme Design Guide (11/28/2006)

3.10.3 Critical System Voltage Operation

Voltage control during abnormal system configurations requires close attention with consideration given to what operations will be necessary following loss of the next component. Voltages approaching 10% above or below the normal value are considered critical with rate of change being of principal importance.

3.11 Point of Change of Ownership (POCO)

Currently there is no equipment that allows a below ground POCO for interconnections at 66 kV and above. Any POCO at these voltage levels will need to be installed above ground to ensure clear distinction between SCE's equipment and the Interconnection Customer's equipment.

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SECTION 4 GENERAL OPERATING REQUIREMENTS:

- System Operating Bulletins:** The Transmission Facilities connecting into SCE's electric system may be subject to operating requirements established by SCE, the CAISO or both. SCE's general operating requirements are discussed in the sections below. SCE may also require additional operating requirements specific to a specific set of Transmission Facilities. If so, these requirements will be documented in SCE's System Operating Bulletins (SOB), Substation Standard Instructions (SSI), and/or interconnection and power purchase agreements. SCE's SOBs and/or SSIs specific to a set of Transmission Facilities, and any subsequent revisions will be provided by SCE to the customer as they are made available.
- Owner of the Interconnecting Transmission Facilities' Responsibility:** The owner of the Transmission Facilities is responsible for complying with all applicable operating requirements. Operating procedures are subject to change as system conditions and system needs change. Therefore, it is advisable for the owner to regularly monitor operating procedures that apply to its generating facilities. The CAISO publishes its operating procedures on its internet site, but it is prudent for the owner to contact the CAISO for specific requirements.
- Quality of Service:** The interconnection of the customer's Transmission Facilities with SCE's electric system shall not cause any reduction in the quality of service being provided to SCE's customers. If complaints result from operation of the customer's Transmission Facilities, such equipment shall be disconnected until the problem is resolved.
- SCE Circuits:** Only SCE is permitted to energize any de-energized SCE circuit.
- Operate Prudently:** The owner of the Transmission Facilities will be required to operate its equipment in accordance with prudent electrical practices.
- Protection in Service:** The Transmission Facilities shall be operated with all of required protective apparatus. Redundant protective devices may be provided at the Interconnection customer's expense. Any deviation for brief periods of emergency may only be by agreement of SCE and is not to be interpreted as permission for subsequent incidents.

4.1 VAR Correction

VAR correction will normally be planned for light load, heavy load and for system normal and contingency conditions. This is to be accomplished by providing transmission system VAR correction to minimize VAR flow and to maintain proper voltage levels. The planning of transmission system VAR requirements should consider the installation of shunt capacitors, shunt reactors and tertiary shunt reactors, synchronous condensers, FACTS and transformer tap changers. The guidelines for reactive planning are as follows:

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4.1.1 Interconnection

Interconnection with other utilities will normally be designed with the capability of maintaining near-zero VAR exchange between systems. Entities interconnecting their transmission system with SCE's e system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. SCE shall not be obligated to supply or absorb reactive power for the customer's Transmission Facilities when it interferes with operation of SCE's electric system, limits the use of SCE interconnections, or requires the use of generating equipment that would not otherwise be required.

4.1.2 Subtransmission System

VAR correction will normally be planned for connection to 55 kV through 160 kV buses to correct for large customer VAR deficit, subtransmission line VAR deficit, and transformer A-Bank VAR losses, the objective being zero VAR flow at the high side of the A-Banks with VAR flow toward the transmission system on the high side of the A-Banks, if required. Adequate VAR correction shall be provided for maximum coincident customer loads (one-in-five year heat storm conditions), after adjusting for dependable local generation and loss of the largest local bypass generator.

4.2 Voltage Regulation/Reactive Power Supply Requirements

Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers, and other dynamic reactive devices.

To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled and adequate reactive reserves shall be provided. If power factor correction equipment is necessary, it may be installed by the customer on its Transmission Facilities, or by SCE at SCE's facilities at the customer's expense.

4.2.1 Reactive Power Equipment – Induction Generators (in aggregate)

4.2.1.1 Facility Reactive Power Equipment Design

The owner of the interconnecting Transmission Facilities shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

The reactive power equipment utilized by the interconnecting customer to meet SCE's Requirements must be designed to minimize the exposure of SCE's customers, SCE's electric system, and the electric facilities of others (i.e., other facilities and utilities in the vicinity) to:

- severe over-voltages that could result from self-excitation of induction generators, transients that result from switching of shunt capacitors, voltage regulation problems associated with switching of inductive and capacitive devices.
- unacceptable harmonics or voltage waveforms, which may include the effect of power electronic switching, and voltage flicker exceeding SCE Voltage Flicker limits as

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indicated in SCE Transmission Planning Criteria and Guidelines Figure 4-1 “VOLTAGE FLUCTUATION DESIGN LIMITS”.

4.2.1.2 Facility Reactive Power Equipment Design - provide variable source

The reactive power equipment utilized by customer’s Transmission Facilities connecting to SCE’s system to meet SCE’s Requirements must be designed to provide a variable source of reactive power (either continuously variable or switched in discrete steps). For discrete step changes, the size of any discrete step change in reactive output shall be limited by the following criteria:

- the maximum allowable voltage rise or drop (measured at the point of interconnection with SCE’s electric system) associated with a step change in the output of the Transmission Facilities’ reactive power equipment must be less than or equal to 1%; and
- the maximum allowable deviation from an Interconnection customer’s reactive power schedule (measured at the point of interconnection with the SCE system) must be less than or equal to 10% of the Interconnection customer’s maximum (boost) reactive capability.

4.2.2 Voltage and Reactive Control

4.2.2.1 Coordination

Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4.2.2.2 Transmission Lines

Although transmission lines should be kept in service as much as possible, during over-voltage system conditions a customer’s transmission line(s) may be subject to removal from operation as a means to mitigate voltage problems in the local area. SCE will notify CAISO when removing such facilities from and returning them back to service.

4.2.2.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

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4.3 Voltage Imbalance and Abnormal Voltage or Current Waveforms (harmonics)

Power quality problems are caused when voltage imbalances and harmonic currents result in abnormal voltage and/or current waveforms. Generally, if a customer's Transmission Facilities connecting to SCE's system degrades power quality to SCE's facilities, or other SCE customer facilities, SCE may require the installation of equipment to eliminate the power quality problem.

4.3.1 Voltage Imbalance

The unbalanced voltage level (magnitude and phase), due to a customer's Transmission Facilities connecting to SCE's system, may not exceed 1% at the Point of Common Connection² (PCC), under steady state system conditions. Under certain conditions (contingency conditions), SCE may allow higher levels of voltage imbalance if justified after a study conducted by SCE. In any event, the unbalanced voltage level created by facilities interconnecting to SCE's system shall not exceed 1.5%.

It is the responsibility of customers connected to SCE's electric system to install adequate mitigation devices to protect their own equipment from damage that may be caused by voltage imbalance condition.

4.3.2 Harmonics

Facilities interconnecting to SCE's system are required to limit harmonic voltage and current distortion produced by static power converters or similar equipment in accordance to good engineering practice used at their facility to comply with the limits set by the current IEEE Standards.

4.3.3 Disconnection

SCE may disconnect any Facility connected to its system until the above requirements are met.

4.4 Grounding Circuits and Substations

Substation Grounding

Customers connecting Transmission Facilities to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous voltage potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying equipment to be handled by personnel.

² The PCC will generally be at the location of the revenue meter or the point of ownership change in the electrical system between SCE and the Interconnection customer. For customers served by dedicated facilities, the location of the PCC will be determined by mutual agreement between the Interconnection customer and SCE.

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Reason for Substation Grounding

Substation grounding practices are outlined in the latest IEEE 80 “IEEE Guide for Safety in AC Substation Grounding.”

According to IEEE 80 – 2013 a safe ground grid design has the following two objectives:

“To provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.”

“To reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of critical electric shock.”

“People often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the ground system as a whole and the maximum shock current to which a person might be exposed. Therefore, a substation of relatively low ground resistance may be dangerous, while another substation with very high resistance may be safe or can be made safe with careful design.” (IEEE 80 – 2013)

Each substation ground grid is a unique design. The conditions at the site: soil type, soil resistivity, fault current, clearing time, size of the substation, and other grounds all factor into the design.

4.4.1 Nominal Voltage and Grounding

SCE's most common primary distribution voltages are 4 kV, 12.47 kV, and 16 kV depending on the geographic area. Other voltages are also used in specific areas. Common subtransmission voltages are nominally 66 kV to 115 kV. Common transmission system voltages are nominally 161 kV, 220 kV, and 500 kV. The majority of the 4 kV, 12.47 kV, and 16 kV circuits are effectively grounded, but some are operated with high impedance or resonant grounding. A substantial number of the effectively grounded circuits are used for four-wire- distribution (phase to neutral connected loads). The system grounding may change over time, such as when high impedance grounding is replaced with solid grounding to accommodate four-wire load or solid grounding is replaced with resonant grounding to reduce wildfire risk. SCE will provide the customer the necessary information on the specific circuit serving its Transmission Facilities for proper grounding.

4.4.2 Grounding Grid Studies shall be conducted in the following situations:

Grounding calculations will be required for each new substation, and at existing substations, when the ground grid is altered or when major additions are made at a substation. A review of existing substation ground grids will be conducted by Engineering in the following situations, especially if triggered by interconnection requests – these shall be considered in queue order:

Short Circuit Duty Changes

1. Circuit breaker replacement for short-circuit duty reasons if a grounding study has not been performed in the last eight years
2. Addition of a transmission or subtransmission line into a substation
3. System changes causing a substantial change in the substation phase-to-ground short-circuit duty

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4. Addition or replacement of a transformer at a substation other than a like for like replacement. The replacement of a transformer bank with the same base MVA is considered a like for like replacement. Replacement transformer banks with a lower base MVA than existing will not require a grounding study.
 - a. Like for like transformer replacements require a review of the ground grid if a grounding study has not been performed in the last eight years.
5. Addition of new generation causing a substantial change in the substation phase-to-ground short-circuit duty

System Protection Changes

1. Changes in system protection that significantly increases the clearing time for ground faults.

Grounding Source Changes

1. Grounding of ungrounded or impedance grounded winding of a transformer
2. Addition or major change of ground source at a substation

Substation Changes

1. Alterations to substation fences including additions, movement, and attachments to other fences. The removal of vegetation that blocks access to a substation fence is considered a fence alteration.
2. Alterations to substation ground grids that change their size or increase the effective substation ground grid impedance.
3. Sale or lease of substation property for other uses.

A grounding review should be conducted any time a grounding problem is reasonably suspected.

4.4.3 Ground Mats

If the customer and SCE substation ground mats are tied together, all cables may be landed without any protection. However, if the customer and SCE substation ground mats are not tied together, all cables shall have protection at both ends. The design of cable protection, if any, on circuits used for protective relaying purposes shall be such that the operation of the protective relaying is not hampered when the cable protection operates or fails.

All customer ground mats shall be designed in accordance with good engineering practice and judgment. Presently the recognized standard for grounding is IEEE 80 "IEEE Guide For Safety in AC Substation Grounding." All ground mat designs should meet or exceed the requirements listed in this standard. If local governmental requirements are more stringent, building codes for example, they shall prevail. All customers shall perform appropriate tests, including soil resistivity tests, to demonstrate that their ground grid design meets the standard. Mats shall be tested at regular intervals to ensure their effectiveness.

Grounding studies shall be performed with industry-recognized software. This study will determine the maximum safe fault current for the ground grid design. It is suggested that the grid be designed for the maximum fault currents expected over the life of the facility.

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If for any reason the worst-case fault current exceeds the design maximum fault current value due to changes in the interconnection customer's facility or changes on the SCE system, the customer shall conduct new grounding studies. Any changes required to meet safety limits and protect equipment shall be borne by the customer.

The customer is responsible to ensure that the GPR (Ground Potential Rise) of its interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the customer. Generator facility and SCE ground grids are typically tied together when they are in close proximity to each other. If it is elected to install separate ground grids for SCE and the customer, they shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the customer's Transmission Facilities connecting to SCE's system.

Any ground grid design, which results in a GPR that exceeds 3,000 Volts (RMS) for the worst-case fault or has a calculated or measured ground grid resistance in excess of 3 ohm, will require special approval by SCE.

4.4.4 Substation Grounding

The customer connecting Transmission facilities to SCE's system shall follow practices outlined in IEEE 80 "IEEE Guide for Safety in AC Substation Grounding." Substation grounding is necessary to protect personnel and property against dangerous potentials and currents during both normal and abnormal conditions of operation. Also, it provides a path to ground for the discharge of lightning strikes, a path to ground for the neutral currents of grounded neutral circuits and apparatus, the facilities for relaying to clear ground faults, the stability of circuit potentials with respect to ground and a means of discharging current-carrying parts to be handled by personnel.

4.5 Non-SCE Pole Grounding

A customer connecting Transmission facilities to SCE's system shall follow SCE Construction, Operation, and Maintenance requirements. The last customer-owned structure shall be designed and constructed to meet SCE grounding requirements.

Customer facilities that will require SCE's crews to climb in order to construct, operate, or maintain SCE facilities shall be constructed so as to meet SCE standards and specifications. Constructing to SCE specifications will ensure that SCE crews can safely perform and complete the jobs at hand in accordance with SCE's Accident Prevention Manual that stipulate the proper training and equipment to safely climb and work. Examples of safety related requirements include:

1. Climbing Steps
2. Belt-Off Locations
3. Grounding Locations
4. Required PPE
5. Jumper Cable Ownership

Grounding bolts and bases are the same as step bolts and bases. If there is the potential need to have SCE personnel work on non-SCE owned poles connecting the customer's Transmission Facilities directly to

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SCE's electric system a dead-end structure adhering to SCE's Construction, Operation, and Maintenance standards, is required.

Please note that these requirements are for poles only. Non-steel or ungrounded poles will have; project-specific grounding requirements as determined by SCE.

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SECTION 5 TELEMETERING REQUIREMENTS (HARDWARE)

5.1 Telemetry Requirements

For a high degree of service reliability under normal and emergency operation, it is essential that the customer's Transmission Facilities connecting to SCE's system have adequate and reliable telecommunication facilities.

The customer shall specify the following at the point of connection: the requested voltage level, MW/MVAR capacity, and/or demand.

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SECTION 6 TELECOMMUNICATIONS REQUIREMENTS

6.1 General Description

The following requirements are to be used as guidelines for typical Telecommunications equipment installation at an Interconnection Facility (INTFAC). Specific design and installation details are addressed during final engineering for each specific INTFAC.

SCE's telecommunications facilities support line clearing in the event of faults in the INTFAC's gen-tie, Supervisory Control and Data Acquisition (SCADA) at the INTFAC's generator (See Section 7), and, if required, a Remedial Action Scheme. As noted in [Section 2](#), the selection of protection devices depends on the INTFAC's generator size and type, number of generators, the composition of the existing protection equipment and the power line characteristics (i.e., voltage, impedance, and ampacity) of its gen-tie and the surrounding area. Identical INTFACs connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. For INTFACs connecting at ≥ 200 kV and above, the primary protection relays are designed to isolate the faulted transmission line within six (6) cycles. Voltage classes as low as 66 kV may have similar time clearing requirement if studies show an electrically faulted transmission line will have severe network impacts if not electrically separated from the grid as quickly as possible. SCE selects high speed relays for these situations.

SCE uses fiber optic (FO) cable for communications between these relays because it is:

1. Fast (speed of light);
2. Resilient (not subject to atmospheric or other interference);
3. Reliable (consistent latency);
4. Available as carrier grade terminal equipment (integral redundancies, design margins, maintenance support); and
5. A best utility practice.
6. Non-conductive (when using All-Dielectric Self-Supporting cable)

SCE does not allow the use of Intermittent and indeterminate communications methods, such as a leased circuits, radios using unlicensed frequencies, and cellular or satellite paths, which defeat the purpose of the line current differential relays.

In cases where a second FO telecommunication is required, for protection relay coordination or to support a RAS, the second FO path must comply with WECC guidelines governing diverse routing. The customer will construct the communications path(s) between its end user Facility and the point of interconnection. Primary path can be provided with a FO cable at the end user Facility or as OPGW (fiber Optical Ground Wire). Diverse routing will be required for secondary path. Telemetry data (SCADA) and line protection control signals will be transported on these paths.

If FO is not required for line protection or RAS, a leased circuit may be used for telemetry (SCADA). See Section 6.6.

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6.2 Fiber Optic Communications Paths:

The INTFAC will install the main and diverse FO cables (if needed) from its facility to SCE designated points just outside of the SCE interconnection substation, from which SCE will extend the FO cables into the substation. A minimum of eight (8) strands within each FO cable will be provided to SCE for its exclusive use. SCE follows the WECC Applicable Reliability Standards for space diversity between the INTFAC's main and diverse FO cables. SCE's implementation is the following:

1. Main and a diverse FO cables (i.e. redundant) on two separate paths (i.e. diverse) and spaced such that a single credible event cannot sever both cables. Equipment redundancy is also required. Options within the right-of-way include:
 - a. Main path: OPGW or underbuilt FO cable on the gen-tie poles and for the
Diverse path: Underground FO cable in the right-of-way; or
 - b. Main and diverse (two) direct buried FO cables separated by ≥ 25 feet; or
 - c. Main and diverse (two) FO cables in conduits separated by ≥ 10 feet and fully encased in concrete.

Protection and Telecom Engineering has final approval for fiber architecture.

Fiber Optic Cable at Aggregation (Collector) Substations

If the INTFAC will be connecting to a non SCE aggregation substation (commonly known as a collector substation) that in turn is connected to an SCE substation, the INTFAC is responsible for providing the telecommunication equipment and communications paths between the collector sub and the INTFAC necessary for line protection and RAS participation. The INTFAC is responsible for confirming its telecommunications plan of service meets the WECC Applicable Reliability Standards. An INTFAC that interconnects to a collector substation:

- a. Is responsible for the telecom for its line protection between the INTFAC and its collector substation, including any lightwave, channel banks, or related terminal equipment.
- b. Is responsible for transport of any RTU data from the INTFAC to the SCE terminal equipment at the collector substation.
- c. May elect to install FO cables and equipment that meet WECC's diversity requirement. Sufficient space and facilities must also be provided at both locations (collector substation and INTFAC) to install appropriate equipment to support the RAS.

The provisions of this Handbook for space diversity apply on the INTFAC's side of the collector sub.

6.3 Space Requirements

SCE shall design, operate, and maintain certain telecommunications terminal equipment at the INTFAC to support line protection, telemetering (SCADA), equipment protection, and RAS communications applicable to the project. Refer to the respective sections for Protection and Telemetering for their space requirements.

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The INTFAC shall provide sufficient floor space within a secure building to install one communication equipment cabinet or 19” EIA/TIA Telecommunication rack for each of the fiber optic cables (corresponding to the Protection requirements in order to support WECC diversity).

The INTFAC shall procure and install the communication equipment cabinet(s) or rack(s) per SCE’s current Telecom Standards. These cabinet(s) or rack(s) shall be secured per current **California Seismic requirements**.

The INTFAC shall provide a working clearance of 36” in front and behind the communication equipment cabinet(s) or rack(s) for the safety of installation and maintenance personnel. The working clearance specified provides a 36” unobstructed space for ladders and/or test equipment carts. Additionally, SCE considers telecommunications equipment cabinet(s) or rack(s) to contain “live electrical equipment,” which is consistent with the 36” working clearance specified in the **National Electric Code**.

6.4 HVAC Requirements

The INTFAC shall provide and maintain suitable environmental controls in the equipment room, including an HVAC system to minimize dust, maintain a temperature of 30° C or less, and 5-95% non-condensing relative humidity.

The HVAC requirements for fiber optic lightwave, transport or data equipment are more stringent than what is required for RTU equipment. Therefore, whenever line protection or C/RAS specifies the use of fiber optic communications and its lightwave, transport or data equipment, the requirements of Section 5: Telemetry Requirements (Hardware) will match those in this Section 6.

6.5 Power and Grounding Requirements

The INTFAC shall provide a connection point to station ground within ten (10) feet of the SCE communication equipment rack(s). SCE will provide and install cabling from the equipment cabinet(s) to the designated station ground termination to protect the communications equipment and service personnel.

The INTFAC shall provide two 15 Amp dedicated branch circuits from the 125 VDC station power to support each required telecommunications equipment rack. The dedicated source breakers shall be labeled “SCE-Telecom A” and “SCE-Telecom B.” If DC power is not available, two 15 Amp, 120 VAC circuits may be used as long as the circuits are sourced from an Uninterruptible Power System (UPS) with a minimum of a 4-hour backup. The 4-hour backup source shall be maintained by INTFAC. The power source shall not be shared with other equipment.

The INTFAC shall provide a 120 VAC, 15 Amp convenience power source adjacent to the telecommunications equipment cabinet(s). As this source will be utilized for tools and test equipment by installation and maintenance personnel, UPS is not required. The INTFAC shall provide ample lighting for the safety of installation and maintenance personnel.

For RTU power and grounding requirements, refer to Section 5

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6.6 Telemetry and Leased Circuit:

If the INTFAC requires a dedicated RTU but is not required to construct fiber optic cables for line protection or C/RAS (typical for INTFACs ≥ 10 MW but < 20 MW), the INTFAC shall:

1. Arrange with the local service provider to deliver a 25Mb or greater Ethernet circuit from the INTFAC location to a SCE designated SCE service center or similar facility;
2. Technical specifications for circuit are as follows:
 - a. Latency Max 20 ms (one-way)
 - b. MTU Max 9126 (on Telco side)
 - c. CIR Min 25 Mbps
 - d. PDR 99.9% (PDR=Packet Delivery Rate)
 - e. Availability 99.99% (network availability)
 - f. Sync None (We will have to provide our own)
 - g. Interface GigE (Multimode preferred)
3. Designate to the service provider that SCE shall be authorized to report trouble and to initiate inquiries, troubleshooting and repairs with the service provider on the INTFAC's behalf in the event of an interruption of service on the communication circuit;
 1. Incur all make ready and reoccurring costs of the leased circuit;
 2. Provide high-voltage protection for the service provider communications, if necessary.
 3. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary for SCE to extend the leased circuit from the Local Exchange Carrier MPOE (Minimum Point of Entry or "demark") to the SCE communications equipment described in Item 6 below. The SCE equipment cabinet(s) shall be no more than 100 feet from the MPOE;
4. Provide conduit, raceway, copper cable, fiber optic cable and any miscellaneous equipment or services as necessary to extend a communications circuit from the RTU to communications equipment and the leased communications circuit in the event the SCE RTU is not located within the same facility as the communications equipment, SCE's RTU and communications equipment shall be no further apart than 100 feet.
5. Provide (1) communications cabinet described in Section 5.3 above.

6.7 Miscellaneous:

1. While SCE may discuss telecommunication connection preferences of the customer's facilities, ultimately, SCE has final discretion regarding the selection of telecommunication connection equipment. The telecommunication connection must fit within the operating requirements, design parameters, and communications network architecture of the entire SCE telecommunications network.

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2. Use of SCE telecommunications infrastructure (including microwave facilities and fiber optic cables) by a customer is not an option.
3. Leased circuits, radio using unlicensed frequencies, cellular, and satellite are not acceptable options at SCE for high speed protective line relays or C/RAS supporting transmissions lines.
4. SCE telecommunications terminal equipment, being electronic devices, will be periodically refreshed, i.e. replaced, sometime after installation. The time until refresh depends on a number of factors, including its operating environment, repair history, and manufacturer support. A refresh typically occurs around 10 years and could be as early as 5 years or as long as 15 years after installation. The interconnection customer should anticipate for these refreshes to be considered Capital Additions under the terms of the interconnection agreement, with the associated cost being the responsibility of the interconnection customer.
5. The customer shall provide access for SCE employees and approved contractors for planned maintenance and service restoration 24 hours a day, 7 days a week after the communication equipment is installed and in operation.

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SECTION 7 PROPERTY REQUIREMENTS

7.1 Right of Way Requirements

The customer must acquire the necessary Right of Way requirements for its transmission line, along with the access requirements to the point of interconnection with SCE's facilities. The use of SCE's Right of Way and/or free owned property shall not be included in any interconnection proposals.

7.2 Transmission Line Crossing Policy

The interconnection transmission line or Access Right of Way that are proposed to cross SCE transmission line or access easements or fee owned property must be submitted to SCE's Vegetation & Land Management (V&LM) organization for a separate review request for approval. For your reference, below are SCE's Transmission Crossing Policy guidelines:

1. A new customer transmission line of equal or lower voltage shall not be allowed the superior position and will cross under the existing SCE facilities and/or the new facilities proposed prior to the new line.
2. A new customer transmission line, triggered by an INTFAC, with higher voltage may be allowed the superior position with G.O. 95³ Grade "A" self-supporting Dead-end construction with minimum of double insulator strings on both sides. This will apply to all voltages. SCE will regain the superior position should SCE lower voltage facilities be upgraded in the future of equal or higher voltage than the customer's Transmission Facilities.
3. A new customer transmission line of higher voltage may be allowed the superior position if it is crossing a SCE multiple circuits corridor (two circuits or more), but this type of crossing will need to be reviewed on a case-by-case basis.
4. A new customer transmission line, regardless of voltage, shall not be allowed the superior position if it is crossing a circuit which terminates at the switchyard for a nuclear power plant.

7.3 Infrastructure Property Requirements

Substation: The following approximate land requirements are needed for typical interconnection facilities (SCE owned substation) on the customer's property:

1. 66 kV Tap: 90 ft. by 120 ft.
2. 66 kV Loop: 150 ft. by 120 ft.
3. 115 kV Tap: 110 ft. by 120 ft.
4. 115 kV Loop: 170 ft. by 200 ft.

Minimum substation land requirements are subject to change according to engineering studies and interaction with SCE is required for final determination. The dimensions above include a required 10 ft. easement bordering the interconnection facility under the assumption that the customer owns the transformer, other facilities; and the land needed for the incoming line(s) is not included.

³ **General Order No. 95. (G.O. 95)** the "Rules for Overhead Line Construction" established by the California Public Utilities Commission is minimum requirements for designing and constructing overhead and underground electrical facilities. In some cases, SCE Practices and Standards may be more stringent. The INTFAC must adhere to the appropriate requirements.

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SECTION 8 CYBERSECURITY PRECUATIONS

The INTFAC shall implement reasonable administrative, technical, and physical safeguards, including any specific safeguards specified from time to time by SCE, to protect the security and integrity of SCE's systems.

A "Cybersecurity Incident" is: (a) unless expressly authorized, any use, reproduction, distribution, transfer, disposition, disclosure, possession, memory input, alteration, erasure, damage, breach in the security, or other activity by a person or party other than SCE of (i) Interconnection Customer's computing systems or equipment, including those that contain information about SCE's systems or provide information to SCE's systems, or (ii) SCE's computing systems or equipment, if caused by the action or inaction of Interconnection Customer; or (b) any unauthorized access to, interception of, disclosure or acquisition of such information.

The Interconnection Customer shall immediately notify SCE at cybersecurity@sce.com of any reasonably suspected or confirmed Cybersecurity Incident immediately upon Interconnection Customer's awareness of the event. Such notification to SCE by the Interconnection Customer shall include the nature of the event, date and time of the event, suspected amount and type of information exposed and steps being taken to investigate the circumstances of the exposure. The Interconnection Customer shall cooperate and assist SCE in the investigation, analysis and resolution of Cybersecurity Incidents affecting SCE's systems. The Interconnection Customer shall provide SCE with details of the investigation and final disposition of the Cybersecurity Incident relating to SCE's services or systems or which may impact the confidentiality, integrity, or availability of those services or systems or of SCE's information.

In addition to the above, Interconnection Customer shall: (i) regularly scan its systems for vulnerabilities, (ii) rank all vulnerabilities and promptly remediate detected vulnerabilities ranked as critical, high or moderate, and (iii) use commercially reasonable efforts to identify any critical, high, or moderate vulnerabilities, risks, or threats that could potentially impact SCE, and shall notify SCE in writing at cybersecurity@sce.com within one (1) Business Day after such identification. If Interconnection Customer determines that it cannot remediate any such potential or detected vulnerabilities, risk or threats within thirty (30) Calendar Days after identifying any such potential or detected vulnerabilities, risks, or threats, it shall promptly notify SCE in writing. Interconnection Customer's notification shall provide detailed information describing the controls used to mitigate these vulnerabilities, risks or threats.

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PART 4

Affected Systems Overview

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SECTION 1 AFFECTED SYSTEMS COORDINATION AND NOTIFICATION

SCE's recognizes the affect an interconnecting generation Facility, end-user Facility or transmission Facility could have on a neighboring system, and firmly believes any mitigation must jointly be developed by all parties involved. To ensure this concept is understood by each of the three types of interconnecting facilities Part 1 Section 4.13, Part 2 Section 3.8 and Part 3 Section 3.9 of the Interconnection Handbook all specify:

“Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability”.

The language identified above binds SCE to assist in working toward a solution. However, as SCE is a Transmission Owner with its BES assets under CAISO operational control these facilities must adhere the CAISO 5th Replacement FERC Electric Tariff (CAISO Tariff) and their associated Transmission Planning Process. These documents clearly identify the responsibility for the study of and coordination with affected systems as belonging to the CAISO. Below is a brief summarization of this documentation:

- **CAISO Tariff, Section 24.10 Operational Review and Impact Analysis**

Section 24.10 of the document clearly states that CAISO will perform an analysis on all Regional Transmission Facilities that are a part of, proposed to be connected to, or made part of, the CAISO Controlled Grid as part of its Transmission Planning Process. This includes analysis identifying the impacts of these facilities on neighboring systems. The CAISO will also coordinate with the affected system to ensure the appropriate mitigation is in place.

- **CAISO Tariff, APPENDIX U Standard Large Generator Interconnection Procedures (LGIP)**

Sections 3.2 and 3.7 of this document describes the responsibilities and procedures for coordination of studies and notification between affected systems for both new and modified generation facilities that are not assigned to a Queue Cluster Window. The CAISO coordinates the conduct of any studies required to determine the impact of the Interconnection Request on affected systems with affected system operators, to the extent possible, and, if possible, the CAISO will include those results (if available) in its applicable Interconnection Study, as described in the LGIP.

- **CAISO Tariff, APPENDIX Y GIP For Interconnection Requests Generator Interconnection Procedures (GIP)**

Section 3.2 and 3.7 of this document describes the responsibilities and procedures for coordination of studies and notification between affected systems for both new and modified generation facilities that are either: (i) assigned to a Queue Cluster, (ii) included in the Independent Study Process, or (iii) included in the Fast Track Process. The CAISO coordinates the conduct of any studies required to determine the impact of the Interconnection Request on affected systems with affected system operators, to the extent possible, and, if possible, the

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CAISO will include those results (if available) in its applicable Interconnection Study, as described in the GIP.

- **CAISO Business Practice Manual for the Transmission Planning Process**

This document describes coordination with affected systems for both new and modified transmission and end-user facilities. The CAISO's Transmission Planning Process (TPP) utilizes a Request Window (Section 4.4) to provide TPP Participants with the opportunity to propose economic or reliability-driven transmission upgrades or additions (projects), requests for Economic Planning Studies, resource alternatives, i.e., Demand management programs or Generation, or otherwise submit additional relevant data to the CAISO for inclusion in the following year's annual Transmission Planning Process. The Request Window opens August 15th and closes October 15th of each planning cycle. The CAISO will post a summary of valid project proposals and study requests it receives from the Request Window on the CAISO website. Reliability transmission projects proposed by SCE shall be submitted by September 15 of each year to allow sufficient time for TPP Participants to review these projects. SCE shall also provide the CAISO the final study reports that document their NERC compliance, updates on the status of transmission projects previously approved by CAISO but not yet in-service and newly proposed transmission additions and upgrades. The CAISO will incorporate relevant planning information from these reports into the annual CAISO Transmission Plan.

Section 7 of this document identifies that through the TPP the CAISO will act as the: (1) initiator; (2) organizer; and (3) participant in relevant forums for sub-regional and regional transmission planning. The TPP is the CAISO's procedure to coordinate joint studies and notify others of new and modified transmission and end user facilities.

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SECTION 2 COORDINATION WITHIN BALANCING AUTHORITY'S METERED BOUNDARIES

It is the responsibility of the INTFAC to make appropriate arrangements with the appropriate BA to ensure its Facilities are within the BA's metered boundaries. SCE as the Transmission Owner is responsible for confirming that the INTFAC interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries. SCE will coordinate with each of the three types of interconnections referred to in this Handbook as INTFAC as follows:

- **Transmission Coordination**
Section 11.1.7 of the Transmission Interconnection Procedure defines how SCE confirms coordination amongst the Transmission Interconnection customer and the appropriate BA.
- **Generation Coordination**
Sections 6.1.4 and 6.1.4.2 of CAISO's Generation Interconnection Deliverability Allocation Procedure (GIDAP) defines the coordination process SCE shall follow when the INTFAC is within the CAISO metered boundaries. In instances where the metered boundaries are outside the CAISO footprint, SCE shall:
 - Inform the INTFAC to coordinate with the appropriate BA during the results meeting.
 - Request appropriate documentation to confirm coordination amongst the INTFAC and the BA has occurred, prior to execution of the IA.
- **End-User Facility Coordination**
SCE shall inform that End-User/MOS customer to coordinate with the appropriate BA and affected systems. Prior to execution of the MOS, SCE shall confirm that coordination amongst the End-User/MOS customer and the BA has occurred.

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GLOSSARY

ACSR - Aluminum Conductor Steel Reinforced

ACSS - Aluminum Conductor Steel Supported

Adverse (System) Effect/Impact – The negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

AGCC - Alternate Grid Control Center

ANSI – American National Standards Institute

Applicable Reliability Standards – The requirements and guidelines of NERC, the Applicable Reliability Council, and the Balancing Authority Area of the Participating TO’s Transmission System to which the Generating Facility is directly connected, including requirements adopted pursuant to Section 215 of the Federal Power Act.

Auxiliary Load – Energy for operating electric equipment, or portions thereof, located on the BESS resource site owned by the same entity that owns the BESS unit, which electrical equipment is used exclusively for the storage, charge, or discharge of the BESS resources energy.

AWG – American Wire Gauge

BESS – Battery Energy Storage System

CAISO – California Independent System Operator.

CAISO Controlled Grid – The system of transmission lines and associated facilities of the parties to the Transmission Control Agreement that have been placed under the CAISO’s Operational Control.

CAISO Tariff – The CAISO’s tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

CPUC - California Public Utilities Commission

CTM - Centralized Telemetry Method

Cybersecurity Incident - is: (a) unless expressly authorized, any use, reproduction, distribution, transfer, disposition, disclosure, possession, memory input, alteration, erasure, damage, breach in the security, or other activity by a person or party other than SCE of (i) Interconnection Customer’s computing systems or equipment, including those that contain information about SCE’s systems or provide information to SCE’s systems, or (ii) SCE’s computing systems or equipment, if caused by the action or inaction of Interconnection Customer; or (b) any unauthorized access to, interception of, disclosure or acquisition of such information.

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Direct Access (DA) – A service option where the customer obtains its electric power and ancillary services from Electric Service Provider (ESP), who is registered with the California Public Utilities Commission (CPUC). See SCE Tariff Books Rule 22 for more information.

Distribution System – Those non-CAISO-controlled transmission, subtransmission, and distribution facilities owned by the Participating TO's.

EBG - Emergency-Backup Generation

Effective Date – The date the Interconnection Handbook is published.

Element – Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Emergency-Backup Generation (EBG) – Customer-owned generation utilized when disruption of utility power has occurred or is imminent.

Emergency Condition – A condition or situation: (1) that is imminently likely to endanger life or property; or (2) that, in the case of the CAISO, is imminently likely to cause a material adverse effect on the security of, or damage to, the CAISO Controlled Grid or the electric systems of others to which the CAISO Controlled Grid is directly connected; (3) that, in the case of the Participating TO, is imminently likely to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, Participating TO's Interconnection Facilities, Distribution System, or the electric systems of others to which the Participating TO's electric system is directly connected; or (4) that, in the case of the Interconnection Customer, is imminently likely to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities.

ESR - Electrical Service Requirements

Facility – A set of electrical equipment that operates as a single electric system Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

FACTS – Flexible Alternating Current Transmission System

Federal Power Act – The Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC – The Federal Energy Regulatory Commission or its successor.

FO – Fiber Optic.

FRT - Fault Ride-Through

GCC - Grid Control Center

Generating Facility Capacity – The total capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

GIA - Generation Interconnection Agreement

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Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

GPR - Ground Potential Rise

Ground Potential Rise (GPR) – The voltage rise of a substation-grounding grid relative to a remote point. GPR is equal to maximum earth current into or out of the grid times the grid resistance. (The Earth current can vary from 0 to 100 percent of the fault current depending on fault location and neutral connections to the substation.) The interconnecting customer is responsible to ascertain that the GPR of the Producer's or interconnected mat does not negatively affect nearby structures or buildings. The cost of mitigation for GPR and other grounding problems shall be borne by the interconnecting customer. If it is elected to install separate ground grids for SCE and the interconnecting facility, the customer shall be responsible to mitigate any transfer voltages and GPR that occur to SCE's grid due to faults on the interconnecting customer's facilities.

HVAC - Heating Ventilation and Air Conditioning

IEEE - Institute of Electrical and Electronics Engineers

Initial Synchronization Date – The date upon which an Electric Generating Unit is initially synchronized and upon which Trial Operation begins.

Interconnection Handbook (Handbook)– A handbook, developed by the SCE and posted its website for customer use which describing the technical and operational requirements necessary for generators, transmission facilities, and end use Facilities to connect to SCE's electrical system. These requirements outlined in the Handbook provide for safe and reliable operation of SCE's electric system, and may be modified or superseded from time to time.

INTFAC – Short for “Interconnection Facility” which refers to all applicable facilities, such as generation, transmission, and end-user facilities.

ISP - Integrated System Planning

L/HFRT - Low/High Frequency Ride Through

L/HVRT - Low/High Voltage Ride Through

LELL - Long Term Emergency Load Limit

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Metering Equipment – All metering equipment installed or to be installed for measuring the output of the Generating Facility, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

ModBus – A serial communications protocol published by Modicon in 1979 for use with its programmable logic controllers (PLCs). Simple and robust, it has since become a *de facto* standard communication protocol, and it is now amongst the most commonly available means of connecting industrial electronic devices.

Monitor - Observe the routine in-service operation of the Component.

MOS – Method of Service

NERC – The North American Electric Reliability Corporation or its successor organization.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, the California Independent System Operator Corporation, control area, or the Distribution Provider's requirements, including those set forth in Generation Interconnection Agreement.

OPGW – Fiber Optical Ground Wire.

Party or Parties – The Participating TO, CAISO, Interconnection Customer, or the applicable combination of the above.

PCC – Point of Common Connection

PLL - Phase-Locked Loop

Point of Change of Ownership (POCO) – The point where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.

Point of Interconnection (POI) – The point where the Interconnection Facilities connect with the Distribution Provider's Distribution System.

POM - Point of Measurement

PPA - Power Purchase Agreement

PSS – Power System Stabilizers

PV - Photovoltaic

RAS - Remedial Action Schemes

Retail Service - The energy metered at the delivery point to meet all customer's energy requirements, minus the wholesale energy, considering the customer's statutory, contractual, and/ or other right or obligation to be served.

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Remote Control Equipment - Automation of new or existing switch capable of operating based on pre-defined conditions or remotely.

Station Power – Incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the BESS resource; located on BESS or hybrid collocated site; and used exclusively in relation to the storage, charge, or discharge of the BESS energy.

RTU – A **remote terminal unit (RTU)** is a microprocessor-controlled electronic device that interfaces objects in the physical world to a distributed control system or SCADA (supervisory control and data acquisition system) by transmitting telemetry data to the system, and by using messages from the supervisory system to control connected objects.

SCADA – (**supervisory control and data acquisition**) generally refers to industrial control systems (ICS): computer systems that monitor and control industrial, infrastructure, or facility-based processes such as electrical power transmission and distribution.

SCE's Electric System – Locations where SCE is owner and/or operating agent.

SOB - System Operating Bulletins

SSCI – Subsynchronous Control Instability

SSI – Subsynchronous Interaction

SSI - Substation Standard Instructions

SSR – Subsynchronous Resonance

SSTI – Subsynchronous Torsional Interactions

STELL - Short Term Emergency Load Limit

TA – Torque Amplification

TI – Torsional Interaction

TO – Transmission Owner

TOP – Transmission Operator

Transmission Control Agreement (TCA) – As defined by the CAISO California Independent Fifth Replacement Electronic Tariff.

Transmission System – Those facilities owned by the Distribution Provider that have been placed under the CAISO's operational control and are part of the CAISO Grid.

UL - Underwriters Laboratories

UPS - Uninterruptible Power System

V&LM - Vegetation & Land Management

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WDAT - Wholesale Distribution Access Tariff

XLPE - Cross-Linked Polyethylene

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APPENDIX A

Following is a list of the technical standards and criteria referenced within SCE’s Interconnection Technical Requirements.

- NERC/WECC Planning Standards
- WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan
- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
- IEEE Standard 2800-2022 for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems
- IEEE 80 Guide for Safety in AC Substation Grounding
- IEEE 929 Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems
- IEEE 519 IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems
- IEEE C37.010-1999 IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- ANSI C84.1 Voltage Ratings for Electric Power Systems and Equipment
- Voltage Fluctuation Design Limits - SCE Company Criteria
- WECC Minimum Operating Reliability Criteria
- Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports
- IEEE C57.13 Standard Requirements for Instrument Transformers
- IEEE C57.13.6 Standard for High-Accuracy Instrument Transformers
- ANSI C12.1 Code for Electricity Metering
- ANSI C12.11 Instrument Transformers for Revenue Metering
- ANSI C12.20 Electricity Meters – 0.1, 0.2, and 0.5 Accuracy Classes

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NEXT REVIEW DATE

This document shall be reviewed upon a change in the referenced documents that may impact this document.

DATA RETENTION

This document shall be retained a minimum of 4 years from last WECC on-site audit and is stored in/on the Compliance Integration Group SharePoint site.

APPROVAL

T&D Organization	Signature	Date
Asset Strategy & Planning	Original copy signed by Patricia Arons	01/31/2024

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REVISION HISTORY

Rev. No.	Date	Description of Revision	By	Next Review Date
1		Revised the Interconnection Handbook, Generators to incorporate interconnection requirements for new Generation, Transmission, and End User facilities	---	---
2	3/19/2009	Replaces all remaining referenced documents in Version 1, so that, this Interconnection Handbook will be used for new Generation, Transmission, and End User facilities	---	---
3	10/2/2009	Revised to incorporate new SCE approved wind turbines set-back criteria.	---	---
4	8/2/2010	Incorporated the new SCE approved Transmission Line Crossing Policy. This update resulted in a reconfiguration of Section 9 and added an additional page to the document.	---	----
5	10/5/2011	Sec# 3: Incorporated new diagrams for inverter-based interconnections. Incorporated Third-Party Protection Equipment Maintenance Responsibility Statement. Sec# 4.15.2: Removal of C-RAS reference from section. Sec# 7: Incorporated exemption of telemetry requirements for Cold Ironing Ships and Emergency back-up generators. And clarification of 1 MVA size definition. Sec# 8: Describe the necessary telecommunications requirements.	---	----
6	10/3/2012	Section 5.11: Isolating Equipment & Switching and Tagging Rules. Re-designed to clarify the need for Isolating Equipment, Inter-Company and Switching and Tagging Rules. Delineating the different voltage classes: (NEW Section) For Generation Facilities (GF's) connecting to voltages >34.5 kV. (NEW Section) For GF's connecting to voltages ≤ 34.5kV. Section 5.12: Grounding Circuit & Substation. Introducing the need for Grounding Studies at the POI for generation interconnection customers. Section 5.13: Non-SCE Pole Grounding. Introducing grounding requirements when Connecting to Customer-Owned Facilities for Generation Interconnections Sections 3: Protection. Updated the Introduction paragraph. Incorporated new Protection diagram for Inverter-based Technology >34.5kV. Section 7: Telemetry. Updated to include the purpose & definition of an RTU. Updated the HVAC Section to align with Telecom. Engineering's Temperature Requirements. Harmonized the Telemetry Requirements with SOB510. Put Telemetry Requirements in a Table format. Added provisions to how to handle "virtual IO." Section 8: Telecommunications. Updated the 3rd paragraph to align with the updates made in Section 3: Identical projects connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication costs. Updated the HVAC section, stipulating more stringent temperature requirements and pointing to the PSC Section. Included new fiber optic section to align with WECC standards and clarified miscellaneous options Section 9: Property Requirements. Removed the footprints for the building 220kV or 500kV Looping Stations. Increased the 66kV and 115kV Looping Station Footprints consistent with new Substation Standards. Introduced New Glossary Section. Section 8: Telecommunications. Updated the 3rd paragraph to align with the updates made in Section 3: Identical projects connected at different locations in SCE's electric system can have widely varying protection requirements and attendant telecommunication	---	----

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		costs. Updated the HVAC section, stipulating more stringent temperature requirements and pointing to the PSC Section. Included new fiber optic section to align with WECC standards and clarified miscellaneous options Section 9: Property Requirements. Removed the footprints for the building 220kV or 500kV Looping Stations. Increased the 66kV and 115kV Looping Station Footprints consistent with new Substation Standards. Introduced New Glossary Section.		
7	12/29/16	Handbook split into 3 major components based on interconnection type for customer ease of use. Introduction/ Summary rewritten to clearly articulate the new format for the Handbook. Transmission Interconnection Requirements revised to more clearly articulate Protection needs. Glossary of terms revised to identify only terminology used in the Handbook.	---	----
8	12/13/2017	Introduction and Summary includes new language to address adverse impact on affected systems and reference to a new fourth section. The Generator Part 1 was revised for clarity and also added several new sections which include: Sub-Synchronous Interaction Evaluation, Voltage Control, Ride Through Requirements and Underground Cable. Method Of Service/End User Facility Part 2 was revised for clarity and added a new section for Underground Cable. Transmission Part 3 was revised for clarity and added several new sections which include: 2-terminal or 3-terminal lines for Dual Pilot, Sub-Synchronous Interaction Evaluations, Sub-Synchronous Resonance Studies, Underground Cable. Updated all sections which references to SPS to RAS to align with NERC's Glossary of Terms. Added a new Affected Systems Part 4 to add clarity. Updated all instances Transmission and Interconnection Planning to Electric System Planning.		
9	12/13/2018	For the Generator Part 1, a new section 5.12.4 Inverter-Based Category 2 and 3 was added. Part 4 Affected Systems Overview was revised to include a new section Coordination Within Balancing Authority's Metered Boundaries. Minor edits were made for clarity.		As needed
10	12/13/2019	The Generator Part 1 was revised for clarity and updated the following sections to align with current SCE practices and/or regulatory bodies: Section 3 – Protection Requirements – updated to reflect current SCE practices; Section 9 – Property Requirements – updated for clarity; Section 11 – Inverter-Based Resource Performance Requirements – This section was updated to align with existing NERC guidelines. Method Of Service/End User Facility Part 2 was revised for clarity. Transmission Part 3 was revised for clarity. Updated all instances Electric System Planning to Integrated System Strategy.		As needed

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11	12/13/2020	The Generator Part 1 - updated the following sections to align with current SCE practices and/or regulatory bodies: Section 8 – Telecommunications Requirements – updated to reflect current SCE practices; Section 9 – Property Requirements – updated for clarity; Section 10 – Generator Sharing Breaker and Half – This section was updated to include guidelines on how SCE will prioritize Generators interconnecting to the same bus position. Method Of Service/End User Facility Part 2 – updated the following section to align with SCE current practices and/or regulatory bodies: Section 7 – Telecommunications Requirements – updated to reflect current SCE practices; Section 8 – Property Requirements – updated for clarity. Transmission Part 3 - updated the following section to align with SCE current practices and/or regulatory bodies: Section 6 – Telecommunications Requirements – updated to reflect current SCE practices; Section 7 – Property Requirements – updated for clarity. Updated Glossary of terms to include definitions of terms referenced.		As needed
12	12/13/2021	The Generator Part 1 - updated the following sections to align with current SCE practices and/or regulatory bodies: Sub-section 5.4 – Table 5.3 was revamped. Sub-section 5.8.1 a new Figure 5.8 was added. Section 8 – Telecommunication was completely redone. Method Of Service/End User Facility Part 2 – updated the following section to align with SCE current practices and/or regulatory bodies: Section 7 – Telecommunications Requirements – updated to reflect current SCE practices; Section 8 – Property Requirements – updated for clarity. Transmission Part 3 - updated the following section to align with SCE current practices and/or regulatory bodies: Section 2 – Protection Requirement – added a new sub-section 2.5 RAS & CRAS; Section 6 – Telecommunications Requirements – updated to reflect current SCE practices; Section 7 – Property Requirements – updated for clarity. Updated Glossary of terms to include definitions of terms referenced. Appendix A was updated as well.		As needed

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13	12/16/2022	The Generator Part 1 - updated the following sections to align with current SCE practices and/or regulatory bodies: Updated note 6 of Figure 3d. Updated note 7 of Figure 3e. Updated note 7 of figure 3f. Revised section 4.2 Governor Droop for clarity. Added new Section 4.14 on Remote Control Equipment. Updated section 6 Revenue Metering Requirements to revise the definition of retail service, added approach to Retail Meter Customer Projects and revised single-line examples. Updated Table 7.1 Telemetry Requirements to include state of charge and AVR status and control mode requirements for generating facilities (aggregate or single unit) greater than or equal to 10MVA. Section 8.3 Space Requirements was updated for clarity and to incorporate the option of a rack. Section 8.5 Power and Grounding Requirements was updated to specify responsibility for maintenance of back-up source. Method Of Service/End User Facility Part 2 – updated the following section to align with SCE current practices and/or regulatory bodies: Section 7.3 Space Requirements was updated for clarity and to incorporate the option of a rack. Section 7.5 Power and Grounding Requirements was updated to specify responsibility for maintenance of back-up source. Transmission Part 3 - updated the following section to align with SCE current practices and/or regulatory bodies: Section 6.3 Space Requirements was updated for clarity and to incorporate the option of a rack. Section 6.5 Power and Grounding Requirements was updated to specify responsibility for maintenance of back-up source. Updated Glossary of terms to include definitions of terms referenced.		As Needed
14	09/12/2023	Summary of Technical Requirements – Added Cybersecurity Measures to the summary list of requirement subjects The Generator Part 1 - updated the following sections to align with current SCE practices and/or regulatory bodies: Revised Section 4.7 Voltage Control with an editorial change. Added new Section 4.15 Point of Change of Ownership to require ownership transitions above ground. Updated Table 5.1 and Section 5.2 to align with SOB 510. Added new Section 5.11.4 Inverter-Based Category 2 and 3. Revised the title to Table 5.7. Updated Section 5.12.4 Inverter-Based Category 2 and 3 to follow IEEE 2800 guidance. Revised Section 11 Inverter-Based Resource Performance Requirements to align with IEEE 2800 guidance. Updated Section 7.2.2 and Table 7.1 to align with SOB 510. Editorial revision to Section 8.2. Revised Section 11 to align with IEEE 2800. Added new Section 12 Cybersecurity Measures for reporting cybersecurity incidents to SCE. Method Of Service/End User Facility Part 2 – Added new Section 3.10 Point of Change of Ownership to require ownership transitions above ground. Editorial revision to Section 7.2. Added new Section 9 Cybersecurity Measures for reporting cybersecurity incidents to SCE. Transmission Part 3 - Added new Section 3.11 Point of Change of Ownership to require ownership transitions above ground. Editorial revision to Section 6.1. Added new Section 8 Cybersecurity Measures for reporting cybersecurity incidents to SCE.		As Needed

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		Updated Glossary of terms to include definitions of terms referenced. Updated the Appendix to include standards referenced.		
15	1/31/2024	The Generator Part 1 - updated the following sections to align with current SCE practices and/or regulatory bodies. Section 3 Protection Requirements, replaced the term Categories with Applicability. Subsection 3.2 Category 2: Total Generation 200kVA and Above, Voltage at 34.5kV or Below, updated Figure 3f, and clarified applicability of section 3.2.3d. Section 3.3 Category 3: Total Generation Less Than 200kVA, in Voltage at 34.5kV & Below, updated Figured 3h, and clarified applicability of section 3.3d. Subsection 4.9.12 Transformer Emergency Rating, revised application of Long-Term Loading Limits (LTEL) and Short-Term Emergency Loading Limits (STELL). Subsection 4.9.15 Path Ratings, updated citation for WECC's Project Coordination, Path Rating and Progress Report and editorial revisions for clarity. New subsection 4.16 Looping High Voltage Transmission Lines. Updated Table 5.2 Typical Required Generating Facility Records and Data and Table 7.2 Telemetry Requirements to specify BESS above 1MVA request state of charge telemetry. New subsection 6.5.3 to ensure revenue metering instrumentation are rated per ANSI C12.11. Revised subsection 6.5.6 clarify expectations for design changes of revenue metering instrumentation. Section 6.6 SCE Meter Panels, replaced the term enclosure with panels, and added new Figures 6e, 6f and 6g. Section 8.5 Power and Grounding Requirements, updated capacity requirement of branch circuit provided by INTFAC, and clarified applicability of AC power. Section 10 Generator Sharing Breaker and a Half, incorporated editorial revisions for clarity. Method Of Service/End User Facility Part 2 – Revised Section 7.2 Fiber Optic Communication Paths, updated FO cable requirements and added Customer cable requirement to each POCO. New Figure 7a: Telecommunications Block Diagram.		As Needed

ATTACHMENTS

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None

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Attachment 7

Section 3.2, Biological Resources - Redline Version

3.2 Biological Resources

This section describes the potential effects the construction, operation, and decommissioning activities associated with the Prairie Song Reliability Project (Project) may have on biological resources at and in the vicinity of the Study Area. The Project will consist of an up to 1,150-megawatt (MW), approximately 9,200-megawatt hour (MWh) containerized battery energy storage system (BESS) facility utilizing lithium-iron phosphate cells, or similar technology, operations and maintenance (O&M) buildings, a Project substation, a 500-kilovolt (kV) overhead generation interconnection (gen-tie) transmission line, and interconnection facilities within the existing Southern California Edison (SCE) owned and operated Vincent Substation.

The biological resources described in this section have been compiled from a literature review of databases, maps, general plans, biological reconnaissance, as well as focused species/resource surveys. The evaluation of biological resources includes the following elements:

- **Section 3.2.1** describes the existing environment that could be affected, including a regional overview, wetlands, habitats, species, vegetation, and biological survey results.
- **Section 3.2.2** identifies potential environmental impacts that may result from Project construction, operation, maintenance, and decommissioning.
- **Section 3.2.3** discusses the potential for cumulative effects.
- **Section 3.2.4** describes project design and mitigation measures that will be implemented to avoid or minimize potentially significant impacts.
- **Section 3.2.5** presents laws, ordinances, regulations, and standards (LORS) applicable to Biological Resources.
- **Section 3.2.6** identifies regulatory agency contacts.
- **Section 3.2.7** describes permits required for the Project related to Biological Resources.
- **Section 3.2.8** provides references used to develop this section.

Biologist's credentials, as well as occurrences survey reports, and record data used for the preparation of this section is located in the following appendices:

- **Appendix 3.2A** – Resumes of Applicant's Biologists
- **Appendix 3.2A** – Preliminary ALTA Surveys (new)
- **Appendix 3.2B** – Potential to Occur Tables and Compendia (updated)
- **Appendix 3.2C** – Resumes of Applicant's Biologists (updated)
- **Appendix 3.2D** – Rare Plant Survey Report (new)
- **Appendix 3.2E** – California Desert Native Plants Act Survey Report (new)
- **Appendix 3.2F** – Crotch's Bumble Bee Survey Report (new)
- **Appendix 3.2G** – Biota Report (new)
- **Appendix 3.2H** – Nitrogen Deposition Model (unchanged from original submittal)
- **Appendix 3.2I** – Photo Exhibit (new)
- **Appendix 3.2C-2J** – CNDDDB Forms (unchanged from original submittal)

- Appendix 3.2D-2K – Completed 1602 Lake and Streambed Alteration Agreement Application Package Form (updated)
- Appendix 3.2L – Correspondence with LA County Planning (new)
- Appendix 3.2E – Completed Waste Discharge Requirements Application Form
- Appendix 3.2F – Nitrogen Deposition Model

A summary of the biological resources evaluation is provided in the table below.

		Potentially Significant Impact	Less than Significant Impact with Mitigation Incorporated	Less than Significant Impact	No Impact
Would the Project:					
1	Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as endangered, threatened, candidate, sensitive, or special status in local or regional plans, policies, or regulations, or by CDFW or USFWS?	☐	☒	☐	☐
2	Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by CDFW or USFWS?	☐	☒	☐	☐
3	Have a substantial adverse effect on federal or state protected WOTUS [waters of the United States] (including wetlands) as defined by Sections 404 and 401 of the 1972 Amendments to the Federal Water Pollution Control Act, commonly known as the Clean Water Act, or the Porter-Cologne Act, either through direct removal, filling, hydrological alteration, or other means?	☐	☒	☐	☐
4	Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory native wildlife corridors or impede the use of wildlife nursery sites?	☐	☐	☒	☐
5	Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☒	☐	☐
6	Conflict with the provisions of an adopted Habitat Conservation Plan, NCCP [natural community conservation plan], or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☒

Notes: CDFW = California Department of Fish and Wildlife; USFWS = U.S. Fish and Wildlife Service;

3.2.1 Affected Environment

The Project is in unincorporated Los Angeles County (County), California south of State Route 14 (SR 14) approximately 3 miles northeast of the unincorporated community of Acton. The Project is within the USGS 7.5-minute Acton and Pacifico Mountain Quadrangles, Township 5N, Range 12W, Sections 27, 28, 33 and 34. The BESS site is comprised of Assessor Parcel Numbers (APNs) 3056-017-007, 3056-017-020, 3056-017-021, 3056-019-013, 3056-019-026, 3056-019-037, and 3056-019-040. Development of the BESS facility will occur on an area of land situated between two (2) existing transportation corridors, the Antelope Valley Freeway (SR 14) to the north and Southern Pacific Railroad lines and Carson Mesa Road to the south, that are approximately 1,200 feet apart.

The Project site (approximately 107.29 acres) refers to the area that will be physically affected by construction activities associated with the Project, including the location of permanent structures (including both gen-tie options) as well as staging and other temporary disturbance areas described in Section 2, Project Description. For the purposes of the biological surveys, the Study Area (~~approximately 531 acres~~) encompasses the Project site parcels, and it is approximately 414 acres and a 100-foot buffer. The Study Area for focused species surveys was expanded per protocol and where necessary to capture nearby resources. Focused survey methods are described below in Section 3.2.1.5, Biological Surveys. Existing conditions within 1,000 feet of the gen-tie route options are similar to the Study Area because there are no significant changes in topography, geology, or hydrology within that distance.

3.2.1.1 Regional Overview

The Study Area is in the western San Gabriel Mountains, in the Transverse Ranges Geomorphic Province (CGS 2002). The Transverse Ranges are an east-west trending series of steep mountains and valleys (CGS 2002). The Study Area is located at the conjunction of Soledad Canyon and Kentucky Springs Canyon (USGS 2022), and at the boundary of the Western Transverse Ranges ecological subregion and Mojave Desert ecological region (Jepson Flora Project 2025). Elevations in the Study Area range from approximately 2,700 feet above mean sea level along the southwestern side to 3,500 feet above mean sea level along the northern hillsides (Google Earth 2025).

The Study Area has an arid climate with the site being located on the northern side of the San Gabriel Mountains and bordering the Antelope Valley. August is the average warmest month with an average high of 93 degrees Fahrenheit (°F) and December is the coolest month on average with a low of 36 °F. Rainfall occurs primarily between November and April, with the maximum average precipitation occurring in February. The mean annual rainfall for the area is approximately 9 inches of rain per year (LACPW 2023).

3.2.1.2 Regional Wetlands and Protected Areas

The National Wetlands Inventory (NWI) and National Hydrography Dataset (NHD) were reviewed to identify wetland or hydrologic features in the Study Area (USFWS 2025a, USGS 2025). Figure 3.2-1, Hydrologic Features, depicts the mapped wetland and hydrologic features in the Study Area. These resources are further described below.

Protected areas within 10 miles of the Study Area were determined through a review of the California Protected Area Database (CPAD) and California Conservation Easement Database (CCED) mapping tools (GreenInfo Network 2025). These resources are further described below.

3.2.1.2.1 Hydrologic Features

The Study Area is in the Santa Clara subbasin (HUC 18070102), Headwaters Santa Clara River watershed (HUC 1807010201), and primarily Kentucky Springs Canyon – Santa Clara River subwatershed, with the western most area of the Project overlapping into the Arrastre Canyon – Santa Clara River subwatershed. The Santa Clara River is the primary natural surface water feature in the vicinity of the Study Area. The Santa Clara River is the largest natural river remaining in Southern California, and travels through two (2) counties, Los Angeles and Ventura (Kennedy/Jenks Consultants 2014). The northern portion in Los Angeles County is largely classified as an intermittent stream/river and only contains flowing water during certain times of the year (USGS 2023; Kennedy/Jenks Consultants 2014)). The intermittent stream channel traverses the southern end of the Study Area within parcels 3056-019-040, 3056-017-907, 3056-017-028, 3056-017-027, 3056-015-008, and 3056-015-023, as shown in Figure 3.2-1, Hydrologic Features. Several other smaller, unnamed ephemeral washes from Soledad Canyon and Kentucky Springs Canyon drain across the northern and southern portions of the Study Area, respectively.

3.2.1.2.2 Protected Areas

CPAD is a database that includes lands that are owned and protected for open space purposed by over 1,000 public agencies or non-profit organizations. CPAD includes national, state, or regional parks, forests, preserves and wildlife areas. It also includes large and small urban parks; land trust preserves and special district open space lands (GreenInfo Network 2025).

A review of the CPAD and CCED confirmed that there are several protected areas or conservation easements within a 10-mile radius of the Study Area (GreenInfo Network 2025), as shown in Figure 3.2-2, Protected Areas. A list of the CPAD and CCED identified areas that occur within the 10-mile buffer of the Project is provided below. Project activities will not generate any potential ground impacts to any conservation easements or protected areas. Parcel APNs: 3056-017-905, 3056-017-904, 3056-017-906, 3056-017-907 are managed by the Mountains Recreation and Conservation Authority and are deed restricted for open space use, as shown in Figure 3.2-3, Local Protected Areas. The Northern Gen-tie option would obtain an aerial easement and span these parcels, but would not generate any impacts on the ground, except for the use of an existing roadway. In addition, as shown in Figures 3.2-2, ~~Protected Areas and 3.2-3,~~ the CPAD data shows project parcel APN 3056-019-040 as a protected area; however, this is a data error. The project applicant owns this parcel and there are no conservation easements or protected areas stipulated in the deed (see Appendix 3.2A). ~~Figure 3.2-2, Protected Areas, depicts protected areas identified within a 10-mile radius of the Study Area. A list of the CPAD and CCED identified areas that occur within the 10-mile buffer of the project is provided below.~~

California Protected Areas Database

The Mountains Recreation and Conservation Authority's Cold Creek Valley Preserve is within one of the parcels where the northern gen-tie route option occurs (GreenInfo Network 2025). The following are the lands that are owned and protected for open space within 10 miles of the Study Area (GreenInfo Network 2025).

- Antelope Valley Union High School District
 - Highland High School Park
 - Knight High School Park
 - Palmdale High School Park

- California State Lands Commission
 - California State Lands Commission
- Desert and Mountain Conservation Authority
 - Joshua Ranch
 - Littlerock Creek Irrigation District
 - Little Rock Wash
 - Littlerock Creek Irrigation District Open Space
- Los Angeles, County of
 - Acton Park
 - Acton Wash Wildlife Sanctuary
 - Everett Martin Park
 - Jackie Robinson Park
 - Juniper Hills Park
 - Mattie M. Primmer Park
 - Vasquez Rocks Natural Area and Nature Center
- Mountains Recreation and Conservation Authority
 - Bird's Nest
 - Bobcat Canyon
 - Cold Creek Valley Preserve
 - Red Rover Mine TaxDef
 - Ritter Ranch
 - SCC Plum Canyon
 - Stickleback Ranch
 - Unnamed site - Mountains Recreation and Conservation Authority
- Palmdale, City of
 - American Indian Little League Site
 - 70th Street East and North of Avenue R
 - A.C. Warnack Nature Park
 - Anaverde Hills Park
 - Avenue S and Dorer Street
 - Demonstration Garden
 - Desert Sands Park
 - Domenic Massari Park
 - Dr. Robert C. St. Clair Parkway
 - Foothill Park
 - Joe Davies Heritage Airpark
 - Joshua Hills Park
 - Legacy Commons

- Manzanita Heights
- Marie Kerr Park
- Melville J. Courson Park
- Palmdale Oasis Park
- Palmdale Park
- Palmdale Youth Pony League Fields
- Palmenthol History Park
- Pelona Vista Park
- Poncitlan Square
- Rancho Vista Neighborhood Park
- Sam Yellen Community Park
- Sam Yellen Community Park - Undeveloped
- Tejon Equestrian Park
- William J. McAdam Park
- Santa Clarita Watershed Recreation and Conservation Authority
 - Rio Dulce Open Space
- Santa Clarita, City of
 - Agua Dulce Canyon Parkland
- The Nature Conservancy
 - Arrastre Canyon
- U.S. Bureau of Land Management
 - BLM Lands
- U.S. Forest Service
 - Angeles National Forest

California Conservation Easement Database

The CCED is a database that defines boundaries of easements and deed-base restrictions on private lands. These lands may be actively farmed, grazed, forested, or held as nature preserves and typically have no public access (GreenInfo Network 2024). No lands with easements and deed-base restrictions are found within 10 miles of the Study Area.

3.2.1.3 Sensitive Habitat Types and Critical Habitat

Sensitive habitat types within a 10-mile radius of the Study Area are shown on Figure 3.2-34, Sensitive Habitat Types, and critical habitats on Figure 3.2-45, Critical Habitat. Descriptions of the sensitive and critical habitats identified are described below.

3.2.1.3.1 Sensitive Habitat Types

The California Department of Fish and Wildlife (CDFW) defines sensitive habitats as plant communities that have limited distributions, high wildlife value, include sensitive species, or are particularly vulnerable to disturbance.

CDFW ranks sensitive communities as “threatened” or “very threatened” (CDFW 2018) and keeps records of their occurrences in the California Natural Diversity Database (CDFW 2025a). Currently, CDFW publishes the California Sensitive Natural Communities List online (CDFW 2025b). Vegetation rarity ranking is based on a rank calculated developed by NatureServe (2025). Vegetation maps were taken from the CDFW Vegetation Classification Reports and Maps (CDFW 2025). CDFW’s Vegetation Program considers vegetation alliances with state (S) ranks of S1 through S3 as sensitive vegetative habitats. CDFW considers species or natural communities with one of the following NatureServe rankings as sensitive: Global (G)/State (S); Presumed Extinct (X); Possibly Extinct (G/S H); Critically Imperiled (G/S 1); Imperiled (G/S 2); Vulnerable (G/S 3). The California Environmental Quality Act (CEQA) requires that potential impacts to sensitive natural communities be evaluated. The following six (6) sensitive natural communities occur within 10 miles of the Study Area (Figure 3.2-34, Sensitive Habitat Types): Mojave Riparian Forest, Southern California Threespine Stickleback Stream, Southern Cottonwood Willow Riparian Forest, Southern Riparian Scrub, Southern Sycamore Alder Riparian Woodland, and Southern Willow Scrub. None of these identified six (6) sensitive natural communities occur on the project site or are crossed by the gen-tie line routes.

3.2.1.3.2 Critical Habitat

Critical habitats are designated areas occupied by the species at the time it was listed that contain the physical or biological features that are essential to the conservation of endangered and threatened species. In designated critical habitat, U.S. Fish and Wildlife Service (USFWS) and National Oceanic and Atmospheric Administration (NOAA) consider the following requirements of the species:

“Space for individual and population growth, and for normal behavior; nutritional or physiological requirements; cover or shelter; sites for breeding, reproduction, or rearing offspring; and, generally, any habitats that are protected from disturbance or are representative of the historic geographical and ecological distributions of this species” (USFWS 2025b).

No designated critical habitats occur within the Study Area but three (3) units of critical habitat for arroyo toad (*Anaxyrus californicus*) were identified within 10 miles of the Study Area, as shown in Figure 3.2-45, Critical Habitat (USFWS 2025c). Unit 6c is located approximately 4 miles southwest of the Study Area and is associated with the Santa Clara River. Unit 7 is located approximately 9 miles to the south and is associated with Big Tujunga Creek. Unit 21 is located approximately 5 miles to the east and is associated with Little Rock Creek. Arroyo toad is not expected to occur in the Study Area because the Study Area lacks suitable habitat (low-gradient intermittent streams with sandy, gravelly soils) for the species.

3.2.1.4 Regional Sensitive or Special-Status Species

Endangered, rare, or threatened species, as defined in CEQA Guideline 15380(b) (14 CCR 15000 et seq.), are referred to as “special-status species” in this report and include (1) endangered, threatened, and candidate species recognized in the context of the California Endangered Species Act (CESA) and the federal Endangered Species Act (FESA) (CDFW 2025d); (2) plant species with a California Rare Plant Rank (CNPS 2025a) (lists 1 through 4; see Appendix 3.2B, Potential to Occur Tables and Compendia, for rank definitions); (3) California Species of Special Concern (SSC) and Watch List species, as designated by CDFW (CDFW 2025e); (4) mammals and birds that are Fully Protected species, as described in California Fish and Game Code Sections 4700 and 3511; and (5) Birds of Conservation Concern as designated by USFWS (2021).

Appendix 3.2B provides a list of special-status species with records within the ~~two (2)~~¹⁴ USGS 7.5-minute topographic quadrangles (Lancaster West, Lancaster East, Sleepy Valley, Ritter Ridge, Palmdale, Littlerock, Agua

Dulce, Acton, and Pacifico Mountain, Juniper Hills, Sunland, Condor Peak, Chilao Flat, and Waterman Mt.) that the Study Area is in and the quadrangles that the 10-mile buffer intersects, as well as the species provided by the query of the USFWS' Information for Planning and Consultation and the surrounding 10 quadrangles Study Area during the literature review (CDFW 2025a, CNPS 2025a, and USFWS 2025d). This appendix includes the status designation for each species, habitat types that may support these species in the regional vicinity, a determination of potential for these species to occur within the Study Area, and a rationale for the occurrence determination. Figures 3.2-56a and 3.2-6b, Sensitive or Special-Status Species Records, depicts the special-status plant and wildlife species known to occur within a 10-mile radius of the Project area.

3.2.1.4.1 Sensitive and Special-Status Species Assessment

Dudek biologists evaluated the regional special-status plant and wildlife species against observed conditions on the Study Area to determine the potential for each species to occur. Habitat requirements, occurrence determinations, and rationale for occurrence determination are included in Appendix 3.2B. The potential for each special-status species to occur was evaluated according to the following criteria:

- **Not Expected.** Habitat on and adjacent to the site is clearly unsuitable for the species requirements (foraging, breeding, cover, substrate, elevation, hydrology, plant community, site history, disturbance regime), and species would have been identifiable on-site if present (e.g., oak trees). Protocol surveys (if conducted) did not detect species.
- **Low.** Few of the habitat components meeting the species requirements are present, and/or the majority of habitat on and adjacent to the site is unsuitable or of very poor quality. The species is not likely to be found on the site.
- **Moderate.** Some of the habitat components meeting the species requirements are present, and/or only some of the habitat on or adjacent to the site are unsuitable. The species has a moderate probability of being found on the site.
- **High.** All the habitat components meeting the species requirements are present and/or most of the habitat on or adjacent to the site is highly suitable. The species has a high probability of being found onsite.
- **Present.** Species was observed on site or within the Study Area.

3.2.1.5 Biological Surveys

Surveys for the BESS and Northern Gen-Tie option portions of the Study Area were conducted in 2023. In 2024 surveys were conducted on the additional parcels for the Southern Gen-Tie option. Dudek conducted comprehensive surveys for sensitive plants for the BESS and Northern Gen-Tie option portions of the Study Area in the spring of 2023 following an above average wet season. Dudek conducted surveys for Crotch's bumble bee (*Bombus crotchii*) in the summer of 2024 on the BESS and Northern Gen-Tie option portions of the Study Area. Dudek is currently conducting supplemental rare plant surveys and Crotch's bumble bee surveys in 2025 for parcels associated with the Southern Gen-Tie option of the Study Area. Table 3.2-1, Schedule of Surveys, lists the dates, conditions, and focus for each survey. While most surveys were conducted within the entire Study Area, Figure 3.2-7, Biological Surveys, depicts the areas for the surveys that deviated from the Study Area. Appendix 3.2C, Resumes of Applicant's Biologists, has resumes for the Dudek staff that conducted the surveys.

Table 3.2-1. Schedule of Surveys

Date	Focus	Biologists	Time	Survey Conditions
1/6/2023	- Vegetation Mapping - Jurisdictional Delineation	MM, ES	7:30 AM–2:55 PM	38°F–52°F; 0–10% cloud cover; 1–8 mph wind
1/11/2023	- Vegetation Mapping - Jurisdictional Delineation	MM, ES	Not recorded	Not recorded
1/12/2023	- Vegetation Mapping - Jurisdictional Delineation	MM, ES	Not recorded	Not recorded
4/28/2023	Rare Plants	VG, TP	6:40 AM–3:04 PM	60°F–80°F; 0% cloud cover; 0–2 mph wind
4/28/2023	Rare Plants	TP	6:40 AM–2:46 PM	57°F–94°F; 0% cloud cover; 0–2 mph wind
5/1/2023	Rare Plants	CB, DM, SN, JR	7:30 AM–3:25 PM	48°F–61°F; 60%–90% cloud cover; 3–5 mph wind
5/2/2023	Rare Plants	DM, VG, SN, JR	7:30 AM–3:25 PM	48°F–70°F; 60%–90% cloud cover; 3–5 mph wind
6/12/2024	Crotch's Bumble Bee	CA, AC, SL, KN	9:30 AM–10:17 AM	74°F–80°F; 0% cloud cover; 0–4 mph wind
6/22/2023–7/7/2023	Protected Tree Mapping	AC, ST, AP	Not recorded	Not recorded
7/1/2024	Crotch's Bumble Bee	LB, JE, DS	7:41 AM–1:34 PM	73°F–90°F; 0% cloud cover; 0–8 mph wind
7/12/2024	Crotch's Bumble Bee	JE	7:02 AM–9:07 AM	70°F–81°F; 1–7 mph wind
7/24/2023/2024	Crotch's Bumble Bee	LB	7:27 AM–10:54 AM	80°F–95°F; 0%–50% cloud cover; 0–1 mph wind
7/25/2024/2024	Crotch's Bumble Bee	LB	7:18 AM–11:01 AM	80°F–95°F; 0% cloud cover; 0–2 mph wind
11/18/2024	- Vegetation Mapping - Jurisdictional Delineation	ES, ZP	8:50 AM–12:56 PM	49°F–56°F; 0% cloud cover; 5–16 mph wind

Table 3.2-1. Schedule of Surveys

Date	Focus	Biologists	Time	Survey Conditions
11/19/2024	- Vegetation Mapping - Jurisdictional Delineation	TP, RS	9:30 AM–3:35 PM	53°F–54°F; 0% cloud cover; 1–7 mph wind
2/26/2025	Raptor Nest Survey	TP, RS	8:28 AM–3:30 PM	63°F–78°F; 0% cloud cover; 2–15 mph wind
4/16/2025	Crotch's Bumble Bee	CA, ES	8:21 AM–1:08 PM	48°F–59°F; 30%–100% cloud cover; 0–3 mph wind
5/21/2025	Crotch's Bumble Bee	CA, ES	8:21 AM–1:08 PM	59°F–71°F; 0% cloud cover; 0–1 mph wind
6/5/2025	Rare Plants	RSw	7:00AM–12:00AM	84°F; 0% cloud cover; 0–5 mph wind
6/30/2025	Crotch's Bumble Bee	ES, LB	9:16 AM–1:30 PM	79°F–86°F; 0% cloud cover
8/22/2025	Jurisdictional Delineation	ES, RS	Not recorded	Not recorded
Supplemental surveys to be conducted in 2025	- Crotch's Bumble Bee - Rare Plants	TBD	TBD	TBD

Notes:

Biologists: AC=Aida Castro, AP=Ana Pfleeger, CA=Callie Amoaku, LB=Luz Badillo, CB= Chelsea Bowers-Doerning, AC=Anna Cassidy, JE=Joshua Elson, VG=Valerie Goodwin, SL=Sony Leming, DM=Dilip Mahto, MM=Max Murray, KN=Kimberly Narel, SN=Sandra Nash, TP=Tracy Park, ZP=Zarina Pringle, JR=Jacob Rogers, ES=Eileen Salas, DS=Dahlia Serrato, RS=Ryan Stanley, RSw=Robert Sweet, ST=Sarah Tian

Survey Conditions: °F=degrees Fahrenheit; mph=miles per hour

Vegetation Community and Land Cover Mapping

Vegetation communities and land uses within the Study Area were mapped in the field using the Environmental Systems Research Institute (Esri) Collector, a mobile data collection application, on a digital aerial-based background (Esri 2025). Following completion of the fieldwork, all vegetation linework was finalized using Esri ArcGIS software and GIS coverage was created. Once in ArcGIS, the acreage of each vegetation community and land cover type within the study area was determined. Vegetation communities within the study area were mapped using CDFW's List of Vegetation Alliances and Associations (or California Natural Community List) (CDFW 2025e), which is based on A Manual of California Vegetation, Second Edition (Sawyer et al. 2009) and A Manual of California Vegetation, Online Edition (CNPS 2025b), where feasible, with modifications made to accommodate the lack of conformity of the observed communities (e.g., developed/disturbed land cover types) using Oberbauer et al. (2008) and Jones and Stokes (1993). Vegetation communities were classified based on site factors, descriptions, distribution, and characteristic species present within an area. Each natural community was mapped to the

association level, where feasible. Special-status vegetation communities are those communities identified as high priority for inventory in the California Natural Communities List (CDFW 2025b).

Rare Plant Surveys

The rare plant surveys were guided by the CNPS Botanical Survey Guidelines (CNPS 2001) and CDFW Protocols for Surveying and Evaluating Impacts to Special Status Native Populations and Sensitive Natural Communities (CDFW 2018). The biologists walked transects in suitable habitat, spaced approximately 5 meters to 10 meters apart based on the density of vegetative cover, throughout the Study Area. Digital mobile maps and 200-scale topographic plots of vegetation polygons were utilized to navigate the survey area. Plant species encountered during the field surveys were identified to subspecies or variety, if applicable, to determine sensitivity status. When rare plants were encountered, field personnel recorded data points demarcating the edge of polygon surrounding the population and assessed population numbers using a GPS with sub-meter accuracy. Appendix 3.2D, Rare Plant Survey Report, has additional details on the surveys.

California Desert Native Plants Act

Dudek biologists conducted a focused desert native plant survey within the survey area (defined as the Project impact footprint and a 150-foot buffer). The desert native plant survey was focused on the species subject to the California Desert Native Plants Act. Biologists walked meandering transects spaced approximately 10 meters apart to obtain 100% visual coverage of the survey area. If desert native plants identified under the California Desert Native Plants Act were encountered, field personnel recorded data points using a GPS with sub-meter accuracy (i.e., Trimble® GeoXT) and a data dictionary. The data dictionary included, at a minimum, the species name, the number of individuals, and the botanist collecting the data. The survey methodology and results were documented in a memorandum, with figures illustrating the location of the mapped desert native plants and representative photos of the species. Appendix 3.2E, California Desert Native Plants Act Survey Report, has additional details on the surveys.

Crotch's Bumble Bee Surveys

The surveys for Crotch's bumble bee (~~*Bombus crotchii*~~) were conducted in accordance with the CDFW survey guidance (CDFW 2023a). The survey passes were led by Callie Amoaku, who holds a Memorandum of Understanding (MOU) and Scientific Collecting Permit (SCP) to capture Crotch's bumble bee. Dudek conducted five protocol level surveys for Crotch's bumble bee in June and July 2024 (June 12, July 1, July 2, July 23, and July 24) and two in April and May 2025 (April 16 and May 21). The surveys were split across 2 years because the Project owner did not have access to the entire Project gen-tie area during the 2024 surveys. The 2024 surveys were conducted from June through July, during the Colony Active Period of April through August, which according to CDFW guidelines had the highest detection period, and were spaced between 2 and 4 weeks apart. The three 2025 surveys, which covered the remainder of the Project site and the BESS location, were conducted between April and June, which is during the Colony Active Period. The 2025 surveys were spaced 4 weeks apart to cover a wider period during the Colony Active Period while also meeting recommended guidelines. Appendix 3.2F, Crotch's Bumble Bee Survey Report, has additional details on the surveys.~~Dudek conducted three (3) protocol level surveys for Crotch's bumble bee spaced in June and July 2024 (June 11, July 1 and July 17). The surveys were conducted by qualified biologists with experience in surveying for Crotch's bumble bee. Surveys occurred after sunrise and 3 hours before sunset and were not conducted during wet conditions (e.g., foggy, raining, or drizzling) or windy conditions (i.e., sustained winds greater than 8 mph).~~

The surveys were conducted during optimal conditions when there were sunny to partly sunny skies that were greater than 60° Fahrenheit. Suitable habitat within the Study Area was visually surveyed for 1 person-hour per 3 acres of potential habitat. Biologists walked wandering transects through these resources with a goal of observing bumble bees in passing and observing bumble bee nest sites associated with small mammal burrow or other appropriate soil cavities.

Raptor Nest Surveys

Surveys for nesting raptors (i.e., eagles, hawks, kites, falcons, and owls) were conducted in early 2025. Dudek biologists conducted a 1-day survey for the Study Area and a 500-foot buffer, with a focus on areas with larger trees and shrubs, residential areas with large ornamental trees, and transmission towers that have potential to support raptor nests.

Aquatic Resources Delineation

Prior to conducting the jurisdictional delineation, USFWS National Wetland Inventory data (USFWS 2024a) was reviewed to determine if the Study Area contained any features mapped by the USFWS. Site-specific topographical data was reviewed in conjunction with aerials, both current and historical, to determine the potential presence of non-wetland waters. Current vegetation mapping was reviewed to assess whether the Study Area supported hydrophytic vegetation and potential wetlands. Jurisdictional boundaries were mapped in the field using ESRI Collector on a mobile device with submeter accuracy. Remote sensing was not used for the delineation.

U.S. Army Corps of Engineers – Potential Waters of the U.S.

The U.S. Army Corps of Engineers (USACE) wetlands delineation was conducted in accordance with the 1987 USACE Wetlands Delineation Manual (USACE 1987) and the Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Arid West Region (USACE 2008a). A Field Guide to the Identification of the Ordinary High Water Mark (OHWM) in the Arid West Region of the Western United States: A Delineation Manual (USACE 2008b) was used to determine the limits of non-wetland waters. Non-wetland waters were delineated on aerial maps in conjunction with ESRI Collector on a mobile device. The widths of each non-wetland water were determined in the field according to the OHWM manual. USACE OHWM Forms were completed at representative cross-sections of non-wetland waters to capture their characteristics and widths.

Regional Water Quality Control Board – Potential Waters of the U.S. and Waters of the State

Waters of the state regulated by the RWQCB were mapped in accordance with the State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State (SWRCB 2021). As described in these procedures, wetland waters of the state are mapped based on the procedures in USACE's 1987 Corps of Engineers Wetlands Delineation Manual (USACE 1987) and its 2008 Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Arid West Region (Version 2.0) (USACE 2008a). Non-wetland waters are mapped at the OHWM based on the procedures defined in USACE's 2008 A Field Guide to Ordinary High Water Mark (OHWM) in the Arid West Region of the Western United States (USACE 2008b).

California Department of Fish and Wildlife – Streams

Potential CDFW jurisdictional areas were mapped to include the bank of the stream/channel and outer dripline of adjacent riparian vegetation, as set forth under California Fish and Game Code Section 1602. Streambeds under

the jurisdiction of CDFW were delineated using the Cowardin method of waters classification, which defines waters boundaries by a single parameter (i.e., hydric soils, hydrophytic vegetation, or hydrology) (Cowardin et al. 1979).

Protected Tree Census

The portions of the Study Area east of the railroad tracks, south of Foreston Drive and the Southern California Edison (SCE) Vincent Substation, and east of the SCE substation are within a County of Los Angeles Significant Ecological Area (SEA) (County of Los Angeles 2025), as shown in Figure 3.2-68, Los Angeles County Significant Ecological Area. The County’s SEA Ordinance includes 60 tree species to be protected, including all sizes of California juniper (*Juniperus californica*) (Los Angeles County Planning 2020). Dudek biologists mapped the California juniper within the SEA portions of the Study Area. Field personnel recorded data points and circumference for each individual plant using a mobile device with sub-meter accuracy. An evaluation of existing health for each California juniper was conducted. Appendix A, Protected Tree Report, of Appendix 3.2G, Biota Report, has additional details on the census.

3.2.1.6 Nitrogen Deposition Model

A nitrogen deposition analysis was performed to assess the proposed Project’s potential operational impact on biological resources within 6 miles of the Study Area and is included as Appendix 3.2H, Nitrogen Deposition Model. During operation, there will be periodic emissions of oxides of nitrogen (NO_x), from the testing and maintenance of three (3) emergency diesel generators (one [1] rated at 323 horsepower [hp] and two [2] rated at 744 hp). These emissions will result in nitrogen deposition around the Project site. To determine the potential impacts during operation, the American Meteorological Society/U.S. Environmental Protection Agency Regulatory Model (AERMOD) Version 24142 was used to model the concentration of nitrogen around the Project site using wet and dry deposition algorithms. The generators would meet the U.S. Environmental Protection Agency (EPA) Tier 4 standards based on the equipment specification sheets and were each assumed to operate up to 50 hours per year for testing and maintenance. Ammonia (NH₃) is a product of combustion with equipment having selective catalytic reduction (SCR) equipment. As the generators would be equipped with SCR, emissions of NH₃ were estimated and added to the NO_x emissions for total nitrogen emissions. Principal parameters of this modeling are presented in Table 3.2-2, AERMOD Principal Parameters – Nitrogen Deposition.

Table 3.2-2. AERMOD Principal Parameters – Nitrogen Deposition

Parameter	Details
Dispersion Model	The air dispersion model used was AERMOD Version 24142, with the Lakes Environmental Software implementation/user interface, AERMOD View, Version 13.0.0.
Meteorological Data	The latest 5-year meteorological data (2016-2020) for the Palmdale Station (KPMD) were obtained from CARB and used in the analysis as the most representative data set based on proximity and wind direction. The input data was also conservative, based on a test run that compared maximum concentrations using the Palmdale Station to the concentrations using the Santa Clarita Station (the other station in general proximity to the Project) meteorological data.
Urban versus Rural Option	Urban areas typically have more surface roughness, as well as structures and low-albedo surfaces that absorb more sunlight—and thus more heat—relative to rural areas. Based on the land use procedure from 4.4.1 of the OEHHA Guidance Manual, the rural dispersion was appropriate for the Project site (OEHHA 2015).

Table 3.2-2. AERMOD Principal Parameters - Nitrogen Deposition

Parameter	Details
Terrain Characteristics and Elevation Data	Digital elevation model files were imported into AERMOD so that complex terrain features were evaluated as appropriate, and elevations were assigned to the emission sources and receptors. Digital elevation data were obtained through AERMOD View in the U.S. Geological Survey's National Elevation Dataset format with an approximately 1 arc-second resolution.
Emission Sources and Release Parameters	The diesel generators were modeled as point sources with release parameters based on the specification sheets and default diesel-fired internal combustion stack parameters (SBCAPCD 2025), if generator specific information was not available. The 323 hp generator was modeled with a vertical stack height of 3.0 meters, inside stack diameter of 0.13 meters, gas exhaust temperature of 780 Kelvin, and gas exhaust velocity of 63.9 meters per second. Each 744 hp generator was modeled with a vertical stack height of 3.7 meters, inside stack diameter of 0.2 meters, gas exhaust temperature of 719.82 Kelvin, and gas exhaust velocity of 14.05 meters per second.
Receptors	A telescoping grid of receptors was generated with the following spacing to evaluate potential nitrogen deposition impacts within a 6-mile radius of the Project: ▪ 25-meter spacing on the facility boundary ▪ 25-meter spacing from the facility boundary out to 100 meters ▪ 50-meter spacing from 100 meters to 250 meters ▪ 100-meter spacing from 250 meters to 500 meters ▪ 250-meter spacing from 500 meters to 1,000 meters ▪ 500-meter spacing from 1,000 meters to 2,000 meters ▪ 1,500-meter spacing from 2,000 meters to 8,000 meters
Gas Deposition	The vegetation in the region is primarily grassland and shrubland. These vegetation categories are classified as "Land Use Category" of "3 - Rangeland" in AERMOD.
NO _x to NO ₂ Conversion	A 100% conversion of NO _x and NH ₃ into atmospherically derived nitrogen (Tier 1).
Gas and Particle Deposition	Nitric acid was assumed for the gas deposition parameters as it has a strong affinity for impacts to soils and vegetation. The default deposition velocity and parameters (pollutant reactivity factor and seasons) were assumed. The following gas deposition parameters were assumed: ▪ Pollutant Diffusivity in Air: 0.1628 cm²/s ▪ Pollutant Diffusivity in Water: 2.98E-05 cm²/s ▪ Cuticular Resistance: 100,000 s/cm ▪ Henry's Law Constant: 8E-08 Pa-m³/mol

Source: OEHHA 2015; SBCAPCD 2025.

Notes: AERMOD = American Meteorological Society/EPA Regulatory Model; hp = horsepower. Pa-m³/mol = pascal-meters cubed per mole; NH₃ = ammonia; NO_x = oxides of nitrogen; s/cm = seconds per centimeter.

See Appendix 3.2F-2H, Nitrogen Deposition Model, for additional information.

The AERMOD model calculates atmospheric deposition of nitrogen by calculating the wet and dry fluxes of total nitrogen. This deposition is accomplished by using a resistance model for the dry deposition part, and by assigning particle phase washout coefficients for the wet removal process from rainout. As discussed above, depositional parameters for nitric acid are input into the model to calculate the deposition of nitrogen. AERMOD sums the results of the wet and dry nitrogen deposition to produce annual deposition rates in units of grams per square meter (g/m²) for the entire 5-year meteorological period modeled, which are converted to kilograms per hectare per year (kg/ha/yr) for comparison to critical loads of nitrogen for biological resources within 6 miles of the Study Area. As discussed in detail below, the testing and maintenance operation of the Project's emergency backup generators will not lead to

nitrogen deposition levels that exceed recognized thresholds and will thus result in less than significant impacts to natural vegetation communities and special status species.

3.2.1.7 Vegetation Communities and Land Cover Types

All plant species encountered during the field reconnaissance surveys and jurisdictional delineations were identified and recorded. Latin and common names for plant species with a California Rare Plant Rank (formerly California Native Plant Society List) follow the California Native Plant Society On-Line Inventory of Rare, Threatened, and Endangered Plants of California (CNPS 2025a). For plant species without a California Rare Plant Rank, Latin names follow the Jepson Interchange List of Currently Accepted Names of Native and Naturalized Plants of California (Jepson Flora Project 2025) and common names follow the California Natural Community list (CDFW 2025e) or the U.S. Department of Agriculture Natural Resources Conservation Service (USDA NRCS) Plants Database (NRCS 2025). A list of plant species observed in the Study Area during initial surveys is presented in Appendix 3.2B. Representative photos of the vegetation communities can be found in Appendix 3.2I, Photo Exhibit.

A total of six (6) vegetation communities are considered sensitive by CDFW. The vegetation communities and land cover locations are summarized in Table 3.2-3, Vegetation Communities and Land Covers in the Study Area, and illustrated in Figure 3.2-79, Vegetation Communities and Land Cover. Vegetation communities within 1,000 feet of the gen-tie route options are expected to be similar to the Study Area because there are no significant changes in topography, geology, or hydrology within that distance.

Table 3.2-3. Vegetation Communities and Land Covers in the Study Area

Alliance	Association	CDFW Sensitive ¹	Ranking ²	Acres
Native Communities				
Cheesebush – sweetbush scrub	<i>Ambrosia salsola - Larrea tridentata</i>	No	G4/S4	0.82
	<i>Ambrosia salsola</i> Association	No	G4/S4	<u>3.992.60</u>
Fiddleneck - phacelia fields	<i>Amsinckia menziesii - Erodium</i> spp.	No	G5/S5	<u>2.252.21</u>
California sagebrush – (purple sage) scrub	<i>Artemisia californica - Eriogonum fasciculatum</i>	No	G4/S4	<u>15.4012.68</u>
Big sagebrush	<i>Artemisia tridentata - Ericameria nauseosa</i>	No	G5/S5	<u>18.6415.42</u>
	<i>Artemisia tridentata - Eriogonum fasciculatum</i>	No	G5/S5	3.98
	<i>Artemisia tridentata</i>	No	G5/S5	<u>0.580.48</u>
	<i>Artemisia tridentata</i> ssp. <i>parishii</i>	Yes	G2/S2	<u>8.587.66</u>
Fourwing saltbush scrub	<i>Atriplex canescens</i>	No	G5/S4	<u>94.0375.57</u>
Mormon tea scrub	<i>Ephedra viridis</i>	No	G4/S4	<u>23.9220.87</u>
Rubber rabbitbrush scrub	<i>Ericameria nauseosa - Juniperus californica</i> / herb	No	G5/S5	<u>20.0618.49</u>
	<i>Ericameria nauseosa</i>	No	G5/S5	<u>8.875.38</u>
California buckwheat scrub	<i>Eriogonum fasciculatum</i>	No	G5/S5	<u>12.404.75</u>
	<i>Eriogonum fasciculatum</i> var. <i>foliolosum - Juniperus californica</i>	Yes	G3/S3	<u>5.244.50</u>

Table 3.2-3. Vegetation Communities and Land Covers in the Study Area

Alliance	Association	CDFW Sensitive ¹	Ranking ²	Acres
California buckwheat - Parish's goldeneye scrub	<i>Eriogonum fasciculatum</i> rock outcrop	Yes	Unranked	4.283.82
California walnut groves	<i>Juglans californica</i> / annual herbaceous	Yes	G3/S3	0.89
California juniper woodland	<i>Juniperus californica</i> / <i>Adenostoma fasciculatum</i> - <i>Eriogonum fasciculatum</i>	Yes	Unranked	34.7731.66
	<i>Juniperus californica</i> / herbaceous	Yes	Unranked	126.21106.67
	<i>Juniperus californica</i> / <i>Eriogonum fasciculatum</i> - <i>Artemisia californica</i>	No	G5/S5	0.480.23
Subtotal:				385.39317.35
Naturalized (Non-Native)				
Wild oats and annual brome grasslands <i>Avena</i> spp. — <i>Bromus</i> spp.	<i>Avena barbata</i> - <i>Bromus hordeaceus</i>	No	GNA/SNA	3.282.22
Red brome or Mediterranean grass grasslands	<i>Bromus rubens</i> - mixed herbs	No	GNA/SNA	3.172.99
Subtotal:				6.455.21
Land Cover Types				
Disturbed habitat	Not applicable	No	NA/NA	30.7219.38
Urban/Developed	Not applicable	No	NA/NA	108.1471.95
Subtotal:				138.8691.33
Total:				530.71413.88

Notes: Totals may not sum due to rounding.

¹ CDFW has determined the community to be sensitive.

² The conservation status of a vegetation community is designated by a number from 1 to 5, preceded by a letter reflecting the appropriate geographic scale of the assessment (G = global, S = state). The numbers have the following meaning:

1 = critically imperiled

2 = imperiled

3 = vulnerable to extirpation or extinction

4 = apparently secure

5 = demonstrably widespread, abundant, and secure

NA = not applicable

GNA = global rank not applicable

SNA = state rank not applicable

Unranked= Associations that are considered sensitive, but have not been ranked

Native Vegetation Communities

Vegetation community descriptions are taken from A Manual of California Vegetation, Online Edition (CNPS 2025b).

Cheesebush – Sweetbush Scrub

Cheesebush – sweetbush scrub (*Ambrosia salsola* – *Bebbia juncea* Shrubland Alliance) has cheesebush (*Ambrosia salsola*), sweetbush (*Bebbia juncea*), woolly brickellbush (*Brickellia incana*), and/or desertsenna (*Senna armata*) as

dominant or co-dominant in the shrub canopy with Wiggins' cholla (*Cylindropuntia echinocarpa*), brittlebush (*Encelia farinosa*), California jointfir (*Ephedra californica*), Mojave rabbitbrush (*Ericameria paniculata*), California buckwheat (*Eriogonum fasciculatum*), white ratany (*Krameria grayi*), creosote bush (*Larrea tridentata*), and beavertail pricklypear (*Opuntia basilaris*). This alliance can be found on intermittently flooded channels, arroyos, washes, valleys, flats, and rarely flooded low-gradient deposits. Soils are alluvial, sandy and gravelly, and disturbed desert pavement. Two (2) associations of the alliance were mapped within the Study Area: *Ambrosia salsola* – *Larrea tridentata* and *Ambrosia salsola* association. These associations were mapped in the gen-tie portion Study Area.

Fiddleneck – Phacelia Fields

Fiddleneck – phacelia fields (*Amsinckia [menziesii, tessellata]* – *Phacelia* spp. Herbaceous Alliance) has Menzies' fiddleneck (*Amsinckia menziesii*), bristly fiddleneck (*Amsinckia tessellata*) and/or *Phacelia* spp. or other *Amsinckia* sp. as seasonally co-dominant in the herbaceous layer. Additional local species present include California saltbush (*Atriplex californica*), *Avena* spp., ripgut brome (*Bromus diandrus*), soft brome (*Bromus hordeaceus*), red brome (*Bromus rubens*), exserted Indian paintbrush (*Castilleja exserta*), and *Erodium* spp. Emergent shrubs may be present at low cover. This alliance can be found along upland slopes, broad valleys, ocean bluffs, grazed or recently burned hills, fallow fields. Soils are well drained and loamy, and they are often subject to high levels of disturbance. One (1) association of the alliance, *Amsinckia menziesii* – *Erodium* spp., was mapped in the BESS portion of the Study Area.

California Sagebrush – (Purple Sage) Scrub

California sagebrush – (purple sage) scrub (*Artemisia californica* – [*Salvia leucophylla*] Shrubland Alliance) has California sagebrush (*Artemisia californica*) and/or purple sage (*Salvia leucophylla*) as dominant or co-dominant in the shrub canopy with chamise (*Adenostoma fasciculatum*), coyotebrush (*Baccharis pilularis*), bladderpod spiderflower (*Cleome isomeris*), orange bush monkeyflower (*Diplacus aurantiacus*), California brittlebush (*Encelia californica*), brittlebush, California jointfir, narrowleaf goldenbush (*Ericameria linearifolia*), California buckwheat, and chaparral yucca (*Hesperoyucca whipplei*). This alliance can be found on slopes of variable aspects, but usually steep and rarely flooded, low-gradient deposits along streams. Soils are alluvial or colluvial derived. One (1) association of the alliance, *Artemisia californica* – *Eriogonum fasciculatum*, was mapped in the gen-tie portion Study Area.

Big Sagebrush

Big sagebrush (*Artemisia tridentata* Alliance) has big sagebrush (*Artemisia tridentata*) as dominant or co-dominant in the shrub canopy with Acton's encelia (*Encelia actoni*), Mormon tea (*Ephedra viridis*), and California buckwheat (*Eriogonum fasciculatum*). Shrub canopy is open to continuous and emergent trees may be present at low cover. The herbaceous layer is usually sparse to intermittent and grassy. ~~Habitat where big sagebrush occurs includes~~ This alliance can be found on plains, alluvial fans, bajadas, pediments, lowers slopes, valley bottoms, seasonal and perennial stream channels, and dry washes. Soils are well drained and consist of loam or sand. Three (3) associations of the alliance were mapped within the Study Area: *Artemisia tridentata* Association, *Artemisia tridentata-Eriogonum fasciculatum* Association, and *Artemisia tridentata-Ericameria nauseosa* Association. These associations were found in the BESS and Southern Gen-tie portions of the Study Area.

Fourwing Saltbush Scrub

Fourwing saltbush scrub (*Atriplex canescens* Shrubland Alliance) has fourwing saltbush (*Atriplex canescens*) as dominant or co-dominant in the shrub canopy with burrobush (*Ambrosia dumosa*), cheesebush (*Ambrosia salsola*), spiny saltbush (*Atriplex confertifolia*), cattle spinach (*Atriplex polycarpa*), Mormon tea, hop sage (*Grayia spinosa*), and creosote bush (*Larrea tridentata*). Emergent trees may be present at low cover. This alliance can be found along playas, old beach and shores, lake deposits, dissected alluvial fans, rolling hills or channel beds. Soils are carbonate rich, alkaline, sandy, or sandy clay loams. One (1) association, *Atriplex canescens*, was mapped in the gen-tie portion Study Area.

Mormon Tea Scrub

Mormon tea scrub (*Ephedra viridis* Shrubland Alliance) has Mormon tea as dominant or co-dominant in the shrub canopy with big sagebrush and rubber rabbitbrush (*Ericameria nauseosa*). Emergent trees may be present at low cover, including California juniper (*Juniperus californica*). This alliance can be found along ridges, hills, mountains, and channel beds. Soils are shallow derived from alluvium, granitic substrate, bedrock, colluvium. One (1) association, *Ephedra viridis*, was mapped primarily in the BESS portion of the Study Area.

Rubber Rabbitbrush Scrub

Rubber rabbitbrush scrub (*Ericameria nauseosa* Shrubland Alliance) has rubber rabbitbrush as dominant or co-dominant in the shrub canopy with big sagebrush, *Ephedra* spp., and California buckwheat (*Eriogonum fasciculatum*). Emergent trees may be present at low cover, including California juniper. This alliance Rubber rabbitbrush can be found along all topographic settings, especially in disturbed settings. Soils are well-drained sands and gravels. Two (2) associations, *Ericameria nauseosa* and *Ericameria nauseosa-Juniperus californica*/herb, were mapped within the BESS and gen-tie portions of the Study Area.

California Buckwheat Scrub

California buckwheat scrub (*Eriogonum fasciculatum* Shrubland Alliance) has California buckwheat or chaparral yucca as dominant or co-dominant in the shrub canopy in cismontane stands with California sagebrush, coyotebrush, orange bush monkeyflower, California brittlebush, brittlebush, and Menzies' goldenbush (*Isocoma menziesii*). Emergent trees may be present at low cover, including California juniper. This alliance can be found in upland slopes, intermittently flooded arroyos, channels and washes, and rarely flooded low-gradient deposits. Soils are coarse, well drained, and moderately acidic to slightly saline. Two (2) associations, *Eriogonum fasciculatum* and *Eriogonum fasciculatum* var. *foliolosum* – *Juniperus californica*, were mapped in the BESS and north of the Vincent Substation portions of the Study Area.

California Buckwheat – Parish's Goldeneye Scrub

California buckwheat – Parish's goldeneye scrub (*Eriogonum fasciculatum* – *Viguiera parishii* Shrubland Alliance) has California buckwheat and/or Parish's goldeneye (*Viguiera parishii*) as dominant or co-dominant in the shrub canopy with burrobush (*Ambrosia dumosa*), cheesebush, big sagebrush (*Artemisia tridentata*), sweetbush, blackbrush (*Coleogyne ramosissima*), buck-horn cholla (*Cylindropuntia acanthocarpa*), Wiggins' cholla, brittlebush, and Nevada jointfir (*Ephedra nevadensis*). This alliance can be found in wash and arroyo margins, rocky to bouldery alluvium, canyons, and moderate to steep colluvial slopes and ridges. Soils are well drained and derived from

granitic or volcanic rock. One (1) association, *Eriogonum fasciculatum* rock outcrop, was mapped north of the Vincent Substation in the Study Area.

California Walnut Groves

California walnut groves (*Juglans californica* Forest and Woodland Alliance) have Southern California walnut (*Juglans californica*) as dominant or co-dominant in the tree canopy with other native trees. One (1) association, *Juglans californica*/annual herbaceous, was mapped adjacent to residential property (possibly ornamental plantings in origin) north of the Vincent Substation in the Study Area.

California Juniper Woodland

California juniper woodland has California juniper as dominant or co-dominant in the small tree canopy with single-leaf pinyon (*Pinus monophylla*) and blue oak (*Quercus douglasii*). Local shrubs may include big sagebrush *Ephedra* spp., chaparral yucca (~~*Hesperoyucca whipplei*~~), and scale broom (*Lepidospartum squamatum*). This alliance can be found along ridges, slopes, valleys, alluvial fans, and valley bottoms. Soils are porous, rocky, coarse, sandy, or silty, and are often very shallow. Three (3) associations, *Juniperus californica*, *Juniperus californica*-*Adenostoma fasciculatum*-*Eriogonum fasciculatum*, and *Juniperus californica*-*Ericameria linearifolia*/annual-perennial herb, were mapped within the BESS and gentle portions of the Study Area.

Naturalized (Non-Native) Vegetation Communities

Wild oats and Annual Brome Grasslands

Wild oats and annual brome grasslands (*Avena* spp.-*Bromus* spp. Herbaceous Semi-Natural Alliance) has slender oat (*Avena barbata*), common wild oat (*Avena fatua*), stiff brome (*Brachypodium distachyon*), greater quaking-grass (*Briza maxima*), great brome, soft brome (*Bromus hordeaceus*) and/or wall barley (*Hordeum murinum*) as dominant or co-dominant with other non-natives in the herbaceous layer. Emergent trees and shrubs may be present at low cover. ~~Wild oats and annual brome grasslands~~ This alliance can be found along all topographic settings in foothills, waste places, rangelands, and openings in woodlands. One (1) association, *Bromus hordeaceus*-*Amsinckia menziesii*-*Hordeum murinum*, was mapped adjacent to the Vincent Substation in the Study Area.

Red Brome or Mediterranean Grass Grasslands

Red brome or Mediterranean grass grasslands (*Bromus rubens* – *Schismus [arabicus, barbatus]* *Bromus rubens* Alliance) has red brome, Arabian schismus (*Schismus arabicus*), and/or common Mediterranean grass (*Schismus barbatus*) as dominant or co-dominant with other non-natives in the herbaceous layer. Emergent shrubs may be present at low cover. This habitat can be found in all topography settings and soil textures. One (1) association, *Bromus rubens* – mixed herbs, was mapped adjacent to the Vincent Substation in the Study Area.

Disturbed and Developed Land Cover Types

Disturbed Habitat

Although not recognized by the Manual of California Vegetation, Online Edition (CNPS 2025b) or the Natural Communities List (CDFW 2025e), disturbed habitat is described in the Draft Vegetation Communities of San Diego County (Oberbauer et. al. 2008). Disturbed habitat is described as areas generally lacking vegetation due to high levels of existing or historical human disturbance and are no longer recognizable as a native or naturalized

vegetation association. Areas mapped as disturbed habitat may include unpaved roads, trails, and graded areas (Oberbauer et. al. 2008). Vegetation in these areas, if present at all, is usually sparse and dominated by non-native weedy herbaceous species (Oberbauer et. al. 2008). Areas mapped as disturbed habitat were found throughout the Study Area and were usually associated with developments or infrastructure.

Urban/Developed

Although not recognized by the Manual of California Vegetation (CNPS 2025b) or the Natural Communities List (CDFW 2025e), the urban/developed mapping unit (or developed land) is described in Draft Vegetation Communities of San Diego County (Oberbauer et. al. 2008). This mapping unit describes areas supporting human-made structures, including homes, yards, sidewalks, and other highly modified lands supporting structures associated with dwellings or other permanent structures. Vegetation in these areas, if present at all, is typically associated with ornamental landscaping that has been included in the development footprint (Oberbauer et. al. 2008). Most of the developed lands in the Study Area included the large, paved substation and roads.

3.2.1.8 Potential Jurisdictional Aquatic Resources

Approximately ~~6.524~~0.53~~80~~ acres of potential jurisdictional waters regulated by RWQCB and CDFW were found within the Study Area, as summarized in Table 3.2-4, Summary of Potential Jurisdictional Waters Within the Study Area, and illustrated in Figure 3.2-1, Hydrologic Features. Impacts to these features will require permits from the RWQCB and CDFW before any Project activities take place. Based upon the current definition of waters of the U.S. per the Clean Water Act, no features were considered to be water of the U.S. under the jurisdiction of the U.S. Army Corp of Engineers due to the ephemeral-nature of each; however, an Approved Jurisdictional Determination will need to be sought from the agency to document this conclusion. No impacts to the Santa Clara River are proposed.

Table 3.2-4. Summary of Potential Jurisdictional Waters Within the Study Area

Jurisdiction	Study Area (acres)
RWQCB/CDFW	
Features	
Non-Wetland Waters	<u>3.346.23</u>
Swales	<u>0.290.27</u>
<u>Erosional Features</u>	<u>0.05</u>
RWQCB-Total	<u>6.523.80</u>
CDFW	
Features	
Non-Wetland Waters	<u>6.23</u>
Swales	<u>0.29</u>
CDFW Total	<u>6.52</u>

Notes: RWQCB = Regional Water Quality Control Board; CDFW = California Department of Fish and Wildlife.

3.2.1.9 Sensitive and Special-Status Plant Species

~~Special status plant surveys were conducted in 2023 to determine the presence or absence of plant species that are considered endangered, rare, or threatened under CEQA Guideline 15380 (14 CCR 15000 et seq.). A list of all~~The 80 special status plant species that are considered endangered, rare, or threatened under CEQA Guidelines

Section 15380 and that are known to occur in the within the 14 USGS 7.5-minute topographic quadrangles that the Study Area is in and the quadrangles that the 10-mile buffer intersects, as well as the species provided by the query of the USFWS' Information for Planning and Consultation, vicinity of the Study Area (and the surrounding nine (9) topographic quadrangles) including their habitat requirements, potential to occur onsite, and survey observations, are provided in Appendix 3.2B (CDFW 2025a; CNPS 2025a; USFWS 2025d). This appendix provides evaluations for each of the special-status species' occurrence in the Study Area vicinity and their potential to occur based on known range, habitat associations, preferred soil substrate, life form, elevation, and blooming period. Special-status plant species that have low potential or are not expected to occur are not further analyzed in this document because no direct, indirect, or cumulative impacts are expected based on the negative surveys and evaluation that these species do not have a moderate or high potential to occur onsite.

A total of 80 special-status and rare plants were identified from the literature review (CDFW 2025a, USFWS 2025d, and CNPS 2025a). Of these the 80 special-status plant species, the following 11 species were initially determined to have a moderate or high potential to occur due to suitable habitat being present and having recent records in the vicinity or region: California androsace (*Androsace elongata* ssp. *acuta*), club-haired Catalina-mariposa lily (*Calochortus clavatus* var. *clavatuscatalinae*), slender mariposa-lily (*Calochortus clavatus* var. *gracilis*), Plummer's mariposa-lily (*Calochortus plummerae*), Peirson's morning-glory (*Calystegia peirsonii*), Robinson's pepper-grass (*Lepidium virginicum* var. *robinsonii*), ocellated Humboldt lily (*Lilium humboldtii* ssp. *ocellatum*), green monardella (*Monardella viridis*), California spineflower (*Mucronea californica*), Robbins' nemacladus (*Nemacladus secundiflorus* var. *robbinsii*), and Lemmon's syntrichopappus (*Syntrichopappus lemmonii*). None of these species are listed under FESA or CESA.

Special-status plant surveys were conducted in 2023 to determine the presence or absence of plant species that had a moderate or high potential to occur in the Study Area. Two (2) sensitive plant species, short-joint beavertail (*Opuntia basilaris* var. *brachyclada*) and golden linanthus (*Leptosiphon aureus*), were mapped during the focused special-status plant surveys in 2023 within the proposed gen-tie route portion of the Study Area, as shown in Figure 3.2-810, Sensitive or Special-Status Species Survey Results. CNDDDB forms for the occurrences are found in Appendix 3.2J, CNDDDB Forms. The remaining nine (9) species were then reduced to a low potential to occur and will not be analyzed further. Sensitive plant species potential to occur within 1,000 feet of the gen-tie route options are expected to be similar to the Study Area because there are no significant changes in topography, geology, or hydrology within that distance.

Short-Joint Beavertail

Short-joint beavertail has a California Rare Plant Ranks (CRPR) of 1B.2, which is defined as plants rare, threatened, or endangered in California and elsewhere, with 20-80% of occurrences threatened (CNPS 2025a). The species is a cactus that can be found in creosote bush scrub, chaparral, pinyon-juniper woodland, and Joshua tree woodland (CDFW 2025a). Short-joint beavertail was mapped within the proposed gen-tie alignment portion of the Study Area, as shown in Figure 3.2-810, Sensitive or Special-Status Species Survey Results.

Golden Linanthus

Golden linanthus has a CRPR of 4.2, which is defined as a plant with limited distribution and is moderately threatened in California (CNPS 2025a). The species can be found in chaparral, cismontane woodland, coastal prairie, and valley and foothill grassland (CDFW 2025a). The species was mapped within the proposed gen-tie alignment portion of the Study Area, as shown in Figure 3.2-810, Sensitive or Special-Status Species Survey Results.

3.2.1.10 Sensitive and Special-Status Wildlife Species

The 61 wildlife species that are considered endangered, rare, or threatened under CEQA Guidelines Section 15380 and that are known to occur within the 14 USGS 7.5-minute topographic quadrangles that the Study Area is in and the quadrangles that the 10-mile buffer intersects, as well as the species provided by the query of the USFWS' Information for Planning and Consultation, are provided in Appendix 3.2B (CDFW 2025a; CNPS 2025a; USFWS 2025d). This appendix provides evaluations for each of the special-status species' occurrence in the Study Area vicinity and their potential to occur based on known range and habitat associations. Special-status wildlife species that have low potential or are not expected to occur are not further analyzed in this document because no direct, indirect, or cumulative impacts are expected based on the negative surveys and evaluation that these species do not have a moderate or high potential to occur on site.

A list of all special-status wildlife species known to occur in the vicinity of the Study Area (the two [2] USGS 7.5-inch quadrangles that the Study Area is in and the surrounding 10 quadrangles), including their habitat requirements, potential to occur in the Study Area, and survey observations, are provided in Appendix 3.2B. A total of 58 special-status wildlife species were identified from the literature and database review. OneTwo (12) special-status species wereas observed foraging in the BESS portion of the Study Area, loggerhead shrike (*Lanius ludovicianus*) and greater roadrunner (*Geococcyx californianus*). One species, mountain lion (*Puma concolor*), has a high potential to occur as a transient. The following six (6) special-status species had moderate to high potential to occur in the Study Area: Crotch's bumble bee, California legless lizard (*Anniella* spp.), Blainville's horned lizard (*Phrynosoma blainvillii*), Southern California rufous-crowned sparrow (*Aimophila ruficeps canescens*), Bell's sage sparrow (*Artemisiospiza belli belli*), and mountain lion. The 51-52 special-status species with a low potential to occur (six [6] species) or species that are not expected to occur (45-46 species) are excluded from further discussion below, except for western burrowing owl (*Athene cunicularia hypugaea*) and American badger (*Taxidea taxus*). A discussion of western burrowing owl is provided below; however, since burrowing owl is not expected in the Study Area it is not further analyzed apart from the discussion in this section. Sensitive wildlife species potential to occur within 1,000 feet of the gen-tie route options are expected to be similar to the Study Area because there are no significant changes in topography, geology, or hydrology within that distance.The following six (6) special-status species had moderate to high potential to occur in the Study Area: Crotch's bumble bee (*Bombus crotchii*), California legless lizard (*Anniella* spp.), Blainville's horned lizard (*Phrynosoma blainvillii*), Southern California rufous-crowned sparrow (*Aimophila ruficeps canescens*), Bell's sage sparrow (*Artemisiospiza belli belli*), and mountain lion (*Puma concolor*).

Crotch's Bumble Bee

Crotch's bumble bee is a candidate for listing as "Endangered" under CESA and is afforded the protection of CESA while the California Fish and Game Commission decides if listing the species is warranted. This species occurs primarily in California, including the Mediterranean region, Pacific Coast, Western Desert, Great Valley, and adjacent foothills through most of southwestern California (The Xerces Society 2018). In California, the species inhabits open grassland and scrub habitats (The Xerces Society 2018). The size of Crotch's bumble bee colonies has not been well documented, but like most other species of bumble bees, the species primarily nests underground (The Xerces Society 2018). Bumble bees, including Crotch's bumble bee, are generalist foragers and have been reported visiting a wide variety of flowering plants. Since it has a very short tongue, Crotch's bumble bee is best suited to forage at open flowers with short corollas (The Xerces Society 2018). The plant families most associated with observations or collections of the species from California include Fabaceae, Apocynaceae, Asteraceae, Lamiaceae, and Boraginaceae (The Xerces Society 2018). Nectar plants known to be visited by Crotch's bumble bee include the

genera *Asclepias*, *Chaenactis*, *Lupinus*, *Medicago*, *Phacelia*, and *Salvia* (Williams et al. 2014, Xerces Society et al. 2018), but it is assumed flowering plants in other genera could also support foraging by this species.

Crotch's bumble bee could use small mammal burrows within all the vegetation communities in the Study Area and forage on suitable plant species within those communities. However, no Crotch's bumble bee were observed during the surveys that occurred over two survey seasons. No bumble bees of any kind were observed during that period. Floral resources for the species are present but in limited numbers, with the Study Area being dominated by California juniper woodland, fourwing saltbush scrub, and Mormon tea scrub, as shown in Table 3.2-3, Vegetation Communities and Land Covers in the Study Area. Additionally, there are few records for the occurrence of the species or any other bumble bee from the Acton region (CDFW 2025a; iNaturalist 2025; The Xerces Society 2025). Due to the limited foraging opportunities and the few records of bumble bees as a whole in the region, the Project is not expected to involve take of Crotch's bumble bee. Focused surveys for the species conducted in June and July 2024 were negative for the species.

California Legless Lizard

This description provides information for three (3) potential species of legless lizard that may be found in the Study Area: Northern California legless lizard (*Anniella pulchra*), Southern California legless lizard (*Anniella stebbinsi*), and California legless lizard (*Anniella* spp.). This is due to the current uncertainty of the taxonomy of the genus in the Study Area's region (Nafis 2025). All three are considered CDFW SSC. These species are most commonly found in coastal dunes and coastal scrub, but also oak woodland, Joshua tree woodland, and pinyon-juniper woodland (Hansen and Shedd 2025), and are generally found in moist, loose soil (CDFW 2025a). California legless lizard has moderate potential to occur in the Study Area beneath the larger California junipers due to the expected higher moisture content of the soil.

Blainville's Horned Lizard

Blainville's horned lizard is a CDFW SSC that occurs throughout most of California in locations west of the desert and Cascade-Sierran highlands, in elevations from sea level to around 2,438 meters (8,000 feet) AMSL (Hansen and Shedd 2025). Despite a wide-ranging distribution, the species seems to be restricted to localized populations because of its association with loose soils that have a high sand content (Jennings and Hayes 1994). The species is found in a wide variety of vegetation types with the requisite loose sandy soils, including California sagebrush scrub, annual grassland, chaparral, oak woodland, riparian woodland, and coniferous forest (Klauber 1939; Stebbins 1954). Up to 90% of the diet of Blainville's horned lizard consists of native harvester ants (*Pogonomyrmex* spp.) (Pianka and Parker 1975), and the species does not appear to eat non-native Argentine ants (*Linepithema humile*) (Jennings and Hayes 1994). The species has a moderate potential to occur in a variety of the vegetation communities in the Study Area.

Greater Roadrunner

Observations of greater roadrunner were made in the Study Area but were not mapped since the species is highly mobile and expected to occur throughout the area. The species habitats include areas dominated by creosote, mesquite, chaparral, and tamarisk, as well as grasslands, riparian woodlands, and canyons (Cornell Lab 2025). Greater roadrunner nest sites are 3 to 10 feet or more off the ground, on a horizontal branch or in the crotch of a sturdy bush, cactus, or small tree (Cornell Lab 2025). Greater roadrunner is considered sensitive by the County (Los Angeles Audubon 2009). The species could use the California juniper in the Study Area for nesting and could forage throughout the Study Area.

Loggerhead Shrike

A single observation of loggerhead shrike was made in the Study Area, as shown in Figure 3.2-108, Sensitive or Special-Status Species Survey Results. The species is a CDFW SSC that occurs throughout the United States, Mexico, and portions of Canada and is widespread at the lower elevations in California (Humple 2008). Preferred habitats for the species are open areas that include scattered shrubs, trees, posts, fences, utility lines, or other structures that provide hunting perches with views of open ground, as well as nearby spiny vegetation or man-made structures (such as the top of chain-link fences or barbed wire) that provide a location to impale prey items for storage or manipulation (Humple 2008). Nest sites are chosen based more on the cover than the particular vegetation species and are usually constructed in a dense shrub or tree well below the crown and are well concealed (Yosef 1996). The species could use the California juniper in the Study Area for nesting and could forage throughout the Study Area.

Southern California Rufous-Crowned Sparrow

Southern California rufous-crowned sparrow is on the CDFW Watch List and occurs in sparse, mixed chaparral and coastal scrub habitats (CDFW 2025a). The species frequents relatively steep, often rocky hillsides with grass and forb patches and also grassy slopes without shrubs, if rock outcrops are present (CDFW 2025a). The species has a moderate potential to occur on the slopes of the gentle portion of the Study Area.

Bell's Sage Sparrow

Bell's sage sparrow is on the CDFW Watch List and occupies semi-open habitats with evenly spaced shrubs that are 1 meters to 2 meters (3.3 feet to 6.6 feet) high (County of Riverside 2008). CDFW still recognizes *A. belli belli* but the subspecies has been reclassified as its own species Bell's sparrow (*A. belli*), with the other subspecies *A. belli nevadensis* reclassified as sagebrush sparrow (*A. nevadensis*). For site selection, specific shrub species may be less important than overall vertical structure, habitat patchiness, and vegetation density (Wiens and Rotenberry 1981). At higher elevations in Southern California, Bell's sage sparrow often occurs in big sagebrush (County of Riverside 2008). Sage sparrows seek cover in fairly dense stands in chaparral and scrub habitats during the breeding season. Bell's sage sparrow has a moderate potential to occur in the *Artemisia tridentata* dominant and codominant vegetation communities in the Study Area.

Mountain Lion

Mountain lions associated with Southern California and Central Coast populations are designated as a State candidate endangered species. On April 16, 2020, the California Fish and Game Commission voted to designate the Southern California and Central Coast mountain lions as a candidate for listing as an endangered species under the CESA. The vote triggered a 1-year review by CDFW to determine whether these mountain lion populations should be formally protected under CESA; however, the listing status of this species is still currently unresolved at the time of this report.

The California mountain lion occurs throughout much of California open space, occurring in or moving through nearly all but the most urbanized settings. This species inhabits a wide range of habitat types where prey items such as mule deer (*Odocoileus hemionus*) and bighorn sheep (*Ovis canadensis*) are present, from interior, arid rocky scrublands, to upper montane coniferous forest, to chaparral, coastal scrub, and woodland habits along the coastal plain.

According to the Mountain Lion Predicted Habitat dataset (CDFW 2025b), the proposed BESS portion of the Study Area consists primarily of high quality habitat and most of the proposed gen-tie route is within low quality habitat. However, CDFW's Mountain Lion Habitat Suitability dataset has most of the proposed BESS portion of the Study Area and gen-tie alignment as low suitable habitat (Dellinger et al. 2020; CDFW 2025b). As such, the species could occur throughout most of the Project area during home range movement, dispersal, and foraging. The potential to occur is based on habitat suitability: scrub vegetation, presence of mule deer, and proximity to high-quality habitat on large swaths of public lands to the east in the Angeles Nation Forest. However, females keep their young in dens located in rocky terrain or in dense vegetation that provide cover but avoid roads and stay at a distance from human disturbance four times greater (approximately 600 meters) than non-reproductive mountain lions (Center for Biological Diversity and the Mountain Lion Foundation 2019). The Study Area is located adjacent to residential neighborhoods, Sierra Highway, the Southern Pacific Railroad lines, Carson Mesa Road, and SR-14, all of which have associated human presence. As such, females of the species are not expected to establish natal dens in the Study Area.

Western Burrowing Owl

As of October 15, 2024, western burrowing owl (*Athene cunicularia hypugaea*) is being considered for listing under the California Endangered Species Act (CESA) and the species is provided with the protection of CESA. Primary habitat requisites for burrowing owl are the presence of burrows for roosting and nesting and vegetation structure that is relatively short and sparse (Center for Biological Diversity et al. 2024). The species was historically abundant throughout Southwestern California, including up to the 610-meter (2,001.31 feet) elevation contour in the Transverse Range, but have been extirpated from Ventura, western Los Angeles, and Orange counties and are near extirpation in San Diego County (Center for Biological Diversity et al. 2024). The petition to list the species does not include the Study Area in the breeding range of the species and does not include the Study Area in one (1) of the 16 burrowing owl regions in California (Center for Biological Diversity et al. 2024).

CDFW's range and predicted habitat for burrowing owl does not include the Study Area (CDFW 2025f). There are five (5) CNDDDB records of the species within 10 miles that are in the Antelope Valley to the north of the Study Area, with the most recent being 2006 (CDFW 2025a). Citizen science-based databases have only five (5) records within 10 miles that are in the Antelope Valley to the north of the Study Area (eBird 2025; iNaturalist 2025).

The Study Area is dominated by shrub-dominant vegetation communities that have relatively high density. The Study Area elevation ranges from 2,700 feet to 3,500 feet above mean sea level, which is above the known historic occurrences of the species in the Transverse Ranges. California ground squirrel burrows are present but are sparse and none of the extensive surveys of the Study Area have identified burrowing owl or diagnostic sign (i.e., pellets, feathers, and extensive whitewash). Based upon the lack of suitable habitat; the Study Area being above the known elevation occurrence of the species in the region; the lack of observations of the species during extensive surveys; and the limited number of records of the species within 10 miles, burrowing owl is not expected in the Study Area and will not be further analyzed.

American Badger

American badger is a CDFW Species of Special Concern that is an uncommon, permanent resident found throughout most of the state, except in the northern North Coast (CDFW 2025f). Suitable habitat for the species is characterized by herbaceous, shrub, and open stages of most habitats with dry, friable soils (CDFW 2025f). American badger dig burrows in friable soil for dens and frequently reuse old burrows; although, some may dig a new den each night, especially in summer (CDFW 2025f). American badger is a highly specialized burrowing

mammal that primarily eats burrowing rats, mice, chipmunks, and especially ground squirrels and pocket gophers (CDFW 2025f).

There is one (1) CNDDDB record of American badger within 20 miles of the Study Area from 1930 at Lake Los Angeles (CDFW 2025a). There is one (1) 2021 iNaturalist record of the species approximately 8.6 miles to the west near Agua Dulce (iNaturalist 2025). American badger has been determined to have a low potential to occur in the Study Area due to the presence of suitable habitat, but no individuals were observed and no diagnostic sign (i.e., burrows or digs with the species' conspicuous claw marks) were observed during the extensive surveys of the Study Area. As such, the species will not be further analyzed.

3.2.1.11 Migratory Bird Treaty Act

The Migratory Bird Treaty Act (16 USC 703 et seq.), as amended (MBTA), prohibits the intentional take of any migratory bird or any part, nest, or eggs of any such bird. Under the MBTA, "take" is defined as pursuing, hunting, shooting, capturing, collecting, or killing, or attempting to do so. ~~In December 2017, Department of the Interior Principal Deputy Solicitor Jorjani issued a memorandum (M-37050) that interprets the MBTA's "take" prohibition to apply only to affirmative actions that have as their purpose the taking or killing of migratory birds, their nests, or their eggs. Unintentional or accidental take is not prohibited.~~ Additionally, Executive Order 13186, Responsibilities of Federal Agencies to Protect Migratory Birds, requires that any project with federal involvement address impacts of federal actions on migratory birds with the purpose of promoting conservation of migratory bird populations (66 FR 3853–3856). The Executive Order requires federal agencies to work with USFWS to develop a memorandum of understanding. USFWS reviews actions that might affect these species.

3.2.1.12 Bald and Golden Eagle Act

Golden eagle is protected by the federal The Bald and Golden Eagle Protection Act (16 U.S.C. 668-668c) and are a fully protected species in California (Fish and Game Code 3511). The species is an uncommon permanent resident and migrant throughout California, except the center of the Central Valley (CDFW 2025f). Golden eagle nest on cliffs of all heights and in large trees in open areas, with rugged, open habitats with canyons and escarpments used most frequently (CDFW 2025f). The species needs open terrain for hunting, including grasslands, deserts, savannahs, and early successional stages of forest and shrub habitats (CDFW 2025f). Golden eagle eats mostly rabbits and rodents, but it also takes other mammals, birds, reptiles, and some carrion (CDFW 2025f).

There is one (1) CNDDDB record of golden eagle nesting within 25 miles of the Study Area (CDFW 2025a). The record dates are from 1963, 1964, and 1965, and document the collection of eggs from the species for each of those years. The record location has a 1-mile accuracy and the location description was "Acton, in Aliso Canyon, off Soledad Canyon, in Angeles National Forest," which CDFW interpreted as being closer to the mouth of Aliso Canyon (CDFW 2025a). The center of the 1-mile circle is approximately 2 miles to the south-southwest of the Study Area in an area that is devoid of cliffs or open areas with large trees (Google Earth 2025).

No eagle or other raptor nests were identified within the Study Area and 500-foot buffer during the focused raptor nest surveys conducted in 2025. The Study Area and surrounding area do not contain the elements (i.e., cliffs or large trees in open areas) associated with nesting by golden eagle, so nesting by the species is not expected. Additionally, the species would not be expected to nest in areas where a variety of human activity occur since the adults of the species have been documented to flush from nest when those activities happen within 1,000 meters of the nest (Spaul and Heath 2017). The activities within the residential neighborhoods surrounding the Study Area and the Vincent Substation are expected to deter golden eagle from nesting within sight of these areas. Potential

nesting in the Angeles National Forest to the east of the site are not expected to be visible from the Study Area and activities during construction would not affect any potential nesting. The species could forage or migrate through the Study Area but the Project transmission facilities will be designed consistent with the *Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006* (Avian Power Line Interaction Committee [APLIC] 2006) where feasible. Transmission facilities will also be evaluated for potential collision reduction devices in accordance with *Reducing Avian Collisions with Power Lines: The State of Art in 2012* (APLIC 2012).

3.2.1.13 Wildlife Corridors and Habitat Linkages

Wildlife movement corridors have been recognized by federal and state agencies as important habitats worthy of conservation. Wildlife corridors provide migration channels seasonally (i.e., between winter and summer habitats), and provide non-migrant wildlife with the opportunity to move within their home range for food, cover, reproduction, and refuge. Habitat linkages are small patches that join larger blocks of habitat and help reduce the adverse effects of habitat fragmentation. Habitat linkages provide a potential route for gene flow and long-term dispersal of plants and animals and may also serve as primary habitat for smaller animals, such as reptiles and amphibians. Habitat linkages may be continuous habitat or discrete habitat islands that function as steppingstones for dispersal.

The Study Area does not overlap with any South Coast Missing Linkages, California Essential Habitat Connectivity Areas or Natural Landscape Block or Natural Landscape Block (South Coast Wildlands 2008, CDFW 2014, 2017). Given that the existing vegetation is surrounded on three (3) sides by similar habitats, the Study Area likely provides habitat for local wildlife movement but is not recognized as an important regional wildlife corridor by any state agency or jurisdiction and is of limited linkage value on a landscape scale. Furthermore, although local wildlife may utilize the Study Area for movement, regional connectivity is highly limited by residential neighborhoods, Sierra Highway, the Southern Pacific Railroad lines, Carson Mesa Road, and SR-14 to the west. Thus, the Project is not expected to impose significant barriers to wildlife movement.

3.2.1.13.1 California Desert Native Plant Act Covered Species

Four (4) species covered by the California Desert Native Plants Act were mapped within the Project footprint and a 150-foot buffer: chaparral yucca, Wiggins' cholla, beavertail pricklypear (*Opuntia basilaris* var. *basilaris*) and short-joint beavertail. Table 3.2-5, California Desert Native Plant Act Covered Species in the Survey Area, summarizes the numbers within each area and Figure 3.2-11, California Desert Native Plant Act Covered Species in the Survey Area, shows the locations of these species.

Table 3.2-5. California Desert Native Plant Act Covered Species in the Survey Area

Species	Amount
chaparral yucca	1,118
Wiggins' cholla	644
beavertail pricklypear	94
short-joint beavertail	4
Total	1,860

3.2.1.14 Los Angeles County Significant Ecological Area - Protected Trees

A total of 1,215 trees were documented within the Survey Area. Of these, 1,134 trees are located within the Santa Clara River SEA, and 1,021 of those are classified as protected California junipers as shown in Figure 3.2-12, Protected Trees, and summarized in Table 3.2-6, Summary of Trees Within the SEA Portion of the Study Area. The species is a shrub that is native to California and found only slightly beyond California borders (Calflora 2025). California juniper typically has several trunks and grows up to 13 feet (Jepson Flora Project 2025). The protected trees include 953 standard protected trees and 68 heritage trees. The remaining 194 trees consist of 81 located outside the SEA and 113 trees within the SEA that are classified as dead. Appendix A, Tree Location, of Appendix A, Protected Tree Report, of Appendix 3.2G, Biota Report, provides detailed locations of all individual trees assessed for the proposed Project and full results of the survey. Because the BESS facility site is located entirely outside of the Santa Clara SEA boundaries, the SEA ordinance and SEA program do not apply to that portion of the Project. Thus, there are no protected trees on the BESS facility site. As depicted in Figure 3.2-12, there are some protected and heritage trees located along the two gen-tie line routes.

Table 3.2-6. Summary of Trees Within the SEA Portion of the Study Area

Scientific Name	Common Name	Total Number of Protected Trees	Number of Heritage Trees	Total Number of Non-Protected Trees	Total Number of Trees
<i>Juniperus californica</i>	California juniper	953	68	113	1,134
Total		953	68	113	1,134

In the portions of the Study Area within the County's SEA, 1,159 California junipers were mapped, as shown in Figure 3.2-9, Protected Trees. Most of the California junipers mapped were located on slopes in the western and eastern portions of the SEA portion of the Study Area. The species is a shrub that is native to California and found only slightly beyond California borders (Calflora 2025). California juniper typically has several trunks and grows up to 13 feet (Jepson Flora Project 2025).

3.2.2 Environmental Analysis

Potential direct, indirect and cumulative impacts to biological resources were evaluated to determine the potential permanent and temporary effects of construction and operation of the proposed Project. Results from the field surveys, habitat evaluations and literature review were evaluated to address the potential for presence of sensitive biological resources within the Study Area were presented in the prior section.

Section 3.2.2, contained herein, identifies the biological resources that may be affected directly or indirectly and may have temporary or permanent impacts. These impact categories are defined as follows:

Direct. The CEQA defines direct impacts as those that result from the project and occur at the same time and place. Project related activities, such as alteration, disturbance or destruction of biological resources are considered a direct impact. Direct impacts for this Project are those associated with the grading and development of the BESS facility site and both gen-tie routes.

Indirect. CEQA defines indirect impacts as impacts that are caused by the project but do not occur at the same time but rather at different but a reasonably foreseeable future time. Indirect impacts associated with the proposed Project include effects to biological or aquatic resources as a result of dust, noise, vibration, or potential erosion.

Permanent. All impacts that result in the irreversible removal of biological resources are considered permanent. Permanent impacts for the proposed Project include the conversion of land for the BESS facility site and associated access facilities.

Temporary. Temporary impacts are considered to have reversible effects on biological resources. Temporary impacts associated with the proposed Project include tension/pulling sites along the gen-tie right of way, and other work associated with temporary access along the gen-tie line.

3.2.2.1 Significance Criteria

Factors typically used to evaluate the significance of project-related impacts are set forth in Appendix G of the CEQA Guidelines. CEQA Guidelines Appendix G is a screening tool, not a method for setting thresholds of significance. Appendix G is typically used in the Initial Study phase of the CEQA process, asking a series of questions. The purpose of these questions is to determine whether a project requires an Environmental Impact Report, a Mitigated Negative Declaration, or a Negative Declaration.

As the Governor's Office of Planning and Research stated, "Appendix G of the Guidelines lists a variety of potentially significant effects but does not provide a means of judging whether they are indeed significant in a given set of circumstances." The answers to the CEQA Guidelines Appendix G questions are not determinative of whether an impact is significant or less than significant. Nevertheless, the questions presented in CEQA Guidelines Appendix G are instructive. Potentially significant biological impacts resulting from the Project were assessed by the following criteria:

- Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as endangered, threatened, candidate, sensitive, or special status in local or regional plans, policies, or regulations, or by CDFW or USFWS.
- Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by CDFW or USFWS.
- Have a substantial adverse effect on federal or state protected WOTUS [waters of the United States] (including wetlands) as defined by Sections 404 and 401 of the 1972 Amendments to the Federal Water Pollution Control Act, commonly known as the Clean Water Act, or the Porter-Cologne Act, either through direct removal, filling, hydrological interruptions, or other means.
- Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory native wildlife corridors or impede the use of wildlife nursery sites.
- Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance.
- Conflict with the provisions of an adopted Habitat Conservation Plan, NCCP [natural community conservation plan], or other approved local, regional, or state habitat conservation plan.

CEQA Section 15380 provides that a plant or animal species may be treated as "rare or endangered" even if the species is not on one of the official lists if, for example, it is likely to become endangered in the foreseeable future.

3.2.2.2 CEQA Appendix G Assessment Criteria

The following impact analysis includes both gen-tie options, so the potential direct permanent and temporary impact acreages presented are in the comprehensive analyses of both gen-tie routes are greater than the expected actual impact acreages associated with constructing only one (1) gen-tie.

3.2.2.2.1 Would the project have a substantial adverse effect, either directly or through habitat modifications, on any species identified as endangered, threatened, candidate, sensitive, or special-status in local or regional plans, policies, or regulations, or by CDFW or USFWS?

Direct Impacts

Permanent and temporary direct impacts to special-status plants and wildlife could occur from construction of the proposed Project.

Special-status Plants

Less than Significant with Mitigation. Two (2) special-status plant species, short-joint beavertail and golden linanthus, were mapped in the gen-tie route portion of the Study Area during surveys in 2023. None of the mapped individuals will be directly impacted by the Project. However, some of the individuals of both species are in close proximity to the Project construction limits. **MM-BIO-1**, Demarcation of Disturbance Limits, requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. **MM-BIO-2**, Biological Monitoring, requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the flagged limits are adhered to during construction. **MM-BIO-3**, Worker Education Awareness Program, requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and Study Area, and measures to avoid and minimize impacts to those resources. Project implementation of MM-BIO-1 through MM-BIO-3 will reduce potential impacts to less than significant. Impacts will be **less than significant with mitigation**.

Special-status Wildlife

Less than Significant with Mitigation. Six (6) special-status wildlife species have a moderate or high potential to occur: Crotch's bumble bee, California legless lizard, Blainville's horned lizard, Southern California rufous-crowned sparrow, Bell's sage sparrow, and mountain lion. One (1) special-status wildlife species (loggerhead shrike) has been observed in the Study Area.

Crotch's Bumble Bee

Protocol surveys for Crotch's bumble bee conducted in 2024 and 2025 were negative for the species. During the initial survey each year, it was noted that there were very limited foraging opportunities within the Study Area. However, bumble bees are opportunistic and highly mobile. The species typically nests underground, so nesting individuals could be highly vulnerable to injury and mortality during construction, which could crush nests and individuals, if present on site. Harm to or the loss of individuals during construction will be significant due to reducing the rare species' numbers and will require mitigation. If Crotch's bumble bee is still a candidate for listing under CESA or has been listed under CESA at the time of the start of construction of the Project, the following

mitigation measures would be implemented. If the species is determined to not warrant listing under CESA at the time of the start of construction of the Project, then no mitigation is necessary. **MM-BIO-4**, Crotch's Bumble Bee Minimization Measures, would require pre-construction surveys for Crotch's bumble bee nests, with buffers established around active nests until the nests are deemed inactive.

MM-BIO-5, On-Site Preservation, would require the establishment of a conservation area that will preserve up to approximately ~~148~~ 136 acres of native vegetation communities (the non-impacted acres of the parcels associated with the ~~southern~~ gen-tie route) within the Study Area parcels associated with the gen-tie routes, as shown in Figure 3.2-13, Conservation Area, which will preserve habitat for the species should an ITP for the species be needed. The proposed mitigation parcels are located in the SEA and are made up of the same habitat as the land where the potential impacts would occur and thus make them ideal parcels for mitigation. The proposed mitigation land is made up of the parcels and gross acreages found in Table 3.2-7, Potential Parcels to be Used for On-Site Preservation, and shown on Figure 3.2-13, Conservation Area.

Table 3.2-7. Potential Parcels to be Used for On-Site Preservation

APN	Gross Acreage
3056-019-040 (south of railroad tracks)	12.85
3056-017-022	9.25
3056-017-016	5.07
3056-027-007	40.31
3056-015-008	40.06
3056-017-028	9.93
3056-017-027	9.90
3056-017-026	9.39
3056-017-023	40.04
Total Gross Acreage	173.36~~176.80~~¹

Notes: APN = Assessor's Parcel Number.

¹ Excludes areas where permanent impacts would occur. There will be up to approximately 3.44 acres of permanent impacts. The gross acreage of the parcels above totals 176.80 acres. Therefore, the total gross acreage when excluding the 3.44 acres of permanent impact is approximately 173.36 acres.

Redacted Preliminary ALTA Surveys have been provided in Appendix 3.2A. The ALTA survey information has been redacted to remove landowner names, non-mitigation land information, and any financial information that may be present in the title reports associated with the ALTA surveys. The parcels being considered for mitigation land are not already conserved, nor do they contain any conflicting easements or encumbrances that would preclude the use of this land for habitat mitigation, such as severed mineral rights, Williamson Act contracts, or subdivision prohibitions. Please note that title report in the Redacted Preliminary ALTA Survey for APN 3056-015-023 includes exception 3 for an oil and gas lease on the APN. That exception has been removed from the title and is no longer applicable to the parcel. Please see the updated title report for APN 3056-15-023 included at the end of the Redacted Preliminary ALTA Survey document.

Phase I Environmental Site Assessment information for the mitigation lands is provided in Appendix 3.5A, Hazardous Materials Handling Appendices Part 1, and no current or historical recognized environmental conditions were found.

MM-BIO-6, Habitat Mitigation and Monitoring Plan, would require the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas and will include flora resources that the species could use in the conservation area. MM-BIO-1 requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the integrity of any buffers established for active nests. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources. If Crotch's bumble bee is still a candidate for listing under CESA or has been listed under CESA at the time of the start of construction, the Project's implementation of MM-BIO-2 through MM-BIO-6 will reduce potential direct impacts to **less than significant with mitigation**.

Special-Status Reptiles

Less than significant with mitigation. California legless lizard and Blainville's horned lizard are designated as CDFW Species of Special Concern. The loss of habitat for a special-status species is not considered as a substantial adverse effect, and therefore not considered a potentially significant impact, simply because there is an impact. That impact must also be shown to have a substantial adverse effect on the resource. In the case of an individual species, the effect of the habitat loss must be substantial and adverse relative to the range of the species (i.e., that the loss of habitat by a particular development activity will adversely affect the species as a whole, and not simply the effect that a development activity will have on a specific population). These species are vulnerable to mortality or injury during vegetation and ground disturbing activities associated with construction. It is highly unlikely that short-term construction activities could cause the greater population of these special-status species to drop below self-sustaining levels due to the relatively small area of construction activity and the short-term nature of the construction schedule. However, mortality or injury to individual species during the vegetation removal and grading portion of construction is a reasonable possibility, so direct permanent impacts are possible and would be significant. **MM-BIO-7**, Special-Status Wildlife Relocation Plan, requires the preparation of a plan that has a process of clearance surveys and relocation of special-status wildlife into non-impacted portions of the Study Area. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for relocating any special-status reptiles. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources. MM-BIO-5 requires the establishment of a conservation area that will preserve suitable habitat for the species *considered to be all of the native vegetation communities for Blainville's horned lizard and the communities with California juniper present for California legless lizard* and where captured individuals would be relocated. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas that the species could use in the conservation area. Project implementation of MM-BIO-2, MM-BIO-3, MM-BIO-5, MM-BIO-6, and MM-BIO-7 will reduce potential direct impacts to **less than significant with mitigation**.

Special-Status Birds and Protected Nesting Bird Species

Less than significant with mitigation Three (3) special-status bird species, loggerhead shrike, Southern California rufous-crowned sparrow, and Bell's sage sparrow, have suitable nesting habitat on the Project site. Additionally, numerous other common species protected under the MBTA and California Fish and Game Code (Sections 3503, 3503.5, and 3513), including greater roadrunner, have suitable nesting habitat on site. Impacts to juvenile and adults of these species are not expected; however, nesting could be disrupted if construction occurs during the breeding season. Direct impacts to nesting birds could occur because of nest abandonment, reduced reproductive success, or other disruptions to nesting. Nests, eggs, and young could also be crushed or otherwise directly affected

during vegetation clearing and grading. Impacts to special-status and protected nesting bird species could be potentially significant. **MM-BIO-8**, Nesting Bird Avoidance, will provide pre-construction surveys and buffer establishment for active nests. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the integrity of any buffers established for active nests. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources. MM-BIO-5 requires the establishment of a conservation area that will preserve suitable habitat for the species (considered to be all of the native vegetation communities for loggerhead shrike, Southern California rufous-crowned sparrow, and Bell's sage sparrow). MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas that the species could use in the conservation area. Project implementation of MM-BIO-2, MM-BIO-3, MM-BIO-5, MM-BIO-6, and MM-BIO-8 will reduce potential direct impacts to **less than significant with mitigation**.

Mountain Lion

Less than significant with mitigation Because California mountain lion is a candidate for state listing under CESA, Project impacts resulting in direct take of California mountain lion will require an ITP under CESA through coordination with CDFW; however, no natal dens have been detected during field efforts that have resulted in extensive cover of the Project site, and none are expected. Therefore, no direct take of California mountain lion is expected to occur because of the proposed Project.

Impacts will be **less than significant with mitigation**.

Indirect Impacts

Special-Status Plants

Less than Significant with Mitigation. Potential short-term or temporary indirect impacts to short-joint beavertail and golden linanthus located in the Study Area could result from construction activities and include impacts related to or resulting from the activities outside of the Project limits, generation of fugitive dust, increased human activity, and the introduction of pollutants from construction equipment. Excessive dust can decrease the vigor and productivity of plants through effects on light, penetration, photosynthesis, respiration, and transpiration; increased penetration of phytotoxic gaseous pollutants; and increased incidence of pests and diseases. Additionally, invasive plant species could be introduced by the Project during construction and through landscaping installation that could alter the habitat and compete with special-status plants. These indirect impacts could result in additional loss of special-status plants that could be significant. Water trucks are expected as part of Project construction, which will reduce fugitive dust. **MM-BIO-9**, Invasive Species Prevention Plan, requires the preparation and implementation of a plan that will avoid and minimize the introduction of non-native plant species that could compete for habitat space with plants that the species forages on by ensuring that vehicles and equipment used during construction are weed free. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the Invasive Species Prevention Plan will be implemented. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources, which will include a discussion on invasive plants. Project implementation of MM-BIO-2, MM-BIO-3, and MM-BIO-9 will reduce potential indirect impacts to less than significant. Impacts will be **less than significant with mitigation**.

Special-Status Wildlife

Construction

Less than Significant with Mitigation. During construction activities, indirect impacts to sensitive wildlife could include construction-related dust, soil erosion, and water runoff decreasing or permanently altering habitat suitability. Without construction-related minimization measures to control dust, erosion, and runoff, and without compliance with National Pollutant Discharge Elimination System (NPDES) requirements, indirect impacts to riparian resources and upland communities could occur. However, standard construction BMPs to control dust, erosion, and runoff, including straw bales and silt fencing, will be implemented through the General Permit for stormwater control during construction to minimize these adverse effects. Additionally, implementation of MM-BIO-2 through MM-BIO-9 to reduce indirect impacts to special-status wildlife species will also contribute to the reduction of indirect impacts to **less than significant with mitigation**.

Operation

Less than Significant. Once constructed, the Project will be available to operate 7 days per week, 365 days per year. The facility will be remotely monitored and operated by an Owner contracted O&M provider as well as 16 on-site staff. Onsite maintenance will be required, which will include replacement of inverter power modules, filters, and miscellaneous electrical repairs on an as-needed basis. During operation of the Project substation, O&M staff will service the substation periodically for switching and other operation activities. Light duty maintenance trucks will be utilized to perform routine maintenance, including but not limited to equipment testing, monitoring, repair, routine procedures to ensure service continuity, and standard preventative maintenance. Typically, one major maintenance inspection will take place annually. The Project transmission facilities will be designed consistent with the *Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006* (Avian Power Line Interaction Committee [APLIC] 2006) where feasible. Transmission facilities will also be evaluated for potential collision reduction devices in accordance with *Reducing Avian Collisions with Power Lines: The State of Art in 2012* (APLIC 2012). Based upon the low volume of human activity and the proposed avian protecting Project design features, indirect impacts to wildlife during Project operation are expected to be **less than significant**.

The infrequent testing of the emergency backup generators onsite will introduce a new source of nitrogen deposition. The modeling showed that the highest nitrogen loading from such testing will be located just outside the northern boundary as shown in Appendix 3.2HF. The nitrogen loading was estimated to 0.66. The potential for nitrogen deposition reduces significantly with distance from the source and the infrequent testing.

As previously discussed, the area consists primarily of vegetation communities that are classified as chaparral, coastal sage scrub, and North American desert woodland (juniper woodland) and the nitrogen loading from the project is below the critical load for those habitats, as shown in Table 3.2-58, Critical Nitrogen Loads for Biological Resources Within 6 Miles of the Project Site. As such, the nitrogen is well below any critical loads for other sensitive biological resources that are present or have the potential to occur, including short-joint beavertail, golden linanthus, Crotch's bumble bee, California legless lizard, Blainville's horned lizard, loggerhead shrike, Southern California rufous-crowned sparrow, Bell's sage sparrow, mountain lion, and jurisdictional waters. While there may be other biological species within 6 miles of the Study Area that are not listed here, the annual nitrogen deposition is well below the maximum impact area indicated above and will not be above other species' critical nitrogen loads.

Table 3.2-58. Critical Nitrogen Loads for Biological Resources Within 6 Miles of the Project Site

Biological Resource	Critical Nitrogen Loads (kg/ha/yr)
Chaparral	5-33
Coastal sage scrub	7.8-10
North American desert woodland	3-8.4

Source: Pardo et al 2011.
Note: kg/ha/yr = kilogram per hectare per year.

The quantity of nitrogen deposition from the Project emissions on vegetation will, in practice, be less than the model results because the assumptions modeled are inherently conservative (e.g., assuming the emergency backup generators are running at the same time). The nitrogen deposition will also be distributed incrementally throughout a year and not all nitrogen added to the soil during each deposition event will be available for plant use because of losses associated with soil processes. As a result, the testing of the Project’s emergency backup generators will not lead to nitrogen deposition levels that exceed critical thresholds associated with significant impacts to natural vegetation communities and special status species in the vicinity of the Project site. Therefore, operations from the testing of the Project’s emergency backup generators will result in less than significant impacts to natural vegetation communities and special status species within 6 miles of equipment operation.

Impacts will be **less than significant**.

3.2.2.2.2 Would the project have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by CDFW or USFWS.?

Direct Impacts

Less than Significant with Mitigation. As currently designed, the proposed Project will result in approximately ~~107.29~~108.26 acres (approximately ~~37.05~~33.23 acres temporary and approximately ~~70.24~~75.03 acres permanent; includes both gen-tie line options) of direct impacts to vegetation communities and land covers through the removal of vegetation and grading of land to construct the proposed Project. Permanent impacts will occur due to the construction and operation of the BESS portion of the Project and access roads and transmission pole pads associated with the gen-tie line. Temporary impacts will occur due to the construction of the two (2) underground fiber optic lines within the Southern Gen-Tie Route corridor, within areas proposed for construction laydown areas for the gen-tie work, within pull areas from stringing the gen-tie, and within the other gen-tie work areas that are outside of the transmission pole pads and access roads. The total acreage for project-related impacts to the mapped vegetation communities located within the development area are provided in Table 3.2-69, Potential Impacts to Vegetation Communities and Land Covers in the Study Area.

Table 3.2-9. Potential Impacts to Vegetation Communities and Land Covers in the Study Area

Alliance	Association	CDFW Sensitive ¹	Ranking ²	Potential Permanent Impacts - BESS ³ (Gross Acreages)	Potential Permanent Impacts - Gen-Tie ⁴ (Gross Acreage) ⁵	Potential Temporary Impacts - Gen-Tie ⁶ (Gross Acreage) ⁵
Native Communities						
<u>Cheesebush – sweetbush scrub</u>	<u>Ambrosia salsola – Larrea tridentata</u>	No	G4/S4	–	–	0.05
	<u>Ambrosia salsola Association</u>	No	G4/S4	–	–	1.57
<u>Fiddleneck – phacelia fields</u>	<u>Amsinckia menziesii – Erodium spp.</u>	No	G5/S5	2.08	–	–
<u>California sagebrush – (purple sage) scrub</u>	<u>Artemisia californica – Eriogonum fasciculatum</u>	No	G4/S4	–	0.08	1.44
<u>Big sagebrush</u>	<u>Artemisia tridentata – Ericameria nauseosa</u>	No	G5/S5	0.42	0.46	2.21
	<u>Artemisia tridentata – Eriogonum fasciculatum</u>	No	G5/S5	2.60	–	–
	<u>Artemisia tridentata ssp. parishii</u>	Yes	G2/S2	–	–	0.20
<u>Fourwing saltbush scrub</u>	<u>Atriplex canescens</u>	No	G5/S4	0.67	2.07	18.09
<u>Mormon tea scrub</u>	<u>Ephedra viridis</u>	No	G4/S4	17.84	–	–
<u>Rubber rabbitbrush scrub</u>	<u>Ericameria nauseosa – Juniperus californica/herb</u>	No	G5/S5	10.98	–	1.23
	<u>Ericameria nauseosa</u>	No	G5/S5	–	–	–
<u>California buckwheat scrub</u>	<u>Eriogonum fasciculatum</u>	No	G5/S5	4.75	–	–
	<u>Eriogonum fasciculatum var. foliolosum – Juniperus californica</u>	Yes	G3/S3	4.32	–	–
<u>California buckwheat – Parish's goldeneye scrub</u>	<u>Eriogonum fasciculatum rock outcrop</u>	Yes	Unranked	–	–	–

Table 3.2-9. Potential Impacts to Vegetation Communities and Land Covers in the Study Area

Alliance	Association	CDFW Sensitive ¹	Ranking ²	Potential Permanent Impacts - BESS ³ (Gross Acreages)	Potential Permanent Impacts - Gen-Tie ⁴ (Gross Acreage) ⁵	Potential Temporary Impacts - Gen-Tie ⁶ (Gross Acreage) ⁵
California walnut groves	<i>Juglans californica</i> / <i>annual herbaceous</i>	Yes	G3/S3	–	–	–
California juniper woodland	<i>Juniperus californica</i> / <i>Adenostoma fasciculatum</i> – <i>Eriogonum fasciculatum</i>	Yes	Unranked	10.68	0.53	0.35
	<i>Juniperus californica</i> / <i>herbaceous</i>	Yes	Unranked	7.16	0.39	1.16
	<i>Juniperus californica</i> / <i>Eriogonum fasciculatum</i> – <i>Artemisia californica</i>	No	G5/S5	–	–	–
Subtotal:				61.49	3.52	26.31
Naturalized (Non-Native)						
<i>Avena</i> spp. – <i>Bromus</i> spp.	<i>Avena barbata</i> – <i>Bromus hordeaceus</i>	No	GNA/SNA	–	–	–
<i>Bromus rubens</i> – <i>Schismus (arabicus, barbatus)</i>	<i>Bromus rubens</i> – mixed herbs	No	GNA/SNA	–	–	–
Subtotal:				–	–	–
Land Cover Types						
Disturbed habitat	Not applicable	No	NA/NA	6.00	0.36	3.34
Urban/Developed	Not applicable	No	NA/NA	3.25	0.41	3.58
Subtotal:				9.26	0.77	6.92
Total:				70.74	4.29 ⁵	33.23 ⁵

Notes: CDFW = California Department of Fish and Wildlife; BESS = battery energy storage system; gen-tie = generation interconnection.

Totals may not sum due to rounding and inclusion of both gen-tie routes.

¹ California Department of Fish and Wildlife (CDFW) has determined the community to be sensitive.

² The conservation status of a vegetation community is designated by a number from 1 to 5, preceded by a letter reflecting the appropriate geographic scale of the assessment (G = global, S = state). The numbers have the following meaning:

1 = critically imperiled

2 = imperiled

3 = vulnerable to extirpation or extinction

4 = apparently secure

5 = demonstrably widespread, abundant, and secure

NA = not applicable

GNA = global rank not applicable

SNA = state rank not applicable

Unranked= Associations that are considered sensitive, but have not been ranked

³ There are no temporary impacts associated with the BESS.

⁴ Permanent impacts for the gen-tie are for access roads and tower pads.

⁵ Includes both gen-tie options.

⁶ Temporary impacts will occur due to the construction of the two (2) underground fiber optic lines within the Southern Gen-Tie Route corridor, within areas proposed for construction laydown areas for the gen-tie work, within pull areas from stringing the gen-tie, and within other gen-tie work areas that are outside of the transmission pole pads and access roads.

Four (4) sensitive vegetation communities have approximately 24.79 acres of direct impacts (includes both gen-tie options): *Artemisia tridentata* ssp. *parishii* association, *Eriogonum fasciculatum* var. *foliolosum*-*Juniperus californica* association, *Juniperus californica*/*Adenostoma fasciculatum*-*Eriogonum fasciculatum* association, and *Juniperus californica*/herbaceous association. There are approximately 23.08 acres of permanent impacts and approximately 1.71 acres of temporary impacts to these communities. Potential impacts to the three (3) sensitive vegetation communities could be considered potentially significant. MM-BIO-5 requires the establishment of a conservation area that contains will preserve up to approximately 71.0776 acres of sensitive vegetation communities (California juniper woodland) of the Study Area parcels associated with the gen-tie routes that are available for preservation. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore the approximately 1.71 acres of temporarily impacted sensitive vegetation communities in the gen-tie portion of the Study Area. MM-BIO-1 requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring that Project construction does not extend beyond Project limits. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources, which will include a discussion about sensitive vegetation communities. Project implementation of MM-BIO-1, MM-BIO-2, MM-BIO-3, MM-BIO-5, and MM-BIO-6 will reduce potential direct impacts to less than significant. Impacts will be **less than significant with mitigation.**

Indirect Impacts

Less than Significant with Mitigation. Potential short-term or temporary indirect impacts to sensitive vegetation located in the Study Area could result from construction activities and include impacts related to or resulting from the activities outside of the Project limits, generation of fugitive dust, increased human activity, and the introduction of pollutants from construction equipment. Excessive dust can decrease the vigor and productivity of plants through effects on light, penetration, photosynthesis, respiration, and transpiration; increased penetration of phytotoxic gaseous pollutants; and increased incidence of pests and diseases. Additionally, invasive plant species could be introduced by the Project during construction and through landscaping installation that could alter the habitat and compete with native vegetation. These indirect impacts could result in additional loss of sensitive vegetation communities that could be potentially significant. Water trucks are expected as part of Project construction, which will reduce fugitive dust. MM-BIO-9 requires the preparation and implementation of a plan to avoid and minimize the introduction of non-native plant species that could compete for habitat space with native plants ensuring that vehicles and equipment used during construction are weed free. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the Invasive Species Prevention Plan will be implemented. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources, which will include a discussion on invasive plants. Project implementation of MM-BIO-2, MM-BIO-3, and MM-BIO-9 will reduce potential indirect impacts to less than significant. Impacts will be **less than significant with mitigation.**

3.2.2.2.3 Would the project have a substantial adverse effect on federal or state protected WOTUS (including wetlands) as defined by Sections 404 and 401 of the 1972 Amendments to the Federal Water Pollution Control Act, commonly known as the Clean Water Act, or

the Porter-Cologne Act, either through direct removal, filling, hydrological alteration, or other means?

Direct Impacts

Less than Significant with Mitigation. As currently designed, the proposed Project will result in approximately 0.23-66 acres (approximately 0.190.33 acres temporary and approximately 0.040.33 acres permanent; includes both gen-tie options) of direct impacts to potential jurisdictional waters through the removal of vegetation and grading of land to construct the proposed Project. Temporary impacts will occur within areas proposed for construction laydown areas and within the gen-tie work areas that are outside of the transmission pole pads and access roads. The total acreage for project-related impacts to potential jurisdictional waters located within the development area are provided in Table 3.2-710, Summary of Potential Impacts to Potential Jurisdictional Waters.

Table 3.2-710. Summary of Potential Impacts to Potential Jurisdictional Waters

Jurisdiction	Potential Temporary Impact (Gross Acreage) ¹	Potential Permanent Impact (Gross Acreage) ¹
RWQCB/CDFW		
Features		
Non-Wetland Waters	0.180.32	0.040.33
Swales	0.020.01	0
RWQCB Total²	0.190.33	0.040.33
CDFW		
Features		
Non-Wetland Waters	0.18	0.04
Swales	0.02	0
CDFW Total²	0.19	0.04

Notes: RWQCB = Regional Water Quality Control Board; CDFW = California Department of Fish and Wildlife.

¹ Includes both gen-tie options.

² Totals may not add up due to rounding.

Streams within the BESS area will be filled. Culverts will manage upstream off-site stormwater runoff throughout the overall Project site and will be used to manage flows previously routed through existing streams. Various culverts running beneath site access driveways will be used to bypass flows from upstream of the site. One existing 36-inch culvert allows runoff to flow south underneath Soledad Canyon Road towards the southern BESS yard. A manhole with an open grate will collect stormwater runoff at the downstream point of the existing 36-inch culvert. A new 60-inch storm sewer will be placed from the manhole to the downstream end of the site to convey upstream stormwater runoff from the BESS facilities. A hydraulic dissipator with riprap will be placed at the downstream site of the BESS facility. This can be seen on drawings PSR-CS-004 S011 and PSR-CS-004 S012 (TN 264472). A 72-inch culvert will also be placed to route stormwater runoff under the site. A manhole with an open grate will collect stormwater runoff and be conveyed, underground, downstream to the south of the substation site. A hydraulic dissipator with riprap will be placed at the downstream site of the substation. Sizing of the culverts, calculations, and figures with the locations of the structures can be seen in the Stormwater Management Report found in Appendix K of Appendix 3.15A, Water Quality Management Plan (TN264386).

There is a 36-inch culvert that conveys flows from NWW-1a across Soledad Canyon Road. The culvert is reinforced with concrete, will be maintained throughout construction, and will not be affected by Project-related traffic. The culvert will not be affected by construction and operation and is not expected to need repair. The downstream end of the culvert will be connected to a new manhole to provide continuation of the stormwater conveyance downstream of the BESS facility.

MM-BIO-10, Jurisdictional Waters Compensation, will require the purchase of mitigation bank credits and/or turnkey projects with a mitigation bank at 3:1 for permanent impacts to jurisdictional waters, for a maximum of approximately ~~0.69~~0.99 acres (dependent on which gen-tie option is used). MM-BIO-5 will preserve up to the ~~remaining~~approximately 2.3 acres of jurisdictional waters in the Study Area parcels associated with the gen-tie routes. MM-BIO-6 will require the preparation of a restoration plan, its implementation, and a monitoring period to restore the approximately ~~0.19~~0.33 acres of temporarily impacted jurisdictional waters. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring that Project construction does not extend beyond Project limits. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources, which will include a discussion about jurisdictional waters. Project implementation of MM-BIO-2, MM-BIO-3, MM-BIO-5, MM-BIO-6, and MM-BIO-10 will reduce potential direct impacts to less than significant. Impacts will be **less than significant with mitigation**.

Indirect Impacts

Less than Significant. Potential temporary indirect impacts to the drainages in the Study Area and downstream waters could result from construction activities and will include potential impacts from the generation of fugitive dust and the potential introduction of chemical pollutants (including herbicides). Excessive dust can decrease the vigor and productivity of vegetation through effects on light, penetration, photosynthesis, respiration and transpiration, increased penetration of phytotoxic gaseous pollutants, and increased incidence of pests and diseases. Erosion and chemical pollution (releases of fuel, oil, lubricants, paints, release agents, and other construction materials) may affect wetlands/ jurisdictional waters. The release of chemical pollutants can reduce the water quality downstream and degrade adjacent habitats. However, during construction, erosion-control measures will be implemented as part of the storm water pollution prevention plan (SWPPP) for the Project. Because the entirety of the Project development footprint will be graded at one time but construction will occur over time in phases, the erosion measures will be maintained until all graded areas are constructed/landscaped. Prior to the start of construction activities, the Contractor is required to file a Permit Registration Document with the State Water Resources Control Board in order to obtain coverage under the National Pollutant Discharge Elimination System General Permit for Storm Water Discharges Associated with the Construction and Land Disturbance Activities (Order No 2009-009-DWQ, NPDES No. CAS000002) or the latest approved general permit. This permit is required for earthwork that results in the disturbance of 1 acre or more of total land area. The required SWPPP will mandate the implementation of best management practices to reduce or eliminate construction-related pollutants in the runoff, including sediment, for all exposed soils. Therefore, temporary indirect impacts will be **less than significant** due to compliance with regulations.

3.2.2.2.4 Would the project interfere substantially with the movement of any native resident or migratory fish or wildlife species or with

established native resident or migratory native wildlife corridors or impede the use of wildlife nursery sites?

Less than Significant. Wildlife movement corridors, or habitat linkages, are generally defined as connections between habitat patches that allow for physical and genetic exchange between otherwise isolated animal populations. Such linkages may serve a local purpose, such as providing a linkage between foraging and denning areas, or they may be regional in nature. Some habitat linkages may serve as migration corridors, wherein animals periodically move away from an area and then subsequently return. Others may be important as dispersal corridors for young animals. A group of habitat linkages in an area can form a wildlife corridor network.

The Study Area does not overlap with any California Essential Habitat Connectivity Areas or Natural Landscape (CDFW 2014, 2017). The Study Area is located adjacent to residential neighborhoods, Sierra Highway, the Southern Pacific Railroad lines, Carson Mesa Road, and SR-14, all of which have associated human presence. The Study Area does not support permanent or relatively permanent waters so fish movement is not expected. As such, no significant direct or indirect permanent impacts will occur on wildlife movement or use of native wildlife nursery sites associated with Project activities. Existing habitat linkages and wildlife corridor functions will remain intact while construction activities are conducted and following Project completion. Construction activities will not likely result in potential impacts to wildlife movement because no new structures that will impede wildlife movement are proposed.

During construction activities, temporary disturbance to local species may occur, but will not substantially degrade the quality or use of the vegetation communities in the vicinity. Some indirect impacts to localized wildlife movement could occur during construction activities due to construction-related noise. However, this impact will be temporary and will not be expected to significantly disrupt wildlife movement during and following construction activities.

During operation of the Project, the BESS and substation are located adjacent to residential neighborhoods, Sierra Highway, the Southern Pacific Railroad lines, Carson Mesa Road, and SR 14, so it is not expected to create a substantial new barrier between open natural lands to the east and west of the Study Area. The Project transmission facilities will be designed consistent with the *Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006* (APLIC 2006) and be evaluated for potential collision reduction devices in accordance with *Reducing Avian Collisions with Power Lines: The State of Art in 2012* (APLIC 2012), so bird migration through the Study Area is expected to continue.

Therefore, direct and indirect impacts on wildlife corridors and migratory routes resulting from the proposed Project will be **less than significant**.

3.2.2.2.5 Would the project conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?

California Desert Native Plant Act

The Project would require the removal of chaparral yucca, Wiggin's cholla, and beavertail pricklypear, at the numbers indicated in Table 3.2-11, Impacts to California Desert Native Plant Act Covered Species.

Table 3.2-11. Impacts to California Desert Native Plant Act Covered Species

Species	Amount
chaparral yucca	843
Wiggins' cholla	543
beavertail pricklypear	85
Total	1,471

The applicant would get appropriate permits, tags, and seals that must be obtained from the designated County official or office that implements the California Desert Native Plant Act but for the CEC's Opt-In Application for Certification process, where the CEC's certification will be in lieu of any permits, tags, or seals issued by the County. Additionally, the harvested individuals are expected to be used as part of the restoration plan required by MM-BIO-6 that would occur in the temporary impacted areas of the Project site.

County of Los Angeles Significant Ecological Area

Less than Significant with Mitigation. The portions of the Study Area east of the railroad tracks, south of Foreston Drive and the Vincent Substation, and east of the substation are within a County of Los Angeles SEA (County of Los Angeles 2025), as shown in Figure 3.2-68, Los Angeles County Significant Ecological Area. The SEA Ordinance establishes the permitting, design standards, and review process for development within SEAs, balancing preservation of the County's natural biodiversity with private property rights. The gen-tie line portion of the Project has the potential to impact resources within the Santa Clara River SEA including special-status wildlife, special-status wildlife foraging habitat, sensitive vegetation communities, Water Resources (i.e., streams), and protected trees.

Special-Status Plants

Two (2) special-status plant species, short-joint beavertail and golden linanthus, were mapped in the gen-tie route portion of the Study Area during surveys in 2023. None of the mapped individuals will be directly impacted by the Project. However, some of the individuals of both species are in close proximity to the Project construction limits. MM-BIO-1, Demarcation of Disturbance Limits, requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. MM-BIO-2, Biological Monitoring, requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the flagged limits are adhered to during construction. MM-BIO-3, Worker Education Awareness Program, requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and Study Area, and measures to avoid and minimize impacts to those resources. MM-BIO-5 requires the establishment of a conservation area that will preserve up to approximately ~~148~~ 136 acres of native vegetation communities within the Study Area parcels associated with the gen-tie routes, which will preserve individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas and will include flora resources that the species could use. Project implementation of MM-BIO-1, MM-BIO-2, MM-BIO-3, MM-BIO-5, and MM-BIO-6 will provide the mitigation for the Project to be compatible with SEA Resources.

Special-Status Wildlife

For all wildlife, MM-BIO-1 requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring the integrity of any buffers established for active nests. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources. For Crotch's bumble bee, MM-BIO-4 requires pre-construction surveys for the Crotch's bumble nests, with buffers established around active nests until the nests are deemed inactive. For special-status reptiles MM-BIO-7 will provide a process of clearance surveys and relocation of special-status wildlife into non-impacted portions of the Study Area. For nesting birds, including loggerhead shrike, Southern California rufous-crowned sparrow, and Bell's sage sparrow, MM-BIO-8 requires pre-construction surveys and buffer establishment for active nests. Project implementation of MM-BIO-1, MM-BIO-2, MM-BIO-3, MM-BIO-4, MM-BIO-7, and MM-BIO-8 will provide the mitigation for the Project to be compatible with SEA Resources.

The Project will impact habitat that supports or has the potential to support several special-status species that are candidates for listing under CESA or are CDFW Species of Special Concern: Crotch's bumble bee, California legless lizard, Blainville's horned lizard, loggerhead shrike, Southern California rufous-crowned sparrow, and mountain lion. Each species is expected to have potentially suitable habitat in all of the native habitats in the Study Area, with the exception of California legless lizard, which is only expected in habitats with California juniper. Indirect impacts to these species will be from the substantial loss of foraging and breeding habitat, as shown in Table 3.2-812, Potential Impacts to Special-Status Wildlife Habitat Within the SEA.

Table 3.2-812. Potential Impacts to Special-Status Wildlife Habitat Within the SEA

Species	SEA Resource Category ¹	SEA Preservation Ratio ¹	Potential Impacted Habitat (acres) ²	Restored Temporarily Impacted Habitat (Gross acreage) ^{2, 3}	Needed Conserved Habitat (Gross acreage) ^{2, 4, 5, 6}
Crotch's bumble bee	1	5:1	30.1629.35 ⁷	28.6725.91	122.11120.84
California legless lizard	2	4:1	3.59 ⁸	2.67	11.69
Blainville's horned lizard	2	4:1	29.35 ⁷ 30.16	25.9128.67	91.9791.49
loggerhead shrike	2	4:1	29.35 ⁷ 30.16	25.9128.67	91.9791.49
greater roadrunner	3	3:1	29.35 ⁷	25.91	62.14
mountain lion	1	5:1	33.4433.06 ⁹	28.6729.26 ¹⁰	138.55136.04

Notes: SEA = Significant Ecological Area.

¹ Los Angeles County Planning 2020.

² Includes impacts from both gen-tie options.

³ Restoration for areas that are temporary impacts (MM-BIO-6).

⁴ Total impacts multiplied by the ratio and minus the restored habitat (MM-BIO-5).

⁵ Includes preservation for impacts from both gen-tie options.

⁶ Acreages are not additive. Conserved habitat needed is overlapping since the species share suitable habitat, so the 138.55136.04 acres for mountain lion will cover all species..

⁷ Includes all native habitats impacted, as listed in Table 3.2-13.

⁸ Includes all habitats that support California juniper, as listed in Table 3.2-13.

⁹ Includes all native habitats and disturbed habitat impacted, as listed in Table 3.2-13.

¹⁰ Includes all restoration of native habitats and disturbed habitats.

MM-BIO-5 requires the establishment of a conservation area that will preserve up to approximately ~~148~~ 136 acres of native vegetation communities within the Study Area parcels associated with the gen-tie routes, which will preserve individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas and will include flora resources that the species could use. MM-BIO-1 requires that the limits of construction be clearly marked to avoid impacting biological resources outside those limits. MM-BIO-2 requires full-time monitoring during all vegetation removal and initial grading activities, and the Biological Monitor(s) will be responsible for ensuring that Project construction does not extend beyond Project limits. MM-BIO-3 requires that a program be developed that informs all construction personnel of the sensitive resources that occur on the Project site and measures to avoid and minimize impacts to those resources, which will include a discussion about sensitive vegetation communities. Project implementation of MM-BIO-1, MM-BIO-2, MM-BIO-3, MM-BIO-5, and MM-BIO-6 will provide the mitigation for the Project to be compatible with SEA Resources.

Vegetation Communities

Table 3.2-9-13, Potential Impacts to Vegetation Communities and Land Covers in the Santa Clara River Significant Ecological Area Portion of the Study Area, summarizes the Project's potential direct impacts to vegetation communities and land covers in the Santa Clara River SEA. There will be approximately 4.12 acres of permanent impacts and approximately 32.25 acres of temporary impacts, which includes both gen-tie options. Potential direct impacts will occur due to removal of vegetation, alteration of soils from grading, and the development of the Project.

Table 3.2-913. Potential Impacts to Vegetation Communities and Land Covers in the Santa Clara River Significant Ecological Area Portion of the Study Area

Alliance	Association	SEA Category ¹	Ratio ¹	Potential Permanent Impacts (gross acreage) ²	Preserved Habitat Temporary Impacts (gross acreage) ²	Total Impacts (gross acreage) ²
Native Communities						
Cheesebush - sweetbush scrub	<i>Ambrosia salsola - Larrea tridentata</i>	4	2:1	~~0.12~~	~~0.24~~ <u>0.05</u>	<u>0.05</u>
	<i>Ambrosia salsola Association</i>	4	2:1	~~1.46~~	~~2.92~~ <u>1.57</u>	<u>1.57</u>
California sagebrush - (purple sage) scrub	<i>Artemisia californica - Eriogonum fasciculatum</i>	4	2:1	~~1.09~~	~~2.18~~ <u>1.15</u>	<u>1.15</u>
Big sagebrush	<i>Artemisia tridentata - Ericameria nauseosa</i>	4	2:1	~~2.52~~ <u>0.46</u>	~~5.04~~ <u>2.21</u>	<u>2.67</u>
	<i>Artemisia tridentata</i> ssp. <i>parishii</i>	4	2:1	~~0.21~~	~~0.42~~ <u>0.20</u>	<u>0.20</u>
Fourwing saltbush scrub	<i>Atriplex canescens</i>	4	2:1	~~19.74~~ <u>2.07</u>	~~39.48~~ <u>18.09</u>	<u>20.15</u>

Table 3.2-913. Potential Impacts to Vegetation Communities and Land Covers in the Santa Clara River Significant Ecological Area Portion of the Study Area

Alliance	Association	SEA Category ¹	Ratio ¹	Potential Permanent Impacts (gross acreage) ²	Preserved Habitat Temporary Impacts (gross acreage) ²	Total Impacts (gross acreage) ²
Rubber rabbitbrush scrub	<i>Ericameria nauseosa</i> - <i>Juniperus californica</i> / herb	4	2:1	<u>-1.18</u>	<u>2.361.12</u>	<u>1.12</u>
California juniper woodland	<i>Juniperus californica</i> / <i>Adenostoma fasciculatum</i> - <i>Eriogonum fasciculatum</i>	3	3:1	<u>0.910.53</u>	<u>2.730.35</u>	<u>0.87</u>
	<i>Juniperus californica</i> / herbaceous	3	3:1	<u>1.500.39</u>	<u>4.501.16</u>	<u>1.55</u>
Total:				<u>28.743.44³</u>	<u>59.8725.91</u>	<u>29.35³</u>

Notes: Totals may not add up due to rounding.

¹ SEA Ordinance Implementation Guide (Los Angeles County Planning 2020).

² Includes impacts from both gen-tie options and permanent and temporary impacts.

³ ~~Impacts also include~~ There are also 3.65-70 acres of Disturbed Habitat and 3.982.18 acres of Urban/Developed.

MM-BIO-5 requires the establishment of a conservation area that will preserve up to approximately 148.136 acres of native vegetation communities within the Study Area parcels associated with the gen-tie routes, which will preserve individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore up to the approximately 32.26 acres of temporarily impacted areas within the conservation area. Project implementation of MM-BIO-5 and MM-BIO-6 will provide the preservation needed for the Project to be compatible with SEA Resources.

Water Resources

The Project will have potential impacts to approximately 0.200.34 acres (approximately 0.01 permanent impacts and 0.190.33 acres temporary impacts) of SEA Water Resources (i.e., streams and swales), which includes both gen-tie options. Potential direct impacts will occur due to grading and the development of the Project. Water Resources are to be preserved at 5:1, resulting in the need for 1.700 acres of preservation. MM-BIO-5 requires the establishment of a conservation area that will preserve up to 0.972.28 acres of unimpacted Water Resources in the Study Area parcels associated with the gen-tie routes, which will preserve individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore an additional approximately 0.190.33 acres of temporarily impacted Water Resources within the conservation area. Project implementation of MM-BIO-5 and MM-BIO-6 will provide the preservation needed for the Project to be compatible with SEA Resources.

Protected Trees

Direct impacts are associated with tree removal or encroachment within the tree protected zone (i.e., canopy dripline plus 5 feet or 15 feet from trunk, whichever is greater; TPZ) of a protected tree. Specifically, potential tree impacts were determined using geographic information system technology, spatial locations of tree crowns, and a minimum distance of each tree relative to the Project impact. A tree is considered removed if it falls within the Project's limits of disturbance or if 30% or more of its TPZ is impacted. The TPZ is defined as 5 feet beyond the dripline or 15 feet from the trunk, whichever is greater. A tree is considered encroached upon if less than 30% of its TPZ is affected by Project activities, including soil or root disturbance and/or pruning, but the tree is not removed, and a tree is considered preserved if they are not removed and do not experience any TPZ disturbance. Impact totals presented herein are based on proposed disturbance limits, fuel modification zones, and development plans as of the date of this report. The following tree impact findings are organized into two categories: non-heritage tree impacts and heritage tree impacts. Heritage tree status is based on the SEA tree classifications (i.e., riparian, coniferous, upland hardwood) and minimum trunk diameter for protected and heritage trees.

Appendix A, Protected Tree Report, of Appendix 3.2G, Biota Report, provides all of the details of the impacts to SEA Protected Trees.

Non-Heritage Tree Impacts (Protected Trees)

Forty-seven protected non-heritage trees could be directly impacted by the proposed Project. The 47 protected non-heritage tree impacts consist of 38 potential removals (trees that are within the grading limits or grading activities affect more than 30% of a TPZ), nine (9) potential encroachments (trees that are not removed, but root damage, soil excavation and compaction, grade changes, loss of canopy, and trunk wounds are anticipated). The nine (9) encroachment trees have encroachments that range from 1% to 24%. The remaining 906 protected non-heritage trees would not be directly impacted by the Project. Table 3.2-14, Summary of Potential Impacts to SEA Protected Trees (Non-Heritage), provides a summary of the potential impacts to non-heritage SEA Protected Trees within and adjacent to the Project.

Table 3.2-14. Summary of Potential Impacts to SEA Protected Trees (Non-Heritage)

Scientific Name	Common Name	Removals	Encroachments	Total Impacts
<i>Juniperus californica</i>	California juniper	38	9	47
Total		38	9	47

Note: SEA = Significant Ecological Area.

Heritage Tree Impacts

California juniper, which have naturally thin trunks, must have a canopy spread of 35 feet to be designated as a heritage tree (Los Angeles County Planning 2020). A total of 68 heritage trees are found on the Project site, of which eight (8) could be directly impacted by the Project. The eight (8) heritage tree comprise six (6) potential removals and two (2) potential encroachments. The remaining 60 heritage trees would not be directly impacted by the Project. Table 3.2-15, Summary of Potential Impacts to SEA Protected Heritage Trees, provides a summary of the potential impacts to SEA protected heritage trees within and adjacent to the Project.

Table 3.2-15. Summary of Potential Impacts to SEA Protected Heritage Trees

Scientific Name	Common Name	Removals	Encroachments	Total Impacts
<i>Juniperus californica</i>	California juniper	6	2	8
Total		6	2	8

Note: SEA = Significant Ecological Area.

Per the County requirements, the removal of any SEA Protected Tree requires mitigation in the form of two (2) replacement plantings, and the removal of a heritage tree requires mitigation in the form of 10 replacement plantings. Replacement trees should be seedlings of the same species as those being removed and should be planted in an area of the Project site where there is suitable habitat and where the trees would be able to remain in perpetuity. As such, based on the August 2025 impact analysis that identified 44 potential direct tree removals (six [6] heritage trees and 38 non-heritage protected trees), the SEA rules may require up to 136 mitigation trees (depending on actual Project impacts based on final design and the selected gen-tie route) to be planted in an area of the Project site where there is suitable habitat and where the trees would be able to remain in perpetuity. Per the County, Table 3.2-16, Summary of Potential Individual Species Replacement Quantities, details the quantity of each species required for planting.

Table 3.2-16. Summary of Potential Individual Species Replacement Quantities

Scientific Name	Common Name	Total Impacted	Replacement Ratio	Total Replacement Required
<i>Juniperus californica</i>	California juniper	38	2:1	76
<i>Juniperus californica</i> (Heritage Tree)	California juniper	6	10:1	60
Totals		44	N/A	136

California juniper is a protected tree under the SEA Ordinance. The Project has the potential to directly impact 35 California juniper due to the construction of the gen tie, which includes both options. The potentially impacted trees will be replaced at 2:1, up to 70 replacement California juniper. MM-BIO-5 requires the establishment of a conservation area that will preserve up to 648 California juniper acres of Water Resources in the Study Area parcels associated with the gen-tie routes. The currently contemplated conservation area has the potential to which will preserve up to 749 California junipers individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas within the conservation area including areas mapped as California juniper woodland. Up to 136 replacement California juniper would be planted and monitored as part of the implementation of MM-BIO-6. Project implementation of MM-BIO-5 and MM-BIO-6 will provide the preservation needed for the Project to be compatible with SEA Resources.

Impacts will be **less than significant with mitigation**.

Significant Ecological Areas Statement of Findings

A *Be highly compatible with the SEA Resources, including the preservation of natural open space areas and providing for the long-term maintenance of ecosystem functions.*

The Santa Clara River SEA (the “SCR SEA”) covers approximately 45,496 acres and its overall boundaries extend upstream along several major tributary creeks and where contiguous drainage areas connect to the river basin through open habitat. On a regional basis, the SCR SEA contains biotic communities, vegetative associations, and habitat of plant or animal species that are either unique or are restricted in distribution. native grassland, coast live oak riparian forest, southern willow scrub, bigcone spruce-canyon oak forest, southern sycamore-alder woodland, southern cottonwood-willow riparian woodland and forest, freshwater marsh, alluvial fan sage scrub, and vernal pool. (PCR 2000).

The portions of the Project within the SCR SEA consist of an approximately 1.1-mile-long or 1.8-mile-long new gen-tie line. There will be a maximum of approximately 11 monopole or steel lattice tower structures. The proposed transmission structures were sited to avoid potential impacts to environmental resources. Where possible, the transmission structure access path will utilize existing access roads to minimize new ground disturbance. Fiber optic or other cabling required for the monitoring system typically will be installed in buried conduit within the access road or planned trenching.

The gen-tie portion of the Project consists of steel lattice tower structures, access roads, and buried lines that create a small footprint (4.12 acres) within the SCR SEA following the completion of construction activities. MM-BIO-5 requires the establishment of a conservation area that will preserve up to approximately 162 acres of native vegetation communities within the Study Area parcels associated with the gen-tie routes, which will preserve individuals and habitat for the species. MM-BIO-6 requires the preparation of a restoration plan, its implementation, and a monitoring period to restore temporarily impacted areas and will include flora resources that the species could use.

B *Avoid or minimize impacts to the SEA Resources and wildlife movement through one or more of the following:*

1 *Avoiding habitat fragmentation;*

The monopole or steel lattice tower structures, access roads, and buried lines create a small footprint within the SCR SEA following the completion of construction activities, and with the restoration of the temporary impacted areas, the Project is not expected to fragment the habitats with the Study Area. Wildlife is expected to be able to pass through the Project post-construction, because the transmission lines are not a barrier to movement.

2 *Minimizing edge effects; or*

The gen-tie portion of the Project consists of steel lattice tower structures, access roads, and buried lines create a small footprint (approximately 4.12 acres) within the SCR SEA following the completion of construction activities. The approximately 32.25 acres of temporary impacts produced by the Project will be restored per MM-BIO-6 and MM-BIO-5 will conserve up to approximately 162 acres of natural habitat. During the operation of the Project, maintenance work on the gen-tie and associated infrastructure is expected to be infrequent, so indirect impacts to wildlife are expected to be low.

3 *Siting development in the least sensitive location.*

The Project has been sited to avoid impacts to special-status plants and only have temporary impacts to Water Resources, which will be restored per MM-BIO-6.

C *Buffer important habitat areas from development by retaining sufficient natural vegetation cover and/or natural open spaces and integrating sensitive design features;*

The gen-tie portion of the Project consists of steel lattice tower structures, access roads, and buried lines create a small footprint (approximately 4.12 acres) within the SCR SEA following the completion of construction activities. The approximately 32.25 acres of temporary impacts produced by the Project will be restored per MM-BIO-6 and MM-BIO-5 will conserve up to approximately 162 acres of natural habitat.

D *Maintain the ecological and hydrological functions of water bodies, watercourses, and their tributaries;*

The gen-tie portion of the Project will impact approximately 0.20 acres of ephemeral Water Resources within the SCR SEA. The approximately 0.19 acres of temporary impacts produced by the Project will be restored per MM-BIO-6 and MM-BIO-5 will conserve up to approximately 0.97 acres of Water Resources.

E *Ensure that roads, access roads, driveways, and utilities do not conflict with Priority Biological Resources, habitat areas or migratory paths; and*

The gen-tie portion of the Project consists of steel lattice tower structures, access roads, and buried lines create a small footprint (approximately 4.12 acres) within the SCR SEA following the completion of construction activities. The Project has potential impacts to Priority Biological Resources (SEA Resource Categories 1 through 3) in the form special-status plants and wildlife, water resources, and vegetation communities; however, all such impacts are mitigated in accordance with SEA ordinance and CEQA guidelines.

The Project transmission facilities will be designed consistent with the *Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006* (Avian Power Line Interaction Committee [APLIC] 2006) where feasible. Transmission facilities will also be evaluated for potential collision reduction devices in accordance with *Reducing Avian Collisions with Power Lines: The State of the Art in 2012* (APLIC 2012). Based upon the low volume of human activity and the proposed avian protecting Project design features, potential impacts to wildlife habitat and movement during Project operation are expected to be less than significant.

F *Promote the resiliency of the SEA to the greatest extent possible. For purposes of this finding, SEA resiliency cannot be preserved when the proposed development may cause any of the following:***1 *Significant unmitigated loss of contiguity or connectivity of the SEA;***

The gen-tie portion of the Project consists of steel lattice tower structures, access roads, and buried lines create a small footprint (approximately 4.12 acres) within the SCR SEA following the completion of construction activities. The approximately 32.25 acres of temporary impacts produced by the Project will be restored per MM-BIO-6 and MM-BIO-5 will conserve up to approximately 162 acres of native vegetation communities within the SEA.

2 *Significant unmitigated impact to a Priority Biological Resource;*

The Project has potential impacts to Priority Biological Resources (SEA Resource Categories 1 through 3) in the form special-status plants and wildlife, water resources, and vegetation communities; however, all such potential impacts are mitigated in accordance with SEA ordinance and CEQA guidelines. A total of 10 preservation, avoidance, and minimization measures have been provided as a part of the Project (MM BIO-1 through BIO-10), including: conserving in perpetuity approximately 162 of on-site natural open space; requiring pre-construction surveys, planning, and biological monitoring during construction; measures protecting against invasive species establishment and spread; preparation of conservation management plans; nesting bird avoidance; and strategically locating development as close as possible to existing urban uses/infrastructure. These measures serve to preserve and limit potential impacts to Priority Biological Resources. As such, potential impacts to Priority Biological Resources will be reduced to less than significant.

3 *Removal of habitat that is the only known location of a new or rediscovered species; or*

No new or rediscovered species are present on the Project site. As such, the Project complies with this finding.

4 *Other factors as identified by SEATAC.*

Not applicable due to the CEC Opt-In process.

Impact 3.2-6 Would the project conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?

No Impact. The Study Area is not within any HCP, NCCP, or other approved local, regional, or state HCP (CDFW 2023b). Therefore, there are **no impacts** to HCP, NCCP, or other approved local, regional, or state HCP.

3.2.3 Cumulative Effects

Cumulative effects on biological resources because of past, present, and reasonably foreseeable future actions, in combination with the Project, can result from loss of habitat and habitat disturbance and degradation. A cumulative impact refers to a project's incremental effect together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the facility (Public Resource Code [PRC] Section 21083; 14 CRR 15064(h), 16065(c), 15130, and 15355). Cumulative impacts from the Project are expected to be **less than significant**.

3.2.4 Mitigation Measures

The following section describes the measures that are intended to avoid and minimize potential adverse effects of the Project to biological resources.

3.2.4.1 Mitigation Measures for Construction and Decommissioning

The following section presents avoidance, minimization, and mitigation measures to avoid, minimize, or mitigate potentially significant impacts to all special-status plant and wildlife species and other sensitive biological or aquatic resources during the construction and operations phases of the proposed Project.

MM-BIO-1 **Demarcation of Disturbance Limits.** Prior to commencement of ground disturbing activities for each phase of Project construction, the construction limits shall be clearly demarcated (e.g., installation of flagging or temporary high visibility construction fence), as recommended by the CEC-approved Biological Monitor. All construction activities including equipment staging and maintenance shall be conducted within the marked disturbance limits to prevent inadvertent disturbance to sensitive vegetation communities outside the limits of work. The flagging shall be maintained throughout construction.

MM-BIO-2 **Biological Monitoring.** Prior to ground disturbing activities, the Applicant shall submit the qualifications of potential Biological Monitor(s) to the CEC for review and approval. The CEC-approved Biological Monitors will monitor construction activities and ensure compliance with all mitigation measures. The Biological Monitors shall be present on site during all vegetation removal and each day prior to the commencement of grading activities. The Biological Monitors shall be responsible for conducting a pre-construction clearance survey and any special-status species shall be relocated to areas of the Study Area that will not be impacted by the Project (see MM-BIO-5). Pre-construction clearance surveys shall be conducted prior to construction of each new phase of the development. The Biological Monitors shall monitor to ensure that wildlife does not become entrapped in excavation or trenching areas. Safeguards shall be implemented during daytime periods of non-activity and overnight, such as placing a platform over trenches, flush with the ground surface; installing escape ramps in trenches; or installing exclusionary fencing. Should relocation of any trapped wildlife be required, construction shall be halted until a Biological Monitor arrives on site and clears the work area (in compliance with all applicable permits and authorizations).

The Biological Monitors shall regularly inspect the Project site as needed after the completion of all grading activities. Monthly spot-check monitoring is anticipated to be required throughout the construction of the Project for those areas that are graded but not yet developed/landscaped. During monthly visits, a Biological Monitor shall address the following: (1) the potential establishment of invasive species and require weed abatement (if necessary) in accordance with MM-BIO-10; (2) address the potential establishment of native vegetation/habitat to reduce the potential for impacts between phases of construction; and (3) identify deficiencies, if applicable, with any erosion control measures that have the potential to negatively impact biological resources.

Daily monitoring reports shall be prepared by the Biological Monitors that document the results of any surveys conducted, wildlife relocations, construction activities performed, compliance issues observed, corrective actions taken during the reporting period. The monitoring reports shall include photos as appropriate and be made available to the CEC at their request. Following the completion of the Project construction, a Construction Monitoring Report will be prepared by the Applicant to document compliance with the minimization measures and permit conditions for the Project.

MM-BIO-3 **Worker Education Awareness Program (WEAP).** Prior to the initiation of the initial ground disturbing activities, all personnel associated with those activities shall attend a worker education awareness program (program) prepared by a CEC-approved qualified biologist. In general, the program shall discuss any potentially occurring sensitive biological resources or species and habitat preference(s), occupied habitat in the area, life histories, as well as potential construction impacts, protection measures, and Project limits. Legal protections and regulations pertinent to the biological resources that may be present shall also be included in the program. A species and

habitat fact sheet shall be developed prior to the training program and distributed at the training program to all contractors, employers and other personnel involved with the construction of the Project.

After the kickoff meeting, the Project Applicant shall notify the CEC-approved qualified biologist in advance if additional contractors are employed during the initial vegetation removal or initial grading activities. A sign-in sheet will be circulated for signatures to all personnel that attend the workers educational training to confirm that program materials were received and that they understand the information presented.

MM-BIO-4 **Crotch's Bumble Bee Avoidance and Minimization Measures.** If Crotch's bumble bee is still a candidate for listing under the California Endangered Species Act (CESA) or has been listed under CESA at the time of the start of construction of the Project, a pre-construction survey for Crotch's bumble bee shall be conducted within the construction footprint prior to the start of initial ground disturbing activities occurring during the Crotch's bumble bee nesting period (February 1 through October 31). If construction commences outside of that period (November 1 through January 31), surveys would not be warranted since the daughter queens (gynes) disperse following a nest's lifecycle and conducting surveys for dormant gynes would not be practical.

The pre-construction survey will be based on recommendations described in the "Survey Considerations for California Endangered Species Act (CESA) Candidate Bumble Bee Species," released by the California Department of Fish and Wildlife (CDFW) on June 6, 2023, or the most current at the time of construction. The pre-construction survey will be performed by a biologist with expertise in surveying for bumble bees and include at least three (3) survey passes that are not on sequential days or in the same week. The biologist shall watch the nest resources for up to five minutes, looking for exiting or entering worker bumble bees. Worker bees should arrive and exit an active nest site with frequency, such that their presence will be apparent after five minutes of observation.

During the bumble bee active nesting season (April 1 through August 30), the CEC-approved Biological Monitors (MM-BIO2) shall continue to conduct daily sweeps of areas proposed for initial vegetation removal and ground disturbance.

If nest resources occupied by Crotch's bumble bee are detected within the construction area, no construction activities shall occur within 50 feet of the nest, or as determined by a qualified biologist through evaluation of topographic features or distribution of floral resources. The nest resources will be avoided for the duration of the Crotch's bumble bee nesting period (February 1 through October 31). The CEC-approved Biological Monitors (MM-BIO2) shall ensure that the nest buffer is complied with during that period. Outside of the nesting season, it is assumed that no live individuals will be present within the nest as the gynes usually leave by September, and all other individuals (original queen, workers, males) die. The gyne is highly mobile and can independently disperse to outside of the construction footprint to proposed open space or other suitable areas beyond that have suitable hibernacula resources. Because construction will have occurred in the area outside of the occupied nesting resources, no suitable habitat will be present in the impact area, and it is assumed that new queens will disperse to habitat outside of the construction area.

If the nest resources cannot be avoided, as outlined in this measure, the project applicant will consult with CEC and CDFW regarding the need to obtain an Incidental Take Permit. In the event an Incidental Take Permit is needed, mitigation for direct impacts to Crotch bumble bee will be fulfilled through compensatory mitigation at a minimum 1:1 nesting habitat replacement of equal or better functions and values to those impacted by the Project, or as otherwise determined through the Incidental Take Permit process. The compensatory habitat mitigation would be accomplished by onsite preservation of suitable habitat.

MM-BIO-5 **On-Site Preservation.** The Applicant shall demonstrate recordation of a conservation easement, as defined by California Civil Code section 815.1, that permanently preserves up to approximately ~~188 acres of open space (up to approximately 148~~ 136 acres of non-impacted vegetation communities, ~~eight acres of land cover types, and up to approximately 32~~ 26 acres of temporary impacted areas ~~that will be restored~~) within the Project boundaries for long-term conservation and management as a natural conservation area ("Conservation Area"). The Conservation Area will be ~~up to approximately 162 acres and~~ located within portions of the Study Area within the Santa Clara River Significant Ecological Area. Table 3.2-~~10~~ 17, **Unimpacted Vegetation Communities and Land Cover Types in the Santa Clara River Significant Ecological Area Portion of the Study Area That Could Be Conserved**, summarizes the potential vegetation communities and land cover that could be preserved.

Table 3.2-~~10~~ 17. Unimpacted Vegetation Communities and Land Cover Types in the Santa Clara River Significant Ecological Area Portion of the Study Area That Could Be Conserved

Alliance	Association	SEA Category ¹	Acres
Vegetation Communities			
Cheesebush – sweetbush scrub	<i>Ambrosia salsola</i> - <i>Larrea tridentata</i>	4	~~0.7~~ <u>10.82</u>
	<i>Ambrosia salsola</i> Association	4	~~1.1~~ <u>142.60</u>
Big sagebrush	<i>Artemisia tridentata</i> - <i>Ericameria nauseosa</i>	4	~~7.0~~ <u>314.04</u>
	<i>Artemisia tridentata</i> - <i>Eriogonum fasciculatum</i>	4	0.06
	<i>Artemisia tridentata</i> ssp. <i>parishii</i>	4	~~0.2~~ <u>70.48</u>
Fourwing saltbush scrub	<i>Atriplex canescens</i>	4	~~65.3~~ <u>766.69</u>
<u>Mormon tea scrub</u>	<u><i>Ephedra viridis</i></u>	<u>4</u>	<u>1.99</u>
Rubber rabbitbrush scrub	<i>Ericameria nauseosa</i> - <i>Juniperus californica</i> / herb	4	~~2.7~~ <u>53.85</u>
California juniper woodland	<i>Juniperus californica</i> / <i>Adenostoma fasciculatum</i> - <i>Eriogonum fasciculatum</i>	3	~~2.6~~ <u>45.60</u>
	<i>Juniperus californica</i> / herbaceous	3	~~68.1~~ <u>669.90</u>
Vegetation Communities Subtotal:			~~148.1~~ <u>3166.03</u>
Land Cover Types			
Disturbed Habitat	NA	NA	~~6.3~~ <u>93.46</u>

Table 3.2-1017. Unimpacted Vegetation Communities and Land Cover Types in the Santa Clara River Significant Ecological Area Portion of the Study Area That Could Be Conserved

Alliance	Association	SEA Category ¹	Acres
Urban Developed	NA	NA	4.452.76
<i>Land Cover Types Subtotal:</i>			<i>7.919.15</i>
Total:			156.04175.18

Notes: NA=Not Applicable; totals may not add up due to rounding

¹ SEA Ordinance Implementation Guide (County Planning 2020).

A cost estimate will be prepared to estimate the initial start-up costs and ongoing annual costs of management activities for the management of the conservation easement area(s) in perpetuity. The funding source will be in the form of an endowment to help the qualified natural lands management entity that is ultimately selected to hold the conservation easement(s). The endowment amount will be established following the completion of a Project-specific Property Analysis Record (PAR) to calculate the costs of in-perpetuity land management. The PAR will take into account all management activities required if an Incidental Take Permit for Crotch's bumble bee is needed for the Project.

The conservation easement holder shall be an entity which has as part of its mission the protection of the environment, including lands, plant species, and/or wildlife species, and can be expected by its organization and history to remain in existence for the foreseeable future. The California Department of Fish and Wildlife per Government Code Section 65967(c) shall review the entity. The entity that holds the endowment shall first meet the criteria outlined in Government Code section 65968(b).

Conservation Management Plan. As part of recording the conservation easement, a Conservation Management Plan (CMP) applicable to the conservation area will be prepared and submitted to the CEC for approval. The CMP shall identify the required resource management activities and the entities that shall be responsible for managing those activities in perpetuity. The CMP will set forth requirements that will be implemented by the entity that holds the conservation easement and/or manages and stewards the Conservation Area, and may include the following: (1) there shall be no grading or other construction activities within the Conservation Area, except for the proposed habitat enhancement/restoration; (2) no fencing or other barriers to wildlife movement shall be installed; (3) commercial honeybee operations shall not be allowed to use the Conservation Area for storing their apiaries; (4) rodenticides shall be prohibited; (5) herbicides and pesticides shall be discouraged, and only those typically used for invasive plant management in California wildlands shall be allowed, per the California Invasive Plant Council & Pesticide Research Institute's Best Management Practices (BMPs) for Wildland Stewardship¹; (6) at least one annual walk-through survey shall be conducted by a biologist to qualitatively monitor the general condition of on-site habitats and to check for any new introduction or expansion of invasive plant species; (13) collect and remove trash, repair vandalized signs, and rectify trespass impacts; and (14) provide annual

¹ California Invasive Plant Council & Pesticide Research Institute. 2015. Best Management Practices (BMPs) for Wildland Stewardship. Accessed October 2023. <https://cal-ipc.org/docs/bmps/dd9jwo1ml8vttq9527zjhek99qr/BMPHerbicide.pdf>.

reporting that document the conditions of the Conservation Area. Approved work will be outlined in the CMP and in the conservation easement, including monitoring and maintenance efforts or for other activities associated with preserve management, and prohibited activities shall be delineated.

MM-BIO-6 **Habitat Mitigation and Monitoring Plan.** Prior to ground disturbing activities, a qualified biologist shall be retained to prepare a Habitat Mitigation and Monitoring Plan (HMMP) detailing the specific approach for each type of habitat restoration and establishment area in the Conservation Area, and short-joint beavertail transplant location, and will outline detailed performance standards and monitoring requirements for each; following the monitoring and reporting methods and performance standards listed below. The HMMP shall be submitted to and approved by the CEC prior to the onset of Project-related ground-disturbing activities. The acreages allotted for on-site establishment apply to approximately 32 acres within the Conservation Area that includes 0.19 acres of ephemeral streams. A minimum of 70 Up to 136 California juniper will be planted, and individuals of the plant species covered by the California Desert Native Plant Act will be evaluated to be used in the installation of native plants. The HMMP shall set out measures for habitat restoration/enhancement implementation, including but not limited to:

- Identification of proposed plant materials
- Signage in the habitat restoration area
- Schedule for habitat restoration/enhancement work
- Use of pesticides and elimination of non-native vegetation
- Habitat monitoring and reporting
- Performance standards

MM-BIO-7 **Special-Status Wildlife Relocation Plan.** Prior to commencement of any ground disturbing activities or the pre-construction staging of equipment on the Project site, the Project Applicant shall contract with a CEC-approved biologist to develop a Preconstruction Wildlife Survey and Relocation Plan for terrestrial reptiles, including California legless lizard and Blainville's horned lizard. The Preconstruction Wildlife Survey and Relocation Plan shall be submitted to the CEC for review prior to any ground-disturbing activities within potentially occupied habitat.

The Plan shall include, at a minimum, the following:

- Protocols for pre-construction surveys to flush out and/or move identified special status wildlife within the Project site, as feasible.
- Relocation to the portions of the Study Area outside of the Project construction limits and within the Conservation Area.
- The timing, frequency, and locations where surveys should be conducted.
- Surveys will be conducted 24 hours prior to construction activities and repeated the morning of the proposed activity.
- Surveys shall be conducted in all areas anticipated to be subject to vegetation clearing.
- The habitat and conditions in the proposed relocation site(s).
- The methods that will be used for trapping and relocating identified species.

- All equipment used in the effort will be cleaned and decontaminated to minimize the spread of herpetofaunal pathogens.²
- Any wildlife handling and relocation methodology from the CDFW-issued Streambed Alteration Agreement, if any, will be incorporated in the Preconstruction Survey and Relocation Plan.
- Protocols for documentation/recording of the species and number of animals relocated.
- Relocations shall be logged and made available to the CEC, if requested.
- Protocols for notifying CDFW if identified species cannot be relocated.
- Attempts at relocation shall be logged and notification shall occur within 24 hours.
- The timing and frequency of reports documenting the results of the surveys.

MM-BIO-8 Nesting Bird Avoidance. Project construction shall be conducted in compliance with the conditions set forth in the Migratory Bird Treaty Act and California Fish and Game Code consistent with methods approved by the California Department of Fish and Wildlife to protect active bird/raptor nests. Vegetation removal shall occur during the non-breeding season for nesting birds and nesting raptors to avoid impacts to nesting birds and raptors.

For the remaining Project activities initiated during the breeding season for nesting birds and nesting raptors, a pre-construction survey shall be conducted by the Biological Monitor (MM-BIO-3) for nesting birds and/or raptors within three days prior to any work within 300 feet for suitable nesting habitat for non-raptors and within 500 feet for suitable nesting habitat for raptors. If the Biological Monitor does not find any active nests immediately adjacent to the impact areas, the Project activity shall be allowed to proceed.

If the Biological Monitors find an active nest adjacent to the construction area and determines that the nest may be indirectly impacted or breeding activities substantially disrupted, the Biological Monitors shall delineate an appropriate buffer zone around the nest depending on the sensitivity of the species and the nature of the construction activity. Any nest found during survey efforts shall be mapped on the construction plans, which will be included in the report(s) documenting the survey(s) that will be submitted to the CEC upon completion of the survey. The active nest shall be protected until nesting activity has ended. To protect any nest site, the following restrictions to construction activities shall be required until nests are no longer active, as determined by the Biological Monitor: (1) work limits shall be established within a buffer around any occupied nest (the buffer shall be 100–300 feet for nesting non-raptors and 300–500 feet for nesting raptors), unless otherwise determined by the Biological Monitors and (2) access and surveying shall be restricted within the buffer of any occupied nest, unless otherwise determined by the Biological Monitor. Encroachment into the buffer area around a known nest shall only be allowed if the Biological Monitor determines that the proposed activity will not disturb the nest occupants. Construction can proceed when the Biological Monitor has determined that fledglings have left the nest, or the nest has failed.

² Julian et al. 2020. Minimizing the Spread of Herpetofaunal Pathogens in Aquatic Habitats by Decontaminating Construction Equipment. *Herpetological Review*, 2020, 51(3), 472–483. <https://parcplace.org/wp-content/uploads/2020/11/Julian-2020-Decontamination-for-Herps-for-large-equipment.pdf>.

MM-BIO-9 **Invasive Species Prevention Plan.** To prevent the spread of invasive plant species during construction and until the establishment of common landscaped areas associated with the Project, the following measures shall be implemented:

- The WEAP (see MM-BIO-3) will include invasive species prevention measures implemented by the Project.
- All mobile vehicles and construction equipment shall be washed prior to entering the Project site in an upland location where any seed material from invasive species will be contained and not carried onto the Project site. Logs of the washing will be submitted monthly to the CEC.
- Following the completion of grading activities, for those areas of the Project site that are graded but not yet developed/landscaped, the City-approved Biological Monitor shall conduct monthly spot checks to prevent the introduction or establishment of invasive plant species onto the graded areas (see MM BIO-2). If abundant invasive species are identified, the Biological Monitor shall inform the construction contractor about the infested area and recommend that the invasive species be removed. The recommendation will be included in the daily report.
- All vegetative material removed from the Project footprint shall be transported in a covered vehicle and will be disposed of at a certified disposal site.

MM-BIO-10 **Jurisdictional Waters Compensation.** Mitigation for up to approximately ~~1.560.99~~ acres of jurisdictional waters shall be implemented through off-site acquisition, such as mitigation bank credits, and/or turnkey projects with mitigation banks (as approved by the CEC) following the issuance of permits from the U.S. Army Corps of Engineers, and Los Angeles Regional Water Quality Control Board, as applicable, and those agencies approval of the mitigation bank, and prior to the issuance of the grading permit. A turnkey mitigation project (establishment of the riparian habitat) will be used should credits not be available at the time of the jurisdictional waters permitting.

3.2.4.2 Mitigation Measure for Site Restoration

Over the long term, once the Project facilities are no longer needed, the structures will be removed the Project area will be in accordance with the approved decommissioning plan. Because rehabilitation of the site is not expected to occur for approximately 40 years, a draft conceptual plan may be included as part of the Biological Resources Mitigation Implementation and Minimization Plan. This draft plan can then be updated at a later date (but no more than 1 year prior to closure). A formal rehabilitation plan for the Project facility closure will be developed by the Project owner and submitted to the CEC Compliance Manager at least 1 year prior to facility closure. The facility closure restoration plan will include the following sections and details:

- Goals and objectives of the restoration
- A description of methods employed to achieve the restoration goals and objectives
- Success criteria used to determine whether the restoration was successful
- A monitoring and maintenance program, including details on remedial measures
- A description of annual reporting
- A restoration implementation and monitoring timeline and schedule of planned activities.

3.2.5 Laws, Ordinances, Regulations, and Standards

The following subsections within Section 3.2.5 describe the laws, ordinances, regulations, and standards (LORS) that apply to potential impacts on biological resources in the Project area and list the agencies responsible for enforcing the regulations. A summary of the applicable federal, state, and local LORS is provided in Table 3.2-118, LORS Applicable to Biological Resources.

Table 3.2-1118. LORS Applicable to Biological Resources

LORS	Applicability	Conformity	Opt-In Application Reference
Federal			
Federal ESA (16 USC 1531 et seq.)	Designates and protects federally threatened and endangered plants and animals and their critical habitat. Applicants for projects that could result in adverse impacts on any federally listed species are required to consult with and mitigate potential impacts in consultation with USFWS.	Yes. Federally threatened and endangered plants and animals analyzed. Avoidance, minimization, and mitigation measures include preconstruction surveys, avoidance buffers, timing restrictions, and take authorization from the USFWS, if necessary.	Section 3.2.1.9 Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.5.1
MBTA (16 USC 703 to 711)	Protects all migratory birds, including nests and eggs	Yes. Pre-construction surveys and avoidance buffers for active nests will prevent impacts to nesting migratory birds.	Section 3.2.1.11 Section 3.2.2.2.1 Section 3.2.5.1
Bald and Golden Eagle Protection Act (16 USC 668)	Specifically protects bald and golden eagles from harm or trade in parts of these species	Yes. Pre-construction surveys and avoidance buffers will prevent take of eagles.	Section 3.2.1.12 Section 3.2.2.2.1 Section 3.2.5.1
State			
CESA (Fish and Game Code Section 2050 et seq.)	Species listed under this act cannot be “taken” or harmed, except under specific permit. Take in the context of CEQA means to hunt, pursue, kill, or capture as well as any other actions that may result in an adverse impact when attempting to take a listed species.	Yes. State threatened and endangered plants and animals analyzed. Avoidance, minimization, and mitigation measures include preconstruction surveys, avoidance buffers, timing restrictions, and take authorization from the CEC/CDFW if necessary.	Section 3.2.1.9 Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.5.2

Table 3.2-1118. LORS Applicable to Biological Resources

LORS	Applicability	Conformity	Opt-In Application Reference
Game Code Section 3511	Describes bird species, primarily raptors that are FP (Fully Protected). FP birds may not be taken or possessed, except under specific permit requirements.	Yes. No take of FP bird species is anticipated.	Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.3.2
Fish and Game Code Section 3503	States that it is unlawful to take, possess, or needlessly destroy the nest or eggs of any bird, except as otherwise provided by this code or any regulation made pursuant thereto.	Yes. Preconstruction surveys and avoidance buffers prevent impacts to nesting birds.	Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.5.2
Fish and Game Code Section 3503.5	It is unlawful to take, possess, or destroy any birds in the order Falconiformes or Strigiformes (birds-of-prey) or to take, possess, or destroy the nest or eggs of any such bird except as otherwise provided by this code or any regulation made pursuant thereto.	Yes. Preconstruction surveys and avoidance buffers will prevent impacts to nesting raptors.	Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.5.2
Fish and Game Code Section 3513	It is unlawful to take or possess any migratory nongame bird as designated in the Migratory Bird Treaty Act or any part of such migratory nongame bird except as provided by rules and regulations adopted by the Secretary of the Interior under provisions of the Migratory Bird Treaty Act.	Yes. Preconstruction surveys and avoidance buffers prevent impacts to migratory birds.	Section 3.2.1.11 Section 3.2.2.2.1 Section 3.2.5.2
Fish and Game Code Sections 351, 4700, 5050, and 5515	Lists bird, mammal, amphibian, reptile, and fish species that are FP in California	Yes. FP species discussed. No take of FP species anticipated.	Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.3.2
NPPA Fish and Game Code Sections 1900 et seq.	The Native Plant Protection Act (NPPA) lists threatened, endangered, and rare plants listed by the State.	Yes. No threatened, endangered, or rare plants anticipated to occur. Preconstruction surveys and avoidance buffers provide further protection.	Section 3.2.1.9 Section 3.2.2.2.1 Section 3.2.5.2

Table 3.2-1118. LORS Applicable to Biological Resources

LORS	Applicability	Conformity	Opt-In Application Reference
CDNPA Food and Agricultural Code Sections 80001 et seq.	The California Desert Native Plants Act (CDNPA) is to protect certain species of California desert native plants from unlawful harvesting on both public and privately owned lands.	Yes. The species listed in the CDNPA have been mapped, and the Project would seek the appropriate permit from the County of Los Angeles to collect those that will be impacted.	Section 3.2.1.9.1 Section 3.2.2.2.5 Section 3.2.5.2.4
Fish and Wildlife Code Sections 1900 et seq.	Lists endangered or rare native plants of the State and establishes criteria for determining rarity or listing status.	Yes. No endangered or rare plants present. Preconstruction surveys and avoidance buffers prevent potential impacts to rare plant species.	Section 3.2.1.9 Section 3.2.2.2.1 Section 3.2.5.2
Title 14 CCR, Sections 670.2 and 670.5	Lists animals designated as threatened or endangered in California	Yes. State threatened and endangered plants and animals analyzed. Avoidance, minimization, and mitigation measures include preconstruction surveys, avoidance buffers, timing restrictions, and take authorization from the CEC/CDFW.	Section 3.2.1.10 Section 3.2.2.2.1 Section 3.2.5.2
CFG Code Sections 1601-1607	Prohibits alteration of any stream, including intermittent and seasonal channels and many artificial channels without a permit from CDFW.	Yes. Permit from CEC/CDFW will be in hand prior to impacts to CDFW jurisdictional features.	Section 3.2.1.8 Section 3.2.2.2.3 Section 3.2.5.2
CEQA Public Resources Code (PRC) Sections 2100, et seq. and CEQA Guidelines (14 C.C.R. 15000, et seq.)	CEQA requires that the effects of a project on environmental resources must be analyzed and assessed using criteria determined by the lead agency.	Yes. Environmental resources analyzed using CEQA and CEC criteria.	Section 3.2.2.2 Section 3.2.5.2

Table 3.2-1118. LORS Applicable to Biological Resources

LORS	Applicability	Conformity	Opt-In Application Reference
Warren Alquist Act Public Resources Code (PRC) 25000, et seq.	A CEQA-equivalent process implemented by the CEC.	Yes. Environmental resources analyzed using CEQA and CEC criteria.	Section 3.2.2.2 Section 3.2.5.2
California Assembly Bill 205	Emergency regulation expanding the CEC's siting authority for renewable energy projects. Allows certification in lieu of CDFW 2081 ITP or CFGC Section 1600 et seq. LSAA.	Yes. Take authorization, if necessary, and LSAA to be coordinated with CEC with input from CDFW.	Throughout the Opt-In Application
Local			
Los Angeles County 2035 General Plan	The Los Angeles County 2035 General Plan provides the policy framework for how and where the unincorporated County will grow through the year 2035, while recognizing and celebrating the County's wide diversity of cultures, abundant natural resources, and status as an international economic center.	Yes. The Project will mitigate impacts to biological resources, which will comply with the General Plan goals and policies related to open space.	Section 3.2.2.2 Section 3.2.5.3
Ord. 2019-0072 § 2, 2019 Significant Ecological Areas	The SEA Program was originally established as a part of the 1980 County General Plan, to help conserve the genetic and physical diversity within Los Angeles County by designating biological resource areas capable of sustaining themselves into the future. The General Plan 2035 updated the SEA boundary map, goals and policies in 2015.	Yes. The Project's Gen-Tie Line will impact SEA Resource Categories 1 through 3 in the form special-status plants and wildlife, water resources, and vegetation communities; however, all such impacts are mitigated in accordance with the SEA ordinance and CEQA guidelines.	Section 3.2.1.13 Section 3.2.2.2.5 Section 3.2.5.3

3.2.5.1 Federal LORS

3.2.5.1.1 Federal ESA (16 United States Code [USC] 153 et seq.)

The federal Endangered Species Act (FESA) of 1973 (16 USC 1531 et seq.), as amended, is administered by the U.S. Fish and Wildlife Service (USFWS) for most plant and animal species, and by the National Oceanic and Atmospheric Administration National Marine Fisheries Service for certain marine species. This legislation is intended to provide a means to conserve the ecosystems upon which endangered and threatened species depend, and to provide programs for the conservation of those species, thus preventing the extinction of plants and wildlife. The FESA defines an endangered species as “any species that is in danger of extinction throughout all or a significant portion of its range.” A threatened species is defined as “any species that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.” Under the FESA, it is unlawful to “take” any listed species, and “take” is defined as, “harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct.”

The FESA allows for the issuance of incidental take permits for listed species under Section 7, which is generally available for projects that also require other federal agency permits or other approvals, and under Section 10, which provides for the approval of habitat conservation plans on private property without any other federal agency involvement.

Federally threatened and endangered plants and animals are analyzed herein. Avoidance, minimization, and mitigation measures will include preconstruction surveys, avoidance buffers, timing restrictions, and take authorization from the USFWS if necessary.

3.2.5.1.2 Migratory Bird Treaty Act (16 USC 703 to 711)

The Migratory Bird Treaty Act (16 USC 703 et seq.), as amended (MBTA), prohibits the intentional take of any migratory bird or any part, nest, or eggs of any such bird. Under the MBTA, “take” is defined as pursuing, hunting, shooting, capturing, collecting, or killing, or attempting to do so. ~~In December 2017, Department of the Interior Principal Deputy Solicitor Jorjani issued a memorandum (M-37050) that interprets the MBTA’s “take” prohibition to apply only to affirmative actions that have as their purpose the taking or killing of migratory birds, their nests, or their eggs. Unintentional or accidental take is not prohibited.~~ Additionally, Executive Order 13186, Responsibilities of Federal Agencies to Protect Migratory Birds, requires that any project with federal involvement address impacts of federal actions on migratory birds with the purpose of promoting conservation of migratory bird populations (66 FR 3853–3856). The Executive Order requires federal agencies to work with USFWS to develop a memorandum of understanding. USFWS reviews actions that might affect these species.

Project pre-construction surveys and avoidance buffers for active nests will prevent impacts to nesting migratory birds.

3.2.5.1.3 Bald and Golden Eagle Protection Act (16 USC 668)

The Bald and Golden Eagle Protection Act (16 U.S.C. 668-668c), enacted in 1940, and amended several times since, prohibits anyone, without a permit issued by the Secretary of the Interior, from “taking” bald or golden eagles, includes their parts, nests, or eggs. The Act provides criminal penalties for person who “take, possess, sell, purchase, bates, offer to sell, transport, export or import, at any time or any manner, any bald eagle... [or any golden

eagle], alive or dead, or any part, nest, or egg thereof.” The Act defines “take” as “pursue, shoot, shoot at, poison, kill, wound, capture, trap, collect, molest or disturb.”

Project pre-construction surveys and avoidance buffers will prevent take of eagles.

3.2.5.2 State LORS

3.2.5.2.1 California Endangered Species Act

CESA (California Fish and Game Code Sections 2050–2068) provides protection and prohibits take of plant, fish, and wildlife species listed by the State of California. Unlike the FESA, under the CESA, state-listed plants have the same degree of protection as wildlife, but insects and other invertebrates may not be listed. Take is defined similarly to the FESA and is prohibited for both listed and candidate species. Incidental Take authorization may be obtained by a project applicant from the California Department of Fish and Wildlife (CDFW) under CESA Section 2081, which also allows take of a listed species for educational, scientific, or management purposes. In this case, private developers consult with CDFW to develop a set of measures and standards for managing the listed species, including full mitigation for impacts, funding of implementation, and monitoring of mitigation measures.

State threatened and endangered plants and animals are analyzed herein. Avoidance, minimization, and mitigation measures include preconstruction surveys, avoidance buffers, timing restrictions, and Incidental Take authorization from the CEC/CDFW, if necessary.

3.2.5.2.2 Fish and Game Code

Sections 3500, 3511, and 3513

Section 3503 of the California Fish and Game Code states that it is unlawful to take, possess, or needlessly destroy the nests or eggs of any bird, except as otherwise provided by this code or any regulation made pursuant thereto. Section 3503.5 protects all birds of prey (raptors) and their eggs and nests. Section 3511 states that fully protected birds or parts thereof may not be taken or possessed at any time. Section 3513 states that it is unlawful to take or possess any migratory non-game bird as designated in the MBTA.

Project pre-construction surveys and avoidance buffers for active nests will prevent impacts to nesting migratory birds.

Fully Protected Species

Sections 3511, 4700, 5050, and 5515 of the California Fish and Game Code outline protection for fully protected species of mammals, birds, reptiles, amphibians, and fish. Species that are fully protected by these sections may not be taken or possessed at any time. CDFW cannot issue permits or licenses that authorize the take of any fully protected species, except under certain circumstances, such as scientific research and live capture and relocation of such species pursuant to a permit for the protection of livestock. Furthermore, it is the responsibility of CDFW to maintain viable populations of all native species. Toward that end, CDFW has designated certain vertebrate species as Species of Special Concern, because declining population levels, limited ranges, and/or continuing threats have made them vulnerable to extinction.

FP species are discussed herein. No take of FP species is anticipated.

Section 1600–1616

CDFW jurisdiction includes ephemeral, intermittent, and perennial watercourses (including dry washes) and lakes characterized by the presence of a definable bed and banks and existing fish or wildlife resources. CDFW takes jurisdiction to the top of bank of the stream or the limit of the adjacent riparian vegetation, which may include oak woodlands in canyon bottoms. Historical court cases have further extended CDFW jurisdiction to include watercourses that seemingly disappear but reemerge elsewhere. Under the CDFW definition, a watercourse need not exhibit evidence of an ordinary high-water mark (OHWM) to be claimed as jurisdictional. CDFW does not have jurisdiction over ocean or shoreline resources.

Under California Fish and Game Code Sections 1600–1616, CDFW has the authority to regulate work that will substantially divert or obstruct the natural flow of, or substantially change or use any material from, the bed, channel, or bank of any river, stream, or lake. CDFW also has the authority to regulate work that will deposit or dispose of debris, waste, or other material containing crumbled, flaked, or ground pavement where it may pass into any river, stream, or lake. This regulation takes the form of a requirement for a Lake or Streambed Alteration Agreement and is applicable to all projects. Applications to CDFW must include a complete, certified California Environmental Quality Act (CEQA) document. The CEC Stands in the shoes of CDFW in ensuring compliance with the substantive requirements of the Lake or Streambed Alteration Agreement program.

3.2.5.2.3 California Native Plant Protection Act

The Native Plant Protection Act of 1977 (see Section 1900 *et seq.* of the California Fish and Game Code) directed CDFW to carry out the Legislature’s intent to “preserve, protect and enhance rare and endangered plants in this State.” The Native Plant Protection Act gave the California Fish and Game Commission the power to designate native plants as “endangered” or “rare,” and to protect endangered and rare plants from take. The CESA expanded on the original Native Plant Protection Act and enhanced legal protection for plants, but the Native Plant Protection Act remains part of the California Fish and Game Code. To align with federal regulations, the CESA created the categories of “threatened” and “endangered” species. It converted all “rare” animals into the CESA as threatened species but did not do so for rare plants. Thus, there are three (3) listing categories for plants in California: rare, threatened, and endangered. Because rare plants are not included in the CESA, mitigation measures for impacts to rare plants are specified in a formal agreement between CDFW and the Project proponent.

No threatened, endangered, or rare plants are anticipated to occur. Preconstruction surveys and avoidance buffers will provide further protection.

3.2.5.2.4 California Desert Native Plant Act

The purpose of the California Desert Native Plants Act is to protect certain species of California desert native plants from unlawful harvesting on both public and privately owned lands. The California Desert Native Plants Act only applies within the boundaries of Imperial, Inyo, Kern, Los Angeles, Mono, Riverside, San Bernardino, and San Diego Counties. Within these counties, the California Desert Native Plants Act prohibits the harvest, transport, sale, or possession of specific native desert plants unless a person has a valid permit or wood receipt and the required tags and seals. The appropriate permits, tags, and seals must be obtained from the County sheriff or commissioner of the County where collecting will occur, and the County will charge a fee.

3.2.5.2.45 Porter–Cologne Water Quality Control Act

Pursuant to provisions of the Porter–Cologne Water Quality Control Act (Porter–Cologne Act), the RWQCBs regulate discharging waste, or proposing to discharge waste, within any region that could affect a water of the state (California Water Code Section 13260[a]). The State Water Resources Control Board defines a water of the state as “any surface water or groundwater, including saline waters, within the boundaries of the state” (California Water Code Section 13050[e]). As of April 2019, the State Water Resources Control Board has narrowed its definition of a water of the state to include the following (SWRCB 2021):

1. Natural wetlands
2. Wetlands created by modification of a surface water of the state
3. Artificial wetlands that meet any of the following criteria:
 - a. Approved by an agency as compensatory mitigation for impacts to other waters of the state, except where the approving agency explicitly identifies the mitigation as being of limited duration
 - b. Specifically identified in a water quality control plan as a wetland or other water of the state
 - c. Resulted from historic human activity, is not subject to ongoing operation and maintenance, and has become a relatively permanent part of the natural landscape
 - d. Greater than or equal to 1 acre in size unless the artificial wetland was constructed and is currently used and maintained, primarily for one or more of the following purposes: industrial or municipal wastewater treatment or disposal; settling of sediment; detention, retention, infiltration, or treatment of stormwater runoff and other pollutants or runoff subject to regulation under a municipal, construction, or industrial permitting program; treatment of surface waters; agricultural crop irrigation or stock watering; fire suppression; industrial processing or cooling water; active surface mining – even if the site is managed for interim wetlands functions and values; log storage; treatment, storage, or distribution of recycled water; maximizing groundwater recharge (this does not include wetlands that have incidental groundwater recharge benefits); or fields flooded for rice growing.

All waters of the United States are waters of the state. Wetlands, such as isolated seasonal wetlands, that are not generally considered waters of the United States are considered waters of the state if, “under normal circumstances, (1) the area has continuous or recurrent saturation of the upper substrate caused by groundwater, or shallow surface water, or both; (2) the duration of such saturation is sufficient to cause anaerobic conditions in the upper substrate; and (3) the area’s vegetation is dominated by hydrophytes or the area lacks vegetation” (SWRCB 2021). If a CWA Section 404 permit is not required for a project, the RWQCB may still require a permit (waste discharge requirements) for impacts to waters of the state under the Porter–Cologne Act.

The Project is expected to be subject to Waste Discharge Requirements (WDRs) from RWQCB. Permits and mitigation plans required prior to construction will be the responsibility of the qualified biologist assigned by the Applicant.

As discussed in Section 3.15.2.3.1 within Section 3.15, Water Resources, the Project is unlikely to encounter shallow groundwater and dewatering is not expected to be required. However, should groundwater be encountered during construction, any dewatering activity that would discharge to the land surface would need to comply with the provisions of General WDRs and ensure compliance with the Basin Plan. If required, the applicant and/or its contractor will submit the following to the Los Angeles RWQCB: a Notice of Intent to comply with these General WDRs, a project map, a copy of the CEQA document, the requisite fee, a discharge monitoring plan, and any

additional information requested by the Los Angeles RWQCB. Please refer to Section 3.15.2.3.1 for additional details.

Additionally, the project will not substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin. For additional details regarding groundwater. Please refer to Section 3.15.2.3.2 within Section 3.15, Water Resources for additional details.

3.2.5.2.56 Plants and Animals of California Declared to be Endangered or Threatened (Title 14, CCR, Sections 670.2 and 670.5)

These codes list plants and animals designated as threatened or endangered in California. State SSC is a category conferred by CDFW of those species that are indicators of regional habitat change or are considered potential future protected species. These species do not have any species legal status but are intended by CDFW for use as a management tool to take these species into special consideration when decisions are made concerning the future of any land parcel.

State threatened and endangered plants and animals are analyzed herein. Avoidance, minimization, and mitigation measures will include preconstruction surveys, avoidance buffers, timing restrictions, and take authorization from the CEC/CDFW, if necessary.

3.2.5.2.67 CEQA (PRC Sections 21000 et seq.)

CEQA requires identification of a project's potentially significant impacts on biological resources and ways that such impacts can be avoided, minimized, or mitigated. CEQA also provides guidelines and thresholds for use by lead agencies for evaluating the significance of proposed impacts.

CEQA Guidelines Section 15380(b)(1) defines endangered animals or plants as species or subspecies whose "survival and reproduction in the wild are in immediate jeopardy from one or more causes, including loss of habitat, change in habitat, overexploitation, predation, competition, disease, or other factors." A rare animal or plant is defined in Section 15380(b)(2) as a species that, although not presently threatened with extinction, exists "in such small numbers throughout all or a significant portion of its range that it may become endangered if its environment worsens; or ... [t]he species is likely to become endangered within the foreseeable future throughout all or a significant portion of its range and may be considered 'threatened' as that term is used in the federal Endangered Species Act." Additionally, an animal or plant may be presumed to be endangered, rare, or threatened if it meets the criteria for listing, as defined further in CEQA Guidelines Section 15380(c).

CDFW has developed a list of "Special Species" as "a general term that refers to all of the taxa the California Natural Diversity Database (CNDDB) is interested in tracking, regardless of their legal or protection status." This is a broader list than those species that are protected under the FESA, CESA, and other California Fish and Game Code provisions, and includes lists developed by other organizations, including, for example, the Audubon Watch List Species. Guidance documents prepared by other agencies, including the Bureau of Land Management Sensitive Species and USFWS Birds of Special Concern, are also included on the CDFW Special Species list. Additionally, CDFW has concluded that plant species listed as California Rare Plant Rank 1 and 2 by the California Native Plant Society, and potentially some California Rare Plant Rank 3 plants, are covered by CEQA Guidelines Section 15380.

Section IV, Appendix G (Environmental Checklist Form), of the CEQA Guidelines requires an evaluation of impacts to “any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations or by the California Department of Fish and Game or the U.S. Fish and Wildlife Service.”

Project environmental resources will be analyzed pursuant to CEQA.

3.2.5.2.78 Warren Alquist Act (PRC Sections 25000, et seq.)

The AFC process is a certified regulatory process pursuant to the Warren-Alquist Act and, therefore, fulfills the requirements of CEQA. CEQA is codified in the California PRC, Sections 21000, et seq. Guidelines for implementation of CEQA are codified in Title 14 of the California Code of Regulations (CRR), Sections 15000-15387.

Project environmental resources will be analyzed pursuant to CEQA.

3.2.5.2.89 California Energy Commission – Assembly Bill 205

Assembly Bill (AB) 205 is an emergency regulation expanding the CEC’s siting authority for renewable energy projects constructed on or before June 30, 2029. AB 205 was signed into law on June 30, 2022, and allows renewable and energy storage projects to apply for direct state permits through the CEC. CEC certification opt-in statute (specifically 25545.1(b)(1)) says “the issuance of a certificate by the commission for a site and related facility pursuant to this chapter shall be in lieu of any permit, certificate, or similar document required by any state, local, or regional agency [except California Coastal Commission, San Francisco Bay Conservation and Development Commission, and State/Regional Water Quality Control Board] ... for the use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency....”

The application for certification process is in lieu of CDFW’s Incidental Take Permit and Lake and Streambed Alteration Agreement processes. However, applications for both of these permits will be submitted to the CEC for informational purposes. The CEC Certification will include conditions and mitigation consistent with the Commission’s AB 205 authorities.

Project take authorization, if necessary, and a LSAA will be administered by the CEC in consultation with CDFW. A completed 1602 Lake and Streambed Alteration Agreement application is included as Appendix 3.2K.

3.2.5.3 Local LORS

3.2.5.3.1 Los Angeles County General Plan

The General Plan includes guiding principles that inform the County’s goals, policies, and implementation actions. The following goals and policies are relevant to the Project and applicable to biological resources (County of Los Angeles 2015):

Goal C/NR 1: Open space areas that meet the diverse needs of Los Angeles County.

Policy C/NR 1.3: Support the acquisition of new available open space areas. Augment this strategy by leveraging County resources in concert with the compatible open space stewardship actions of other agencies, as feasible and appropriate.

Goal C/NR 2: Effective collaboration in open space resource preservation.

Policy C/NR 2.2: Encourage the development of multi-benefit dedicated open spaces.

Policy C/NR 3.8: Discourage development in areas with identified significant biological resources, such as Significant Ecological Areas (SEAs).

The Project will mitigate impacts to biological resources, which will comply with the General Plan goals and policies related to open space.

3.2.5.3.2 County of Los Angeles Significant Ecological Areas

SEAs are officially designated areas within the County with irreplaceable biological resources. The SEA program objective is to conserve genetic and physical diversity within the County by designating biological resource areas that can sustain themselves into the future. The SEA also protects native trees and provides a list of the protected species and the size of the diameter of the trunk that triggers protection. The SEA Ordinance establishes the permitting, design standards, and review process for development within SEAs, balancing preservation of the County's natural biodiversity with private property rights. A discretionary SEA Conditional Use Permit application is required for development that cannot demonstrate compliance with Section 22.102.070 (Protected Tree Permit), or Sections 22.102.090 (SEA Development Standards) and 22.102.100 (Natural Open Space Preservation) of the County Code. County Planning has issued the SEA Ordinance Implementation Guide (County Planning 2020) to help proposed development comply with the ordinance.

SEA Resource Categories

The SEA Ordinance includes SEA Resource Categories 1 through 5. These categories are defined as follows (County Planning 2020):

- **Category 1:** FESA and CESA listed plant and wildlife species; CESA candidate species, CRPR 1A or B, 2A or B, and 3 (CNPS 2025a), critically imperiled natural communities (those that have a Global [G] and/or State [S] ranking of 1 (NatureServe 2025), and water resources
- **Category 2:** CDFW SSC and their occupied habitat, and imperiled natural communities (those that have are G2/S2) (NatureServe 2025)
- **Category 3:** Vulnerable natural communities that are G3/S3 (NatureServe 2025), sensitive local native resources, and oak woodlands
- **Category 4:** Apparently secure natural communities that are G4/S4 (NatureServe 2025), secure natural communities that are G5/S5 (NatureServe 2025), and CRPR 4 species
- **Category 5:** All other lands including those dominated by non-native vegetation, agricultural fields, hedges, early successional vegetation that has yet to form into a distinct natural community, cleared or disturbed areas, and non-native trees and shrubs.

Table 3.2-12-19, Recommended Preservation Ratios for SEA CUP, lists the recommended preservation ratios for impacts to SEA Resources Categories for projects that require a Conditional Use Permit.

Table 3.2-1219. Recommended Preservation Ratios for SEA CUP

SEA Resources	Preservation Ratio
Category 1 - State or federally listed species and their habitats - California Rare Plant Ranks 1,2,3 - Natural communities ranked G1/S1 - Water resources (e.g., wetlands, streams, ponds, lakes, vernal pools, marshes) - Beach and dune	5:1
Category 2 - Natural communities ranked G2/S2 - Species of Special Concern and their habitats	4:1
Category 3 - Natural communities ranked G3/S3 - Oak woodland - Sensitive local native resources - Rock outcrops/rocklands	3:1
Category 4 - Natural communities ranked G4/S4/G5/S5 - California Rare Plant Rank 4 - Non-native grasslands	2:1
Category 5 Wildlife linkage or corridor or open space buffer	1:1

Source: County Planning 2020.

Notes: SEA = Significant Ecological Area; G = Global; S = State.

The Project's Gen-Tie Line will potentially impact SEA Resource Categories 1 through 3 in the form special-status plants and wildlife, water resources, and vegetation communities; however, all such impacts are mitigated in accordance with the SEA ordinance and CEQA.

SEA Protected Trees

The SEA Ordinance includes 60 tree species to be protected in addition to already protected oak trees (County Planning 2020). The SEA Protected Tree List specifies the species of tree protected in each individual SEA and the size of the tree when regulations are applied. A Protected Tree Permit from the County shall be required for development that complies with Section 22.102.090 (SEA Development Standards) except for Subsection 22.102.090.B (SEA Protected Trees) of the County Code, and which includes any of the following impacts:

1. Pruning or trimming of branches of SEA Protected Trees in excess of 2 inches in diameter or 25% of live foliage for one or more trees;
2. Encroachments of up to 30% into an SEA Protected Tree's protected zone; any encroachment of more than 30% into the protected zone of a tree shall be considered as a tree removal
3. Removal of up to two SEA Protected Trees that are not designated as heritage trees (single trunk that measures 36 inches or more in diameter, or two trunks that collectively measure 54 inches or more in diameter)
4. Tree relocation poses significant risk to the health or survival rate of a tree. Any relocation of an SEA Protected Tree shall, therefore, be processed as a removal

California juniper is a protected tree under the SEA Ordinance. The Project will potentially impact 35 California juniper due to the construction of the gen-tie, however, all such impacts are mitigated in accordance with the SEA ordinance.

3.2.6 Permit and Permit Schedule

The Project is expected to require a Lake or Streambed Alteration Agreement from CDFW, but for the CEC's Opt-In Application for Certification process, and a WDR from RWQCB. Permits and mitigation plans required prior to construction will be the responsibility of the qualified biologist assigned by the Applicant. Lake or Streambed Alteration Agreement and WDR permit application packages are included herein as Appendixes 3.2D-2K and 3.2E. It is expected that the WDR would be issued within 90 days after certification by the CEC of the environmental impact report for the Project.

Table 3.2-20, Biological Resource Permits, lists the permits related to biological resources.

Table 3.2-20. Biological Resource Permits		
Permit	Agency	Status
Lake or Streambed Alteration Agreement (LSAA)	California Department of Fish and Wildlife – Region 5, South Coast	Submitted as part of this Opt-In application (see Appendix 3.2K)
Waste Discharge Requirements (WDR)	Los Angeles Regional Water Quality Control Board (RWQCB)	Application will be submitted to Los Angeles RWQCB in October 2025
California Desert Native Plants Act Permit	Los Angeles County	Will be obtained prior to collection of plants that will be impacted

3.2.7 Agency Contacts

Table 3.2-21, Summary of the Agency Contacts, The table below lists regulatory agency contacts for biological resources for this project.

Table 3.2-1321. Summary of the Applicable Federal, State, and Local LORS Agency Contacts

Natural Resource	Agency	Contact Information
State-listed Species	CDFW – Region 5, South Coast	(858) 467-4201 AskR5@wildlife.ca.gov
Federally-listed speciesLocally Sensitive Species	County of Los Angeles Regional PlanningUSFWS – Pacific Southwest Region, Ventura Field Office	Joseph Decruyenaere, Senior Biologist; jdecruyenaere@planning.lacounty.gov ¹ (805) 644-1766 Chris dellith@fws.gov

Notes: CDFW = California Department of Fish and Wildlife; USFWS = U.S. Fish and Wildlife Service.

¹ This correspondence is included as Appendix 3.2L.

3.2.8 References

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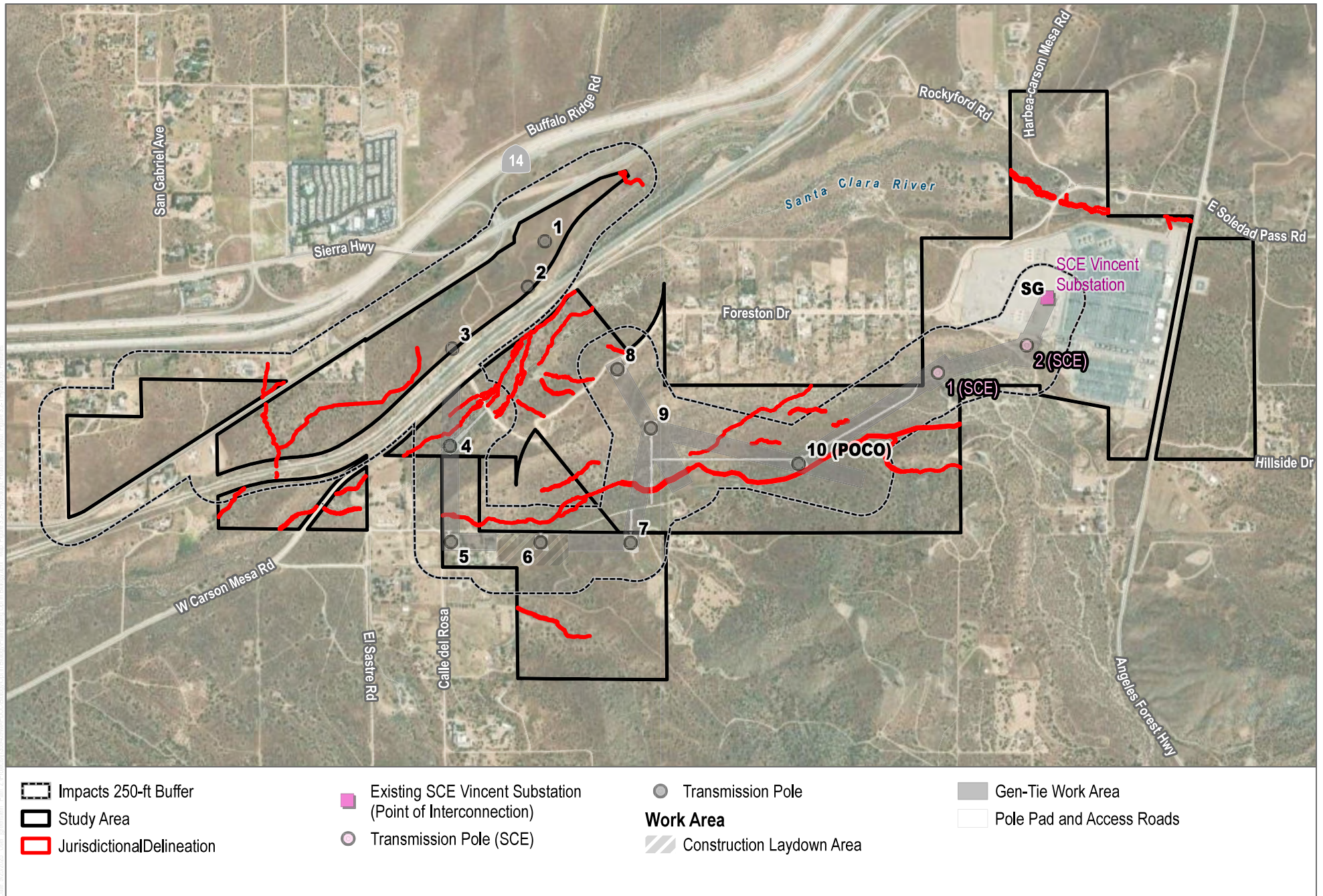
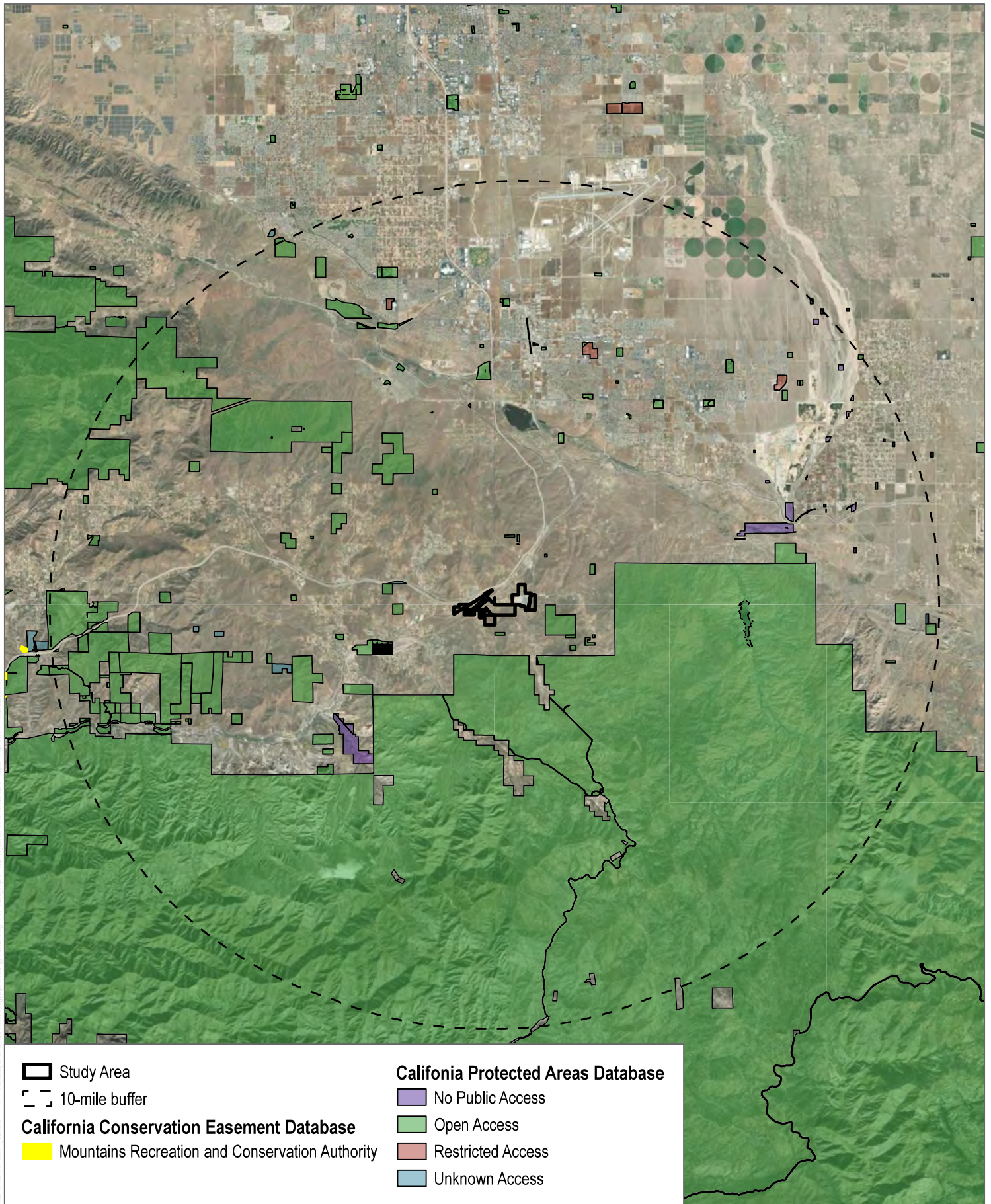


FIGURE 3.2-1
Hydrologic Features
Prairie Song Reliability Project

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SOURCE: World Imagery; CPAD 2024; CCED 2024

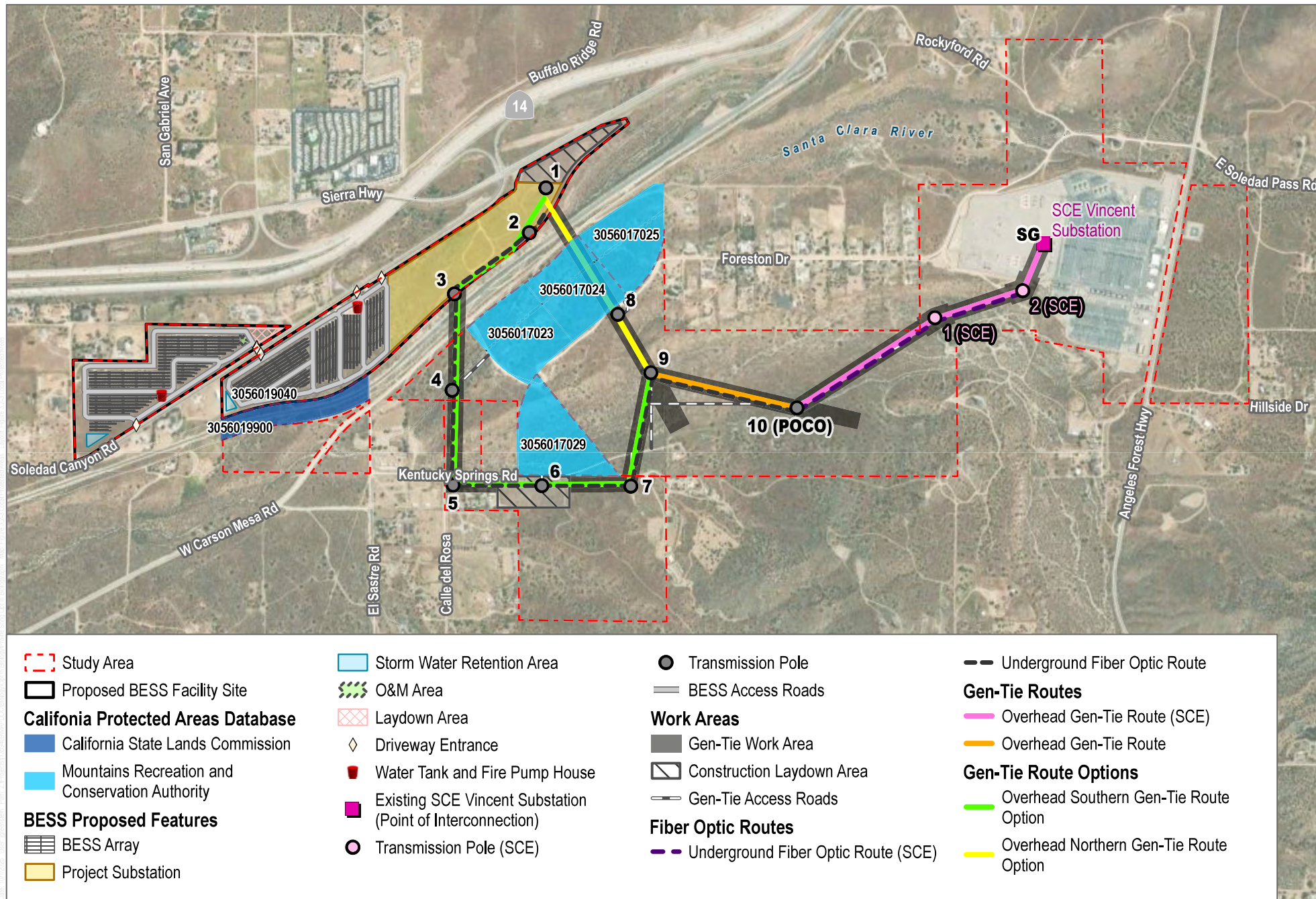
DUDEK



0 8,000 16,000 Feet

FIGURE 3.2-2
Protected Areas
Prairie Song Reliability Project

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SOURCE: World Imagery; CPAD 2024

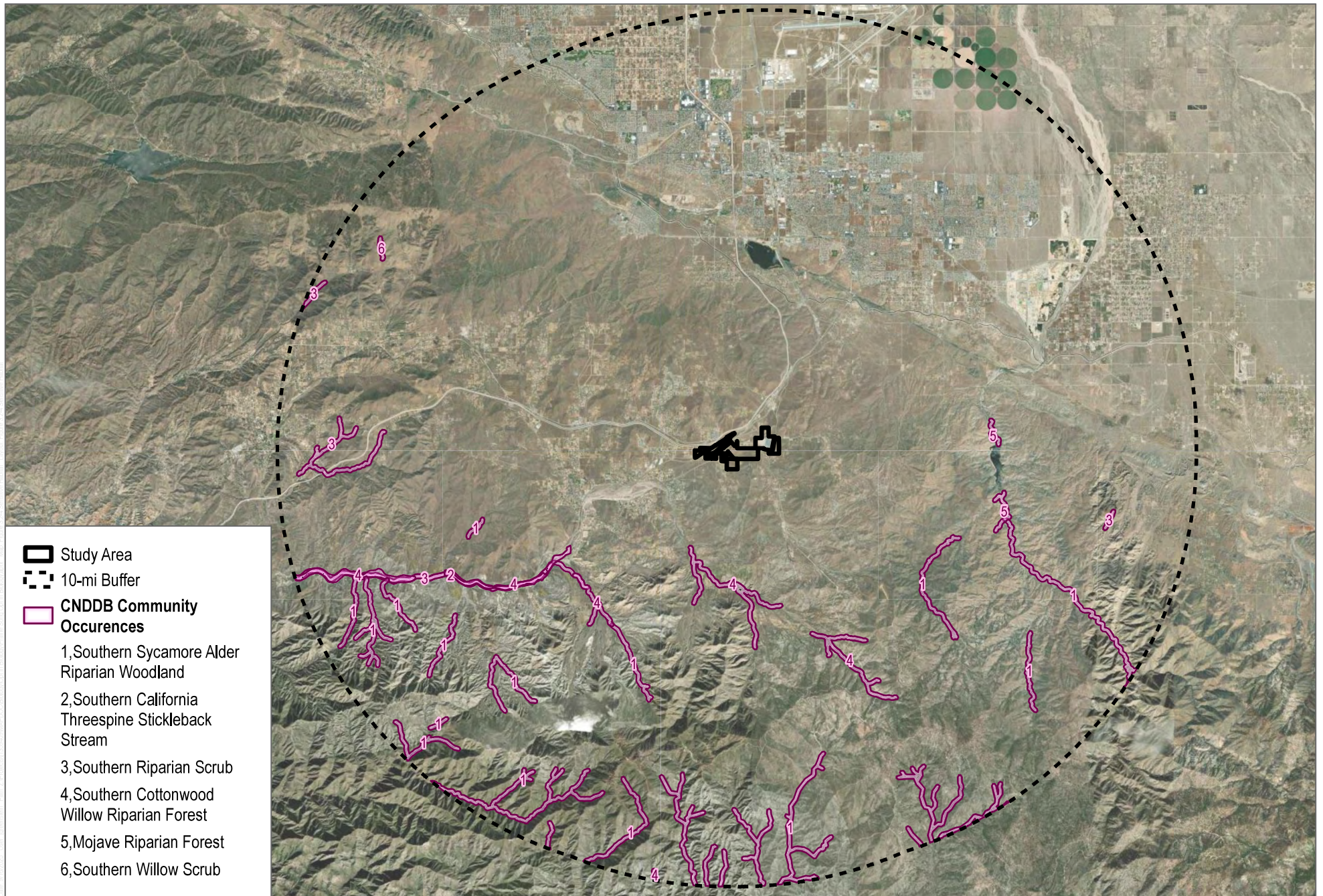
DUDEK



0 550 1,100 Feet

FIGURE 3.2-3
Local Protected Areas
Prairie Song Reliability Project

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SOURCE: Bing Maps 2023; Open Street Map 2023; CA Dept. of Fish and Wildlife 2023

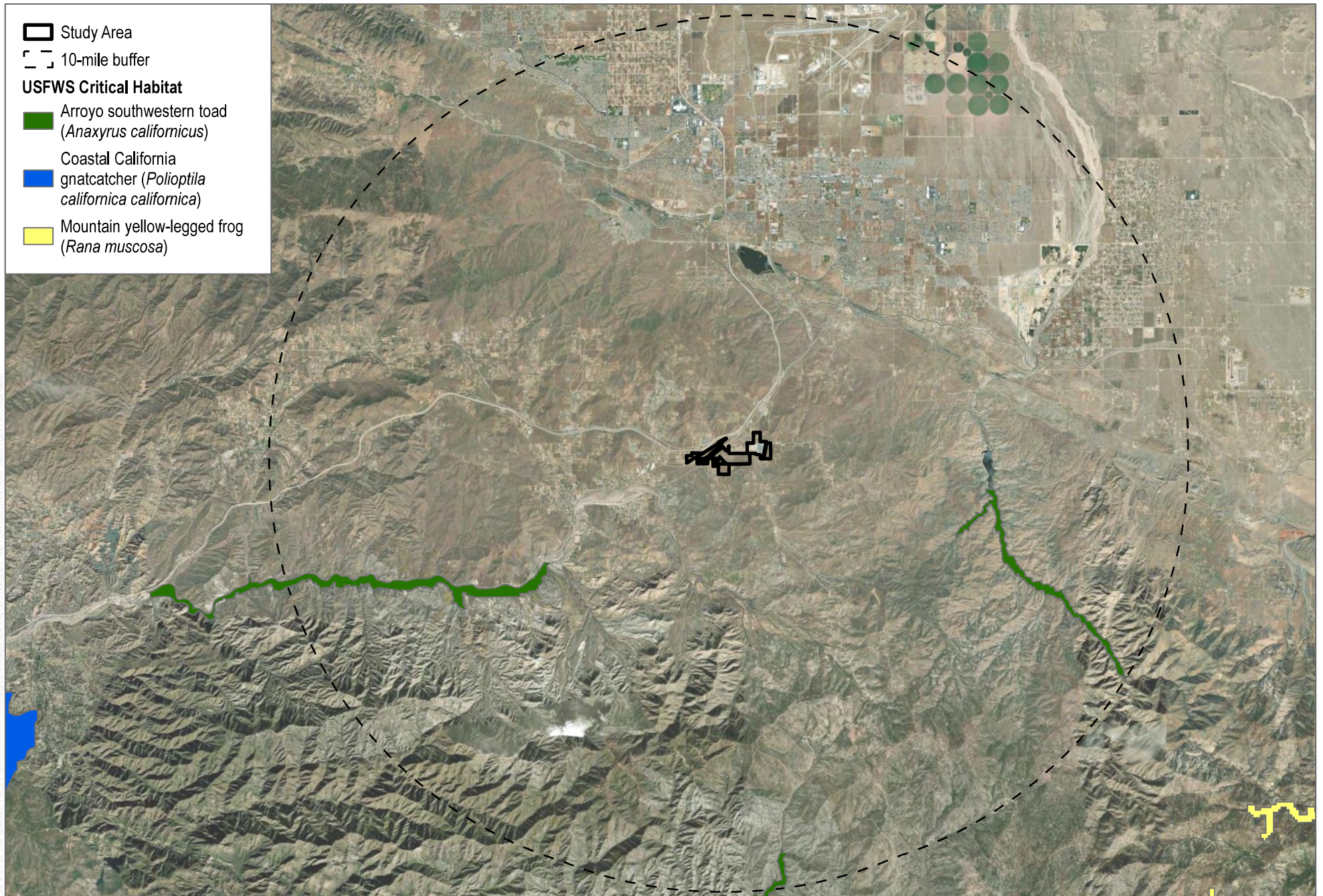
DUDEK



0 7,000 14,000 Feet

FIGURE 3.2-4
Sensitive Habitat Types
Prairie Song Reliability Project

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SOURCE: World Imagery; USFWS

DUDEK



0 8,000 16,000 Feet

FIGURE 3.2-5
Critical Habitat
Prairie Song Reliability Project

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