California Independent
System Operator Corporation

July 5, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER12-____-000

Filing of Service Agreement Nos. 2566
Unexecuted Non-Conforming Small Generator Interconnection Agreement

Dear Secretary Bose:

The California Independent System Operator Corporation submits for Commission filing and acceptance the attached unexecuted Small Generator Interconnection Agreement (SGIA) among Western Antelope Dry Ranch, LLC (Dry Ranch), Southern California Edison Company (SCE), and the ISO.[1]

The ISO is filing this agreement in an unexecuted form pursuant to the interconnection customer's request that the ISO do so pursuant to Section 11.3 of the ISO's Generator Interconnection Procedures (GIP).[2] As explained below, the parties have been unable to agree regarding certain terms in the SGIA relating to two issues:

(1) language added to Attachment 2 of the SGIA to cover the potential reclassification of facilities needed to interconnect the project from network upgrades to distribution facilities; and

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[1] This filing is submitted pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d and Part 35 of the Commission's regulations, 18 C.F.R. Part 35, and in compliance with Order No. 714, *Electronic Tariff Filings*, FERC Stats. & Regs. ¶ 31,276 (2008). The ISO is also sometimes referred to as the CAISO. All capitalized terms used herein, and not otherwise defined, have the meanings ascribed to such terms in the ISO tariff.

[2] Section 11.3 of the GIP (Appendix Y to the ISO tariff) requires an interconnection customer to "either: (i) execute the appropriate number of originals of the tendered GIA as specified in the directions provided by the CAISO and return them to the CAISO, as directed, for completion of the execution process; or (ii) request in writing that the applicable Participating TO(s) and CAISO file with FERC an GIA in unexecuted form."

(2) the appropriate commercial operation date for the project.

The ISO requests that the Commission accept this SGIA effective as of the day after the submittal of this filing, July 6, 2012.

On this same date, the ISO is also filing an unexecuted SGIA regarding a companion project, Western Antelope Blue Sky Ranch A. Both the Dry Ranch and Blue Sky Ranch A projects are wind projects of similar size and composition and will be interconnected in the same electrical area at the same point of interconnection. The SGIAs for both projects present the same issues for the Commission's consideration. SCE is concurrently filing identical versions of the unexecuted SGIAs for each project. In order to promote administrative efficiency, the ISO respectfully requests that the Commission consolidate all four of the dockets related to these agreements for purposes of consideration and decision.

I. Background

The Dry Ranch SGIA stems from a small generator interconnection request received by the ISO on December 15, 2010 from the sponsoring entity, Silverado Power. . The interconnection request is being processed under the ISO's GIP (ISO tariff Appendix Y), which the Commission accepted with an effective date of December 19, 2010. Under the terms of the GIP small generator interconnection requests such as Dry Ranch – which were received close in time to the new GIP – were transitioned to the GIP for processing, and the ISO refers to these interconnection requests as the SGIA transition cluster. Dry Ranch is a 20 MW wind project located in the Tehachapi area, and the interconnection studies for the project were performed as part of the combined queue cluster 1 and 2 Phase II interconnection studies as energy only.[3]

Interconnection Study Report and Upgrades known as the EKWRA Project. The Dry Ranch project received a study report which included the group study report for all of the projects in its study group, the Northern Bulk Cluster. One of the upgrade projects described in this group study report as a necessary reliability mitigation measure to accommodate interconnection of new generation in this area is the "East Kern Wind Resource Area 66kV Reconfiguration Project," also known as the "EKWRA" project. The group study report explains that the EKWRA project will separate the existing Antelope-Bailey 66 kV system into two systems in order to serve multiple distribution load centers in the area. The northern system will be served in a radial fashion from the Windhub Substation. A significant portion of the southern system will also be served in a radial fashion from either the Antelope Substation or the Bailey Substation. Finally, all the north-to-south lines that once connected the northern and

[3] The Dry Ranch project has elected to proceed with Energy-Only Deliverability Status, which means that it will only be responsible for funding reliability network upgrades, as opposed to delivery network upgrades, but will not be eligible to be considered a resource adequacy resource. See ISO Tariff Appendix A definition for Energy Only Deliverability Status.

southern systems will be opened.[4] The report also discussed the EKWRA project in the context of the Antelope West Area Upgrade. It noted that the inclusion of new generation on the western portion of the 66 kV sub-transmission system would cause overloads on the Bailey-Neenach-Westpac and Antelope-Neenach 66 kV lines. It indicated that mitigation for these overloads would consist of reconfiguring portions of these lines from parallel to radial.

Potential Reclassification of EKWRA Upgrades. Because the EKWRA project will ultimately result in operating portions of the existing Antelope-Bailey 66kV system as radial distribution systems, the group study report indicated that although the EKWRA facilities were assumed to be network upgrades for purposes of providing cost estimates, they might subsequently be reclassified as distribution facilities. Likewise, the report stated that because the mitigation of overloads on the Bailey-Neenach-Westpac and Antelope-Neenach 66kV lines involved a radial configuration, these upgrades might also be classified as distribution.

Because the EKWRA upgrades were originally identified as network upgrades, Dry Ranch was required to post financial security for these components under the GIP as network upgrades. This practice of having interconnection customers in the Northern Bulk Cluster post for the EKRWA project components (a.k.a. Western Antelope Upgrades) as network upgrades, subject to later a possible reclassification, was followed for all queue cluster 1 and 2 interconnection customers. In the later interconnection study cycle for queue cluster projects in clusters 3 and 4, the ISO adjusted its approach for addressing the EKWRA project components and treated the assumed classification of the upgrades as distribution upgrades and so excluded the upgrades from the ISO second financial postings.

EKWRA Upgrades and ISO 2010 Transmission Plan. Prior to its inclusion in the August 19, 2011 SCE Northern Bulk Cluster Group Study Report, the EKWRA reconfiguration project was included in the ISO's 2010 transmission planning process and incorporated in the ISO's April 7, 2010 Final 2010 Transmission Plan.[5] Prior to the adoption of the Final 2010 Transmission Plan, the ISO included, among its stakeholder efforts leading up to final Board consideration of the plan, a special stakeholder

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[4] The public version of the Northern Bulk Cluster Group Report is attached to this filing as Attachment C. In this version, the ISO has redacted certain confidential information regarding the specifications of certain assets because such information is confidential Critical Energy Infrastructure Information and has redacted cost information. The ISO has included a complete version of the Northern Bulk Cluster Group Report as Attachment B and asks that the Commission receive this as a confidential submittal because it contains confidential information.

[5] The Final 2010 Transmission Plan can be accessed on the ISO's website at http://www.caiso.com/Documents/Final2010ISOTransmissionPlan.pdf. The EKWRA discussion in contained in Chapter 4 [SCE Service Area Reliability Assessment] in Sections 4.3 [Study Results and Discussions], Section 4.4 [Recommended solutions for facilities not meeting thermal and voltage performance requirements] and Section 4.5 [Key Conclusions].

conference call, which was held March 19, 2010, to discuss the EKWRA reconfiguration. In this call, the ISO made a presentation to stakeholders highlighting the EKWRA reconfiguration and potential impacts to generators interconnecting to that region, calling out specific ISO queue positions then currently in the queue as potentially affected projects.[6]

II. Issues Presented for Commission Resolution

A. Provision to Cover Potential Reclassification of Network Upgrades to Distribution Upgrades

As noted above, the EKWRA reconfiguration project will result in certain facilities in the Antelope-Bailey area becoming radial in nature, including, potentially, the facilities currently identified as reliability network upgrades in the Dry Ranch SGIA. The ISO understands that SCE will most likely seek to remove any such ISO controlled grid facilities that in the future become radial in nature.

SCE has the right to seek to remove facilities from the ISO's operational control pursuant to the Transmission Control Agreement (TCA). The TCA governs the relationship between the ISO and its participating transmission owners with respect to the transmission systems placed under ISO operational control.[7] TCA Section 4.2.3 allows participating transmission owners to submit changes to the ISO Register for each addition or removal of a transmission line or associated facility or entitlement from the ISO's operational control or any change in a transmission line or associated facility's ownership, rating or the identity of the responsible participating transmission owner.[8] Section 4.7.1 of the TCA allows the ISO to release operational control over any transmission lines and associated facilities constituting part of the ISO controlled grid if, after consulting the participating transmission owners owning or having entitlements to those lines or facilities, (i) the ISO determines that it no longer requires to exercise operational control over those lines or facilities in order to meet the ISO's balancing authority area responsibilities; and (ii) the lines or facilities are:

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[6] A copy of the ISO's March 19, 2010 presentation can be accessed on the ISO's webpage containing archived materials pertaining to the 2010 transmission planning efforts, at http://www.caiso.com/Documents/Presentation-EastKernWindResourceArea_EKWRA_66kVReconfiguration.pdf.

[7] The Transmission Control Agreement can be accessed from the ISO's Transmission Operations webpage (http://www.caiso.com/market/Pages/TransmissionOperations/Default.aspx). The TCA, updated as of December 10, 2010, can be accessed at http://www.caiso.com/Documents/TransmissionControlAgreement-Updatedas-Dec3_2010.pdf.

[8] Under TCA Section 4.2.1 the ISO maintains a register (known as the ISO Register) of all transmission lines, associated facilities and Entitlements that are for the time being subject to the ISO's Operational Control.

i. directly assignable radial lines and associated facilities interconnecting generation (other than lines and facilities interconnecting ISO controlled grid critical protective systems or generators contracted to provide black start or voltage support); or

ii. lines and associated facilities which, by reason of changes in the configuration of the ISO controlled grid, should be classified as "local distribution" facilities in accordance with the Commission's applicable technical and functional test, or should otherwise be excluded from the facilities subject to ISO operational control consistent with Commission established criteria; or

iii. lines and associated facilities which are to be retired from service in accordance with good utility practice.

If SCE were to request that facilities related to the EKWRA reconfiguration project be removed from the ISO controlled grid, the ISO would post that request on its website and, under the TCA, provide the opportunity for interested parties to submit written comments objecting to the removal of the facilities. If the ISO cannot resolve any such objections to the satisfaction of the objecting parties and the participating transmission owner then the objections can be submitted to ISO alternative dispute resolution procedures or, alternatively, the ISO may apply to the Commission for approval.

In the case of the Dry Ranch project, it is not yet clear whether the reliability network upgrades identified in the Dry Ranch SGIA will become radial in nature, and therefore, subject of a likely SCE request to remove EKWRA-related facilities from the ISO controlled gird. The EKWRA reconfiguration, by itself, will not cause the upgrades identified in the Dry Ranch SGIA to become distribution upgrades. Rather, an additional system reconfiguration required to interconnect another project in the ISO's queue will cause the existing Antelope 66 kV substation and the upgrades associated with that substation identified for the Dry Ranch project to become radial.

Although it is not yet certain that these facilities will be removed from the ISO's operational control, to clarify the potential impact to interconnection customer, proposed language has been added to the Dry Ranch SGIA to address the consequences to the interconnection customer if they were to be removed. That language, set forth in Section 18 of Attachment 1 of the SGIA, reads as follows:

> Should the Point of Interconnection change from the CAISO Controlled Grid to the Distribution System, then the Participating TO and the Interconnection Customer will negotiate in good faith to replace this SGIA with a Generation Interconnection Agreement ("GIA") consistent with the pro forma contained in the Participating TO's Wholesale Distribution Access Tariff ("WDAT"), Attachment I, Appendix 5. Upon the effective date of the replacement GIA, the Parties will terminate this SGIA. Prior to the effective date of the reclassification of the Network Upgrades as Distribution Upgrades, the Interconnection Customer will be required to

> obtain distribution service for the [generating facility] pursuant to the Participating TO's WDAT to deliver power from the Point of Interconnection on the Distribution System to the CAISO Controlled Grid.
>
> The obligation for the CAISO and the Participating TO to provide repayment of amounts advanced for Network Upgrades or Congestion Revenue Rights in accordance with Article 5.3 of this SGIA associated with the reclassified facilities will cease as of the effective date of the reclassification from Network Upgrades to Distribution Upgrades.
>
> The new GIA will reflect the following terms:
>
> a. The reclassified facilities will be reflected in the GIA as Distribution Upgrades.
>
> b. The Interconnection Customer's cost responsibility for Distribution Upgrades will be increased to reflect the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
>
> c. The Interconnection Customer's cost responsibility for Network Upgrades will be decreased to remove the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
>
> d. The Credit Support amounts reflected in Section 10 and Section 11 of this SGIA Attachment 2, will be modified to reflect the facilities' reclassification.[9]

Dry Ranch has opposed the addition of this language, arguing that, regardless of whether or not the identified network upgrades remain as part of the ISO controlled grid, there should be no change in treatment of the upgrades under the SGIA for purposes of reimbursement of the customer's funding for their construction. The ISO, however, supports the inclusion of this language, as it appropriately reflects the outcome that would occur under the ISO's current tariff if the facilities identified in the SGIA as transmission facilities are removed from the ISO's operational control, per the process articulated in the TCA as described above.

The ISO's tariff makes clear that the ISO's interconnection process applies only to interconnections to the ISO controlled grid.[10] Likewise, the ISO's pro forma SGIA,

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[9] SCE has also added language to Section 18 to address a situation in which the network upgrades would be reclassified as distribution upgrades, but the customer's point of interconnection would not be removed from the ISO controlled grid. The ISO understands that this scenario is not possible with respect to the Dry Ranch project, but the language was included by SCE as part of SCE's efforts to develop a standard provision to include in all interconnection agreements where the reclassification issue is presented.

which is the basis for the Dry Ranch SGIA, indicates that it governs the terms and conditions under which the customer's facility will be interconnected and operate in parallel with "the Participating TO's Transmission System," which is defined as those facilities turned over to the ISO's operational control and that form part of the ISO controlled grid.[11]

Therefore, if the point of interconnection between the Dry Ranch project and SCE's system (the Antelope substation) is removed from the ISO's operational control, and no longer part of the ISO controlled grid, the ISO will, by definition, no longer be providing interconnection service to the customer. Under such circumstances, interconnection service would be provided directly and solely by SCE. Therefore, it is appropriate that if the Dry Ranch project is not interconnected to an ISO controlled grid, interconnection should be governed by the terms of SCE's tariff and agreements. This outcome is also dictated by the terms of the TCA, which provides that wholesale interconnection customers seeking to interconnect to the utility distribution systems of the participating transmission owner parties to the TCA will do so pursuant to the terms of the applicable transmission owner's open access tariff.[12]

If the ISO is no longer providing interconnection service to a particular customer, then the ISO agrees that the correct outcome is to terminate the affected generator interconnection agreement under the ISO tariff and replace it with an appropriate WDAT interconnection agreement under SCE's Wholesale Distribution Access Tariff. Under such circumstances, the ISO commits to work closely with SCE and the interconnection customer to resolve any implementation and operational issues, so as to ensure that the transition between the ISO's SGIA and an SCE WDAT is as seamless as possible.

With respect to repayment of amounts advanced by the customer to fund the reclassified facilities, given that the ISO would no longer have an SGIA with the customer, it logically follows that any further repayment for such facilities would cease upon termination of the SGIA. There is no provision under the ISO tariff that provides for repayment of amounts advanced by an interconnection customer for distribution facilities, much less for facilities that are no longer part of the ISO controlled grid.[13] This outcome is also consistent with the principle articulated in Order No. 2003 and other relevant Commission precedent that interconnection customers are eligible for repayment for costs advanced for network facilities because all users of the

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10 ISO Tariff, Appendix Y, Section 1.1 ("The objective of this GIP is to implement the requirements for both Small and Large Generating Facility interconnections *to the CAISO Controlled Grid*.") (emphasis added); ISO Tariff, Appendix T (SGIA), Section 1.2.

11 *See* Dry Ranch SGIA at Section 1.2, Attachment 1 (definition of "Transmission System").

12 Transmission Control Agreement at Section 10.1.

13 *Cf.* Dry Ranch SGIA at Section 5.3.1.1 ("Notwithstanding the foregoing, if this Agreement terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination.").

transmission system, not just the generator, derive a benefit from network facilities, even if those facilities would not have been installed but for the generator. On the other hand, those facilities that are radial in nature and solely benefit the generator are not eligible for reimbursement.[14]

If the facilities identified as network upgrades in the Dry Ranch SGIA are re-classified as distribution facilities, it will be because they will operate in a radial fashion, and therefore, will no longer provide a network benefit to transmission customers. As a result, it would be inappropriate and unfair to expect the ISO's transmission customers to bear the burden of funding repayment of such facilities.[15]

For these reasons, the ISO believes that the language proposed by SCE for inclusion in Section 18 of Attachment 2 is just and reasonable, and should be accepted by the Commission.

B. Classification of Protective Relays and Telecommunications Equipment

Dry Ranch takes the position that the protective relays and Telecommunications equipment at the Antelope Substation should be classified as network upgrades. The ISO and SCE disagree with that position.[16] The protective relays and Telecommunications equipment should be classified as interconnection facilities, not network upgrades. The Commission's precedent regarding the Green Borders project explains why such facilities should be classified as interconnection facilities.[17]

C. Commercial Operation Date

Dry Ranch has taken the position that the appropriate commercial operation date to include in the SGIA is the one indicated in the original interconnection application for the project. The ISO and SCE disagree. The factual circumstances surrounding this project demonstrate that the date set forth in the interconnection application is not currently feasible.

The reliability network upgrades required for this customer require twenty-four (24) months to be built. Moreover the facilities cannot start until the SGIA is effective and Dry Ranch has made its third posting.[18] Thus since the effective date is requested

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14 *See e.g., Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 21 (2004).

15 The costs of network upgrades paid for by interconnection customers are repaid by ISO transmission customers through the Transmission Access Charge, which is based on the transmission revenue requirements of each of its participating transmission owners.

16 Attachment 2, Section 1 to the SGIA.

17 *See Southern California Edison Co.*, 139 FERC ¶ 61,185 (2012).

18 Attachment 4(f) to the SGIA.

as July 6, 2012, even assuming that Dry Ranch makes its third posting that same day, the facilities will not be built and available for interconnection, based on current estimated schedule, July 2014.

For these reasons, the ISO maintains that the appropriate commercial operation date to include in the Dry Ranch SGIA is July 1, 2014.

III. Effective Date and Request for Waiver

The ISO requests that the Commission permit the Dry Ranch SGIA to become effective as of the day after this filing, July 6, 2012, to allow the customer to post funds to permit the SCE to begin construction of the upgrades as soon as possible to facilitate the interconnection customers request to reach commercial operation as soon as possible. In this regard, the ISO understands that both the customer and SCE desire to commence construction activities in the short term to complete the interconnection configuration as near as possible to 24 months from July 6, 2012. To accommodate the foregoing requested effective date, the ISO respectfully requests waiver, pursuant to Section 35.11 of the Commissions regulations (18 C.F.R. § 35.11), of the 60-day notice requirement contained in Section 35.3 of the Commission's regulations (18 C.F.R. § 35.3), and to the extent necessary, the ISO respectfully requests that the Commission grant any other waivers of its regulations that may be required in connection with the requested effective date. Good cause exists in that such waiver will permit SCE and the interconnection customer to begin engineering and design work as soon as possible. No harm will result to any entity from the specified effective dates for the SGIA. Granting the requested waiver, therefore, is appropriate.

IV. Request for Confidential Treatment

The ISO has included a complete version of the Northern Bulk Cluster Group Report as Attachment B and asks that the Commission receive this as a confidential submittal because it contains confidential information. The confidential information pertains to specifications of certain transmission assets because such information is confidential Critical Energy Infrastructure Information and to certain cost information pertaining to the EKWRA upgrades. Pursuant to 18 C.F.R. § 388.112, the ISO asks that the Commission receive the report as a confidential submittal because it contains confidential information. The ISO has also attached public version of the Northern Bulk Cluster Group Report as Attachment C, which has redacted the confidential information.

V. Expenses

No expense or cost associated with this filing has been alleged or judged in any judicial or administrative proceeding to be illegal, duplicative, unnecessary, or demonstratively the product of discriminatory employment practices.

VI. Attachments

In addition to this transmittal letter, the following documents support the instant filing:

Attachment A	Service Agreement No. 2566
Attachment B	CEII version of Northern Bulk Cluster Group Report for Queue Clusters 1 and 2 (with Critical Energy Infrastructure Information and cost information included)
Attachment C	Public version of the Northern Bulk Cluster Group Report for Queue Clusters 1 and 2 (with Critical Energy Infrastructure Information and cost information redacted)

VII. Service

The ISO has served copies of this transmittal letter and all attachments on SCE, Western Antelope Dry Ranch, LLC, the California Public Utilities Commission, and the California Energy Commission. In addition, the ISO is posting this transmittal letter and all attachments on the ISO's website.

VIII. Correspondence

The ISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

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* Individuals designated for service pursuant to Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3).

IX. Conclusion

The ISO respectfully requests that the Commission accept this SGIA as filed and permit the SGIA to be effective as of the date requested. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

/s/ Michael Kunselman

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ATTACHMENT A

Small Generator Interconnection Agreement (SGIA)
Among
Western Antelope Dry Ranch LLC
And
Southern California Edison Company
And
California Independent System Operator Corporation

SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA) AMONG

WESTERN ANTELOPE DRY RANCH LLC
AND

SOUTHERN CALIFORNIA EDISON COMPANY
AND

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

PROJECT: Western Antelope Dry Ranch TOT516 (Q653H)

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SMALL GENERATOR INTERCONNECTION AGREEMENT

This Small Generator Interconnection Agreement ("Agreement") is made and entered into this ________ day of ________________, 20__, by Southern California Edison Company , a corporation organized and existing under the laws of the State of California ("Participating TO"), the California Independent System Operator Corporation, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("CAISO") and Western Antelope Dry Ranch LLC , a limited liability company organized and existing under the laws of the State of Delaware ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or referred to collectively as the "Parties."

Participating TO Information

Participating TO: Southern California Edison Company
Attention: Mr. William Law, Manager, Grid Contract Management
Address: P. O. Box 800
2244 Walnut Grove Avenue
City: Rosemead State: California Zip: 91770
Phone: (626) 302-9640 Fax: (626) 302-1152
E-mail Address: william.law@sce.com

CAISO Information

Attention: Mr. Brij Basho, Contracts Negotiator Lead
Address: 250 Outcropping Way
City: Folsom State: CA Zip: 95630
Phone: (916) 608-7136 Fax: (916) 608-7292
E-mail: bbasho@caiso.com

Interconnection Customer Information

Interconnection Customer: Western Antelope Dry Ranch LLC
Attention: Adam Foltz
Address: 44 Montgomery St, Ste. 3065
City: San Francisco State: CA Zip: 94104
Phone: 415-692-7578 Fax: 415-362-4001
E-mail Address: a.foltz@silveradopower.com

Interconnection Customer Queue Position number: Q653H

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

ARTICLE 1. SCOPE AND LIMITATIONS OF AGREEMENT

1.1 This Agreement shall be used for all Small Generating Facility Interconnection Requests submitted under the applicable generator procedure (either the Generator Interconnection Procedures (GIP) set forth in Appendix Y or the Small Generator Interconnection Procedures (SGIP) set forth in Appendix S) except for those submitted under the 10 kW Inverter Process contained in GIP Attachment 7 or SGIP Attachment 5. For those Interconnection Requests, Attachment 5 contains the terms and conditions which serve as the Interconnection Agreement.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Participating TO's Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity in accordance with the CAISO Tariff.

1.4 Nothing in this Agreement is intended to affect any other agreement between or among the Parties.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice. The Parties shall use the Large Generator Interconnection Agreement (CAISO Tariff Appendix V or Appendix CC, as applicable) to interpret the responsibilities of the Parties under this Agreement.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Participating TO shall construct, operate, and maintain its Interconnection Facilities and Upgrades in accordance with this Agreement, and with Good Utility Practice. The CAISO and the Participating TO shall cause the Participating TO's Transmission System to be operated and controlled in a safe and reliable manner and in accordance with this Agreement.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Participating TO and any Affected Systems. The Interconnection Customer shall comply with the Participating TO's Interconnection Handbook. In the event of a conflict between the terms of this Agreement and the terms of the Participating TO's Interconnection Handbook, the terms in this Agreement shall govern.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Participating TO and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the CAISO Controlled Grid, the Participating TO's electric system, the Participating TO's personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Participating TO and the CAISO shall coordinate with Affected Systems to support the interconnection.

1.5.7 [This provision is intentionally omitted.]

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the CAISO Balancing Authority Area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the CAISO Tariff for the CAISO Controlled Grid and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the terminals of each generating unit at a power factor within the range of 0.95 leading to 0.90 lagging, unless the CAISO has established different requirements that apply to all similarly situated generators in the CAISO Balancing Authority Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators and the requirements of Attachment 7 shall apply instead.

1.8.2 Payment to the Interconnection Customer for reactive power that the Small Generating Facility provides or absorbs when the CAISO requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1 will be made by the CAISO in accordance with the applicable provisions of the CAISO Tariff.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

ARTICLE 2. INSPECTION, TESTING, AUTHORIZATION, AND RIGHT OF ACCESS

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Participating TO and the CAISO of such activities no fewer than five (5) Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Participating TO and the CAISO may, at their own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Participating TO and the CAISO a written test report when such testing and inspection is completed.

2.1.2 The Participating TO and the CAISO shall provide the Interconnection Customer written acknowledgment that they have received the

Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Participating TO or the CAISO of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Participating TO and the CAISO shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Participating TO and the CAISO shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Participating TO and the CAISO shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Participating TO's Transmission System without prior written authorization of the Participating TO. The Participating TO will provide such authorization to the Interconnection Customer and the CAISO once the Participating TO receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access to Premises

2.3.1 Upon reasonable notice, the Participating TO and the CAISO may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Participating TO and the CAISO at least five (5) Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Participating TO and the CAISO shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

ARTICLE 3. EFFECTIVE DATE, TERM, TERMINATION, AND DISCONNECTION

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The Participating TO and the CAISO shall promptly file this Agreement with the FERC upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of thirty-five (35) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Participating TO and the CAISO twenty (20) Business Days written notice.

3.3.2 Any Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the CAISO Controlled Grid. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection of the Small Generating Facility or associated Interconnection Facilities shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; (2) that, in the case of the CAISO, is imminently likely (as determined in a non-discriminatory manner) 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 (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, the 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 (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the CAISO or the Participating TO may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Participating TO or the CAISO shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall notify the Participating TO and the CAISO promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the CAISO Controlled Grid, the Participating TO's Interconnection Facilities, or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Interconnection Customer's or Participating TO's facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Participating TO or the CAISO may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the CAISO Controlled Grid when necessary for routine maintenance, construction, and repairs on the CAISO Controlled Grid or the Participating TO's electric system. The

Party scheduling the interruption shall provide the Interconnection Customer with (5) five Business Days notice prior to such interruption. The Party scheduling the interruption shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

The Interconnection Customer shall update its planned maintenance schedules in accordance with the CAISO Tariff. The CAISO may request the Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the CAISO Controlled Grid in accordance with the CAISO Tariff. Such planned maintenance schedules and updates and changes to such schedules shall be provided by the Interconnection Customer to the Participating TO concurrently with their submittal to the CAISO.

3.4.3 Forced Outages

During any forced outage, the Participating TO or the CAISO may suspend interconnection service to effect immediate repairs on the CAISO Controlled Grid or the Participating TO’s electric system. The Participating TO or the CAISO shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Participating TO or the CAISO shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection. The Interconnection Customer shall notify CAISO, as soon as practicable, of all forced outages or reductions of the Small Generating Facility in accordance with the CAISO Tariff.

3.4.4 Adverse Operating Effects

The Participating TO or the CAISO shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the CAISO Controlled Grid, the Participating TO's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Participating TO or the CAISO may disconnect the Small Generating Facility. The Participating TO or the CAISO shall provide the Interconnection Customer with (5) five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the Participating TO and the CAISO before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the CAISO Controlled Grid or the Participating TO's electric system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Participating TO's and the CAISO's prior written authorization, the Participating TO or the CAISO shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, the Participating TO's electric system, and the CAISO Controlled Grid to their normal operating state as soon as reasonably practicable following a temporary disconnection.

ARTICLE 4. COSTS FOR INTERCONNECTION FACILITIES & DISTRIBUTION UPGRADES

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Participating TO shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, the CAISO, and the Participating TO.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Participating TO's Interconnection Facilities.

4.2 Distribution Upgrades

The Participating TO shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

ARTICLE 5. COST RESPONSIBILITY FOR NETWORK UPGRADES

5.1 Applicability

No portion of this Article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Participating TO shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Participating TO elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

5.3 Transmission Credits

No later than thirty (30) days prior to the Commercial Operation Date, the Interconnection Customer may make a one-time election by written notice to the CAISO and the Participating TO to receive Congestion Revenue Rights as defined in and as available under the CAISO Tariff at the time of the election in accordance with the CAISO Tariff, in lieu of a refund of the cost of Network Upgrades in accordance with Article 5.3.1.

5.3.1 Repayment of Amounts Advanced for Network Upgrades

5.3.1.1 Repayment of Amounts Advanced Regarding Non-Phased Generating Facilities

Upon the Commercial Operation Date of a Generating Facility that is not a Phased Generating Facility, the Interconnection Customer shall be entitled to a repayment, equal to the total amount paid to the Participating TO for the cost of Network Upgrades. Such amount shall include any tax gross-up or other tax-related payments associated with Network Upgrades not refunded to the Interconnection Customer, and shall be paid to the Interconnection Customer by the Participating TO on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years from the Commercial Operation Date. Notwithstanding the foregoing, if this Agreement terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination.

5.3.1.2 Repayment of Amounts Advanced Regarding Phased Generating Facilities

Upon the Commercial Operation Date of each phase of a Phased Generating Facility, the Interconnection Customer shall be entitled to a repayment equal to the amount paid to the Participating TO for the cost of Network Upgrades for that completed phase for which the Interconnection Customer is responsible, if all of the following conditions are satisfied:

(a) The Generating Facility is capable of being constructed in phases;

(b) The Generating Facility is specified in the SGIA as being constructed in phases;

(c) The completed phase corresponds to one of the phases specified in the SGIA;

(d) The Interconnection Customer has tendered notice pursuant to the SGIA that the phase has achieved Commercial Operation;

(e) All parties to the SGIA have agreed that the completed phase meets the requirements set forth in the SGIA and any other operating, metering, and interconnection requirements to permit generation output of the entire capacity of the completed phase as specified in the SGIA;

(f) The Network Upgrades necessary for the completed phase to meet the desired level of deliverability are in service; and

(g) The Interconnection Customer has posted one hundred (100) percent of the Interconnection Financial Security required for the Network Upgrades for all the phases of the Generating Facility.

Upon satisfaction of these conditions (a) through (g), the Interconnection Customer shall be entitled to receive a partial repayment of its financed cost responsibility in an amount equal to the percentage of the Generating Facility declared to be in Commercial Operation multiplied by the cost of the Network Upgrades associated with the completed phase. The Interconnection Customer shall be entitled to repayment in this manner for each completed phase until the entire Generating Facility is completed.

If the SGIA includes a partial termination provision and the partial termination right has been exercised with regard to a phase that has not been built, then the Interconnection Customer's eligibility for repayment under this Article as to the remaining phases shall not be diminished. If the Interconnection Customer completes one or more phases and then defaults on the SGIA, the Participating TO and the CAISO shall be entitled to offset any losses or damages resulting from the default against any repayments made for Network Upgrades related to the completed phases, provided that the party seeking to exercise the offset has complied with any requirements which may be required to apply the stream of payments utilized to make the repayment to the Interconnection Customer as an offset.

Any repayment amount for completion of a phase shall include any tax gross-up or other tax-related payments associated with Network Upgrades not refunded to the Interconnection Customer, and shall be paid to the Interconnection Customer by the Participating TO on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years from the Commercial Operation Date. Notwithstanding the foregoing, if this Agreement terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination.

5.3.1.3 Interest Payments and Assignment Rights

Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. Interest shall continue to accrue on the repayment obligation so long as this Agreement is in effect. The Interconnection Customer may assign such repayment rights to any person.

5.3.1.4 Failure to Achieve Commercial Operation

5.3.2 Special Provisions for Affected Systems

The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected owners of portions of the CAISO Controlled Grid, as applicable, in accordance with the applicable generation interconnection procedure under which the Small Generating Facility was processed (SGIP or GIP). Such agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected owners of portions of the CAISO Controlled Grid. In no event shall the Participating TO be responsible for the repayment for any facilities that are not part of the Participating TO's Transmission System.

5.3.3 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Small Generating Facility.

ARTICLE 6. BILLING, PAYMENT, MILESTONES, AND FINANCIAL SECURITY

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Participating TO shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within thirty (30) calendar days of receipt, or as otherwise agreed to by the Parties. Notwithstanding the foregoing, any invoices between the CAISO and another Party shall be submitted and paid in accordance with the CAISO Tariff.

6.1.2 Within six (6) months of completing the construction and installation of the Participating TO's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Participating TO shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Participating TO for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Participating TO shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Participating TO within thirty (30) calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Participating TO shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, as defined in article 7.5.1, it shall immediately notify the other Parties of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Attachment 4. The Parties affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) they will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) they have reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements for Small Generating Facilities Processed Under the Fast Track Process or Small Generating Facilities Processed under SGIP

The terms and conditions of this Article 6.3 shall apply only to:

1. Small Generating Facilities that are no larger than 5 MW that are processed under the Fast Track Process under the Generation Interconnection Procedures, CAISO Tariff Appendix Y; and
2. Small Generating Facilities processed under the Small Generation Interconnection Procedures set forth in CAISO Tariff Appendix S. In such case, the terms of Article 6.4 below do not apply to this Agreement.

For easy reference, the Parties shall check the Box below when this Article 6.3 applies:

[ ] THIS ARTICLE 6.3 APPLIES

6.3.1 At least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Participating TO's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Participating TO, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Participating TO and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Participating TO's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Participating TO under this Agreement during its term.

6.3.2 If a guarantee is provided, the guarantee must be made by an entity that meets the creditworthiness requirements of the Participating TO, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.3 If a letter of credit or surety bond is provided, the letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

6.4 Financial Security Arrangements for All Other Small Generating Facilities

The terms of this Article 6.4 apply to Small Generating Facilities that have been processed under either

1. the Cluster Study Process or
2. the Independent Study Track Process

of the Generation Interconnection Procedures set forth in CAISO Tariff Appendix Y. In such case, the provisions of Article 6.3 do not apply to this Agreement.

In such case, the terms of Article 6.3 above do not apply to this Agreement.

For easy reference, the Parties shall check the Box below when this Article 6.4 applies:

[X] THIS ARTICLE 6.4 APPLIES

6.4.1 The Interconnection Customer is obligated to provide all necessary Interconnection Financial Security required under Section 9 of the GIP in a manner acceptable under Section 9 of the GIP. Failure by the Interconnection Customer to timely satisfy the GIP's requirements for the provision of Financial Security shall be deemed a breach of this Agreement and a condition of Default of this Agreement.

6.4.2 Notwithstanding any other provision in this Agreement for notice of Default and opportunity to cure such Default, the CAISO or the Participating TO shall provide Interconnection Customer with written notice of any Default due to timely failure to post Financial Security, and the Interconnection Customer shall have five (5) Business Days from the date of such notice to cure such Default by posting the required Interconnection Financial Security. If the Interconnection Customer fails to cure the Default, then this Agreement shall be deemed terminated.

ARTICLE 7. ASSIGNMENT, LIABILITY, INDEMNITY, FORCE MAJEURE, AND DEFAULT

7.1 Assignment

This Agreement may be assigned by any Party upon fifteen (15) Business Days prior written notice and opportunity to object by the other Parties; provided that:

7.1.1 Any Party may assign this Agreement without the consent of the other Parties to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Participating TO and the CAISO of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Participating TO or the CAISO, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Participating TO and the CAISO of any such assignment.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall any Party be liable to the other Parties for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, no Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing by the Party claiming Force Majeure."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Parties, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Parties informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of another Party. Upon a Default, the affected non-defaulting Party(ies) shall give written notice of such Default to the defaulting Party. Except as provided in Article 7.6.2 and in Article 6.4.2, the defaulting Party shall have sixty (60) calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the affected non-defaulting Party(ies) shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not such Party(ies) terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

ARTICLE 8. INSURANCE

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Participating TO or CAISO, except that the Interconnection Customer shall show proof of insurance to the Participating TO and CAISO no later than 10 Business Days prior to the anticipated Commercial Operation Date. If the Interconnection Customer is of sufficient credit-worthiness, it may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 The Participating TO agrees to maintain general liability insurance or self-insurance consistent with the Participating TO's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Participating TO's liabilities undertaken pursuant to this Agreement.

8.3 The CAISO agrees to maintain general liability insurance or self-insurance consistent with the CAISO's commercial practice. Such insurance shall not exclude coverage for the CAISO's liabilities undertaken pursuant to this Agreement.

8.4 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

ARTICLE 9. CONFIDENTIALITY

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to another Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties to this Agreement when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

ARTICLE 10. DISPUTES

All disputes arising out of or in connection with this Agreement whereby relief is sought by or from CAISO shall be settled in accordance with the provisions of Article 13 of the CAISO Tariff, except that references to the CAISO Tariff in such Article 13 of the CAISO Tariff shall be read as reference to this Agreement. Disputes arising out of or in connection with this Agreement not subject to provisions of Article 13 of the CAISO Tariff shall be resolved as follows:

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within 2 Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

10.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

ARTICLE 11. TAXES

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy and Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other Parties to maintain the other Parties' tax status. Nothing in this Agreement is intended to adversely affect the Participating TO's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

ARTICLE 12. MISCELLANEOUS

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of California, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by all of the Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between or among the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects all transmission providers, market participants, and interconnection customers interconnected to electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Parties, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Parties copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Participating TO or the CAISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The CAISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following articles of this Agreement and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these articles:

Introductory Paragraph, 1.1, 1.2, 1.3, 1.4, 1.5.1, 1.5.2, 1.5.3, 1.5.4, 1.5.5, 1.5.6, 1.5.7, 1.6, 1.7, 1.8.1, 1.9, 2.1, 2.2.1, 2.3, 3, 4.1.1 (last sentence only), 5.1, 5.3, 6.2, 7, 8, 9, 11, 12, 13, Attachment 1, Attachment 4, Attachment 5, and Attachment 7.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this Agreement pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following articles of this Agreement and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these articles:

2.2.2, 4.1.1 (all but the last sentence), 4.1.2, 4.2, 5.2, 6.1.1 (all but the last sentence), 6.1.2, 6.3, 10 (all but preamble), Attachment 2, Attachment 3 and Attachment 6.

The CAISO shall have the exclusive right to make a unilateral filing with FERC to modify this Agreement pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following articles of this Agreement and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these articles:

1.8.2, 6.1.1 (last sentence only) and 10 (preamble only).

The Interconnection Customer, the CAISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise mutually agree as provided herein.

ARTICLE 13. NOTICES

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:
Interconnection Customer: Western Antelope Dry Ranch LLC
Attention: Adam Foltz
Address: 44 Montgomery St. Ste 3065
City: San Francisco State: CA Zip: 94104
Phone: 415-692-7578 Fax: 415-362-4001

If to the Participating TO:
Participating TO: Southern California Edison Company
Attention: Mr. William Law, Manager, Grid Contract Management
Address: P. O. Box 800
2244 Walnut Grove Avenue
City: Rosemead State: California Zip: 91770
Phone: (626) 302-9640 Fax: (626) 302-1152

If to the CAISO: California Independent System Operator
Attention: Ms. Roni Reese, Sr. Contract Analyst
Address: 250 Outcropping Way
City: Folsom State: CA Zip: 95630
Phone: (916) 351-4400 Fax: (916) 608-7292

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: Western Antelope Dry Ranch LLC
Attention: Maggie Spangler
Address: 44 Montgomery St. Ste. 3065
City: San Francisco State: CA Zip: 94104

Participating TO: Southern California Edison Company
Attention: Accounts Receivable (GCM)
Address: P. O. Box 800

2244 Walnut Grove Avenue
City: Rosemead State: California Zip: 91770

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by any Party to the other Parties and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: Western Antelope Dry Ranch LLC
Attention: Adam Foltz
Address: 44 Montgomery St. Ste. 3065
City: San Francisco   State: California   Zip: 94104
Phone: 415-692-7578   Fax: 415-362-4001
E-mail address: a.foltz@silveradopower.com

If to the Participating TO:

Participating TO: Southern California Edison Company
Attention: Mr. William Law, Manager, Grid Contract Management
Address: P. O. Box 800
2244 Walnut Grove Avenue
City: Rosemead State: California Zip: 91770
Phone: (626) 302-9640   Fax: (626) 302-1152
E-mail Address:william.law@sce.com

If to the CAISO:

If to the CAISO: California Independent System Operator
Attention: Ms. Roni Reese, Sr. Contract Analyst
Address: 250 Outcropping Way
City: Folsom   State: California   Zip: 95630
Phone: (916) 351-4400   Fax: (916) 608-7292
E-mail Address: rreese@caiso.com

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party’s facilities.

Interconnection Customer’s Operating Representative:

Interconnection Customer: Western Antelope Dry Ranch LLC
Attention: Adam Foltz
Street Address: 44 Montgomery St. Ste. 3065
City: San Francisco State: California Zip: 94104
Phone: 415-692-7578 Fax: 415-362-4001

Participating TO's Operating Representative:

Participating TO: Southern California Edison Company
Attention: Mr. William Law, Manager, Grid Contract Management
Street Address: 2244 Walnut Grove Avenue
City: Rosemead State: California Zip: 91770
Phone: 626-302-9640 Fax: 626-302-1152

CAISO's Operating Representative

California Independent System Operator Corporation
Attention: Mr. Robert Kott
Address: 250 Outcropping Way
City: Folsom State: California Zip: 95630
Phone: (916) 351-4400 Fax: (916) 608-5762

13.5 Changes to the Notice Information

Any Party may change this information by giving five (5) Business Days written notice to the other Parties prior to the effective date of the change.

ARTICLE 14. SIGNATURES

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For Southern California Edison Company

By: ______________________________

Name: Kevin M. Payne

Title: Vice President, Engineering & Technical Services, TDBU

Date: ______________________________

For California Independent System Operator Corporation

By: ______________________________

Name:____

Title: ____

Date: ____

For Western Antelope Dry Ranch LLC

By: ____

Name:____

Title: ____

Date: ____

ATTACHMENT 1

Glossary of Terms

Affected System – An electric system other than the CAISO Controlled Grid that may be affected by the proposed interconnection, including the Participating TO's electric system that is not part of the CAISO Controlled Grid.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Balancing Authority Area - The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Business Day – Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.

CAISO Controlled Grid – The system of transmission lines and associated facilities of the parties to a 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.

Commercial Operation Date – The date on which a Small Generating Facility commenced generating electricity for sale as agreed upon by the Participating TO and the Interconnection Customer and in accordance with any implementation plan agreed to by the Participating TO and the CAISO for multiple individual generating units or project phases at a Small Generating Facility where an Interconnection Customer intends to establish separate Commercial Operation Dates for those generating units or project phases.

Default – The failure of a breaching Party to cure its breach under this Agreement.

Distribution System – Those non-CAISO-controlled transmission and distribution facilities owned by the Participating TO.

Distribution Upgrades – The additions, modifications, and upgrades to the Participating TO's Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility 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 any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, CAISO, Participating TO, or any affiliate thereof.

Interconnection Facilities – The Participating TO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Participating TO's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Handbook – A handbook, developed by the Participating TO and posted on the Participating TO’s website or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's Transmission System, as such handbook may be modified or superseded from time to time. The Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and applicable reliability standards.

Interconnection Request – A request, in accordance with the CAISO Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the CAISO Controlled Grid.

CAISO Controlled Grid – The system of transmission lines and associated facilities of the parties to a 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.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Participating TO's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the CAISO Controlled Grid to accommodate the interconnection of the Small

Generating Facility with the CAISO Controlled Grid. Network Upgrades do not include Distribution Upgrades.

Operational Control – The rights of the CAISO under a Transmission Control Agreement and the CAISO Tariff to direct the parties to the Transmission Control Agreement how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting applicable reliability criteria.

Operating Requirements – Any operating and technical requirements that may be applicable due to the CAISO, Western Electricity Coordinating Council, Balancing Authority Area, or the Participating TO's requirements, including those set forth in this Agreement.

Phased Generating Facility – A Generating Facility that is structured to be completed and to achieve Commercial Operation in two or more successive sequences that are specified in this SGIA, such that each sequence comprises a portion of the total megawatt generation capacity of the entire Generating Facility.

Party or Parties – The Participating TO, CAISO, Interconnection Customer or the applicable combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Participating TO's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Transmission Control Agreement – CAISO FERC Electric Tariff No. 7.

Transmission System – The facilities owned and operated by the Participating TO and that have been placed under the CAISO's Operational Control, which facilities form part of the CAISO Controlled Grid.

Upgrades – The required additions and modifications to the Participating TO's Transmission System and Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

ATTACHMENT 2

Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Participating TO. The Participating TO will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

The Participating TO's Interconnection Facilities, Network Upgrades and Distribution Upgrades described in this Attachment 2 are based on the Participating TO's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities constructed and installed following the Participating TO's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) Install a substation with one (1) 66/12.47 kV main step-up transformer with an 8.0 percent impedance on a 10 MVA base.

(ii) Install a new 66 kV generation tie-line from the Small Generating Facility to a position designated by the Participating TO, outside of the Participating TO's Antelope Substation, where Interconnection Customer shall install a structure ("Last Structure"). This generation tie-line will be referred to as the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line. The right-of-way for the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line shall extend up to the edge of the Antelope Substation property line.

(iii) Install a main breaker or ring bus between Antelope Substation and all shared projects on the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line.

(iv) Install fiber optical cable (either ADSS or optical ground wire) on the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line to provide one of two telecommunication paths required for the line protection and the Remote Terminal Unit ("RTU"). A minimum of eight (8) strands within the fiber optical cable shall be provided for the Participating TO's exclusive use into Antelope Substation.

(v) Install appropriate single-mode fiber-optic cables for the diverse telecommunication paths and panels to terminate the telecommunication fiber-optic cables for both diverse telecommunication paths, as specified by the Participating TO to match the telecommunication equipment used by the Participating TO at Antelope Substation and at the Small Generating Facility, in order to protect the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line.

(vi) Own, operate and maintain both telecommunication paths (including any fiber-optic cables, and appurtenant facilities) from the Point of Change of Ownership to the Small Generating Facility, with the exception of the terminal equipment at the Small Generating Facility, which terminal equipment will be installed, owned, operated and maintained by the Participating TO.

(vii) Allow the Participating TO to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Participating TO's terminal equipment and protection engineering requirements; allow the Participating TO to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(viii) Install one (1) dedicated 125 VDC circuit, one (1) dedicated 115 VAC convenience circuit and required station interface data connections up to the Participating TO's RTU located at the Small Generating Facility.

(ix) Make available adequate space and facilities necessary for the installation of the Participating TO's RTU.

(x) Provide sufficient floor space within a secure building having suitable environmental controls for the Participating TO to install and operate one (1) 8-foot high by 19-inch wide communications equipment rack; provide either one (1) 115 VAC dedicated circuit (separate from the RTU) or a 130 VDC dedicated circuit to power the communications equipment rack at the Small Generating Facility site.

(xi) Install an optical entrance cable extending the fiber optic cable communications to a patch panel in the Participating TO's communications equipment rack specified above.

(xii) Install all required CAISO-approved compliant metering equipment at the Small Generating Facility, in accordance with Section 10 of the CAISO Tariff.

(xiii) Install revenue metering equipment (typically, voltage and current transformers with an accuracy of 0.3% and 0.15%, respectively; associated cabinetry and wiring) at the Small Generating Facility to meter the Small Generating Facility retail load, as specified by the Participating TO.

(xiv) Provide a metering cabinet and sufficient space for the Participating TO to install its retail metering equipment and related meters. Such equipment must be placed at a location that would allow twenty-four hour access for the Participating TO's metering personnel.

(xv) Allow the Participating TO to install revenue meters and appurtenant equipment required to meter the retail load at the Small Generating Facility.

(xvi) Install appropriate relay protection for the diverse telecommunication paths. Relay protection to be specified by the Participating TO to match the relay protection used by the Participating TO at Antelope Substation and at the Small Generating Facility, in order to protect the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line, as follows:

1. One (1) G.E. L90 current differential relay with dual dedicated digital communication channels to Antelope Substation.
2. One (1) SEL 311L current differential relay with dual dedicated digital communication channels to Antelope Substation.

(xvii) Install disconnect facilities in accordance with the Participating TO's Interconnection Handbook to comply with the Participating TO's switching and tagging procedures.

(b) **Participating TO's Interconnection Facilities.** The Participating TO shall**:**

(i) **Antelope Substation.**

1. Install dead-end structure, insulators and line drop, as necessary, to terminate the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line.
2. Three (3) voltage transformers with steel pedestal support structures.
3. Install the following relays for the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line
    a. One GE L90 line current differential relay with dual dedicated digital communication channels to the Small Generating Facility.
    b. One SEL-311 line current differential relay with dual dedicated digital communication channels to the Small Generating Facility.
4. Install new telecommunication equipment to support the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line protection, SCADA and the Participating TO's applicable voice and data requirements.

(ii) **Antelope - Western Antelope Dry Ranch 66 kV Transmission Line.**

1. Install appropriate number of 66 kV poles including insulators, hardware assemblies, and appropriate number of spans of conductors and fiber optic cable between the last Interconnection Customer-owned pole structure on the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line. It is expected that the actual location and number of 66 kV poles and number of spans will be determined as part of final engineering performed upon execution of this SGIA. Studies for this project assumed six 66 kV structure and seven spans. Upon completion of final engineering, the SGIA shall be amended accordingly, subject to FERC's acceptance, for any significant scope changes or modifications.

(iii) **Telecommunications**. Install new telecommunication equipment to support the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line protection, SCADA and the Participating TO's applicable voice and data requirements.

1. Install all required light-wave, channel, fiber optic cables and associated equipment (including terminal equipment at both Antelope Substation and Small Generating Facility), supporting diverse protection, RTU and SCADA requirements for the interconnection of the Small Generating Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain such telecommunication equipment as part of the Participating TO's Interconnection Facilities

2. Install approximately 1300 feet of optical fiber cable to extend the OPGW from the Last Structure into the communication room at Antelope Substation.
3. Install approximately 1300 feet of optical fiber cable to extend the customer's diverse telecommunication path from Antelope Substation property line into the communication room at Antelope Substation.
4. Install circuit cross connections to support the interconnection of the RTU.

(iv) **Real Properties, Transmission Project Licensing, and Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Participating TO's Interconnection Facilities, including any associated equipment for the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line, and telecommunication route from the Last Structure into Antelope Substation.

(v) **Metering.**
Install revenue meters required to meter the retail load at the Small Generating Facility. Notwithstanding that the metering cabinet and meters will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain such facilities as part of the Participating TO's Interconnection Facilities.

(vi) **Power System Control.**
Install one (1) RTU at the Small Generating Facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status for the Small Generating Facility and plant auxiliary load, and transmit the information received thereby to the Participating TO's Grid Control Center. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain the RTU as part of the Participating TO's Interconnection Facilities.

2. Network Upgrades. See Attachment 6, Section 1.

3. Distribution Upgrades. See Attachment 6, Section 2.

4. Affected System Upgrades. Not Used.

5. Point of Change of Ownership.

(a) Antelope - Western Antelope Dry Ranch 66 kV Transmission Line: The Point of Change of Ownership shall be the point where the conductors of the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line attach to the Last Structure, which will be connected on the side of the Last Structure facing Antelope Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Small Generating Facility. The Participating TO will own and maintain the

Antelope Substation, as well as all circuit breakers, disconnects, relay facilities and metering within the Antelope Substation, together with the line drop, in their entirety, from the Last Structure to Antelope Substation. The Participating TO will own the insulators that are used to attach the Participating TO-owned conductors to the Last Structure.

(b) Telecommunication fiber optic cable: The Point of Change of Ownership shall be the point where the fiber optic cable (either ADSS or optical ground wire) for the Antelope – Western Antelope Dry Ranch 66 kV Transmission Line is attached to the Last Structure as well as the jumper loops used to connect the Participating TO-owned conductors to the Interconnection Customer-owned conductors.

(c) Telecommunication diverse fiber optic cable: The Point of Change of Ownership shall be the point where the fiber-optic cable is attached to the Last Structure.

6. **Point of Interconnection.** The Participating TO's Antelope 66 kV Substation at the 66 kV bus.

7. **One-Line Diagram of Interconnection to Antelope 66 KV Substation.**

See Attachment 3.

8. **Additional Definitions.** For the purposes of these Attachments, the following terms, when used with initial capitalization, whether in the singular or the plural, shall have the meanings specified below:

(a) Accounting Practice: Generally accepted accounting principles and practices applicable to electric utility operations.

(b) Annual Tax Security Reassessment: In accordance with the directives of FERC Orders 2003-A and 2003-B associated with Section 11 of this Attachment 2, the annual reassessment of the current tax liability, which will commence the first year after Interconnection Customer's in-service date.

(c) Applicable Reliability Council: The Western Electricity Coordinating Council or its successor.

(d) Applicable Reliability Standards: The requirements and guidelines of the North American Electric Reliability Corporation (NERC), the Applicable Reliability Council, and the Balancing Authority Area of the Participating TO's Transmission System to which the Generating Facility is directly interconnected, including the requirements adopted pursuant to Section 215 of the Federal Power Act.

(e) Back Feed: Retail service for energy delivered to and used by IC in accordance with applicable CPUC rules & regulations.

(f) Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

(g) Capital Additions: Any modifications to the Participating TO's Interconnection Facilities or to the Distribution Upgrades. Such modifications may be any Units of Property which are added to the Participating TO's Interconnection Facilities; Distribution Upgrades; the enlargement, modification or betterment of any Units of Property constituting a part of the Participating TO's Interconnection Facilities; Distribution Upgrades; or the replacement of any Units of Property constituting a part of the Participating TO's Interconnection Facilities or Distribution Upgrades, irrespective of whether such replacement constitutes an enlargement, modification or betterment of that which it replaces; and the costs of which additions, enlargements, modifications, betterments or replacements in accordance with Accounting Practice would be capitalized and have not previously been included in the Interconnection Facilities Cost or the Distribution Upgrades Cost.

(h) Capital Additions Cost: All costs, excluding One-Time Cost, determined by Distribution Provider to be associated with the design, engineering, procurement, construction and installation of Capital Additions.

(i) CPUC: The California Public Utilities Commission, or its regulatory successor.

(j) Credit Support: A parent guarantee, letter of credit, surety bond, or other security meeting the requirements of Article 6.3 or Article 6.4, as applicable of the SGIA.

(k) Customer-Financed Monthly Rate: The rate most recently adopted by the CPUC for application to the Participating TO's retail electric customers for added facilities, which does not compensate the Participating TO for replacement of added facilities. The currently effective Customer-Financed Monthly Rate is as provided in Section 16 of this Attachment 2.

(l) Delivery Network Upgrades Cost: The Interconnection Customer's allocated share of all costs, excluding One-Time Cost, determined in the Participating TO to be associated with the design, engineering, procurement, construction and installation of the Participating TO's Delivery Network Upgrades. The Delivery Network Upgrades Cost is provided in Section 15 of this Attachment 2.

(m) Delivery Network Upgrades Payment: The sum of the Delivery Network Upgrades Cost and associated One-Time Cost. The Delivery Network Upgrades Payment is provided in Section 17 of this Attachment 2.

(n) Distribution Upgrades Cost: The Interconnection Customer's allocated share of all costs, excluding ITCC and One-Time Cost, determined by the Participating TO to be associated with the design, engineering, procurement, construction and installation of the Distribution Upgrades. The Distribution Upgrades Cost is provided in Section 15 of this Attachment 2.

(o) Distribution Upgrades Payment: The sum of the Distribution Upgrades Cost and associated One-Time Cost. The Distribution Upgrades Payment is provided in Section 17 of this Attachment 2.

(p) Effective Date: The date on which this Agreement becomes effective pursuant to Article 3.1.

(q) Electric Generating Unit: An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered.

(r) In-Service Date: The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO's Interconnection Facilities to obtain back feed power.

(s) Initial Synchronization Date: The date upon which an Electric Generating Unit is initially synchronized and upon which Trial Operation begins.

(t) Interconnection Customer's Interconnection Facilities: All facilities and equipment, as identified in Attachment 2 of this SGIA, that are located between the Small Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Small Generating Facility to the Participating TO's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

(u) Interconnection Facilities Charge: The monthly charge to the Interconnection Customer to recover the revenue requirements for the Participating TO's Interconnection Facilities, calculated as the product of the Customer-Financed Monthly Rate and the Interconnection Facilities Cost. The Interconnection Facilities Charge is provided in Section 16 of this Attachment 2.

(v) Interconnection Facilities Completion Date: The date upon which the construction of the Participating TO's Interconnection Facilities is complete and such facilities are successfully tested and ready for service.

(w) Interconnection Facilities Cost: All costs, excluding One-Time Cost, determined by the Participating TO to be associated with the design, engineering, procurement, construction and installation of the Participating TO's Interconnection Facilities. The Interconnection Facilities Cost is provided in Section 15 of this Attachment 2.

(x) Interconnection Facilities Payment: The sum of the Interconnection Facilities Cost and associated One-Time Cost. The Interconnection Facilities Payment is provided in Section 17 of this Attachment 2.

(y) ITCC (Income Tax Component of Contribution): The ITCC is equal to the estimated tax liability as described in FERC Order 2003 and FERC Order 2003-A and applicable to this SGIA pursuant to Article 1.5.1. ITCC is the Income Tax Component of Contribution specified in the Preliminary Statement, Part M of the Participating TO's tariff on file with the CPUC, applicable to the Distribution Upgrades Cost and Interconnection Facilities Cost. The ITCC applicable to the Distribution Upgrades Cost and Interconnection Facilities Cost is described in Section 11 of this Attachment 2 and is shown in Section 15 of this Attachment 2.

(z) NERC: The North American Electric Reliability Corporation or its successor organization.

(aa) One-Time Cost: All costs determined by the Participating TO to be associated with the installation of the Participating TO's Delivery Network Upgrades, Distribution Upgrades, Participating TO's Interconnection Facilities, Participating TO's Reliability Network Upgrades, or Capital Additions which are not capitalized.

(bb) Participating TO's Delivery Network Upgrades: The additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies, as identified in Attachment 6, to relieve constraints on the CAISO Controlled Grid.

(cc) Participating TO's Interconnection Facilities: Those facilities as described in Section 5(b) of this Attachment 2, as such facilities may be modified during the term of this Agreement.

(dd) Participating TO's Reliability Network Upgrades: The additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, identified in the Interconnection Studies, as identified in Attachment 6, necessary to interconnect the Small Generating Facility safely and reliably to the Participating TO's Transmission System, which would not have been necessary but for the interconnection of the Small Generating Facility, including additions, modifications, and upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Small Generating Facility to the Participating TO's Transmission System. Participating TO's Reliability Network Upgrades also include, consistent with Applicable Reliability Standards and Applicable Reliability Council practice, the Participating TO's facilities necessary to mitigate any adverse impact the Small Generating Facility's interconnection may have on a path's Applicable Reliability Council rating. Participating TO's Reliability Network Upgrades do not include any Participating TO's Delivery Network Upgrades.

(ee) Point of Change of Ownership: The point, as set forth in Attachment 3 to this SGIA, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.

(ff) Q660 Project (TOT522): Western Antelope Blue Sky Ranch A Project.

(gg) Reliability Network Upgrades Cost: The Interconnection Customer's allocated share of all costs, excluding One-Time Cost, determined by the Participating TO to be associated with the design, engineering, procurement, construction and installation of the Participating TO's Reliability Network Upgrades. The Reliability Network Upgrades Cost is provided in Section 15 of this Attachment 2.

(hh) Reliability Network Upgrades Payment: The sum of the Reliability Network Upgrades Cost and associated One-Time Cost. The Reliability Network Upgrades Payment is provided in Section 17 of this Attachment 2.

(ii) Removal Cost: The actual cost the Participating TO incurs for the removal of the Participating TO's Interconnection Facilities, Distribution Upgrades, or any portion thereof, which is calculated as the amount, if positive, of the costs of removal minus the salvage value of the Participating TO's Interconnection Facilities and Distribution Upgrades.

(jj) Special Protection System ("SPS"): A system that reduces or trips generation under contingency outages to maintain system stability or to limit overloads on electric system facilities.

(kk) Tax Security: The Interconnection Customer's provision of Security with respect to the Interconnection Customer's tax indemnification obligations, provided in accordance with Section 11 of this Attachment 2.

(ll) Trial Operation: The period during which the Interconnection Customer is engaged in on-site test operations and commissioning of an Electric Generating Unit prior to Commercial Operation.

(mm) Units of Property: As described in FERC's "List of Units of Property for Use in Connection with Uniform System of Accounts Prescribed for Public Utilities and Licensees" in effect as of the date of this SGIA, as such "List" may be amended from time to time.

9. **Transmission Credits.** Pursuant to Article 5.3 of the SGIA, the Interconnection Customer elects to receive repayment of the amounts advanced for its share of the costs of the Network Upgrades, which equals the sum of the Reliability Network Upgrades Payment and the Delivery Network Upgrades Payment, as shown in Section 17 of this Attachment 2.

10. **Security Amount for the Distribution Upgrades, the Participating TO's Interconnection Facilities and Network Upgrades.**

(a) Distribution Upgrades: Pursuant to Article 6.3 or 6.4 (as applicable) and Attachment 4 of the SGIA, the Interconnection Customer shall provide Credit Support in the total amount of $0 to cover the Western Antelope Dry Ranch Project's pro rata share of the costs for constructing, procuring and installing the Distribution Upgrades.

(b) The Participating TO's Interconnection Facilities: Pursuant to Article 6.4 and Attachment 4 of the SGIA, the Interconnection Customer shall provide a total Credit Support in the amount of $2,441,000 to cover the Western Antelope Dry Ranch Project's pro rata share of the costs for constructing, procuring and installing the Participating TO's Interconnection Facilities.

(c) Network Upgrades: Pursuant to Article 6.4 and Attachment 4 of the SGIA, the Interconnection Customer shall provide a total Credit Support in the amount of $563,584 to cover the Western Antelope Dry Ranch Project's pro rata share of the costs for constructing, procuring and installing the Network Upgrades.

(d) To the extent that any Credit Support is not utilized by the Participating TO, the release of such Credit Support shall be made in accordance with the Interconnection Customer's instruction.

(e) The Phase II Interconnection Study identified shared Reliability Network Upgrades and shared Participating TO's Interconnection Facilities that will be used by a group of projects, Q660 Project (TOT522) and Western Antelope Dry Ranch Project. The Credit Support that must be posted for the shared Reliability Network Upgrades and shared Participating TO's Interconnection Facilities were calculated by assigning a pro rata share of the costs to each of the projects based on the number of projects that will use the relevant facilities at the time when the Credit Support for Q660 Project (TOT522) and Western Antelope Dry Ranch Project must be posted. If, prior to the completion of construction of the shared Reliability Network Upgrades or shared Participating TO's Interconnection Facilities, any of the interconnection requests for these projects are withdrawn or any of the interconnection agreements for these projects are terminated, the Credit Support obligation for shared Reliability Network Upgrades or shared Participating TO's Interconnection Facilities, as applicable, shall be reallocated and divided among the remaining projects in the group. If such an event occurs, this SGIA shall be amended accordingly to reflect the Interconnection Customer's updated Credit Support obligations.

11. Security Amount for Estimated Tax Liability. The Interconnection Customer's estimated tax liability is as follows:

Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation)/(1 – Current Tax Rate) = 35%

Estimated tax liability for Distribution Upgrades = 35% x (Distribution Upgrades Cost) = 35% x ($0) = $0

Estimated tax liability for Participating TO's Interconnection Facilities = 35% x (Interconnection Facilities Cost) = 35% x $2,441,000 = $854,350

Estimated tax liability assumes the following costs:

Interconnection Facilities Cost = $2,441,000

Distribution Upgrades Cost = $0

Based upon the total estimated tax liability, the Interconnection Customer shall provide the Participating TO cash, or a letter of credit in the amount of $854,350, pursuant to Attachment 4 of the SGIA. The cash or letter of credit shall be in the form provided for in Section 6.4 of the SGIA.

Upon notification of the Annual Tax Security Reassessment, the Interconnection Customer shall modify its Tax Security accordingly. If the Annual Tax Security Reassessment results in a deficiency in the Tax Security amount, the Interconnection Customer will be required to increase its Tax Security Amount within 30 days after receipt of the deficiency notification. If the Annual Tax Security Reassessment results in a reduction of the Tax Security amount, the Interconnection Customer may choose to reduce its Tax Security amount or maintain the Tax Security in the current amount for the following year.

The Annual Tax Security Reassessment will be calculated utilizing the following methodology:

1) Tax Assessment Event:
((Current Tax Rate x (Gross income - NPV Tax Depreciation)) + Interest)/(1 - Current Tax Rate)

2) Subsequent Taxable Event:
(Current Tax Rate x (Replacement Facility Cost – NPV Tax Depreciation))/(1- Current Tax Rate)

The Credit Support obligation required in this Article 11 shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by the Participating TO upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations.

12. **Removal of the Participating TO's Interconnection Facilities and Distribution Upgrades.** Following termination of the SGIA, where such termination is not in accordance with Section 18 of Attachment 2, the Participating TO will remove the Participating TO's Interconnection Facilities and Distribution Upgrades from service to the Interconnection Customer, pursuant to Article 3.3 of the SGIA. On or before the date one year following termination of the SGIA, the Participating TO shall notify the Interconnection Customer as to whether the Participating TO intends to physically remove the Participating TO's Interconnection Facilities, Distribution Upgrades, or any part thereof. If the Participating TO intends to physically remove the Participating TO's Interconnection Facilities, Distribution Upgrades, or any part thereof, then the Participating TO shall physically remove such

facilities within two years from the date of notification of intent, and the Interconnection Customer shall pay the Removal Cost. If the Participating TO does not intend to physically remove the Participating TO's Interconnection Facilities, Distribution Upgrades, or any part thereof, then the Interconnection Customer shall have no obligation to pay such Removal Cost.

13. Charges.

(a) The Interconnection Customer shall pay to the Participating TO the following charges in accordance with the SGIA: (i) Distribution Upgrades Payment; (ii) Delivery Network Upgrades Payment; (iii) Interconnection Facilities Payment; (iv) Reliability Network Upgrades Payment; (v) payments for any Capital Additions; (vi) Interconnection Facilities Charge; (vii) any reimbursable FERC fees pursuant to Section 14(g) of this Attachment 2; (viii) Removal Cost pursuant to Section 12 of this Attachment 2; (ix) termination charges pursuant to Article 3.3.4 of the SGIA; (x) disconnection costs pursuant to Article 3.3.3 of the SGIA; and (xi) suspension costs if suspension of work under this SGIA is permitted by the CAISO and the Participating TO.

(b) The Distribution Upgrades Cost, Delivery Network Upgrades Cost, Interconnection Facilities Cost, Reliability Network Upgrades Cost, Capital Additions Cost, One-Time Cost and Removal Cost shall be compiled in accordance with Accounting Practice.

(c) If, during the term of the SGIA, the Participating TO executes an agreement to provide service to another entity (other than retail load) that contributes to the need for the Participating TO's Interconnection Facilities, the charges due hereunder may be adjusted to appropriately reflect such service based on the Participating TO's cost allocation principles in effect at such time and shall be subject to FERC's approval.

(d) If Capital Additions are required in order to benefit the Participating TO, or because of damage caused by negligence or willful misconduct of the Participating TO, then the Interconnection Customer will not bear cost responsibility for such Capital Additions; and no adjustment will be made to the Interconnection Facilities Cost or the Distribution Upgrades Cost; and no Capital Additions Cost or One-Time Cost will be charged to the Interconnection Customer for such Capital Additions.

14. Supplemental Billing and Payment Provisions.

(a) Pursuant to Article 6 of the SGIA, the Participating TO shall submit to the Interconnection Customer invoices due for the preceding month for the Distribution Upgrades Payment, Delivery Network Upgrades Payment, Interconnection Facilities Payment and Reliability Network Upgrades Payment.

(b) Pursuant to Article 4.1.2 of the SGIA, commencing on or following the Interconnection Facilities Completion Date, each month the Participating TO will render bills to the Interconnection Customer for the Interconnection Facilities Charge. The

Interconnection Facilities Charge shall initially be based on the estimated Interconnection Facilities Cost, as specified in Section 15 of this Attachment 2, and payments made for such Interconnection Facilities Charge shall be subject to later adjustment pursuant to Sections 14(b)(i) and 14(b)(ii) of this Attachment 2. The Interconnection Facilities Charge for the first and last month of service hereunder shall be pro-rated based on the number of days in which service was provided during said months.

(i) If the amounts paid for the Interconnection Facilities Charge are less than the amounts due for the Interconnection Facilities Charge, as determined from the actual recorded Interconnection Facilities Cost, the Participating TO will bill the Interconnection Customer the difference between the amounts previously paid by the Interconnection Customer and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.

(ii) If the amounts paid for the Interconnection Facilities Charge are greater than the amounts due for the Interconnection Facilities Charge, as determined from the actual recorded Interconnection Facilities Cost, the Participating TO will credit the Interconnection Customer the difference between the amounts previously paid by the Interconnection Customer and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.

(iii) Commencing on or following the Distribution Upgrades Completion Date, each month the Participating TO will render bills to the Interconnection Customer for the Distribution Upgrades Charge. The Distribution Upgrades Charge shall initially be based on the estimated Distribution Upgrades Cost for the applicable Distribution Upgrades, as specified in Section 15 of this Attachment 2, and payments made for such Distribution Upgrades Charge shall be subject to later adjustment pursuant to Section 14(c)(i) and 14(c)(ii) of this Attachment 2. The Distribution Upgrades Charge for the first and last month of service hereunder shall be pro-rated based on the number of days in which service was provided during said months. If the amounts paid for the Distribution Upgrades Charge are less than the amounts due for the Distribution Upgrades Charge, as determined from the actual recorded Distribution Upgrades Cost for the applicable Distribution Upgrades, the Participating TO will bill the Interconnection Customer the difference between the amounts previously paid by the Interconnection Customer and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.

(iv) If the amounts paid for the Distribution Upgrades Charge are greater than the amounts due for the Distribution Upgrades Charge, as determined from the actual recorded Distribution Upgrades Cost for the applicable Distribution Upgrades, the Participating TO will credit the Interconnection Customer the difference between the amounts previously paid by the Interconnection Customer and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.

(c) In the event that any portion of the Participating TO's Interconnection Facilities is not complete but, at the request of the Interconnection Customer, the Participating TO commences interconnection service under this SGIA notwithstanding the incomplete facilities, the Participating TO shall commence billing, and the Interconnection Customer shall pay, the Interconnection Facilities Charge commencing on the date that such service commences.

(d) In accordance with Article 4.1.2 of the SGIA, the Participating TO shall submit invoices to the Interconnection Customer for the preceding month for Capital Additions payments due, if any.

(i) For Capital Additions that are the cost responsibility of the Interconnection Customer, the Participating TO will provide at least sixty (60) calendar days advance written notification to the Interconnection Customer prior to commencing work, except that the Participating TO may commence the work on the Capital Additions with either shorter advance written notification or written notification after the work has commenced, at the Participating TO's sole discretion, if the Participating TO determines that the Capital Additions are required to comply with safety or regulatory requirements or to preserve system integrity or reliability. Any such written notification will include the estimated cost of the Capital Additions, and the amount of and due date for the security, if any, required to be paid by the Interconnection Customer, which is sufficient to cover the costs for constructing, procuring and installing the Capital Additions consistent with the applicable terms of Article 6 of the SGIA.

(ii) Except as provided in Section 13(d) of this Attachment 2, if certain of the Participating TO's Interconnection Facilities are removed to accommodate Capital Additions and such removal results in a change in the Interconnection Facilities Cost, the Interconnection Facilities Charge shall be adjusted to reflect the change in the Interconnection Facilities Cost as of the in-service date of such Capital Additions.

(iii) Except as provided in Section 13(d) of this Attachment 2, if Capital Additions result in an increase in the Interconnection Facilities Cost, then the Interconnection Facilities Charge shall be adjusted as of the in-service date of such Capital Additions to reflect the change in such costs.

(e) As soon as reasonably practicable, but within six (6) months after the in-service date of any Capital Additions, the Participating TO shall provide an invoice of the final cost of the construction of the Capital Additions to the Interconnection Customer, and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. The Participating TO will refund to the Interconnection Customer any amount by which the payment made by the Interconnection Customer for estimated costs of the Capital Additions exceeds the actual costs of construction within thirty (30) calendar days of the issuance of such final construction invoice; or, in the event the actual costs of construction exceed the Interconnection Customer's payment made for the estimated costs of the Capital Additions, then the Interconnection Customer shall pay to the Participating TO any amount by which the actual costs of construction exceed the payment made by the Interconnection Customer for estimated costs within thirty (30) calendar days of the issuance of such final construction invoice.

(f) If, in accordance with the removal of the Participating TO's Interconnection Facilities, as specified in Section 12 of this Attachment 2, the Participating TO decides to physically remove the Participating TO's Interconnection Facilities, or any part thereof, the Participating TO shall render a bill to the Interconnection Customer for the Removal Cost. The Interconnection Customer shall pay the Removal Cost within thirty (30) calendar days of such bill. Such billing shall initially be based on the Participating TO's estimate of the Removal Cost. Within twelve (12) months following the removal of the Participating TO's Interconnection Facilities, or any part thereof, the Participating TO shall determine the actual Removal Cost and provide the Interconnection Customer with a final invoice. The Participating TO shall refund to the Interconnection Customer any amount by which the payment by the Interconnection Customer for the estimated Removal Cost exceeds the actual Removal Cost within thirty (30) calendar days of the issuance of such final invoice; or, in the event the actual Removal Cost exceeds the Interconnection Customer's payment for the estimated Removal Cost, then the Interconnection Customer shall pay to the Participating TO any amount by which the actual Removal Cost exceeds the payment by the Interconnection Customer for the estimated Removal Cost within thirty (30) calendar days of the issuance of such final invoice.

(g) The Interconnection Customer shall reimburse the Participating TO for all fees and charges related to the FERC fees and annual charges provided in Sections 381 and 382 of the FERC's regulations (18 C.F.R. § 381 and 382), as such regulation may from time to time be amended, that are imposed on the Participating TO attributable to the service provided under the SGIA, or any amendments thereto. The Participating TO will render bills to the Interconnection Customer for any such fees and charges incurred since the preceding billing. As of the Effective Date, no such fees and charges have been imposed on the Participating TO attributable to the service provided under the SGIA.

(h) If suspension of work under this SGIA is permitted by the CAISO and the Participating TO, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this SGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection

Customer's authorization to do so. The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. The suspension period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the CAISO, if no effective date is specified.

15. Distribution Upgrades Cost, Delivery Network Upgrade Cost, Interconnection Facilities Cost and Reliability Network Upgrade Cost Summary.

(a) Estimated Cost:

Element-	Shared Interconnection Facilities Cost*	Sole-Use Intercon-nection Facilities Cost	Intercon-nection Facilities Cost*	Shared Reliability Network Upgrades Cost*	Reliability Network Upgrades Cost*	Distribution Upgrades Cost	Total	ITCC**
Participating TO's Interconnection Facilities								
66 kV Gen-Tie Segment into Antelope Substation	$1,704,000		$852,000				$852,000	$298,200
66 kV Gen-Tie Line Position – Line Drop (Dead End Structure, Relays)	$282,000		$141,000				$141,000	$49,350
Telecommunications	$324,000		$162,000				$162,000	$56,700
Telecom – cable, lightwave, etc. to support diverse protection & SCADA	$694,000		$347,000				$347,000	$121,450
Corporate Environmental Health & Safety	$618,000		$309,000				$309,000	$108,150
Real Properties		$70,000	$70,000				$70,000	$24,500
Corporate Environmental Health & Safety - to support telecom for RTU at generating facility		$428,000	$428,000				$428,000	$149,800
Metering Services		$32,000	$32,000				$32,000	$11,200

Power System Control – RTU at Generating Facility		$100,000	$100,000				$100,000	$35,000
Subtotal		**$630,000**	**$2,441,000**				**$2,441,000**	**$854,350**
Distribution Upgrades						**$0**	**$0**	
Participating TO's Reliability Network Upgrades								
Corporate Environmental Health & Safety				$58,000	$29,000		$29,000	
Antelope Circuit Breakers & Disconnect Sw.				$1,010,000	$505,000		$505,000	
RTU points at Antelope Sub				$36,000	$18,000		$18,000	
Vincent Sub Circuit Breaker Upgrades					$11,584		$11,584	
Subtotal				**$1,104,000**	**$563,584**		**$563,584**	
Total			**$2,441,000**		**$563,584**	**$0**	**$3,004,584**	**$854,350**

*Note: Western Antelope Dry Ranch Project and Q660 Project (TOT522) will share the same Interconnection Facilities and Reliability Network Upgrades, excluding Reliability Network Upgrades identified in Attachment 6, Section 1(b)(i)2. On the Effective Date, Western Antelope Dry Ranch Project will be responsible for 50% of the shared Interconnection Facilities Costs and shared Reliability Network Upgrades Costs as shown above. The Interconnection Facilities Costs and Reliability Network Upgrades costs shown above reflect Western Antelope Dry Ranch Project's current share of the cost responsibility. The remaining 50% will be the cost responsibility of Q660 Project (TOT522). In the event that Q660 Project (TOT522) terminates its SGIA prior to completion of construction of the shared Interconnection Facilities and shared reliability Network Upgrades, this SGIA shall be amended to reflect that Western Antelope Dry Ranch Project will be responsible for 100% of the shared Interconnection Facilities Costs and shared Reliability Network Upgrades Costs.

**Note: ITCC/Estimated Tax Liability will be provided pursuant to Attachment 2, Section 11.

All amounts shown above are in nominal dollars.

(b) Actual Cost:

[TO BE INSERTED AFTER TRUE-UP OF ACTUAL COSTS]

Element	Interconnection Facilities Cost	Reliability Network Upgrades Cost	Distribution Upgrades Cost	Total	ITCC

Total					

16. Interconnection Facilities Charge and Distribution Upgrades Charge.

(a) Interconnection Facilities Charge = Customer-Financed Monthly Rate x (Interconnection Facilities Cost)

		Estimated		Actual	
Effective	Customer-Financed Monthly Rate	Interconnection Facilities Cost	Interconnection Facilities Charge	Interconnection Facilities Cost	Interconnection Facilities Charge
As of the Interconnection Facilities Completion Date	0.38%	$2,441,000	$9,275.80	[to be inserted after true-up]	[to be inserted after true-up]

17. Payment Schedule and Associated ITCC.

The payment amounts shown below are based on an estimate of the monthly incurred costs for the Distribution Upgrades, Participating TO's Interconnection Facilities, and Network Upgrades.

Payment No.	**Payment Due Date**	**Interconnection Facilities Cost (A)**	**Reliability Network Upgrades Cost (B)**	**Circuit Breaker Reliability Upgrades (Not Subject to ITCC) (C)**	**Total Payment Amount (D = A+B+C)**	**ITCC (E = (A) *35%)**
1	7/1/12	$0	$1,000	$34	**$1,034**	**$854,350**
2	8/1/12	$37,000	$3,000	$35	**$40,035**	
3	9/1/12	$75,000	$5,000	$76	**$80,076**	
4	10/1/12	$80,000	$6,000	$101	**$86,101**	
5	11/1/12	$86,000	$8,000	$131	**$94,131**	
6	12/1/12	$90,000	$9,000	$162	**$99,162**	
7	1/1/13	$100,000	$10,000	$192	**$110,192**	
8	2/1/13	$108,000	$13,000	$228	**$121,228**	
9	3/1/13	$114,000	$15,000	$264	**$129,264**	
10	4/1/13	$130,000	$17,000	$316	**$147,316**	
11	5/1/13	$162,000	$19,000	$415	**$181,415**	
12	6/1/13	$207,000	$38,000	$840	**$245,840**	

13	7/1/13	$212,000	$58,000	$1,296	**$271,296**	
14	8/1/13	$142,000	$59,000	$1,333	**$202,333**	
15	9/1/13	$110,000	$52,000	$1,177	**$163,177**	
16	10/1/13	$113,000	$26,000	$555	**$139,555**	
17	11/1/13	$128,000	$25,000	$534	**$153,534**	
18	12/1/13	$139,000	$30,000	$617	**$169,617**	
19	1/1/14	$154,000	$37,000	$721	**$191,721**	
20	2/1/14	$126,000	$37,000	$776	**$163,776**	
21	3/1/14	$72,000	$35,000	$744	**$107,744**	
22	4/1/14	$43,000	$30,000	$622	**$73,622**	
23	5/1/14	$12,000	$15,000	$351	**$27,351**	
24	6/1/14	$1,000	$4,000	$64	**$5,064**	
Totals		$2,441,000	$552,000	$11,584	**$3,004,584**	**$854,350**

All amounts shown above are in nominal dollars.

*Note: Western Antelope Dry Ranch Project and Q660 Project (TOT522) will share the same Interconnection Facilities and Reliability Network Upgrades, excluding Reliability Network Upgrades identified in Attachment 6, Section 1(b)(i)2. On the Effective Date, Western Antelope Dry Ranch Project will be responsible for 50% of the shared Interconnection Facilities Costs and shared Reliability Network Upgrades Costs. The Interconnection Facilities Costs and Reliability Network Upgrades costs shown in the Payment Schedule above reflect Western Antelope Dry Ranch Project's current share of the cost responsibility. The remaining 50% will be the cost responsibility of Q660 (TOT522) Project. In the event that Q660 Project (TOT522) terminates its SGIA prior to completion of construction of the shared Interconnection Facilities and shared Reliability Network Upgrades, this SGIA shall be amended, and Western Antelope Dry Ranch Project will be responsible for 100% of the shared Interconnection Facilities Costs and shared Reliability Network Upgrades Costs.

Interconnection Facilities Payment = (Interconnection Facilities Cost + associated One-Time Cost) = $2,441,000

Reliability Network Upgrades Payment = (Reliability Network Upgrades Cost + associated One-Time Cost) = $563,584

Transmission credits pursuant to Section 9 of this Attachment 2 = Reliability Network Upgrades Payment + Delivery Network Upgrades Payment = $563,584

*ITCC will be provided by Interconnection Customer in accordance with Section 11 of this Attachment 2.

18. Costs for Distribution Upgrades.

(a) **Reclassification of Network Upgrades**: The following Network Upgrades identified for the Western Antelope Dry Ranch Project may be reclassified as Distribution Upgrades as represented in the Phase II Interconnection Study:

All of the Participating TO's Reliability Network Upgrades described in Attachment 6 of this SGIA.

The estimated cost of these Network Upgrades subject to reclassification is approximately $563,584. The ITCC associated with these upgrades is $197,254.

Upon reclassification of facilities from Network Upgrade to Distribution Upgrades, one of the following alternatives will be applicable:

i) Should the Point of Interconnection remain part of the CAISO Controlled Grid, this SGIA will be amended to reflect the following:

a. The reclassified facilities will be reflected in the SGIA as Distribution Upgrades.
b. The Interconnection Customer's cost responsibility for Distribution Upgrades will be increased to reflect the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
c. The Interconnection Customer's cost responsibility for Network Upgrades will be decreased to remove the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
d. The Credit Support amounts reflected in Section 10 and Section 11 of this SGIA Attachment 2, will be modified to reflect the facilities' reclassification.
e. The obligation for the CAISO and the Participating TO to provide repayment of amounts advanced for Network Upgrades or Congestion Revenue Rights in accordance with Article 5.3 of the SGIA associated with the reclassified facilities will cease as of the effective date of the reclassification from Network Upgrades to Distribution Upgrades.

ii) Should the Point of Interconnection change from the CAISO Controlled Grid to the Distribution System, then the Participating TO and the Interconnection Customer will negotiate in good faith to replace this SGIA with a Generation Interconnection Agreement ("GIA") consistent with the pro forma contained in the Participating TO's Wholesale Distribution Access Tariff ("WDAT"), Attachment I, Appendix 5. Upon the effective date of the replacement GIA, the Parties will terminate this SGIA. Prior to the effective date of the reclassification of the Network Upgrades as Distribution Upgrades, the Interconnection Customer will be required to obtain distribution service for the Western Antelope Dry Ranch Project pursuant to the Participating TO's WDAT to deliver power from the Point of Interconnection on the Distribution System to the CAISO Controlled Grid.

The obligation for the CAISO and the Participating TO to provide repayment of amounts advanced for Network Upgrades or Congestion Revenue Rights in accordance with Article 5.3 of this SGIA associated with the reclassified facilities will cease as of the effective date of the reclassification from Network Upgrades to Distribution Upgrades.

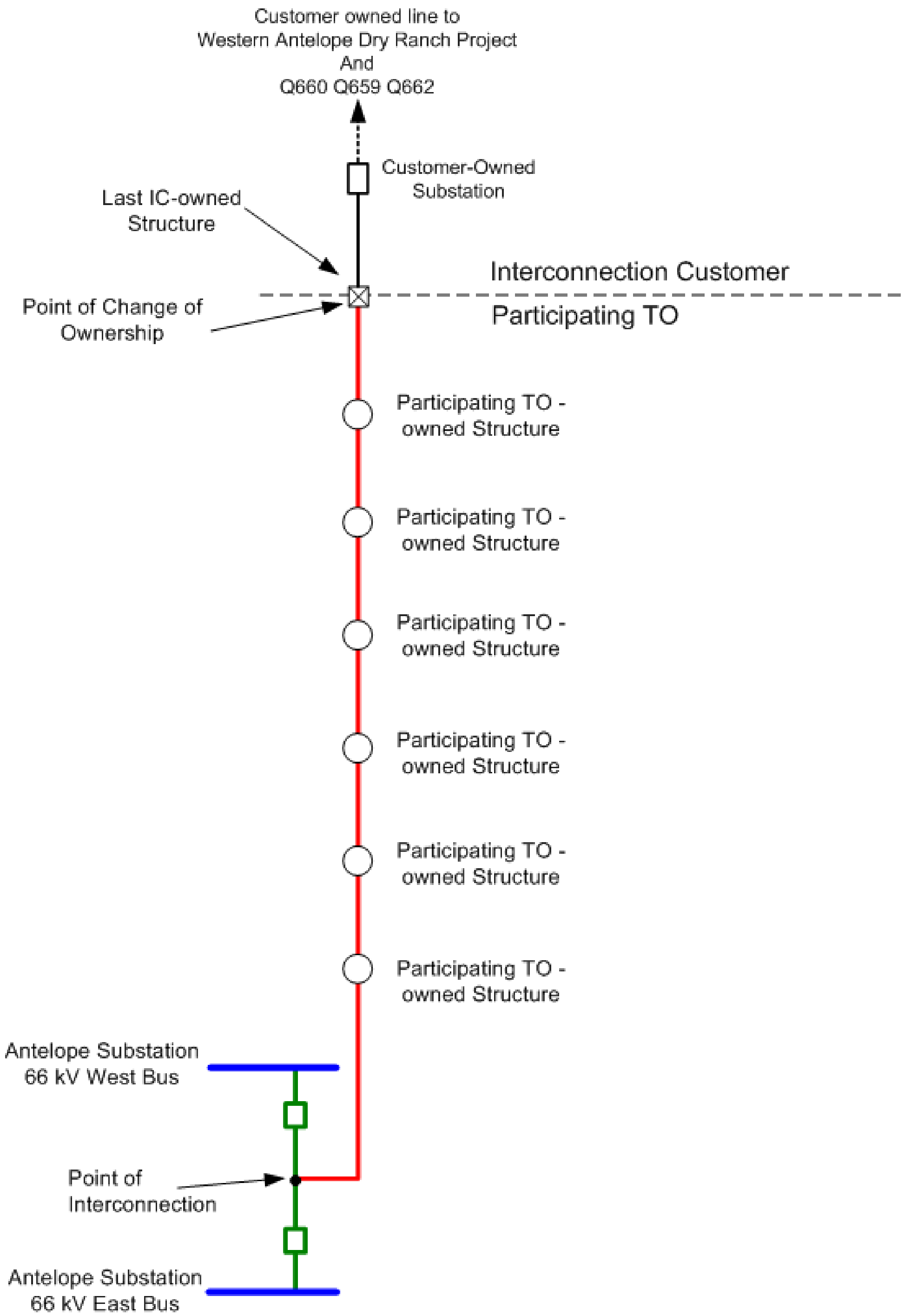
The new GIA will reflect the following terms:

a. The reclassified facilities will be reflected in the GIA as Distribution Upgrades.

b. The Interconnection Customer's cost responsibility for Distribution Upgrades will be increased to reflect the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
c. The Interconnection Customer's cost responsibility for Network Upgrades will be decreased to remove the Interconnection Customer's allocated share of the total cost of the reclassified facilities.
d. The Credit Support amounts reflected in Section 10 and Section 11 of this SGIA Attachment 2, will be modified to reflect the facilities' reclassification.

ATTACHMENT 3

One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades



Note: This one-line diagram depicts technical information known by the Parties as of the date of the filing of this SGIA.

ATTACHMENT 4

Milestones

In-Service Date: June 30, 2014

Critical milestones and responsibility as agreed to by the Parties[1]:

Item	Milestone	Responsible Party	Due Date
(a)	Submit proof of insurance coverage in accordance with Article 8.1 of the SGIA	Interconnection Customer	Within ten (10) calendar days of the Effective Date
(b)	Submittal of second posting of Interconnection Financial Security for the Participating TO's Interconnection Facilities and Network Upgrades to the Participating TO, pursuant to Section 9.3 of the GIP and Article 6.4 and Section 10 of Attachment 2 of the SGIA	Interconnection Customer	Completed
(c)	Submittal of third posting of Interconnection Financial Security for the Participating TO's Interconnection Facilities and Network Upgrades to the Participating TO, pursuant to Section 9.3 of the GIP and Article 6.4 and Section 10 of Attachment 2 of the SGIA	Interconnection Customer	On or before the start of construction of Network Upgrades or Participating TO's Interconnection Facilities (whichever is earlier).
(d)	Submittal of security for the estimated tax liability to the Participating TO, pursuant to Section 11 of Attachment 2 of the SGIA	Interconnection Customer	Within thirty (30) calendar days of the Effective Date
(e)	Completion of the Participating TO's Interconnection Facilities, Distribution Upgrades, and Network Upgrades	Participating TO	Within (24) months following the Effective Date*

[1] The Parties acknowledge that the milestone dates in this table reflect the Participating TO's current estimates, based on currently available information, and that in order to expedite the SGIA process, the Participating TO is providing these dates prior to the completion of its final engineering studies. The Parties understand and acknowledge that following the Participating TO's completion of its final engineering studies, the milestones may change to either earlier or later dates.

(f)	Submittal of initial specifications for the Interconnection Customer's Interconnection Facilities and Small Generating Facility, including system protection facilities, to the Participating TO and the CAISO	Interconnection Customer	At least one hundred eighty (180) calendar days prior to the Initial Synchronization Date
(g)	Submittal of initial information including the Participating TO's Transmission System information necessary to allow the Interconnection Customer to select equipment	Participating TO	At least one hundred eighty (180) calendar days prior to Trial Operation
(h)	Submittal of updated information by the Interconnection Customer, including manufacturer information	Interconnection Customer	No later than one hundred eighty (180) calendar days prior to Trial Operation
(i)	Review of and comment on the Interconnection Customer's initial specifications	Participating TO and CAISO	Within thirty (30) calendar days of the Interconnection Customer's submission of initial specifications
(j)	Submittal of final specifications for the Interconnection Customer's Interconnection Facilities and Small Generating Facility, including System Protection Facilities, to the Participating TO and the CAISO	Interconnection Customer	At least ninety (90) calendar days prior to the Initial Synchronization Date.
(k)	Review of and comment on the Interconnection Customer's final specifications	Participating TO and CAISO	Within thirty (30) calendar days of the Interconnection Customer's submission of final specifications
(l)	Notification of Balancing Authority Area to the Participating TO and the CAISO	Interconnection Customer	At least three (3) months prior to the Initial Synchronization Date
(m)	Performance of a complete calibration test and functional trip test of the system protection facilities	Interconnection Customer and Participating TO	At least thirty (30) calendar days prior to the In-Service Date
(n)	In-Service Date	Interconnection Customer	June 30, 2014
(o)	Initial Synchronization Date/Trial Operation	Interconnection Customer	July 1, 2014

(p)	Testing of the Participating TO's Interconnection Facilities, Distribution Upgrades, Network Upgrades, and testing of the Interconnection Customer's Interconnection Facilities and Small Generating Facility in accordance with Article 2.1 of the SGIA	Interconnection Customer and Participating TO	At least thirty (30) calendar days prior to the Initial Synchronization Date
(q)	Provide written approval to the Interconnection Customer for the operation of the Small Generating Facility, in accordance with Article 2.2.2 of the SGIA	Participating TO	At least fifteen (15) calendar days prior to the Initial Synchronization Date
(r)	Commercial Operation Date	Interconnection Customer	July 30, 2014
(s)	Submittal to the Participating TO of "as-built" drawings, information and documents for the Interconnection Customer's Interconnection Facilities and the Electric Generating Units to the Participating TO and the CAISO	Interconnection Customer	Within one hundred twenty (120) calendar days after the Commercial Operation Date, unless otherwise agreed

* Note: The Interconnection Customer understands and acknowledges that such timeline is only an estimate and that equipment and material lead times, labor availability, outage coordination, regulatory approvals, right-of-way negotiations, or other unforeseen events could delay the actual in-service dates of the Participating TO's Interconnection Facilities, Distribution Upgrades, or Network Upgrades beyond those specified. The Participating TO shall not be liable for any cost or damage incurred by the Interconnection Customer because of any delay in the work provided for in this SGIA.

If suspension of work under this SGIA is permitted by the CAISO and the Participating TO, then all milestones for each Party set forth in this Attachment 4 shall be suspended during the suspension period except for the milestones requiring posting of Interconnection Financial Security for the Network Upgrades common to multiple generating stations. Upon the Interconnection Customer's request to recommence the work, the Parties shall negotiate in good faith new revised milestone dates for each milestone, taking into account the period of suspension and necessary re-studies, if required. Attachment 4 and any terms and conditions associated with the estimated costs and payment schedule, if necessary, shall be amended following the establishment of such revised milestone dates.

The Interconnection Customer also understands and agrees that the method of service required to interconnect the Small Generating Facility may require re-evaluation due to the suspension of the project and changes to the Participating TO's electrical system or addition of new generation.

Agreed to by:

For the Participating TO________________________________ Date_______________

Kevin M. Payne

For the CAISO____ Date_______________

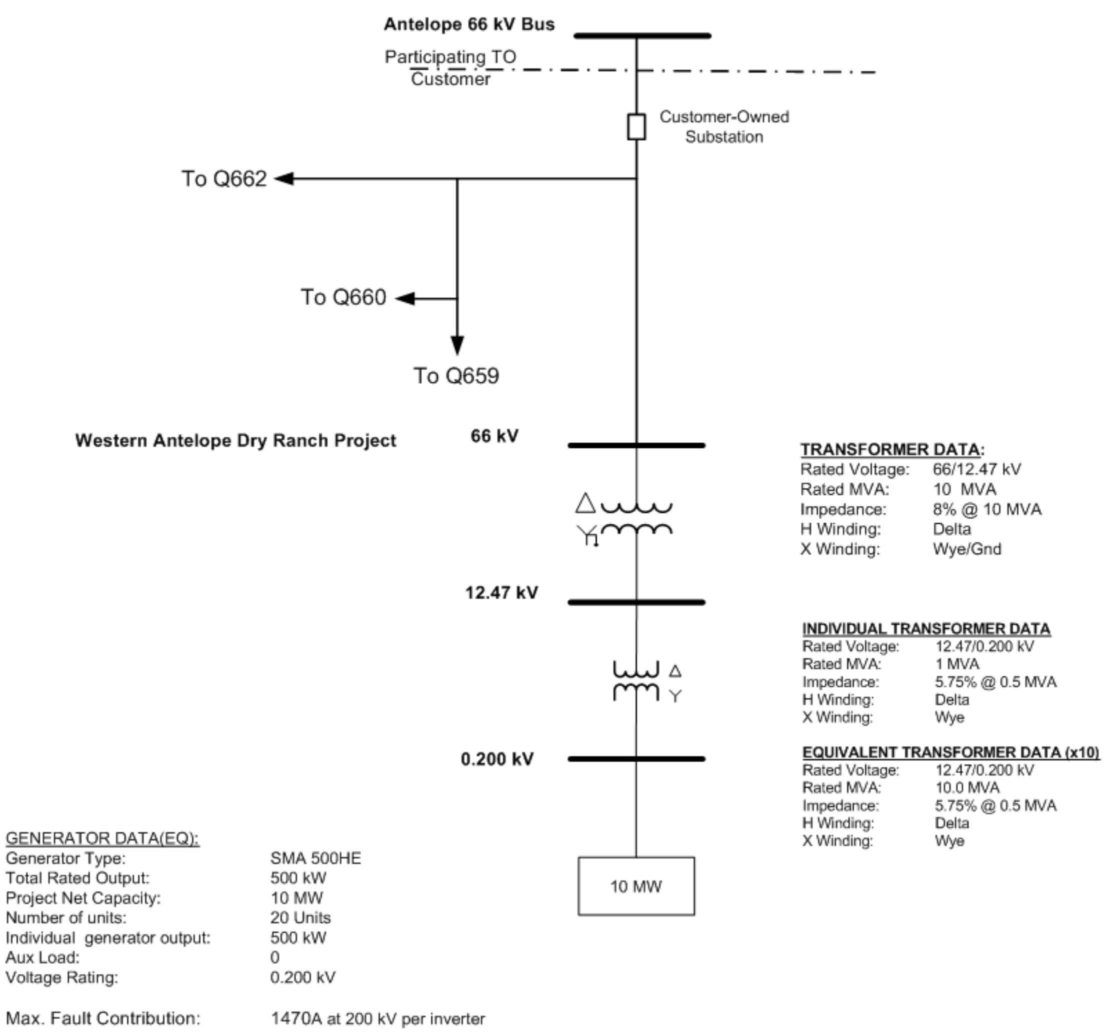
For the Interconnection Customer________________________ Date_______________

ATTACHMENT 5

Additional Operating Requirements for the CAISO Controlled Grid and Affected Systems Needed to Support the Interconnection Customer's Needs

The Participating TO and the CAISO shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the CAISO Controlled Grid.

1. **Generating Facility:** All equipment and facilities comprising the Western Antelope Dry Ranch generating facility in Lancaster, California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have been amended during the Interconnection Study process, which consists of (i) a solar photovoltaic generating facility with a maximum capacity of 10 MW, (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, and (iv) appurtenant equipment. The Western Antelope Dry Ranch Project shall consist of the Small Generating Facility and the Interconnection Customer’s Interconnection Facilities.



2. Interconnection Customer Operational Requirements.

(a) Pursuant to Article 1.5.2 of the SGIA, the Interconnection Customer shall operate the Small Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the CAISO Tariff; NERC and the Applicable Reliability Council requirements; and Applicable Reliability Standards.

(b) The Small Generating Facility shall be operated so as to prevent or protect against the following adverse conditions on the Participating TO's electric system: inadvertent and unwanted re-energizing of a utility dead line or bus; interconnection while out of synchronization; overcurrent; voltage imbalance; ground faults; generated alternating current frequency outside permitted safe limits; power factor or reactive power outside permitted limits; and abnormal waveforms.

(c) The Parties agree that the Interconnection Customer shall not hold the Participating TO liable for damage to any Small Generating Facility turbines that may be caused due to sympathetic generation tripping associated with the Interconnection Customer's induction turbine design.

(d) Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard or any alternative Applicable Reliability Standard or applicable reliability council standard. In the event of a conflict among ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, or any alternative Applicable Reliability Standard or applicable reliability council standard, the alternative Applicable Reliability Standard or applicable reliability council standard shall control.

3. Interconnection Principles:

(a) This SGIA provides for interconnection of a total capacity of 10 MW, resulting from the interconnection of the Western Antelope Dry Ranch Project, as described in Section 1 of this Attachment 5. The Interconnection Customer acknowledges that if the Interconnection Customer wishes to increase the amount of interconnection capacity provided pursuant to this SGIA, the Interconnection Customer shall be required to submit a new Interconnection Request in accordance with the terms and conditions of the CAISO Tariff.

(b) The costs associated with any mitigation measures required to third party transmission systems, which result from interconnection of the Western Antelope Dry Ranch Project to the Participating TO's electrical system, are not reflected in this SGIA. The Participating TO shall have no responsibility to pay costs associated with any such mitigation measures. If applicable, the Interconnection Customer shall enter into an agreement with such third parties in accordance with Section 12.4 of the GIP to address any required mitigation.

(c) In the event the Participating TO's Interconnection Facilities are utilized to provide retail service to the Interconnection Customer in addition to the wholesale Interconnection Service provided herein, and the Interconnection Customer fails to make payment for such retail service in accordance with the Participating TO's applicable retail tariffs, then the Participating TO's Interconnection Facilities may be removed from service to the Interconnection Customer, subject to the notice and cure provisions of such retail tariffs, until payment is made by the Interconnection Customer pursuant to such retail tariffs.

(d) Review by the Participating TO of the electrical specifications, design, construction, operation, or maintenance of the Western Antelope Dry Ranch Project or the Interconnection Customer's Interconnection Facilities shall not constitute any representation as to the economic or technical feasibility, operational capability, or reliability of such facilities. The Interconnection Customer shall in no way represent to any third party that any such review by the Participating TO of such facilities, including, but not limited to, any review of the design, construction, operation, or maintenance of such facilities by the Participating TO, is a representation by the Participating TO as to the economic or technical feasibility, operational capability, or reliability of the Western Antelope Dry Ranch Project or the Interconnection Customer's Interconnection Facilities.

(e) The Participating TO's approval process specified in Article 2.1.1 of the SGIA will include verification that the low-voltage ride-through, SCADA capability, and power factor correction equipment, if any, required pursuant to Attachment 7 of this SGIA, have been installed.

(f) The Interconnection Customer shall complete and receive approval for all environmental impact studies and any permitting necessary for the construction, operation and maintenance of the Western Antelope Dry Ranch Project. The Interconnection Customer shall include the Participating TO's Interconnection Facilities Distribution Upgrades and Network Upgrades described in Attachment 2 of this SGIA in all such environmental impact studies, where applicable. The Interconnection Customer shall provide the results of such studies and approvals to the Participating TO for use in the Participating TO's application(s) to obtain the regulatory approvals required to be obtained by Participating TO for the construction, operation and maintenance of the Participating TO's Interconnection Facilities, Distribution Upgrades and Network Upgrades described in Attachment 2 of this SGIA.

(g) The Interconnection Customer is responsible for all costs associated with any necessary relocation of any of the Participating TO's facilities as a result of the Western Antelope Dry Ranch Project and acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross the Participating TO's facilities and property. The relocation of the Participating TO's facilities or use of the Participating TO's property rights shall only be permitted upon written agreement between the Participating TO and the Interconnection Customer.

Any proposed relocation of the Participating TO’s facilities or use of the Participating TO’s property rights may require a study and/or evaluation, the cost of which would be borne by the Interconnection Customer, to determine whether such use may be accommodated. The terms and conditions of any such use of the Participating TO’s facilities or property rights would be the subject of a separate agreement and any associated costs to the Interconnection Customer would not be considered to be associated with a Network Upgrade or Distribution Upgrade and would not be refundable to the Interconnection Customer pursuant to Article 5.3 of this SGIA.

(h) This SGIA does not address any requirements for standby power or temporary construction power that the Small Generating Facility may require prior to the in-service date of the Interconnection Facilities. Should the Small Generating Facility require standby power or temporary construction power from the Participating TO prior to the in-service date of the Interconnection Facilities, the Interconnection Customer is responsible to make appropriate arrangements with the Participating TO to receive and pay for such retail service.

4. Cluster Study Group:

The Western Antelope Dry Ranch Project participated in the CAISO’s Queue Cluster 1&2 for purposes of assessing impacts to the Participating TO’s electrical system and that portion of the Participating TO’s electrical system that constitutes the CAISO Controlled Grid.

5. Interconnection Operations:

(a) The Interconnection Customer shall cause the Western Antelope Dry Ranch Project to participate in any SPS required to prevent thermal overloads and unstable conditions resulting from outages. Such participation shall be in accordance with applicable FERC regulations, and CAISO Tariff provisions and protocols. The Interconnection Customer will not be entitled to any compensation from the Participating TO, pursuant to the SGIA, for loss of generation output when (i) the Small Generating Facility’s generation is reduced or the Western Antelope Dry Ranch Project is tripped off-line due to implementation of the SPS; or (ii) such generation output is restricted in the event the SPS becomes inoperable. In accordance with Good Utility Practice, the Participating TO will provide the Interconnection Customer advance notice of any required SPS beyond that which has already been identified in the Phase II Interconnection Study and this SGIA.

(b) The SGIA governs the facilities required to interconnect the Small Generating Facility to Participating TO's electrical system pursuant to the CAISO Tariff and as described herein. Interconnection Customer shall be responsible for making all necessary operational arrangements with the CAISO, including, without limitation, arrangements for obtaining transmission service from the CAISO, and for scheduling delivery of energy and other services to the CAISO Controlled Grid.

(c) The Interconnection Customer shall cause the Small Generating Facility to participate in CAISO congestion management.

(d) Following outages of the Interconnection Facilities or the Small Generating Facility, the Interconnection Customer shall not energize the Western Antelope Dry Ranch Project for any reason without specific permission from the Participating TO's and the CAISO's operations personnel. Such permission shall not be unreasonably withheld.

(e) The Interconnection Customer shall maintain operating communications with the Participating TO's designated switching center. The operating communications shall include, but not be limited to, system parallel operation or separation, scheduled and unscheduled outages, equipment clearances, protective relay operations, and levels of operating voltage and reactive power.

(f) The Interconnection Customer has elected for the Small Generating Facility to have Energy-Only Deliverability Status, as such term is defined in the CAISO Tariff. The Interconnection Customer acknowledges and understands that, until the Participating TO's Delivery Network Upgrades are constructed and placed in service, the Small Generating Facility will have Energy-Only Deliverability Status, as such term is defined in the CAISO Tariff.

(g) Technical assessments may be performed by the Participating TO on an as needed basis, at the Interconnection Customer's expense, to confirm if any of the facilities, upgrades or replacements identified in the Phase II Interconnection Study are required to be advanced in order to accommodate interconnection of the Western Antelope Dry Ranch Project. In the event that it is determined by the Participating TO that any such facilities, upgrades or replacements are required to be advanced in order to accommodate interconnection of the Small Generating Facility, such advancement shall be addressed in accordance with Section 12.2.2 of the GIP. Additionally, technical assessments may be required prior to the interconnection of the Western Antelope Dry Ranch Project due to the changes in the generation interconnection queue and the electrical system since the Interconnection Studies were completed. These technical assessments may identify Participating TO's Reliability Network Upgrades and Participating TO's Delivery Network Upgrades that are different from those included in the SGIA. As a result of these technical assessments, this SGIA may require amending to reflect such upgrades and associated costs.

(h) Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Small Generating Facility with the Participating TO's Transmission System; (ii) operate and maintain the Small Generating Facility, the Interconnection Facilities and the Participating TO's electrical system; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this SGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party. The Interconnection Customer and Participating TO shall execute any necessary supplemental agreements, as determined by the Participating TO, to effectuate and record such easement(s) which provides the Participating TO unrestricted 24 hour access to Participating TO's Interconnection Facilities, and Distribution Upgrades, and Network Upgrades, if applicable, located on the Interconnection Customer's side of the Point of Change of Ownership for construction, operation, and maintenance.

(i) Compliance with Applicable Reliability Standards: The Interconnection Customer shall comply with all Applicable Reliability Standards for the Interconnection Customer's Interconnection Facilities and the Small Generating Facility. The Participating TO will not assume any responsibility for complying with mandatory reliability standards for such facilities and offers no opinion as to whether the Interconnection Customer must register with NERC. If required to register with NERC, the Interconnection Customer shall be responsible for complying with all Applicable Reliability Standards for the Interconnection Customer's Interconnection Facilities and the Small Generating Facility up to the Point of Change of Ownership, as described in Section 5 of Attachment 2 of this SGIA.

6. Insurance:

(a) Each Party shall, at its own expense, maintain in force throughout the period of this SGIA, and until released by the other Party, the following minimum insurance coverage, with insurers rated no less than A- (with a minimum size rating of VII) by Bests' Insurance Guide and Key Ratings and authorized to do business in the state where the Point of Interconnection is located:

(i) Employer's Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. Either party may meet the requirement for workers compensation insurance through self-insurance if it is authorized to self-insure by the applicable state.

(ii) Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of one million dollars ($1,000,000.00) per occurrence/one million dollars ($1,000,000.00) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

(iii) Business Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of one million dollars ($1,000,000.00) per occurrence for bodily injury, including death, and property damage.

(iv) For this 10 MW project, excess Public Liability Insurance over and above the Employer's Liability Commercial General Liability and Business Automobile Liability Insurance coverage, with a minimum combined single limit of one million dollars ($1,000,000.00) per occurrence/ten million dollars ($10,000,000.00) aggregate. The requirements of section ii and iv may be met by any combination of general and excess liability insurance.

(v) The Commercial General Liability Insurance, Business Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, its subsidiaries and the respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this SGIA against the Other Party Group and endeavor to provide thirty (30) calendar days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

(vi) The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer’s liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

(vii) The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this SGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

(viii) The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this SGIA.

(ix) No later than ten (10) Business Days prior to the anticipated commercial operation date of this SGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) calendar days thereafter, each Party shall provide certification of all insurance required in this SGIA, executed by each insurer or by an authorized representative of each insurer.

(b) Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Article 8 of this SGIA and this Attachment 5 Section 6 to the extent it maintains a self-insurance program; provided that, Interconnection Customer's senior unsecured debt or issuer rating is BBB-, or better, as rated by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Article 8 of this SGIA and this Attachment 5 Section 6. For any period of time that Interconnection Customer's senior unsecured debt rating and issuer rating are both unrated by Standard & Poor's or are both rated at less than BBB- by Standard & Poor's, each Party shall comply with the insurance requirements applicable to it under Article 8 of this SGIA and this Attachment 5 Section 6.In the event that a Party is permitted to self-insure, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 8 of this SGIA and this Attachment 5 Section 6.

(c) The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this SGIA.

ATTACHMENT 6

Participating TO's Description of its Upgrades and Best Estimate of Upgrade Costs

The Participating TO shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Participating TO shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

1. Network Upgrades.

(a) **Stand Alone Network Upgrades.** None.

(b) **Other Network Upgrades.**

(i) **Participating TO's Reliability Network Upgrades.** The Participating TO shall:

1. **Antelope Substation**. Implement the following upgrades at the Antelope 66kV Substation to support interconnection for the Western Antelope Dry Ranch Project and termination of the Antelope - Western Antelope Dry Ranch 66 kV Transmission Line.

   a. Circuit Breakers – Two (2) 2000 A 40 kA 66 kV circuit breakers

   b. Disconnect Switches – Four (4) 2000 A 40 kA horizontal-mounted group-operated disconnect switches

   c. Bay position conductor

   d. Power System Controls: Modify points on existing RTU to account for new gen-tie

2. **Short-Circuit Duty Mitigation:** The Participating TO shall: Replace four Vincent 500 kV circuit breakers (CB722, CB852, CB952, and CB862) to achieve 63 kA rating. The timing of replacement of these four circuit breakers is tied to actual development of generation projects throughout SCE's service territory as well as completion of corresponding Deliverability Network Upgrades. Additional review of these breakers will be performed as projects execute interconnection agreements to identify need and schedule installation of these circuit breaker replacements.

3. **Real Properties, Transmission Project Licensing, and Environmental Health and Safety.**
   Perform all required functions to obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental

activities for the installation of the Participating TO's Reliability Network Facilities.

(ii) **Participating TO's Delivery Network Upgrades.** None.

2. Distribution Upgrades. None. See Attachment 2, Section 18.

ATTACHMENT 7

Interconnection Requirements for an Asynchronous Generating Facility

Attachment 7 sets forth requirements and provisions specific to all Asynchronous Generating Facilities. All other requirements of this Agreement continue to apply to all Asynchronous Generating Facility interconnections.

A. Technical Standards Applicable to Asynchronous Generating Facilities

i. Low Voltage Ride-Through (LVRT) Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. Remaining on-line shall be defined as continuous connection between the Point of Interconnection and the Asynchronous Generating Facility's units, without any mechanical isolation. Asynchronous Generating Facilities may cease to inject current into the transmission grid during a fault.

4. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Attachment 7

or single-phase faults exceeding the duration described in Section A.i.2 of this Attachment 7.

5. The requirements of this Section A.i. of this Attachment 7 do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

6. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

7. Asynchronous Generating Facilities may meet the requirements of this Section A.1 of this Attachment 7 through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility or by a combination of generating unit performance and additional equipment.

8. The provisions of this Section A.i of this Attachment 7 apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

ii. Frequency Disturbance Ride-Through Capacity

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the WECC Under Frequency Load Shedding Relay Application Guide or successor requirements as they may be amended from time to time.

iii. Power Factor Design and Operating Requirements (Reactive Power)

An Asynchronous Generating Facility shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this SGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The

Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

ATTACHMENT 8

[This Attachment is Intentionally Omitted]

ATTACHMENT B

QC1 and QC2 Phase II
Interconnection Study Report
Group Report in SCE's Northern Bulk System
Final Report

Redacted Public Version

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

QC1 and QC2 Phase II Interconnection Study Report

Group Report in SCE's Northern Bulk System

Final Report

California ISO

Shaping a Renewed Future

August 19, 2011

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y, including Appendix 8 of the GIP ("Transition of Existing SGIP Interconnection Requests to the GIP") for Interconnection Requests in a Queue Cluster Window

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Definitions

CAISO	California Independent System Operator Corporation
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EKWRA	East Kern Wind Resource Area
EO	Energy Only Deliverability Status
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
IC	Interconnection Customer
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
PMax	Maximum generation output
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment
PG&E	Pacific Gas and Electric Company
Phase I Study	Cluster Phase I Study
Phase II Study	Cluster Phase II Study
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
SVC	Static VAR Compensator
TPP	CAISO's Transmission Planning Process
TWRA	Tehachapi Wind Resource Area
TRTP	Tehachapi Renewable Transmission Project
WECC	Western Electricity Coordinating Council

1. Executive Summary

In accordance with Federal Energy Regulatory Commission (FERC) approved Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), including Appendix 8 of the GIP ("Transition of Existing SGIP Interconnection Requests to the GIP"), this Phase II Study was performed to determine the combined impact of all the projects in the Queue Cluster 1 (QC1), Queue Cluster 2 (QC2) and SGIP Transition Cluster (STC).all Generator Interconnection Procedures (SGIP) Transition Cluster on the CAISO Controlled Grid.

There are 50 generation projects in SCE's service territory for the Phase II Study. Four general groups[1] are formed based on the electrical impact among the generation projects: Northern Bulk System, Eastern Bulk System, East of Lugo Bulk System and Metro System. This study report provides the following:

1. Transmission system impacts caused by the addition of 36 Phase II projects requesting interconnection in the Northern System including 28 Small Generation Interconnection requests that were moved into this Phase II per the CAISO's Generation Interconnection Procedures Tariff modification approved by FERC. These 28 Small Generator Interconnection requests will be referred to as SGIP Transition Cluster (STC);

2. System reinforcements necessary to mitigate the adverse impacts of the 36 Phase II projects requesting interconnection in the Northern Bulk System under various system conditions and;

3. The responsibility for financing the cost of necessary system reinforcements and interconnection facilities, and a good faith estimate of the time required to permit, engineer, design, procure, construct, and place into operation these necessary system reinforcements and interconnection facilities.

To determine the system impacts caused by Phase II projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short-Circuit Duty Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Deliverability Assessment
- Operational Studies

[1] Precise electrical groupings were created during the deliverability study for Delivery Network cost allocation purposes.

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The results of above studies indicated that Phase II projects are responsible for the overloading of several transmission facilities and overstressing of several circuit breakers at a number of substations in SCE's service territory. Network Upgrades[2] and Distribution Upgrades to mitigate identified problems corresponding to the 36 Phase II projects requesting interconnection in the Northern Bulk System have been proposed in this report. The following tables show a summary of the proposed Network Upgrades along with an estimated cost.

Table A – Plan of Service Reliability Network Upgrades ($ 1,000)

1	Various (see individual Appendix A reports)	
	TOTAL	$223,554

Table B – Reliability Network Upgrades ($ 1,000)

1	Replace Wavetraps on Lugo – Vincent No.1 & No.2 500 kV T/Ls	
2	Northern Area 500 kV SPS	
3	Modify Previously Proposed Whirlwind SPS (AA Bank N-1)	
4	Modify Previously Proposed Windhub SPS (AA Bank N-1)	
5	Eastern Antelope Area 66 kV Upgrades*	
6	Windhub 66 kV Area Upgrades* Rebuild portion of Correction-Cummings-KR1 Reconfig. Windhub-Goldtown-Monolith-Windlands New 66 kV line (Windhub-Q522)	
7	Western Antelope Area 66 kV Upgrades*	
8	Fiber Optic Backbones* STC North 1 STC North 2 STC West 1 STC West 2 STC East	
9	Short-Circuit Duty (SCD) Mitigation Lugo Vincent Windhub	
	TOTAL	**$308,767**

* With EKWRA, these facilities may ultimately be classified as Distribution Upgrades

Table C – Delivery Network Upgrades ($ 1,000)

1	None	
	TOTAL	**$0**

[2] The additions, modifications, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distribution Upgrades.

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Table D – Distribution Upgrades ($ 1,000)

1	SCD Mitigation	
2	Other Antelope-Bailey 66 kV (See individual Appendix A reports)	
3	Other Vestal 66 kV System (See individual Appendix A reports)	
	TOTAL	**$29,329**

These upgrades do not include Interconnection Facilities, which are the obligation of each Interconnection Customer to fund. Interconnection facilities relating to each individual project are discussed in the corresponding Appendix A. Distribution upgrades identified in Table D are non-refundable.

Given the magnitude of above upgrades, a good faith estimate to engineer, license, procure, and construct all facilities identified in the above tables could be up to 72 months from LGIA execution. Timelines required to engineer, license, procure, and construct facilities necessary for interconnection and/or delivery of each individual project are discussed in Appendix A.

2. Phase II Interconnection Information

Thirty-six generation projects totaling a maximum output of 1,739.3 MW are included in Phase II in SCE's Northern Bulk System. Table 2.1 lists the eight QC1 and QC2 generator projects in Phase II with essential data obtained from the CAISO Generation queue and updated to reflect the most current information and Table 2.2 lists the 28 Small Generation Interconnection Projects that are part of the STC. All the STC projects are studied for Energy Only deliverability status in the Phase II study.

Table 2.1: QC1 and QC2 Phase II Projects (Northern Bulk System)

Project Number	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW
CAISO Q494	Windhub Substation 220 kV	FC	Solar	350
CAISO Q506	Whirlwind Substation 220 kV	EO	Solar	300
CAISO Q512	Neenach-Bailey 66 kV	FC	Solar	26
CAISO Q513	Whirlwind Substation 220 kV	FC	Solar	141
CAISO Q585	Antelope Substation 66 kV	FC	Wind	150
CAISO Q602	Whirlwind Substation 220 kV	FC	Solar	146
SCE WDAT 425	Weldon 66 kV Substation	FC	Solar	37.5
SCE WDAT 433	Vestal-Glennville line	FC	Solar	40
Total QC1 and QC2 Phase II Generation				**1,190.5**

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Table 2.2: STC Projects (Northern Bulk System)

Project Number	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW
CAISO Q485	Highwind 230 kV Bus	EO	Wind	20
CAISO Q521	Corum - Goldtown 66 kV Line	EO	Solar	20
CAISO Q522	Corum - Goldtown - Rosamond 66 kV Line	EO	Solar	20
CAISO Q522C	Correction - Cummings - Kern River 1 66 kV Line	EO	Solar	20
CAISO Q613A	Arbwind - Monolith 66 kV Line	EO	Wind	20
CAISO Q614A	Corum - Goldtown - Rosamond 66 kV Line	EO	Solar	20
CAISO Q628	Antelope - Cal Cement - Rosamond 66 kV Line	EO	Solar	20
CAISO Q639	Piute - Redman 66 kV Line	EO	Solar	20
CAISO Q640	Antelope - Cal Cement - Rosamond 66 kV Line	EO	Solar	20
CAISO Q649B	Antelope - Del Sur - Rosamond 66 kV Line	EO	Solar	20
CAISO Q649C	Antelope - Cal Cement - Rosamond 66 kV Line	EO	Solar	20
CAISO Q650A	Lancaster - Purify - Redman 66 kV Line	EO	Solar	20
CAISO Q650AA	Antelope - Del Sur - Rosamond 66 kV Line	EO	Solar	15
CAISO Q651A	Antelope 66 kV Bus	EO	Solar	20
CAISO Q653BA	Correction - Cummings - Kern River 1 66 kV Line	EO	Solar	20
CAISO Q653EF	Arbwind - Monolith 66 kV Line	EO	Wind	20
CAISO Q653FA	Lancaster - Little Rock - Piute 66 kV Line	EO	Solar	20
CAISO Q653FB	Lancaster - Little Rock - Piute 66 kV Line	EO	Solar	20
CAISO Q653H	Antelope 66 kV Bus	EO	Solar	10
CAISO Q657A	Antelope - Neenach 66 kV Line	EO	Solar	20
CAISO Q657B	Corum - Goldtown 66 kV Line	EO	Solar	20
CAISO Q658	Antelope - Lancaster - Lanpri - Shuttle 66 kV Line	EO	Solar	20
CAISO Q659	Antelope 66 kV Bus	EO	Solar	20
CAISO Q660	Antelope 66 kV Bus	EO	Solar	20
CAISO Q661	Antelope - Rosamond 66 kV Line	EO	Solar	20
CAISO Q662	Antelope 66 kV Bus	EO	Solar	20
CAISO Q663	Lancaster - Purify - Redman 66 kV Line	EO	Solar	20
CAISO Q664	Piute 66 kV Bus	EO	Solar	20
			Total STC Phase II Generation	**545**

3. Study Objectives

This Phase II Interconnection study was performed in accordance with Section 7.1 of Appendix Y of the CAISO tariff, which states:

The Phase II Interconnection Study shall:

(i) update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of Interconnection Requests,
(ii) identify final Reliability Network Upgrades needed to physically interconnect the Large Generating Facilities,
(iii) assign responsibility for financing the identified final Reliability Network Upgrades,
(iv) identify, following coordination with the CAISO's Transmission Planning Process, final Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;
(v) assign responsibility for financing Delivery Network Upgrades needed to interconnect those Large Generating Facilities selecting Full Capacity Deliverability Status;
(vi) identify for each Interconnection Request final Point of Interconnection and Participating TO's Interconnection Facilities;
(vii) provide a +/-20% estimate for each Interconnection Request of the final Participating TO's Interconnection Facilities;
(viii) optimize in-service timing requirements based on operational studies in order to maximize achievement of the Commercial Operation Dates of the Large Generating Facilities; and
(ix) if it is determined that the Delivery Network Upgrades cannot be completed by the Interconnection Customer's identified Commercial Operation Date, provide that operating procedures necessary to allow the Large Generating Facility to interconnect as an energy-only resource, on an interim-only basis, will be developed and utilized until the Delivery Network Upgrades for the Large Generating Facility are completed and placed into service.

This same section continues and further states that the Phase II Interconnection Study shall:

(x) specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the CAISO Controlled Grid to implement the conclusions of the updated Phase II Interconnection Study technical analyses in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the CAISO Controlled Grid; and
(xi) also identify the electrical switching configuration of the connection equipment, including, without limitation: the

transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

The Phase II Study analysis was performed to identify the Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades necessary to safely and reliably interconnect the Phase II projects into the CAISO Controlled Grid. An estimated cost and construction schedule for these facilities has also been provided in this report.

4. Study Assumptions

4.1 Power flow base cases

The Phase II Study used power flow base cases representing summer peak 2014 and off-peak 2014 system conditions in the SCE service territory. These base cases included all CAISO approved transmission projects, as well as higher queued generation projects with associated Network Upgrades and Special Protection Systems.

4.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 25,845 MW load in SCE system with an import target as shown in Table 4.2. The Off-Peak case modeled a 16,140 MW load in SCE system.

Table 4.2: On-Peak Deliverability Assessment Import Target

Branch Group (BG) Name	BG Import Direction	Net Import MW	Import Unused ETC MW
Lugo_victrville_BG	N-S	1138	171
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	107	0
CASCADE_BG	N-S	1	0
CFE_BG	S-N	-55	0
ELDORADO_BG	E-W	1158	0
IID-SCE_BG	E-W	315	0
IID-SDGE_BG	E-W	-159	0
INYO_BG	E-W	0	0
LAUGHLIN_BG	E-W	0	0
MCCULLGH_BG	E-W	30	316
MEAD_BG	E-W	469	505
MERCHANT_BG	E-W	439	0
N.GILABK4_BG	E-W	-140	168
NOB_BG	N-S	1469	0
PALOVRDE_BG	E-W	3139	175
PARKER_BG	E-W	108	27
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	0	0
SYLMAR-AC_BG	E-W	0	471

The Reliability Assessment Summer Peak Case modeled a 26,272 MW load. The off-peak load case represented about 60% of summer peak load.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area.

4.3 Generation Assumptions

Generation assumptions for SCE's Northern Bulk System[3] are shown in Table 4.3.1 (existing) and 4.3.2 (active queued ahead serial), Table 4.3.3 (Transition Cluster), and Table 4.3.4 (Pre Phase II SGIPs).

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/1c44/1c44b5c31cce0.html. In the on-peak Deliverability Assessment, the Summer Peak Qualified Capacity for proposed Full Capacity generation projects is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for Solar generation initially. The Summer Peak QC may be adjusted to 40% of the requested PMax for wind generation and 85% for solar generation if a mix of different fuel type generations is identified in the Deliverability Assessment as the 5% DFAX group for a transmission

[3] Only SCE's Northern Bulk System generation (including Big Creek Corridor and Ventura areas) is shown in the provided tables.

limitation. In the off-peak Deliverability Assessment, the proposed Full Capacity wind generation is dispatched at its requested PMax and solar generation at 85% of its requested PMax.

In the Reliability Assessment, the generation is dispatched at PMax.

Table 4.3.1: Existing Generation

Generation unit	Type	Size (MW)
Antelope-Bailey 66 kV, Big Creek and CDWR	Hydro	1,110
Pastoria Energy Facility, Mandalay, Ormond Beach, and Pandol	Market	2,876
Antelope-Bailey 66 kV, Sagebrush Partnership, Ultragen, Omar and Sycamore	Qualifying Facility	1,271
Sagebrush	RPS Wind Project	65
	Total (Existing)	**5,322**

Table 4.3.2: Higher Queued Serial Interconnection Requests

CAISO Queue Position	Type	Size (MW)
CAISO Queue #20	New Wind Project	300
CAISO Queue #41	Combustion Turbine	159
SCE WDAT 190	Combustion Turbine	50
CAISO Queue #73	New Wind Project	250
CAISO Queue #79	New Wind Project	51
CAISO Queue #84	New Wind Project	340
CAISO Queue #86 A	New Wind Project	33
CAISO Queue #86 B	New Wind Project	34
CAISO Queue #91	New Wind Project	51
CAISO Queue #92	Combined Cycle	570
CAISO Queue #93	New Wind Project	220
CAISO Queue #94	New Wind Project	180
CAISO Queue #95	New Wind Project	550[4]
CAISO Queue #96	New Wind Project	600[5]
CAISO Queue #97	New Wind Project	160
CAISO Queue #100	New Wind Project	120
CAISO Queue #119	New Wind Project	500
CAISO Queue #132	New Wind Project	297
CAISO Queue #153	New Wind Project	100
	Total	**4,565**

[4] 270 MW have been placed into service.
[5] 450 MW have been placed into service.

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Table 4.3.3: Transition Cluster Interconnection Requests

CAISO Queue Position	Type	Size (MW)
CAISO Queue #154	New Solar Project	250
CAISO Queue #175	New Wind Project	650
CAISO Queue #188	New Wind Project	200
CAISO Queue #297	New Solar Project	66
CAISO Queue #342	New Solar Project	50
CAISO Queue #348	New Solar Project	40
CAISO Queue #349	New Solar Project	100
CAISO Queue #407	New Solar Project	325
CAISO Queue #408	New Solar Project	325
CAISO Queue #409	New Wind Project	150
CAISO Queue #412	New Solar Project	250
SCE WDAT 270	New Solar Project	33
	Total	**2,439**

Table 4.3.4: Pre-Phase II Serial SGIP Interconnection Requests

CAISO Queue Position	Type	Size (MW)
CAISO Queue #483	New Solar Project	10
CAISO Queue #486	New Solar Project	20
CAISO Queue #522A	New Solar Project	20
CAISO Queue #522B	New Solar Project	20
WDT361	New Solar Project	5
WDT368	New Solar Project	4.9
WDT390	New Solar Project	20
WDT391	New Solar Project	20
WDT392	New Solar Project	20
WDT394	New Solar Project	20
CAISO Queue #531A	New Solar Project	20
CAISO Queue #537A	New Solar Project	19.5
WDT402	New Solar Project	10
WDT403	New Solar Project	2
WDT404	New Solar Project	10
WDT353	New Solar Project	20
CAISO Queue #540	New Solar Project	20
CAISO Queue #546	New Solar Project	15
CAISO Queue #547	New Solar Project	20
CAISO Queue #609	New Solar Project	20
WDT435	New Solar Project	20
WDT407	New Solar Project	20
WDT453	New Solar Project	5
CAISO Queue #617A	New Solar Project	20
	Total	**381.4**

4.4 New Transmission Projects

This Phase II Study included the modeling of all CAISO-approved transmission projects in the Northern Bulk System base cases. In addition, a number of transmission upgrades are needed to support queued ahead serial generation projects in the Northern Bulk System were modeled in order to determine if additional facilities would be needed to support the Phase II projects.

4.4.1 The Antelope Transmission Project (ATP)

The Antelope Transmission Project ("ATP") consists of new transmission between Antelope and Pardee, between Antelope and Vincent, and between Antelope and Tehachapi. The project also includes the addition of two new substations in the TWRA. This project is broken down into the following three segments:

Segment 1:

- Expand Antelope Substation and rating increase to 500 kV
- New 25.6-mile Antelope - Pardee single-circuit 500 kV T/L (in-service)

Segment 2:

- New 21.0-mile Antelope-Vincent single-circuit 500 kV T/L (in-service)

Segment 3:

- New 25.6-mile Antelope - Windhub single-circuit 500 kV T/L (in-service)
- New 9.6-mile Windhub - Highwind single-circuit 220 kV T/L
- New Windhub 500/220/66 kV Substation (portion of 220 kV in-service)
- New Highwind 220/66 kV Substation

With the addition of the Antelope Transmission Project, the maximum amount of increased system capability has been identified to be 700 MW, as limited by transmission south of Antelope.

4.4.2 The Tehachapi Renewable Transmission Project (TRTP)

The Tehachapi Renewable Transmission Project ("TRTP") is the final plan of service developed to interconnect new planned generation resources, above the 700 MW provided by the ATP, in the TWRA. These facilities, needed to interconnect and transmit the electrical power from the new planned generation resources, have been identified through a collaborative planning process held as part of the CAISO South Regional Transmission Plan; and commence upon completion of ATP. Summarized below are the major components of these facilities.

Segment 4:

- New 16 mile Antelope-Whirlwind 500 kV T/L, initially energized to 220 kV
- New 500 kV T/Ls to loop existing Midway-Vincent No.3 500 kV line in and out of proposed Whirlwind (part of Segment 9) Substation

Segment 5:

- New 18-mile Antelope-Vincent No.2 single-circuit 500 kV T/L in existing ROW

Segment 6:

- Replacement of Vincent-Rio Hondo No.2 T/L 500 kV
- Rebuild approximately 32 miles of existing 220 kV T/L to 500 kV standards from existing Vincent Substation to the southern boundary of the Angeles National Forest ("ANF")

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Segment 7:

- New Vincent-Mira Loma 500 kV T/L (Vincent-Mesa Area)
- Rebuild approximately 16 miles of existing 220 kV T/L to 500 kV standards from the southern boundary of the ANF to existing Mesa Substation. This segment would replace the existing Antelope – Mesa 220 kV T/L

Segment 8:

- New Vincent-Mira Loma 500 kV T/L (Mesa Area-Mira Loma)
- Rebuild of approximately 33 miles of existing 220 kV T/L to 500 kV standards from a point approximately 2 miles east of the existing Mesa Substation (the "San Gabriel Junction") to the existing Mira Loma Substation. This segment would also include the rebuild of approximately 7 miles of the existing Chino – Mira Loma No. 1 line from single-circuit to double-circuit 220 kV structures.

Segment 9:

- New 500/220 kV Whirlwind Substation.
- Upgrade of the existing Antelope, Vincent, Mesa, Gould, and Mira Loma Substations to accommodate new T/L construction and system compensation elements.

Segment 10:

- New 17 mile Whirlwind - Windhub 500 kV T/L

Segment 11:

- New Vincent-Mesa (via Gould) 500/220 kV T/L
- Rebuild approximately 19 miles of existing 220 kV T/L to 500 kV standards between the existing Vincent and Gould Substations. This segment would also include the addition of a new 220 kV circuit on the vacant side of the existing double-circuit structures of the Eagle Rock –

Mesa 220 kV T/L between the existing Gould Substation and the existing Mesa Substation

4.4.3 "East Kern Wind Resource Area 66 kV Reconfiguration Project"

The East Kern Wind Resource Area ("EKWRA") 66 kV project will separate the existing Antelope-Bailey 66 kV system into two systems. The northern system will be served in a radial fashion from Windhub Substation. A significant portion of the southern system will also be served in a radial fashion from either Antelope Substation or Bailey Substation. The only portions of the southern system that will remain parallel includes the Antelope 66 kV bus, Bailey 66 kV bus, Neenach 66 kV bus, Antelope-Neenach 66 kV line, and Bailey-Neenach portion of the Bailey-Neenach-Westpac 66 kV line. All north-to-south lines that once connected the northern system to the southern system will be opened. Summarized below are the major components of these facilities.

Antelope-Bailey 66 kV System

The Antelope-Bailey 66 kV system will be reconfigured to serve a total of 27 load centers and retain three normally open tie lines to the Windhub 66 kV system. The distribution load centers are: Acton, Anaverde, Bailey, Del Sur, Frazier Park, Gorman, Great Lakes, Lancaster, Little Rock, Neenach, Oasis, Palmdale, Piute, Quartz Hill, Redman, Ritter Ranch, Rosamond, Shuttle, and Wilsona substations. The eight customer substations are: Helijet, Lanpri, Oso[6], Purify, Rite Aid, Rock Air, Tortoise, and Westpac substations.

Following the split, the remaining Antelope-Bailey system will have three tie lines to the Windhub system:

- Antelope-Cal Cement-Rosamond 66 kV (normally open at Cal Cement)
- Corum-Goldtown-Rosamond 66 kV (normally open at Corum)
- Gorman-Kern River 66 kV (normally open at Kern River)

Windhub 66 kV System

The Windhub 66 kV System will have a total of 11 load centers, 389 MW of nameplate local generation and three tie lines. Windhub system will have eight distribution load centers: Corum, Cummings, Goldtown, Havilah, Loraine, Monolith, Northwind and Walker Basin and three large customer substations: Breeze, Cal Cement and Correction.

A total of 389 MW of nameplate local generation in the Antelope-Bailey system will be transferred to Windhub substation. This includes 310 MW of coincident wind generation from Windpark, Windland, and Windfarm and 34 MW of coincident hydro generation from Borel and Kern River.

The Windhub system will have three tie lines:

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[6] Oso load will be rolled to Alamo.

- Antelope-Cal Cement-Rosamond 66 kV (normally open at Cal Cement)
- Corum-Goldtown-Rosamond 66 kV (normally open at Corum)
- Gorman-Kern River 66 kV (normally open at Gorman)

Substations

There will be line rearrangements in the following substations: Antelope, Cal Cement, Corum, Goldtown, Gorman, Kern River, Lancaster, Monolith, and Rosamond.

- Antelope Substation: Two existing 66 kV lines will be operated as tie lines
- Goldtown Substation: An existing line will be configured to Windhub-Goldtown-Midwind-Monolith-Morwind and the termination of Goldtown-Lancaster will be de-energized
- Cal Cement Substation: Four existing 66 kV lines will be configured to Cal Cement-Windpark 66 kV, Windhub-Cal Cement-Monolith, Windhub-Cal Cement, Antelope-Cal Cement-Rosamond 66 kV
- Gorman and Kern River Substations: The line terminating at Gorman to Kern River No. 1 will be operated as a tie line
- Lancaster Substation: The existing Goldtown-Lancaster 66 kV line will be configured to Lancaster-Rosamond
- Monolith Substation: Two existing substation lines will be reconfigured to Windhub-Goldtown-Midwind-Monolith-Morwind and Windhub-Cal Cement-Monolith
- Windhub Substation 66 kV switch rack will be configured to a breaker-and-a-half configuration. Initially there will be two 280 MVA transformer banks, three capacitor banks and five 66 kV lines
- Rosamond Substation: Two 66 kV lines will be reconfigured; Corum-Rosamond will be reconfigured to Corum-Goldtown-Rosamond with the Corum and Goldtown leg normally open and operated as a tie line. A new line will be terminated at Rosamond, Lancaster-Rosamond
- Corum Substation: Existing Corum-Rosamond 66 kV line will configured as Corum-Goldtown-Rosamond.

Subtransmission lines

The following 66 kV subtransmission lines will be rearranged:

- Goldtown-Lancaster
- Corum-Rosamond
- Cal Cement-Monolith-Rosamond-Windfarm
- Cal Cement-Goldtown-Monolith-Windland
- Cal Cement-Monolith-Windpark
- Antelope-Cal Cement

The project will result in the following newly reconfigured 66 kV lines:

- Windhub-Cal Cement
- Windhub-Cal Cement-Monolith
- Windhub-Goldtown-Midwind-Monolith-Morwind
- Windhub-Enwind-Canwind-Varwind
- Windhub-Flowind-Dutchwind
- Cal Cement-Windpark
- Corum-Goldtown-Rosamond
- Arbwind-Monolith
- Lancaster-Rosamond
- Antelope-Cal Cement-Rosamond

4.5 Other SPSs and Operator Actions

4.5.1 Operating Procedures

Operating procedures, which may include curtailing the output of the Phase II projects during planned or extended forced outages, may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

4.6 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

This Phase II Study assumed that all previously triggered short-circuit duty impacts, where duty contributions are increased with the addition of these Phase II projects, would be mitigated by the corresponding triggering project. Consequently, for cost allocation purposes this study evaluated the incremental impacts associated with the addition of the Phase II projects, including appropriate transmission upgrades as identified in this study, in effort to cost allocate the incremental upgrades associated with the addition of the Phase II projects. However, it should be clear that for reliability reasons it may be necessary to implement operational mitigation upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of Phase II generation projects.

A determination of such mitigation upgrade needs will be based on the study results of the Operational Studies undertaken for the Phase II generation projects. Should an impact to circuit breakers be identified in the Operational Study that requires the implementation of mitigation upgrades, such upgrades will need to be advanced by the corresponding projects in Operational Queue order to enable interconnection of the project.

The following provide the mitigation details of all previously triggered short-circuit duty impacts at locations where duty contributions are increased with the addition of these Phase II projects.

5. Study Criteria and Methodology

The applicable reliability criteria, which incorporate the Western Electricity Coordinating Council (WECC), the North American Electric Reliability Council (NERC) planning criteria and the CAISO Planning Standards, were used to evaluate the impact of Phase II projects on the CAISO Controlled Grid.

5.1 Steady State Study Criteria

5.1.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility ratings. The CAISO Controlled Grid Reliability Criteria requires the loading of all transmission system facilities be within their normal ratings. Normal overloads refer to overloads that occur during normal operating conditions (no contingency).

5.1.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings. Emergency overloads refer to overloads that occur during single element contingencies (Category “B”) and multiple element contingencies (Category “C”).

5.1.3 Voltage Violations

Voltage violations will occur if voltage deviations exceed +/- 5% of the pre-disturbance level for Category B contingencies and +/ -10% for Category C contingencies.

5.1.4 Contingencies

The contingencies used in this analysis are provided in Appendix C. Various categories of contingencies used are summarized in Table 7-2:

Table 7-2: Power flow contingencies

Contingencies	Description
CAISO Category "A" (No contingency)	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages.
CAISO Category "C"	•C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) •C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. •C3 - Combination of any two-generator/transmission line/transformer outages. •C4 - Bipolar (dc) Line •C5 - Outages of double circuit tower lines (60-230 kV) •C6 - SLG Fault, with Delayed Clearing: Generator •C7 - SLG Fault, with Delayed Clearing: T/L •C8 - SLG Fault, with Delayed Clearing: Transformer •C9 - SLG Fault, with Delayed Clearing: Bus Section

As required under NERC standard TPL-003-0 R1.3.1, all of the relevant CAISO Category "C" contingencies were considered as part of this study.

5.2 Short-Circuit Duty Criteria

Short circuit studies are performed to determine the maximum fault duty on the adjacent buses to the Phase II projects in the SCE service territory. This study determines the impact of increased fault current resulting from Phase II projects. Short circuit results will allocate costs for overstressed breakers to each cluster, which are formed from generation projects with a fault contribution above a threshold value. The Computer Aided Protection Engineering (CAPE) software is used to conduct the detailed short circuit studies with three phase (3PH) and single-line-to-ground (SLG) faults.

To determine the impact on short-circuit duty within SCE's electrical system, after inclusion of the Phase II generation projects, the study calculated the maximum 3PH and SLG short-circuit duties. Generation, transformer, and generation tie-line data provided by each Phase II Interconnection Customer was utilized. Bus locations where short-circuit duty is increased with the proposed Phase II projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. It should be noted that other WECC entities may request specific information within the WECC process to evaluate potential impact within their respective systems of this project addition.

5.3 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a contingency. Transient stability studies are performed to ensure system stability following critical faults on the system.

The system is considered stable if the following conditions are met:

1. All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist);

2. A stability simulation will be deemed to exhibit positive damping if a line defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second line connecting the valleys of the curves with the passing of time;

3. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable;

4. Duration of a stability simulation run will be ten seconds unless a longer time is required to ascertain damping;

5. The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;

6. A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the WECC Reliability Criteria and the NERC Planning Standards.

Table 5.3 illustrates the NERC/WECC Reliability Criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

Table 5.3
WECC Disturbance-Performance Table of Allowable Effects on Other Systems (in addition to NERC requirements)

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 2: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

5.4 Post-Transient Voltage Stability Criteria

The last column of the above Table 5.3 illustrates the Post-Transient Voltage Stability Criteria. For some large generator contingencies, the governor power flow is utilized to test for the post-transient voltage deviation criteria.

5.5 Reactive Margin Criteria

Table 5.5 summarizes the voltage support and reactive power criteria in the NERC/WECC Planning Standards. The system performance will be evaluated according to the NERC/WECC planning criteria.

Table 5.5: Reactive Margin Analysis Criteria Summary

Performance Level/Category	Disturbance	Reactive Power Deficiency Criteria
B	Generator One Circuit One Transformer DC Single Pole Block	Governor power flow to reach convergence at 105% of load level or operational transfer capability
C	Two Generators Two Circuits DC Bipolar Block	Governor power flow to reach convergence at 102.5% of load level or operational transfer capability

5.6 Power Factor Criteria

Table 5.6 summarizes the power factor criteria per the CAISO tariff. The voltage at the POI must be within criteria under normal and contingency conditions. Additional requirements may also be imposed by the CAISO Tariff or by the SCE Interconnection Handbook. For wind generation and photovoltaic solar projects, FERC issued a decision requiring the identification of need for power factor correction, beyond unity power factor.

Table 5.6: CAISO Tariff Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Asynchronous Generator	0.95 lagging to 0.95 leading at the POI if identified in the study
All other Generator Types	0.90 lagging to 0.95 leading at Generator terminals

6. Deliverability Assessment

This assessment is comprised of on-peak and off-peak deliverability assessments for the Phase II projects in the Northern Bulk System. Both SCE and PG&E bulk systems were monitored for any adverse impacts.

6.1 On-Peak Deliverability Assessment

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf). The main steps of the on-peak deliverability assessment are described below.

Master Deliverability Assessment Base Case

A master base case was developed for the on-peak deliverability assessment which modeled all the queued generation projects up to Phase II. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of summer peak net qualified capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of summer peak NQC.
- Energy-only resources are set off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table 4.1.
- Non-pump load is at the 1 in 5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

Northern Bulk Group Deliverability Assessment Base Case

The Northern Bulk group deliverability assessment base case was developed from the master base case by dispatching all proposed full capacity resources in the Northern Bulk System to 80% of the NQC.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater

- Distribution factor (DFAX) = Δ flow on the analyzed facility / Δ output of the generating unit *100%

  or

- Flow impact = DFAX * NQC / Applicable rating of the analyzed facility *100%.

Load flow simulations were performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle were increased starting with units with the largest impact on the transmission facility. No more than twenty units were increased to their maximum output. In addition, no more than 1500 MW of generation was increased. All remaining generation within the Control Area was proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. The Facility Loading Adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders was negative, the impact was set to zero and the flow on the analyzed facility without applying Facility Loading Adders was reported.

6.2 Off-Peak Deliverability Assessment

The assessment was performed following the off-peak Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e46815090.pdf).

One of the critical study assumptions to assess the impact of the QC3 projects in the Northern Bulk System is Path 26 (Midway to Vincent) flow. The off-peak deliverability assessment was performed in coordination with the deliverability assessment for PG&E QC3 projects.

The off-peak deliverability assessment base case modeled proposed generation interconnection projects in both SCE Northern Bulk System and PG&E Fresno and Kern area. The resources were dispatched as follows:

- Wind generation at its maximum nameplate output
- Solar generation at 85% of its nameplate output
- Hydro generation at its high hydro dispatch level for the spring off-peak load period
- Gas fired combustion turbines off-line
- Gas fired combined cycle units at minimum load or off-line
- QF's at historical output for off-peak period
- Imports at average historical schedules for off-peak period

6.3 On-Peak Deliverability Assessment Results

The Phase II projects were not identified to contribute to overloads in the on-peak deliverability assessment.

6.4 Off-Peak Deliverability Assessment Results

A contingency analysis was performed using the off-peak deliverability assessment base case. The table below summarizes the divergence and overloads identified in the off-peak deliverability assessment.

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

Table 6.1: Off-Peak Deliverability Assessment for Northern Bulk System

Contingency	Overloaded Facilities	E-Rating	Flow
	LUGO - VINCENT 500kV No. 2		105.60%
	LUGO - VINCENT 500kV No. 1		105.59%
	WINDHUB 500/230 kV No.2 Transformer		121.67%
	Whirlwind 500/230 kV No. 1 and No. 2 Transformer		115.1%

6.5 Required Network Upgrades

6.5.1 Windhub 500/230kV Transformer Bank T-1 SPS

Two 500/230kV transformer banks are modeled on each side of the Windhub 230kV bus. Under the outage of one transformer bank, the remaining transformer bank is overloaded. Projects that interconnect to Windhub 230kV bus need to participate in the Windhub T-1 SPS that has been triggered by the Transition Cluster.

6.5.2 Whirlwind 500/230kV Transfomer Bank T-1 SPS

Three Whirlwind 500/230kV transformer banks are modeled. Under the outage of one transformer bank, the remaining two transformer banks are overloaded. Projects that interconnect to Whirlwind 230kV bus need to participate in the Whirlwind T-1 SPS that has been triggered by the Transition Cluster.

6.5.3 Replacement of Wavetraps on Lugo – Vincent lines

The Lugo – Vincent 500kV line No. 1 or No. 2 is overloaded when the one of the two lines is lost. To mitigate the overloads, the wavetraps on both Lugo – Vincent 500kV lines need to be replaced to achieve higher emergency rating for the lines.

Because these are low-cost upgrades, they are classified as Reliability Network Upgrades.

6.6 Operational Deliverability Assessment

The tariff allows the Generating Facilities to interconnect as an energy-only resource on an interim-only basis before all the required Delivery Network Upgrades are in service. In the Phase II study, the CAISO performed the operational deliverability assessment to provide information on the interim deliverability for the Phase II projects requesting Full Capacity deliverability status. Such interim and partial deliverability is for information only.

The operational deliverability assessment follows the same on-peak deliverability assessment methodology as described in Section 6. The key components of the operational deliverability assessments are discussed below.

Study Years

The assessment for the Northern Bulk System was performed for 2013 and 2014. All projects requesting Full Capacity deliverability status in the SCE Northern Bulk System are deliverable after 2015 under the study assumptions for the generation and transmission detailed below.

Assumptions for Generation Interconnection Projects

The Phase II projects and generation projects queued ahead of Cluster 1 and Cluster 2 are modeled in the operational deliverability assessment according to the latest Commercial Operation Date (COD) information available. A project is modeled in a study year if the COD of the project is before the summer of the study year. The projects not listed in Table 11.1 have COD later than 2014 summer.

Table 6.2 Generation Projects in SCE Northern Bulk System Modeled in the Operational Deliverability Assessment

Queue Position	PMAX	Point of Interconnection	First Operational Deliverability Study Year
20	300	Whirlwind 230kV	2012
79	51	Windhub 66kV	2012
91	51	Windhub 66kV	2012
95	550	Windhub 230kV	2012
96	600	Windhub 230kV	2012
100	120	Vincent Substation through Sagebrush 230 kV line	2012
WDAT270	33	Little Rock-Wilsona 66 kV	2013
41	157	Pastoria Substation	2013
73	250	Whirlwind 230kV	2013
84	340	Whirlwind 230kV	2013
92	570	Vincent 230kV	2013
93	220	Windhub 230kV	2013
94	180	Highwind 230kV	2013
97	160	Whirlwind 230kV	2013
132	297	Highwind 230kV	2013
153	100	Whirlwind 230kV	2013
297	66	Neenach-Bailey 66kV line	2013
342	50	Del Sur Substation 66kV	2013
585	150	Antelope 230kV	2013
602	150	Whirlwind 230kV	2013
86A	33.1	Vincent Substation	2013
86B	34	Canwind Substation	2013

119	500	Windhub 230kV	2014
348	40	Windhub 66kV	2014
349	100	Windhub 66kV	2014
407	325	Whirlwind 230kV	2014
408	325	Whirlwind 230kV	2014
412	250	Whirlwind 230kV	2014
512	26	Neenach Substation 66kV	2014
513	141	Whirlwind 230kV	2014
WDAT425	60	Vestal 66kV	2014
WDAT433	40	Vestal 66kV	2014

Assumptions for Transmission Upgrades

Transmission upgrades are modeled in the operational deliverability assessment based on their estimated COD. A transmission upgrade is modeled in a study year if the estimated COD is before the summer of the study year. All the required SPSs are assumed to be in-service when the associated generation project is in commercial operation.

Table 6.3 Transmission Upgrades in SCE Northern Bulk System Modeled in the Operational Deliverability Assessment

Transmission Upgrade	First Operational Deliverability Study Year
Windhub No.3 and No.4 500/230 kV Transformer Banks (Segment 9)	2012
Whirlwind 500/230 kV Substation (TRTP Segment 9) with 1 AA-Bank	2012
Antelope-Windhub Operation to 500 kV (TRTP Segment 3C)	2012
Antelope-Whirlwind 500 kV (TRTP Segment 4)	2012
Midway-Vincent 500 kV Loop-In Whirlwind 500 kV (TRTP Segment 9)	2012
Whirlwind-Windhub 500 kV T/L (TRTP Segment 10)	2012
Highwind 230 kV Substation (TRTP Segment 3B)	2013
Windhub-Highwind 230 kV T/L (TRTP Segment 3B)	2013
Antelope 500/230 kV Substation (TRTP Segment 9) with 2 AA-Banks	2013
Antelope-Vincent No.2 Operation to 500 kV (TRTP Segment 3C)	2013
Antelope-Vincent No.1 500 kV (TRTP Segment 5)	2013
Chino-Mira Loma No.3 500 kV Operated at 230 kV (TRTP Segment 8B)	2013
Oasis – Tortoise 66kV line upgrade	2013
Neenach substation upgrade	2013

Mira Loma-Vincent 500 kV (TRTP 6, 7, 8)	2014
Whirlwind No.2 500/230 kV Transformer Bank	2014
East Kern Renewable Wind Area (EKWRA)	2014

Method for Determining Deliverable Partial Capacity

Assuming the system conditions cannot accommodate the full deliverability of all generators in the study area that will be in commercial operation for the study year, the partial deliverability of each generator is determined from the amount of its power output that can be accommodated on a portion of the transmission constraint that is binding in the deliverability power flow. For each generator, the portion of the binding transmission constraint is calculated as a function of the queue position, generator's size and its flow impact on the constraint.

For each deliverability constraint facility, the available capacity without the generation projects being tested is allocated to projects in the order from higher queued projects to lower queued projects until it is depleted. The projects in the same cluster are considered to have the same queue position. If there is available partial capacity for projects in the same cluster, each project's partial deliverability capacity is determined based on the generator's size and its flow impact.

Operational Deliverability Assessment Results

No deliverability constraint was identified in the operational deliverability assessment for SCE Northern Bulk System under the study assumptions described above.

7. Steady State Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis and **reactive power deficiency analysis** were performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004, as well as other NERC/WECC reliability standards, with the proposed interconnection. The results of these analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. The reactive power deficiency analysis also determines whether the asynchronous facilities proposed by the interconnection projects are required to provide 0.95 leading/lagging power factor at the Point of Interconnection.

The study results for this Phase II study will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from neighboring entities is solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that Phase II projects can operate at maximum rated output 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in the Phase II Study.

The following power flow base cases were used for the analysis in the Phase II Study:

- **Summer Peak Full Loop Base Case:**

  Power flow analyses were performed using SCE's summer peak full loop base case (in General Electric Power Flow format). This base case was developed from base cases that were used in the SCE annual transmission expansion plan studies. It has a 1-in-10 year adverse weather load level for the SCE service territory.

- **Off-Peak Full Loop Base Case:**

  Power flow analyses were also performed using the off-peak full loop base case in order to evaluate system performance due to the addition of Phase II generation projects during light load conditions. The off-peak load was modeled at about 65% of the 1-in-5 summer load level.

The base cases modeled all CAISO approved SCE transmission projects. The base cases also modeled all proposed generation projects that were higher queued than the generation projects included in this Phase II study. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery.

The power flow study included a bulk system power flow analysis, which modeled all Phase II projects in the Northern Bulk System with plans of service as originally requested, but without any network upgrades identified in the Phase I Study. This power flow study, discussed in Section 7.1 and Section 7.2 below, was used to identify potential impacts on SCE's 220 and 500 kV system. The subtransmission power flow analysis, which modeled all Phase II projects connecting to the Antelope-Bailey 66 kV system, was performed to focus on the 66 kV subtransmission impacts associated with a subgroup of the 36 projects. This power flow study is discussed in Section 7.3 and 7.4. Section 7.3 provides the study conclusions associated with inclusion of the projects but without any upgrades beyond the method of service facilities needed to interconnect the project. Section 7.4 provides the study conclusions after inclusion of the facility upgrades identified as part of the initial study.

7.1 Bulk System Steady State Study

The study modeled all Phase II generation projects and did not model any transmission network upgrades apart from serial project upgrades, and transition cluster upgrades. This assessment was intended to identify changes in the deliverability or reliability network upgrade requirements between Phase I and Phase II. The assessment was also intended to help identify problems in the plan of service requested by developers in the Phase II Study that would require modifications to the customer requested plans of service or points of interconnection.

7.1.1 South of Vincent Flow Limit (8,500 MW)

Previous cluster studies have identified severe VAR deficiencies and power flow non-convergence issues in the Northern Bulk System. These studies concluded that these issues were due to excessive power flows “South of Vincent”. For this study, South of Vincent is defined as the following three 500-kV and six 220-kV lines:

- Vincent-Mira Loma 500 kV (part of TRTP with estimated COD of 2015)
- Lugo-Vincent No.1 & No. 2 500 kV
- Rio Hondo-Vincent No. 1 & No. 2 220 kV
- Mesa-Vincent No. 1 & No. 2 220 kV
- Pardee-Sylmar No.1 & No. 2 220 kV

These nine transmission lines take generation from the Northern Bulk System and the Ventura area and imports from PG&E via Path 26 and deliver them to load centers in the Los Angeles basin.

Previous cluster studies have found that existing South of Vincent facilities can support approximately 8,500 MW based on the most critical credible contingency limitation. This limit was assumed as a base case power flow constraint in the steady state analysis.

7.1.2 Higher Queued Project Generation Dispatch Assumptions

Not counting Phase II projects, there is approximately 12,700 MW of existing generation and active pre-Phase II projects in the Northern Bulk System. Subtracting local area loads (5,138 MW in summer peak and 3,149 MW in off-peak), this yields a pre-Phase II Northern Bulk System theoretical export potential of approximately 7,560 MW in summer peak and 9,550 MW in off-peak. The off-peak value exceeds the 8,500 MW South of Vincent limit. To maintain less than 8,500 MW of South of Vincent flows, part of the queued generation interconnection requests in the Northern Bulk System was dispatched northbound on Path 26.

7.1.3 Phase II Project Generation Dispatch Assumptions

The study dispatched all 1,738 MW of Phase II projects in a manner that continued to maintain South of Vincent flows at 8,500 MW. In other words, all Northern Bulk System Phase II projects were dispatched north via Path 26 in the study.

7.1.4 Power Flow Results (Category "A", "B" and "C")

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)	Post-Project Loading (Amps / %Rating)	% Change from Pre-Project Loading	Comment
Category B (N-1) Overloads – Peak					
Windhub AA-Bank Transformers		100%		15%	
Whirlwind AA-Bank Transformers		109%		24%	
Antelope-Windhub 500 kV T/L		90%	Non-Convergence		
Whirwind-Winhub 500 kV T/L		89%		13%	
Vincent-Whirlwind 500 kV T/L		106%	Non-Convergence		
Bailey-Pardee 220 kV T/L		153%		24%	
Pardee-Pastoria-Warne 220 kV T/L		193%		16%	
Non-Convergence					
Non-Convergence					

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)		Post-Project Loading (Amps / %Rating)		% Change from Pre-Project Loading	Comment
Category B (N-1) Overloads – Off Peak							
Windhub AA-Bank Transformers			99%			17%	
Whirlwind AA-Bank Transformers			109%			24%	
Antelope-Windhub 500 kV T/L			91%	Non-Convergence			
Whirwind-Winhub 500 kV T/L			89.7%	Non-Convergence			
Category C (N-2) Overloads – Off Peak							
Vincent-Whirlwind 500 kV T/L			106%	Non-Convergence			
Bailey-Pardee 220 kV T/L			153%			24%	
Pardee-Pastoria-Warne 220 kV T/L			193%			16%	
Non-Convergence							
Non-Convergence							

7.2 Bulk System Steady State Study Conclusions

Based on the findings of the steady state study, the following conclusions were reached.

7.2.1 Reactive Power Deficiency Analysis

The contingency analysis identified power flow non-convergence issues under several 500 kV N-1 and N-2 contingency conditions, as shown in Section 7.1.4 above. The non-convergence issues are associated with the excessive power flows that lack necessary reactive support from the asynchronous generation projects seeking interconnection in this area.

The net generation in the Windhub area is exported through two 500 kV lines out of Windhub substation. Under the outage of one of the lines, the system is not capable of exporting all the generation via the remaining line without sufficient reactive support. With all projects in the Windhub area, including those interconnecting to the Windhub 66 kV subtransmission system, providing necessary reactive capability, the reactive deficiency problem can be mitigated by tripping generation that is directly interconnecting to the Windhub 220 kV bus.

All the N-2 non-convergence problems identified in this study are caused by high area generation export south of Antelope and south of Vincent. With all the projects in the

Northern Bulk System, including those interconnecting to the Antelope-Bailey 66 kV subtransmission system, providing necessary reactive capability, the reactive deficiency problems can be mitigated by tripping generation and maintaining an 8,500 MW South of Vincent flow.

Therefore, all Phase II projects in the Northern Bulk System are required to provide reactive capability in consistence with the tariff requirement. In particular, the asynchronous facilities must provide 0.95 leading/lagging power factor at the POI.

The study concluded that all asynchronous generating facilities in the Northern Bulk System are required to provide 0.95 leading/lagging power factor at the Point of Interconnection.

7.2.2 "Northern Bulk System Area Export" Limits

The Northern Bulk System area export limits are defined by the 3,000 MW northbound flow limit on Path 26 and the 8,500 MW South of Vincent area export limit. The power flow study concluded that the Northern Bulk System Phase II projects will not trigger the need for additional area export facilities beyond this 11,500 MW total.

To maintain 8,500 MW or less of "South of Vincent" flow levels may require a significant amount of curtailment or re-dispatch of existing generation, queued generation, or southbound flow on Path 26, due to the amount of existing generation and queued generation projects in the Northern Bulk System.

Northern Bulk System Phase II generation projects must displace existing local area generation, other higher queued local area generation, and/or SCE-area imports via Path 26 to maintain within the "South of Vincent" 8,500 MW capability.

Note that no area export Delivery Network Upgrades were identified in the Deliverability Assessment performed for the Phase II, based on the existing Deliverability Assessment methodology which assumes no energy-only projects dispatched and a high coincidence offset for wind and solar projects. Such results imply that:

- Congestion management is inherently a viable means of addressing the severe area export problems identified in this study;
- Phase II generation output needs to be scheduled exclusively north (i.e. to PG&E) in the Phase II Study in off-peak conditions; and

The CAISO will need to develop appropriate operating procedures to ensure safe and reliable transmission system operation should real-time conditions demonstrate that the above assumptions are inconsistent with operational reality. Such procedures could involve the physical curtailment of local area generation, including these Phase II interconnection projects. If such procedures are ultimately found to be unworkable, additional facility upgrades to increase area export capability may ultimately be required. Furthermore, if it is economically justifiable or required to achieve the

California state Renewable Portfolio Standard (RPS) goal, then the upgrade will be included in the CAISO Transmission Plan.

7.2.3 Windhub AA-Bank Transformer Overloads

The study identified to need to expand the previously proposed SPS to include the Phase II projects interconnecting to the Windhub 220 kV bus to address the identified Windhub AA-Bank transformer bank overloads.

The study concluded that an SPS to trip Windhub area generation is required to mitigate N-1 overloads on the Windhub AA-bank transformers.

Note: It was identified that the STC projects interconnecting to the Windhub 66 kV system increased the flow on the Windhub AA-Banks but would not need to take part in this SPS.

7.2.4 Whirlwind AA-Bank Transformer Overloads

The QC2 Phase I study had previously identified the need for a fourth Whirlwind AA-bank transformer. At the time of the Phase I study, the need was identified based on the need to sectionalize the Whirlwind 220 kV bus to mitigate short circuit duty levels in excess of 63 kA and Whirlwind Substation line and bus configuration constraints. The sectionalization and line and bus configuration constraints resulted in overloads on the section connected with only one Whirlwind AA-bank.

The aggregate MW loading on the three Whirlwind AA-banks has not decreased between the Phase I and Phase II studies, and the line and bus configuration constraints at Whirlwind have likewise not changed. However, numerous project withdrawals (not directly at Whirlwind) resulted in a reduction of SCD thereby deferring the need to sectionalize the Whirlwind 220 kV bus to projects beyond QC1 and QC2.

As a result, the Phase II study has found that Whirlwind Substation can operate with three AA-bank transformers in parallel without exceeding 63 KA design limits. This eliminates the Whirlwind AA-bank base case overloads previously identified in the Phase I studies, but does not eliminate the Whirlwind AA-bank N-1 overload issues. Expanding the previously proposed SPS to include the Phase II projects interconnecting to the Whirlwind 220 kV bus was sufficient to address Whirlwind AA-Bank transformer overloads under N-1 conditions.

The study concluded that an SPS to trip Whirlwind area generation is required to mitigate N-1 overloads on the three Whirlwind AA-bank transformers.

7.2.5 Northern Area 500 kV SPS

The power flow study found significant system VAR requirements and convergence problems under various N-1 and N-2 outage combinations among North of Vincent 500 kV lines. A Northern Area 500 kV SPS that trips the Phase II projects would help improve system performance under these outage conditions.

The study concluded that an SPS to trip the Northern Bulk System area generation is required to mitigate the identified N-2 problems.

7.2.6 Lugo – Vincent Overloads

The power flow study results summarized in Section 7.1.4 above did not identify N-1 overloads on the Lugo-Vincent 500 kV transmission lines. However, N-1 overloads on these lines were identified through the CAISO deliverability study methodology as described in Section 6 of this report.

Based on the study results in Section 6 of this report, ***the study concluded that upgrades to the existing 3,000 A wavetraps on the existing Lugo-Vincent 500 kV lines is required for the Northern Bulk System Phase II projects.***

7.2.7 Whirlwind-Windhub 500 kV or Antelope-Windhub 500 kV Line Outage Issues (system resource needs)

There is an operational risk associated with N-1 outages of 500 kV lines at Windhub. As these two lines are non-common corridor, simultaneous outage of both lines is not a credible N-2 contingency event for planning purposes. However, loss of these two lines is a Category "C" N-1-1 contingency event, where the reliability criteria allow for manual system adjustments between contingencies (see Table I in NERC TPL-002-0).

With the interconnection of Phase II generation projects at Windhub, the substation will connect up to 3,800 MW of generation resources with only two lines of service. Upon any extended outage of one 500 kV line serving Windhub, system reserve requirements may substantially change due to the risk of generation loss at Windhub under the next N-1 outage. Therefore, CAISO system operators may need to turn off up to ~2,800 MW of resources at Windhub in real-time in anticipation of the next contingency. The CAISO will need to develop and implement operating procedures to curtail generation level to a value equivalent to its Most Severe Single Contingency (MSSC) following the loss of one of the 500 kV lines connecting to the Windhub substation. Also, it is expected that the CAISO market system should be able to replace the "expected curtailment of renewable" generation capacity with conventional resources in sufficient time to maintain reliability and compliance with operating requirements.

7.2.8 South of Pastoria 220 kV Line Overloads

The power flow study found base-case and contingency overloads on the South of Pastoria 220 kV lines, which are protected in today's existing system by the PEF SPS. The most problematic overloads were observed on the existing Pardee-Pastoria-Warne 220 kV line. This line was the only south of Pastoria 220 kV line not upgraded as part of the "South of Pastoria Reconductor Project" completed in 2005. This project reconductored the former Pardee-Pastoria, Bailey-Pardee, and Bailey-Pastoria 220 kV lines from 605 ACSR to 666 ACSS/TW which has comparable physical properties but better sag performance. The Pardee-Pastoria-Warne line was not reconductored at that time because at the time its higher rating (1033 ACSR) was sufficient to meet system needs. The CAISO reviewed the increased loading on this line and has concluded that the base-case and contingency overloads can be mitigated by congestion management and the PEF SPS.

On the basis of the conclusions as stated above, ***no Network Upgrades are required for mitigation of Pardee-Pastoria-Warne 220 kV line overloads identified as part of the Phase II Study***. Use of congestion management is identified as the plan for mitigation of these overloads.

7.3 Subtransmission System Power Flow Study

7.3.1 Previously Triggered Windhub No.3 A-Bank

It is important to note that queued ahead projects have identified the need and have been allocated the cost for the installation of the third Windhub A-Bank (expected to be classified as a Distribution Upgrade). However, withdrawals or changes to the queued ahead projects may result in assigning such cost to the Phase II projects on the northern (Windhub area) portion of the Antelope-Bailey 66 kV subtransmission system.

7.3.2 Classification of Upgrades Triggered by Phase II

The EKWRA project will result in operating portions of the existing Antelope-Bailey 66 kV system as radial systems. As a result, 66 kV facilities identified in this report may ultimately be classified as Distribution Upgrades not subject to cost cap. The ultimate determination of facility classification is outside the scope of the Phase II Study. For the purpose of this study, cost estimates were provided assuming Network Upgrades classification.

7.3.3 Modeling and Dispatch Assumptions

A total of 64 projects, including higher queued and the 28 SGIP Transition Cluster generation projects that are part of this Phase II, are requesting interconnection to the 66 kV Subtransmission system these 64 projects total 1,499.5 MW and impact this Subtransmission system. All of the projects were fully dispatched to evaluate the adequacy of the 66 kV Subtransmission system.

Table 7.3.1 below provides the load assumptions used at all of the 66 kV substations internal to the Antelope-Bailey 66 kV system.

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

TABLE 7.3.1— Antelope-Bailey 66 kV Load Assumptions

Bus Name	Summer		Off-Peak	
	P Load	Q Load	P Load	Q Load
Northern 66 kV Portion				
Breeze	26.1	0.0	26.1	0.0
Cal Cement	11.6	13.6	11.6	13.6
Corrections	4.0	2.4	4.0	2.4
Corum	2.4	0.0	1.4	0.0
Cummings	18.4	0.0	10.6	0.0
Goldtown	9.5	0.0	5.5	0.0
Havilah	0.7	0.0	0.4	0.0
Loraine	1.6	0.0	0.9	0.0
Monolith	16.6	0.0	9.6	0.0
Northwind	9.1	0.0	5.3	0.0
Walker Basin	0.3	0.0	0.2	0.0
Total Northern	100.3	16.0	75.6	16.0
Southern 66 kV Portion				
Acton	17.4	0.0	10.1	0.0
Anaverde	58.2	0.0	33.7	0.0
Bailey	0.0	0.0	0.0	0.0
Del Sur	20.3	0.0	11.7	0.0
Frazier Park	9.4	0.0	5.4	0.0
Great Lakes	7.0	0.0	4.1	0.0
Gorman	3.0	0.0	1.7	0.0
Helijet	19.0	9.7	19.0	9.7
Lancaster	77.0	0.0	44.6	0.0
Lanpri	4.5	2.6	4.5	2.6
Little Rock	25.5	0.0	14.7	0.0
Neenach	6.3	0.0	3.6	0.0
Oasis	49.8	0.0	28.8	0.0
Palmdale	78.7	0.0	45.6	0.0
Piute	6.9	0.0	4.0	0.0
Purify	11.1	6.0	11.1	6.0
Quartz Hill	51.6	0.0	29.9	0.0
Redman	4.5	0.0	2.6	0.0
Rite Aid	2.5	1.4	2.5	1.4
Ritter Ranch	9.6	0.0	5.6	0.0
Rockair	9.0	0.8	9.0	0.8
Rosamond	17.7	0.0	10.2	0.0
Shuttle	89.2	0.0	51.6	0.0
Tortoise	11.0	6.3	11.0	6.3
Westpac	22.4	10.1	22.4	10.1
Wilsona	5.0	0.0	2.9	0.0
Total Southern	616.6	36.9	390.3	36.9

7.3.4 Subtransmission System Power Flow Results (Category "A", "B" and "C")

Based on the assumptions listed above, the power flow analysis results for summer peak and off-peak conditions are shown in Table 7-3-2 and Table 7-3-3 below.

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

Table 7-3-2: Summer Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)		Post-Project Loading (Amps / %Rating)		% Change from Pre-Project Loading	Comment
Northern System – Category A (N-0) Overloads							
Correction-Q522C/Q653BA L/P			41%		112%	71%	
Windhub-TAP 22			59%		120%	61%	
Southern System – Category A (N-0) Overloads							
Little Rock Leg of Helijet-Palmdale-Rockair-Littlerock 66 kV Line			84%		144%	60%	
Portion of the Little Rock Leg of Lancaster-Little Rock-Piute 66 kV Line			50%		110%	60%	
Lancaster Leg of the Lancaster-Little Rock-Piute 66 kV Line			37%		110%	74%	
Lancaster Leg of the Lancaster-Purify-Redman 66 kV Line			34%		167%	134%	
Antelope – Q657A 66 kV line			84%		108%	24%	
Northern System – Category B (N-1) Overloads With Base Case Mitigation Implemented (Pre-Project results did not dispatch Phase II Projects)							
Rosamond-Q614A			16%		173%	157%	
Southern System – Category B (N-1) Overloads With Base Case Mitigation Implemented (Pre-Project results did not dispatch Phase II Projects)							
Bailey leg of Bailey-Neenach-Westpac			62%		109%	47%	
Neenach leg of Bailey-Neenach-Westpac			84%		132%	48%	
Portion of Antelope-Neenach			80%		107%	27%	
Portion of Antelope-Neenach			80%		127%	47%	
Lancaster leg of Lancaster-Little Rock-Piute			45%		103%	57%	
Piute leg of Lancaster-Little Rock-Piute			50%		165%	114%	
Portion of Piute-Redman			60%		144%	83%	
Portion of Lancaster-Purify-Redman			65%		119%	54%	
Portion of Little Rock leg of Lancaster-Little Rock-Piute			56%		113%	58%	

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

Table 7-3-3: Off-Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)		Post-Project Loading (Amps / %Rating)		% Change from Pre-Project Loading	Comment
Northern System – Category A (N-0) Overloads							
Correction-Q522C/Q653BA L/P			41%		108%	67%	
Windhub-TAP 22			67%		128%	61%	
Southern System – Category A (N-0) Overloads							
Little Rock Leg of Helijet-Palmdale-Rockair-Littlerock 66 kV Line			92%		152%	60%	
Lancaster Leg of the Lancaster-Little Rock-Piute 66 kV Line			54%		128%	74%	
Lancaster Leg of the Lancaster-Purify-Redman 66 kV Line			48%		181%	133%	
Antelope – Q657A 66 kV line			85%		105%	20%	
Northern System – Category B (N-1) Overloads With Base Case Mitigation Implemented (Pre-Project results did not dispatch Phase II Projects)							
Rosamond-Q614A			7%		183%	174%	
Southern System – Category B (N-1) Overloads With Base Case Mitigation Implemented (Pre-Project results did not dispatch Phase II Projects)							
Bailey leg of Bailey-Neenach-Westpac			66%		113%	47%	
Neenach leg of Bailey-Neenach-Westpac			87%		135%	48%	
Portion of Antelope-Neenach			83%		109%	26%	
Portion of Antelope-Neenach			83%		128%	46%	
Lancaster leg of Lancaster-Little Rock-Piute			34%		102%	68%	
Lancaster leg of Lancaster-Little Rock-Piute			57%		113%	56%	
Piute leg of Lancaster-Little Rock-Piute			57%		174%	116%	
Portion of Piute-Redman			63%		148%	85%	
Portion of Lancaster-Purify-Redman			72%		126%	54%	
Portion of Little Rock leg of Lancaster-Little Rock-Piute			74%		130%	56%	

7.3.5 Subtransmission Voltage Performance Results

The study identified a voltage rise problem under specific outage conditions. As shown below in Table 7-3-4, this problem would result in a voltage level that may be in excess of the equipment design limits.

CEII information has been redacted pursuant to 18 CFR Sec. 388.112

Table 7-3-4
Voltage Performance Results

Outage	Bus	Base Case Voltage		Post-Cont. Voltage		Voltage Rise	
		W/O Upgrade	W/ Upgrade	W/O Upgrade	W/ Upgrade	W/O Upgrade	W/ Upgrade
Lancaster-Collector 66 kV	Purify	1.022	1.025	1.037	**1.096**	0.015	0.071
	Collector	1.025	1.028	1.040	**1.099**	0.015	0.071
Helijet-Little Rock-Palmdale-Rock Air 66 kV	LittleRock	1.047	1.038	1.095	1.078	0.048	0.040
	Wilsona	1.059	1.050	1.107	**1.090**	0.048	0.040
	WDT270	1.061	1.052	1.109	**1.092**	0.048	0.040
	WDT404	1.052	1.043	1.100	1.083	0.048	0.040
Antelope-Q628 66 kV	Q628	1.027	1.030	1.048	**1.123**	0.021	0.093
	Q649C	1.030	1.039	1.047	**1.118**	0.017	0.079
	Q640	1.039	1.055	1.046	1.085	0.007	0.030
	Q614A	1.040	1.071	1.044	**1.095**	0.004	0.024
	Rosamond	1.039	1.053	1.043	1.077	0.004	0.024
	Great Lakes	1.049	1.063	1.044	1.078	-0.005	0.015
Antelope-Q661 66 kV	Q649C	1.030	1.039	1.031	1.057	0.001	0.018
	Q640	1.039	1.055	1.044	1.082	0.005	0.027
	Q614A	1.040	1.071	1.045	**1.100**	0.005	0.029
	Rosamond	1.039	1.053	1.044	1.082	0.005	0.029
	Great Lakes	1.049	1.063	1.045	1.083	-0.004	0.020

Note: Voltages in excess of 1.09 may exceed equipment design limits.

7.4 Subtransmission System Study Conclusions

Based on the findings of the Subtransmission steady state study, the following conclusions were reached.

7.4.1 Reactive Power Deficiency Analysis

In addition to the reactive power deficiencies shown in Section 7.2, the contingency analysis identified multiple voltage regulation issues under specific 66 kV N-1 and N-2 contingency conditions shown in Section 7.3 above. To maintain voltage that is safe to the equipment, the Phase II projects interconnecting in the eastern portion of the Antelope-Bailey 66 kV subtransmission system must provide power factor regulation at POI.

7.4.2 Windhub Area Upgrade

Based on the study findings, the inclusion of projects on the northern portion of the Antelope-Bailey 66 kV subtransmission system resulted in base case and contingency overloads on the following facilities:

- Windhub 220/66 kV Transformer Banks (A-Banks)
- Portion of Correction-Cummings-Kern River 1 66 kV line
- Portions of Windhub-Goldtown-Monolith-Windlands 66 kV line

Phase II projects seeking interconnection on the northern portion of the Antelope-Bailey 66 kV subtransmission system will need to participate in mitigation upgrades to address the problems identified. To address the identified problems, the following upgrades are proposed:

- Reconductor Correction-Cummings-Kern River 1 66 kV line segment
- Reconfigure Windhub-Goldtown-Monolith-Windlands 66 kV line creating new Windhub-Goldtown-Morwind and new Windhub-Midwind-Monolith 66 kV line
- Construct new 66 kV line from the Goldtown area to Windhub

7.4.3 Antelope East Area Upgrade

Based on the study findings, the inclusion of projects on the eastern portion of the Antelope-Bailey 66 kV subtransmission system resulted in base case and contingency overloads on the following facilities:

- Lancaster-Purify-Redman 66 kV line
- Piute-Redman 66 kV line
- Lancaster-Little Rock-Piute 66 kV line
- Helijet-Little Rock-Palmdale-Rock Air 66 kV line

The Northern Area Phase II projects that increase power flows on these facilities drive the need for additional capacity. To provide such additional capacity, the following upgrades are proposed:

- Removal of relay limitations to allow full utilization of the Piute – Redman 66 kV Line
- Install a new 66 kV line of approximately 11-miles from Oasis to Piute area
- Reconductor line segments, where necessary (See Section 11)

It is important to note that the completion of the EKWRA project will result in operating this portion of the system as a radial distribution system. As a result, the mitigation identified above may end up being classified as distribution. The ultimate determination of facility classification is outside the scope of the Phase II Study. For purpose of this study, cost estimates were provided assuming Network Upgrades classification.

7.4.4 Antelope West Area Upgrade

Based on the study findings, the inclusion of projects on the western portion of the 66 kV subtransmission system resulted in base case and contingency overloads on the following facilities:

- Bailey-Neenach-Westpac 66 kV line
- Antelope-Neenach 66 kV line

The Northern Area Phase II projects that increase power flows on these facilities drive the need for mitigation. To provide such mitigation, it is recommended that the Bailey-Neenach portion of the Bailey-Neenach-Wespac 66 kV line be reconstructed and that the Antelope-Neenach 66 kV line be operated as normally open at Neenach. This would result in breaking the system parallel between Antelope and Bailey and serving Neenach radial from Bailey. It is important to note that the mitigation may result in reclassifying these upgrades as distribution. The ultimate determination of facility classification is outside the scope of the Phase II Study. For purpose of this study, cost estimates were provided assuming Network Upgrades classification.

8. Short-Circuit Duty Assessment

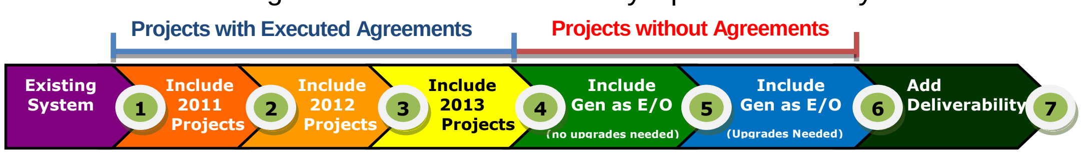
8.1 Application Queue Analysis

Application queue short circuit duty (SCD) studies were performed to determine the impact on circuit breakers with the interconnection of Phase II projects to the transmission system. The application queue considered all existing and higher queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the Phase II projects. In addition, the application queue included all CAISO approved transmission projects and all SCE approved non-CAISO upgrades into the starting base case as a pre-condition prior to adding the Phase II projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the Phase II projects to establish the starting base line. The Phase II projects including the identified Reliability and Delivery Network Upgrades from the power flow and stability analysis were then added and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the Phase II projects. The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in the Phase II study pro rata on the basis of SCD contribution of each proposed Generating Facility. In addition, trhe SCD impact of the associated Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade. The pro rata contribution corresponding to each Phase II project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A).

8.2 Operational Analysis

The Operational short-circuit duty studies were performed to identify timing of need for short-circuit duty mitigations. The operational study considered seven different scenarios as shown below in Figure 8.2.1. These scenarios were selected as the most appropriate operational study conditions.

Figure 8.2.1 – Short Circuit Duty Operational Study



8.2.1 Projects with Executed Agreements

Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated for the existing system condition to establish the starting operational base line conditions. Generation projects with an active executed agreement (LGIA, SGIA, or Letter Agreement) were then added for years 2011, 2012 and 2013. In addition, transmission upgrades already permitted which are under construction or scheduled to be in-service by the end of 2013 were included into these operational studies. The list of new generation projects with executed agreements are summarized below in Table 8.2.1, Table 8.2.2 and Table 8.2.3 for years 2011, 2012, and 2013 respectively and the list of transmission upgrades scheduled to be in-service by the end of 2013 is summarized below in Table 8.2.4.

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Table 8.2.1
Generation Projects with Executed Agreement Expected to be In-Service in End of 2011

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
WDAT	WDT042	01/07/00	Devers-Banning-Windpark 115 kV line	40
WDAT	WDT213	11/02/05	Garnett-Banning-Windfarm 115 kV line	49
95	TOT162	03/01/06	Windhub 230 kV	150[7]
96	TOT163	03/01/06	Windhub 230 kV	150[8]
WDAT	WDT323	12/16/08	Cottonwood 33 kV (Victor System)	20

Table 8.2.2
Generation Projects with Executed Agreement Expected to be In-Service in End 2012

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
7	TOT041	10/06/00	El Segundo 230 kV	630
66	TOT135	05/06/05	Walnut 230 kV	500.5
20	TOT108	09/04/03	Whirlwind 230 kV	300
73	TOT148	06/27/05	Whirlwind 230 kV	250
79	TOT146	09/07/05	Windhub 66 kV	51
91	TOT153	02/22/06	Windhub 66 kV	51
95	TOT162	03/01/06	Windhub 230 kV	130[9]
131	TOT180	09/25/06	Ivanpah 115 kV	100
132	TOT179	09/27/06	Highwind 230 kV	297
WDAT	WDT240	10/19/06	Brea 66 kV (Olinda System)	25
WDAT	WDT273	03/26/08	Saugus 66 kV System	20
WDAT	WDT268	04/02/08	Brea 66 kV (Olinda System)	9
297	TOT278	07/31/08	Neenach 66 kV	66
412	TOT345	07/31/08	Whirlwind 230 kV	125[10]

Table 8.2.3
Generation Projects with Executed Agreement Expected to be In-Service by End 2013

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
3	TOT032	06/14/00	Devers 230 kV (Sentinel Project)	850
93	TOT161	03/01/06	Windhub 230 kV	220
100	TOT167	04/17/06	Vincent 230 kV (via Sagebrush Gen-Tie)	120
119	TOT173	08/08/06	Windhub 230 kV	500
125	TOT175	08/22/06	Water Valley 230 kV	250
135	TOT183	10/10/06	Jasper 230 kV (Looping Lugo-Pisgah No.2)	60
146	TOT198	11/16/06	New Red Bluff 230 kV	150
147	TOT199	11/16/06	New Red Bluff 230 kV	400
162	TOT210	01/05/07	Ivanpah 115 kV	114
233	TOT242	06/27/07	Ivanpah 115 kV	200
188	TOT219	07/31/08	Windhub 230 kV	200
294	TOT276	07/31/08	Colorado River 230 kV	500[11]
365	TOT321	07/31/08	Red Bluff 230 kV	500
412	TOT345	07/31/08	Whirlwind 230 kV	125

[7] This figure reflects partial interconnection of 150 MW in 2011 for a total of 420 MW by end of 2011.
[8] This figure reflects interconnection the balance of 150 MW in 2011 for a total project of 600 MW by end of 2011.
[9] This figure reflects interconnection of balance of 130 MW in 2012 for a total project of 550 MW in 2012.
[10] This figure reflects partial interconnection of 125 MW in 2012.
[11] This figure reflects partial 500 MW interconnection (1,000 MW Project) in 2013

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Table 8.2.4
Transmission Upgrades with a Well Defined In-Service Date Prior to End of 2013

System Upgrade	OD
Acton 66 kV Loop-In	2011
Chino-Mira Loma No.1 and No.2 230 kV (Segment 8C)	2011
Devers-Mirage 115 kV System Split	2012
Mirage No.3 230/115 kV Transformer Bank (third bank)	2012
Devers-Coachella 230kV Loop into Mirage	2012
Highwind 230 kV Substation (TRTP Segment 3B)	2012
Windhub-Highwind 230 kV T/L (TRTP Segment 3B)	2012
Antelope 500/230 kV Substation (TRTP Segment 9) with 2 AA-Banks	2012
Windhub No.3 and No.4 500/230 kV Transformer Banks (Segment 9)	2012
Whirlwind 500/230 kV Substation (TRTP Segment 9) with 1 AA-Bank	2012
Antelope-Vincent No.2 Operation to 500 kV (TRTP Segment 3C)	2012
Antelope-Windhub Operation to 500 kV (TRTP Segment 3C)	2012
Antelope-Whirlwind 500 kV (TRTP Segment 4)	2012
Antelope-Vincent No.1 500 kV (TRTP Segment 5)	2012
Midway-Vincent 500 kV Loop-In Whirlwind 500 kV (TRTP Segment 9)	2012
Whirlwind-Windhub 500 kV T/L (TRTP Segment 10)	2012
Victor No.3 230/115 kV Bank and Bus Rebuild	2012
Victor-Savage No.3 115 kV Line	2012
New Eldorado-Merchant No.2 with Merchant Tie CBs Operated as Normally Open	2012
Chino-Mira Loma No.3 500 kV Operated at 230 kV (Segment 8B)	2013
Colorado River 500/230 kV Substation with one AA-Bank	2013
Devers-Colorado River 500 kV	2013
Devers-Valley No.2 500 kV	2013
Eldorado-Ivanpah 230 kV	2013
Ivanpah 230 kV Substation with two A-Banks	2013
Rio Hondo-Vincent No.2 220 kV Replacement (TRTP 6, 7)	2013
Red Bluff 500/230 kV Substation with one AA-Bank	2013
Saugus No.3 220/66 kV Transformer Bank	2013

8.2.2 Projects without Executed Agreements Assumed To Be Interconnected as Energy Only Without Transmission Upgrades

In order to provide a preview of additional circuit breaker upgrade or replacement requirements that could materialize as more and more generation projects are interconnected, the operational study considered the inclusion of all other generation projects that do not yet have an executed agreement in place assuming they could be interconnected as Energy Only resource before the required Delivery Network Upgrades are in service. This excludes generation projects that require transmission upgrades beyond the method of service and telecomm needed to support the Energy Only interconnection. These projects were added to the 2013 operational study scenario. While the interconnection customers may be requesting an earlier in-service dates, this operational study method will define all of the circuit breaker upgrades and/or replacements needed to interconnect every single generation project that can be interconnected as Energy Only without any additional transmission upgrades beyond the method of service and telecomm needed to support the Energy Only interconnection.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection and simply assumed such facilities would be in place. The objective of this Operational Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements could materialize as interconnection agreements are executed so that resource requirements could be identified in order to enable interconnection of any generation project which does not yet have an executed interconnection agreement. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes. Consequently, the study performed grouped these projects together with all other projects which do not yet have an active interconnection agreement. The list of the generation projects modeled in this operational study scenario is summarized below in Table 8.2.5.

Table 8.2.5
Generation Project without an Executed Agreement That Can Be Interconnected as Energy Only without Additional Transmission Upgrades

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
WDAT	WDT011	03/23/98	Renwind 12 kV (Out of Devers System)	9
WDAT	WDT016	07/09/98	Garnet 33 kV (Out of Devers System)	11.57
1	TOT022	09/30/98	Buckwind 115 kV (Out of Devers System)	16.5
N/A	TOT023	01/22/99	Buckwind 115 kV (Out of Devers System)	2.4[12]
17	TOT079	04/22/03	Colorado River 500 kV	520
49	TOT120	12/14/04	Devers 115 kV	100.5
58	TOT127	02/22/05	Control 115 kV	62
WDAT	WDT179	03/18/05	Colton-Bloomington 66 kV Line	49.9
WDAT	WDT182	05/06/05	Valley 115 kV	507.5

[12] 2.4 MW (Solar) of the total 3.82 MW Interconnection Request requires Agreement Amendment

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68	TOT131	05/11/05	Pisgah 230 kV	575[13]
72	TOT132	06/16/05	Alberhill 500 kV (Previously Lee Lake)	500
WDAT	WDT190	06/17/05	Tap into 66kV line into Browning Substation	49.9
41	TOT119	11/18/04	Pastoria 230 kV	158.8
84	TOT151	12/01/05	Whirlwind 230 kV	340
219	TOT237	05/23/07	Colorado River 500 kV	50
240	TOT250	07/12/07	Pisgah 230 kV	400
241	TOT245	07/12/07	Pisgah 230 kV	400
WDAT	WDT292	04/10/08	Irvine Substation (Out of Santiago System)	19.6
WDAT	WDT314	06/30/08	Pan Aero 115 kV	20
154	TOT203	07/31/08	Windhub 230 kV	250
163	TOT211	07/31/08	Ivanpah 230 kV	300
175	TOT215	07/31/08	Whirlwind 230 kV	650
193	TOT233	07/31/08	Colorado River 230 kV	500
205	TOT226	07/31/08	Eldorado 230 kV	300
294	TOT276	07/31/08	Colorado River 230 kV	500[14]
342	TOT307	07/31/08	Del Sur 66 kV	50
383	TOT327	07/31/08	Arco-Hinson 230 kV	85
407	TOT340	07/31/08	Whirlwind 230 kV	325
408	TOT341	07/31/08	Whirlwind 230 kV	325
409	TOT342	07/31/08	Highwind 230 kV	150
421	TOT349	07/31/08	Blythe-Eagle Mountain 161 kV T/L	49.5
467	TOT381	07/31/08	Primm 230 kV (Loop Eldorado-Ivanpah)	230
WDAT	WDT285	07/31/08	Cottonwood-Savage 115 kV	100
WDAT	WDT286	07/31/08	Victor-Phelan 115 kV	150
WDAT	WDT270	07/31/08	Little Rock-Wilsona 66 kV	33
WDAT	WDT315	07/31/08	Casa Diablo 115 kV	40.7
WDAT	WDT401	10/08/08	Venwind 115 kV	20
WDAT	WDT328	01/27/09	Cottonwood 115 kV Distribution	20
483	TOT389	04/29/09	Tehachapi 66 kV (Sagebrush Line)	10
WDAT	WDT334	06/09/09	Hi Desert 115 kV Distribution	18.5
485	TOT390	06/18/09	Highwind 230 kV	20
486	TOT393	06/29/09	Neenach 66 kV	20
488	TOT394	07/31/09	Eldorado 230 kV	92
490	TOT412	07/31/09	San Onofre 230 kV	48
494	TOT398	07/31/09	Windhub 230 kV	350
502	TOT405	07/31/09	Primm 230 kV (Loop Eldorado-Ivanpah)	20
503	TOT404	07/31/09	Eldorado 230 kV	155
506	TOT411	07/31/09	Whirlwind 230 kV	300
512	TOT410	07/31/09	Antelope 66 kV	94
513	TOT409	07/31/09	Whirlwind 230 kV	141

[13] This figure reflects the balance of an 850 MW project (275 MW assumed in-service by 2013).
[14] This figure reflects the balance of the 1,000 MW Interconnection Request.

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WDAT	WDT345	07/31/09	Highgrove 115 kV	49.9
WDAT	WDT357	08/17/09	Blythe 33 kV Distribution	20
WDAT	WDT371	08/25/09	Cottonwood-Savage 115 kV	20
WDAT	WDT372	08/25/09	Victor 115/33 kV	20
WDAT	WDT390	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT391	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT392	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT394	10/19/09	Vestal 66 kV Subtransmission	20
531A	TOT427	10/29/09	Antelope-Del Sur 66 kV	20
537A	TOT430	11/23/09	Highwind 230 kV	19.5
WDAT	WDT403	11/30/09	Little Rock 66/12 kV	2
WDAT	WDT404	11/30/09	Little Rock-Wilsona 66 kV	10
WDAT	WDT353	12/03/09	Vestal 66 kV Subtransmission	20
WDAT	WDT409	12/09/09	Cottonwood 115/33 kV	20
540	TOT431	12/22/09	Lancaster-Little Rock-Piute 66 kV Line	20
546	TOT437	01/06/10	Piute-Redman 66 kV Line	15
547	TOT436	01/06/10	Lancaster-Purify-Redman 66 kV Line	20
WDAT	WDT421	01/25/10	Cottonwood 115/33 kV	20
WDAT	WDT407	01/31/10*	Rector Distribution	20
WDAT	WDT435	01/31/10*	Windhub 66 kV	20
WDAT	WDT453	01/31/10*	Palmdale 66/12 kV	5
WDAT	WDT458	01/31/10*	Hi Desert 115/33 kV	10
WDAT	WDT459	01/31/10*	Hi Desert 115/33 kV	9
552	TOT438	02/01/10	Jasper 230 kV	60
585	TOT443	02/01/10	Antelope 230 kV	150
576	TOT446	02/01/10	Colorado River 230 kV	485
593	TOT448	02/01/10	Mohave 500 kV	310
589	TOT452	02/01/10	Victor 115 kV	60
588	TOT453	02/01/10	Red Bluff 230 kV	200
602	TOT455	02/01/10	Whirlwind 230 kV	150
628	TOT471	02/01/10	Del Sur 66 kV	20
632AA	TOT476	02/01/10	Mountwind 115 kV	10
651A	TOT508	02/01/10	Antelope 66 kV	20
653H	TOT516	02/01/10	Antelope 66 kV	20
650A	TOT521	02/01/10	Antelope 66 kV	20
661	TOT525	02/01/10	Antelope 66 kV	20
663	TOT527	02/01/10	Antelope 66 kV	20
WDAT	WDT425	02/01/10	Weldon 66 kV	60
WDAT	WDT433	02/01/10	Vestal-Glenville 66 kV	40
WDAT	WDT400	02/01/10	Pan Aero 115 kV	30

* Date adjusted as a result of the recently FERC approved Generation Interconnection Procedure modifications

8.2.3 Projects without Executed Agreements That Require Reliability Network Upgrades to be Interconnected as Energy Only

The operational study included a scenario that added the transmission upgrades needed to enable Energy Only interconnection of specific number of projects. This scenario also included transmission upgrades already permitted but scheduled to be in-service after 2013. The list of the transmission upgrades included in this scenario is provided below in Table 8.2.6. The list of the generation projects modeled in this operational study scenario is summarized below in Table 8.2.7.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection of these remaining generation project and simply assumed such facilities would be in place. The objective of this Operational Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements not yet defined could materialize as interconnection agreements are executed. This would ensure that resource requirements could be identified in order to enable interconnection of the remaining generation projects which do not have an executed interconnection agreement. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes.

Table 8.2.6
Transmission Upgrades with an In-Service Date After End of 2013 or an In-Service Date prior to the End of 2013 which is dependent on ongoing Environmental Review

System Upgrade	OD
Alberhill 500/115 kV Substation	2014
Colorado River No.2 500/230 kV Transformer Bank	2014[15]
East Kern Renewable Wind Area (EKWRA)	2014
Loop Magnolia-NSO 230 kV T/L into Eldorado and reconfigure to operated Merchant No.1 and No.2 230 kV T/L as radial gen-ties	2014
Mira Loma-Vincent 500 kV (TRTP 6, 7, 8)	2014
San Bernardino-Vista 230 kV Reconductor	2014
San Joaquin Cross Valley Loop	2014
Whirlwind No.2 500/230 kV Transformer Bank	2014[16]
Wildlife 230 kV Substation (City of Riverside MOS)	2015
Mesa-Vincent No.2 230 kV (TRTP 11)	2015
Whirlwind No.3 500/230 kV Transformer Bank	2016

[15] Installation of second AA-Bank at Colorado River Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.
[16] Installation of second AA-Bank at Whirlwind Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.

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Table 8.2.7
Generation Project without an Executed Agreement That Can Be Interconnected as Energy Only without Additional Transmission Upgrades

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
348	TOT313	07/31/08	Corum-Goldtown 66 kV	40
349	TOT314	07/31/08	Goldtown 66 kV	100
522A	TOT416	08/19/09	Rosamond 66 kV	20
522B	TOT417	08/19/09	Antelope-Cal Cement-Rosamond 66 kV Line	20
WDAT	WDT361	08/20/09	Great Lakes 66/12 kV	5
WDAT	WDT368	08/20/09	Goldtown 66/12 kV	4.9
474	TOT387	09/15/08	Cool Water-Dunn Siding-Baker 115 kV Line	20
WDAT	WDT325	11/17/08	Kramer 11 kV Distribution	20
WDAT	WDT326	12/10/08	Gale 11 kV Distribution	20
WDAT	WDT329	02/13/09	Kramer 11 kV Distribution	20
491	TOT396	07/31/09	Cool Water-Dunn Siding-Baker 115 kV Line	230
WDAT	WDT402	11/25/09	Goldtown 66/12 kV	10
WDAT	WDT417	01/19/10	Inyokern 115/33 kV	5.5
609	TOT456	01/31/10*	Rosamond 66 kV	20
617A	TOT465	01/31/10*	Piute-Redman 66 kV	20
WDAT	WDT419	01/31/10*	Randsburg 115/33 kV	20
515	TOT413	02/01/10**	Kramer-Inyokern-Randsburg No.1 115 kV	20
522C	TOT415	02/01/10**	Correction-Cummings-Kern River 1-Monolith 66 kV Line	20
521	TOT419	02/01/10**	Corum-Goldtown 66 kV Line	19.9
522	TOT420	02/01/10**	Corum-Goldtown-Rosamond 66 kV Line	20
613A	TOT461	02/01/10	Monolith 66 kV	19.5
614A	TOT462	02/01/10	Coram-Goldtown-Rosamond 66 kV Line	20
639	TOT472	02/01/10	Piute 66 kV	20
640	TOT473	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
649C	TOT499	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
650AA	TOT501	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	15
649B	TOT502	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	20
640A	TOT503	02/01/10	Lancaster-Purify-Redman 66 kV Line	20
653EF	TOT512	02/01/10	Monolith 66 kV	20
653BA	TOT513	02/01/10	Correction-Cummings-Kern River 1-Monolith 66 kV Line	20
653FB	TOT514	02/01/10	Lancaster-Little Rock-Piute 66 kV Line	20
653FA	TOT515	02/01/10	Lancaster-Little Rock-Piute 66 kV Line	20
657A	TOT518	02/01/10	Antelope-Neenach 66 kV	20
657B	TOT519	02/01/10	Corum-Goldtown 66 kV	20
660	TOT522	02/01/10	Lancaster-Purify-Redman 66 kV Line	20
658	TOT523	02/01/10	Piute 66 kV	20
659	TOT524	02/01/10	Antelope-Rosamond 66 kV	20
664	TOT526	02/01/10	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20

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8.2.4 Inclusion of All Long-term Deliverability Network Upgrades

The operational study included a final scenario that added all of the long-term Deliverability Upgrades needed to provide for the requested Full Capacity level of service to all generation projects in queue including the Phase II project requests.

8.3 Application Queue SCD Results

All bus locations where the Phase II Projects increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.1.1 (three-phase-to-ground) and Table H.1.2 (single-phase-to-ground). These values have been used to determine if any *additional* equipment, beyond what has previously been identified to be overstressed due to queued ahead projects, is triggered with the addition of the Phase II interconnections and corresponding network upgrades.

The Phase II breaker evaluation identified that the inclusion of the Phase II Projects triggers the need for SCD mitigation Vincent 500 kV, Lugo 230 kV, Antelope 66 kV, and Windhub 66 kV. The effective three-phase-to-ground and single-phase-to-ground duties are shown below in Table 8.3.1 and Table 8.3.2 respectively.

Table 8.3.1
Effective Three-Phase-to-Ground Duties at Locations
Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	48.8	21.4	49.8	50.0	21.6	51.1	1.2	1.3
Lugo	230	41.5	33.6	46.1	50.9	33.2	56.5	9.4	10.4
Antelope	66	34.8	28.4	34.8	36.6	46.8	42.1	1.8	7.3
Windhub	66	34.4	50.2	39.3	35.6	49.1	40.9	1.4	1.6

***** Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

Table 8.3.2
Effective Single-Phase-to-Ground Duties at Locations
Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	39.1	15.4	39.1	39.7	15.3	39.7	0.6	0.6
Lugo	230	41.9	25.5	44.4	52.4	25.2	55.5	10.5	11.1
Antelope	66	22.8	22.5	22.8	24.4	25.3	24.4	1.6	1.6
Windhub	66	25.5	23.8	25.5	26.6	23.7	26.6	1.1	1.1

***** Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

A detailed discussion of the upgrade requirements is provided below.

8.3.1 Vincent 500 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Vincent 500 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of four 500 kV circuit breakers.

To mitigate these identified overstressed circuit breakers, replacement of these four CBs with 63 kA rating is recommended.

8.3.2 Lugo 220 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Lugo 220 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of six220 kV circuit breakers.

To mitigate these identified overstressed circuit breakers, replacement of six CBs with 63 kA rating is recommended.

8.3.3 Antelope 66 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Antelope 66 kV Substation beyond the 40 kA standard design breaker capabilities with the Antelope Substation operating with three 220/66 kV transformer banks in parallel. Such duty increases were identified to impact a total of forty 66 kV circuit breakers.

To address this problem, the use of an Operating procedure[17] to reduce duty to within circuit breaker limits will be required.

8.3.4 Windhub 66 kV Substation

The study identified that the addition of the Phase II projects results in increasing SCD at SCE's Windhub 66 kV Substation beyond the 40 kA standard design breaker capabilities with the Windhub Substation operating with three 220/66 kV transformer banks in parallel.

To mitigate this problem the Windhub 66 kV switchrack will need to be operated in a split bus configuration. This configuration will necessitate the installation of the fourth 220/66 kV transformer bank at Windhub.

[17] SCE anticipates that the appropriate long-term mitigation of the Antelope 66 kV SCD problem involves sectionalizing the Antelope 66 kV bus. For this Phase II study, an operating procedure to de-loop or de-energize sufficient transmission facilities to keep Antelope 66 kV SCD below 40 KA will be required.

8.4 Operational Study SCD Results

8.4.1 Existing System with the inclusion of projects in 2011

All bus locations where the inclusion of projects in 2011 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.2.1 (three-phase-to-ground) and Table H.2.2 (single-phase-to-ground). These values were used to determine which SCD mitigation needs to be placed into service by the end of 2011.

The 2011 Operational Study breaker evaluation identified the need for SCD mitigation at the following location:

8.4.1.1 Vincent 220 kV

8.4.2 Inclusion of projects in 2012

All bus locations where the inclusion of projects in 2012 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.3.1 (three-phase-to-ground) and Table H.3.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2012.

The 2012 Operational Study breaker evaluation identified the need for SCD mitigation at the following locations:

8.4.2.1 Antelope 220 kV

8.4.3 Inclusion of projects in 2013

All bus locations where the inclusion of projects in 2013 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.4.1 (three-phase-to-ground) and Table H.4.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2013.

8.4.3.1 Devers 220 kV

8.4.3.2 Mira Loma 220 kV

8.4.4 Inclusion of Generation Projects Assuming Energy Only Interconnection (excluding Generation projects requiring EKWRA to enable Energy Only Interconnection)

All bus locations where the inclusion of generation projects that do not yet have an executed interconnection agreement assuming interconnection can be implemented as Energy Only without transmission upgrades increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.5.1 (three-phase-to-ground) and Table H.5.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to enable such Energy Only Interconnections.

8.4.4.1 Vista 115 kV

8.4.5 Inclusion of EKWRA and all Generation Projects that required EKWRA to enable Energy Only Interconnection

All bus locations where the inclusion of the remaining generation projects that do not yet have an executed interconnection agreement, assuming interconnection can be implemented as Energy Only but require transmission upgrades for interconnection, increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.6.1 (three-phase-to-ground) and Table H.6.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to enable such Energy Only Interconnections.

8.4.5.1 Antelope 66 kV

8.4.5.2 Cal Cement 66 kV

8.4.5.3 Windhub 66 kV

8.4.6 System with Generation Projects Assuming Energy Only Interconnection (without and with upgrades) and inclusion of the Deliverability Network Upgrades

All bus locations where the inclusion of the Deliverability Network Upgrades increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60%

of the minimum breaker nameplate rating are listed in Appendix H Table H.7.1 (three-phase-to-ground) and Table H.7.2 (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to provide for the requested Full Capacity Deliverability service.

8.4.6.1 Vincent 500 kV

8.4.6.2 Etiwanda 220 kV

8.4.6.3 Lugo 220 kV

8.4.6.4 Mira Loma East 220 kV

8.4.6.5 Pisgah 220 kV

8.4.6.6 Vincent 220 kV

8.4.6.7 Windhub 220 kV

8.5 Additional SCD Discussion

The Phase II Study has shown significant increases in SLG short-circuit duty with the addition of numerous grounded interconnection transformers. For details, see Appendix H. It is strongly recommended that Phase II generation projects, to the extent possible, install transformers that limit each project's contribution to SLG SCD on the SCE system. This may be accomplished by installing transformers with delta-connected high side windings or with "impedance-grounded" wye-connected high side windings.

9. Transient Stability Analysis

Transient stability analysis was conducted using both the summer peak and off-peak full loop base cases to ensure that the transmission system remains stable with the addition of Phase II generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report.

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Phase II projects will create any system instability during a variety of line and generator outages. For SCE's Northern Bulk System, selected line and generator outages within the Northern Bulk System were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

9.1 Bulk System Results

The transient stability study concluded that with the addition of the QC1&2PII projects proposed system upgrades in place as well as assuming each project can provide 0.95 power factor correction at their POI, the transient stability performance of the system is acceptable. Transient stability plots for summer peak and off-peak load conditions are provided in Appendix F.

9.2 Sub transmission System Results

The transient stability study concluded that with the addition of the Phase II projects interconnecting to the eastern portion of the Antelope 66 kV Subtransmission System resulted in a transient system problem which would trip off the generation projects due to system overvoltage conditions under specific outages. Transient stability plots for summer peak and off-peak load conditions illustrating this problem are provided in Appendix F. It is recommended for the Phase II projects interconnecting in the eastern portion of the Antelope-Bailey 66 kV subtransmission system to provide dynamic reactive capability.

10. Post-Transient Voltage Stability Analysis

The reactive deficiency analysis in Section 7 concluded that the asynchronous generating facilities are required to provide 0.95 leading/lagging power factor correction at the POI.

A post-transient voltage stability analysis was performed for this Phase II Study. The post-transient analysis focused on evaluating the system after the inclusion of all transmission upgrades and the use of the identified SPS, assuming all new generation projects meeting the power factor requirements. Under such conditions, the post-transient study showed acceptable system performance.

11. Mitigation of Phase II Project Impacts

The mitigation requirements triggered by Phase II projects, based on the results described in Sections 6-10 above, are as follows:

11.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for Phase II projects in the Northern Bulk System are discussed in detail in each individual project report (Appendix A).

11.2 Reliability Network Upgrades

Assumed scope for the Reliability Network Upgrades for Phase II projects in the Northern Bulk System are discussed below.

11.2.1 Wave Trap Upgrades – Lugo – Vincent No.1 and No.2 500 kV Transmission Lines

11.2.2 Northern Area 500 kV Special Protection System

Install a new SPS for Q494, Q506, Q513, Q585 and Q602 projects.

Substations:

Antelope Substation – SPS Central Processing Location

- Install three N60 Relays for each SPS A and SPS B (Total of six relays) for line monitoring, logic processing and sending of generator tripping signals
- Install one SEL-2407 Satellite Synchronized Clock

Vincent Substation

- Install two N60 Relays for each SPS A and SPS B (Total of four relays) for line monitoring
- Install one SEL-2407 Satellite Synchronized Clock

Whirlwind Substation

- Install two N60 Relays for each SPS A and SPS B (Total of four relays) for line monitoring
- Install one SEL-2407 Satellite Synchronized Clock

Windhub Substation

- Install one N60 Relays for each SPS A and SPS B (Total of two relays) for line monitoring
- Install one SEL-2407 Satellite Synchronized Clock

NOTE: The SPS Relays to be installed at each Generating Facility have been already addressed as part of the Interconnection Facilities Elements of this report.

Telecommunications:

Telecomm Channels - Use existing infrastructure to provide two diversely routed telecommunication channels.

Equipment - Install all required light-wave, channel and related terminal equipment at the Antelope, Vincent, Whirlwind, and Windhub Substations and the Alhambra Communications Site to provide the required interface between the existing channels and the SPS Relays.

NOTE: The required diverse – route telecommunication channels and related terminal equipment at each Generating Facility have been addressed as part of the Interconnection Facilities Elements of this report.

Power System Control

Expand existing RTU's at Antelope Substation to support the SPS

11.2.3 Modify Previously Proposed Whirlwind Special Protection System

Expand the previously triggered Whirlwind SPS to include Q506, Q513 and Q602 projects. The SPS would monitor Whirlwind 500/220 kV transformer banks (total of three) and trip generation under for loss of one.

NOTE: The SPS Relays to be installed at each Generating Facility have been already addressed as part of the Interconnection Facilities Elements of this report.

Power System Control

Expand existing RTU's at Whirlwind Substation to add each project to the SPS as projects interconnect.

11.2.4 Modify Previously Proposed Windhub Special Protection System

Expand the previously triggered Windhub SPS to include Q494 project. The SPS would monitor Windhub 500/220 kV transformer banks (total of two on west-section) and trip generation under for loss of one.

NOTE: The SPS Relays to be installed at the Generating Facility have been already addressed as part of the Interconnection Facilities Elements of this report.

Power System Control

Expand existing RTU's at Windhub Substation to add the project to the SPS as the project interconnects.

11.2.5 Eastern Antelope Area 66 kV Upgrades

11.2.5.1 Install new eleven (11) mile line from Oasis to New Substation in Piute Area

Sub-Transmission:

Install ten (10) tubular steel poles, 280 light weight steel poles, and 58,100 circuit feet of 954 ACSR conductor

Substation:

- Oasis Substation – Expand Oasis 66 kV substation and equip one position
- New Substation in Piute Area – Equip one position

Power Systems Control:

Add additional Points to the SA2 at Oasis Substation and to the RTU at the new substation in the Piute Area in order to monitor the line data and status/control for the associated circuit breakers

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the new eleven (11) mile 66 kV line

11.2.5.2 Rebuild of Little Rock Leg of Helijet-Little Rock-Palmdale-Rock Air 66 kV line

Sub-Transmission:
Rebuild Little Rock Substation to Palmdale Tap (8.4 miles of 2/0 CU) of Helijet-Little Rock-Palmdale-Rock Air 66 kV line with 954 SAC

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.5.3 Rebuild Lancaster Leg of Lancaster-Purify-Redman 66 kV line

Sub-Transmission:
Rebuild Lancaster Substation to Redman Tap (4.5 miles of 2/0 CU) of Lancaster-Purify-Redman 66 kV line with 954 SAC

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.5.4 Rebuild portions of the Lancaster-Little Rock-Piute 66 kV line with 954 SAC

Sub-Transmission:
Rebuild portions of the Lancaster-Little Rock-Piute 66 kV line (3.0 mile, 0.5 mile, and 2.0 mile sections of 2/0 CU) with 954 SAC

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.5.5 Rebuild portion of the Piute-Redman 66 kV line with 954 SAC

Sub-Transmission:
Rebuild portion of the Piute-Redman 66 kV line (1.0 mile section of 2/0 CU) with 954 SAC

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.5.6 Removal of relay limitations to allow full utilization of the 66 kV Lines

Substations:

Redman Substation

- Replace existing relay scheme on Lancaster-Purify 66 kV line with one (1) D60 and one (1) SEL-311C relay scheme and install one (1) additional 66 kV potential transformer
- Replace existing relay scheme on Piute 66 kV line with one (1) D60 and one (1) SEL-311C relay scheme and install one (1) additional 66 kV potential transformer

Redman Substation

- Replace existing relay scheme on Redman 66 kV line with one (1) D60 and one (1) SEL-311C relay scheme and install three (3) additional 66 kV potential transformer

11.2.6 Windhub 66 kV Area Upgrades

11.2.6.1 Rebuild portion of the Correction-Cummings-KR1 66 kV line with 954 SAC

Sub-Transmission:
Rebuild approximately 2.2 miles (4/0 CU) between the proposed Q522Q653 Substation and Correction Substation with 954 SAC

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.6.2 Reconfigure the planned Windhub-Goldtown-Monolith-Windlands 66 kV line

Sub-Transmission:

- Remove the connection between Goldtown and Windhub Tap
- Remove the connection of Morwind to existing line
- Construct a new 1.5 miles double-circuit 66 kV line section with new 954 SAC
- Connect Monolith-Midwind line segment to western circuit of new line segment forming new Windhub-Monolith-Midwind 66 kV line

- Construct a new 0.5 mile from Morwind to eastern circuit of new line segment and connect together with Goldtown leg forming the new Windhub-Goldtown-Morwind 66 kV

Substation:
Windhub Substation - Equip a new 66 kV position

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.6.3 Construct new 66 kV line from Windhub

Sub-Transmission:

- Construct approximately 5.5 mile 66 kV line from Windhub Substation to a new collector substation
- Reconfigure 66 kV lines in the surrounding collector substation area (operate line segment of EKWRA planned Corum-Rosamond-Goldtown 66 kV line as normally open at pole-switch near collector substation)

Substations:

- Windhub Substation - Equip a new 66 kV position
- New SCE 66 kV Collector Substation - Install two 66 kV low profile buses and equip one position to terminate the Windhub 66 kV line.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.7 Western Antelope Area 66 kV Upgrades

11.2.7.1 Rebuild of the Neenach leg of the Bailey – Neenach – Westpac 66 kV Line

Rebuild the Neenach leg of the Bailey – Neenach – Westpac 66 kV Line. Open Antelope – Bailey parallel at Neenach Substation towards Antelope Substation. Create an operational procedure to serve Neenach out of Antelope upon Bailey – Neenach – Westpac 66 kV outage.

Sub-Transmission:
Rebuild approximately 13.7 miles of the Bailey – Neenach – Westpac 66 kV line from 336 ACSR to 954 SAC on the Neenach tap.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.8 Fiber Optic Backbones

11.2.8.1 STC North 1

Telecom:
A fiber optic ring will be built to provide diverse communication paths to the new substations Construct new fiber optic cable between Corum, Goldtown, Rosamond, Windhub, Q521, and Q657B Substations. This construction includes approximately 48.7 miles of new fiber optic cable and 1 mile of 5" conduit. Install lightwave and terminal equipment at Corum, Goldtown, Rosamond, and Windhub Substations.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.8.2 STC North 2

Telecom:
A fiber optic ring will be built to provide diverse communication paths to the new substations. Construct new fiber optic cable between Arbwind, Highwind, Monolith, Q522Q653, and Q613Q653 Substations. This construction includes approximately 37.9 miles of new fiber optic cable, 1.7 miles of 5" conduit and 30 poles. Install lightwave and terminal equipment at Arbwind and Highwind Substations.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.8.3 STC West 1

Telecom:
A fiber optic ring will be built to provide diverse communication paths to the new substations. Construct new fiber optic cable between Antelope, Del Sur, Neenach, Rosamond, Q628, Q640, Q649B, Q649C, Q657A, Q650AA, Q661, and Q658. This construction includes approximately 54.9 miles of new fiber optic cable, 2.4 miles of 5" conduit and 120 poles. Install lightwave and terminal equipment at Antelope, Cal Cement, Corum, Del Sur, Lancaster, Neenach, and Shuttle Substations.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.8.4 STC West 2

Telecom:
A fiber optic ring will be built to provide diverse communication paths to the new substations. Construct new fiber optic cable between Goldtown, Rosamond, Windhub, Q522, and Q614A Substations. This construction

includes approximately 29.9 miles of new fiber optic cable, and 0.8 miles of 5” conduit. Install lightwave and terminal equipment at Goldtown, and Rosamond Substations.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.2.8.5 STC East

Telecom:
A fiber optic ring will be built to provide diverse communication paths to the new substations. Construct new fiber optic cable between Lancaster, Piute, Redman, Collector No. 1 and Collector No. 2 with dual taps into the Collector No. 3 Substation.. This construction includes approximately 22.3 miles of new fiber optic cable, and 0.5 miles of 5” conduit. Install lightwave and terminal equipment at Lancaster, Little Rock, and Redman Substations.

Corporate Environmental Health and Safety, Licensing, and Real Properties
Perform all required activities to support the upgrade

11.3 Short-Circuit Duty (SCD) Mitigation

Short Circuit Duty (SCD) Mitigation
Transmission Network Circuit Breaker Upgrades
Upgrade transmission network circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

Vincent Substation
Upgrade four (4) 500 kV circuit breakers.

Lugo Substation
Upgrade six (6) 220 kV circuit breakers.

Windhub Substation
Split the bus by performing the following:
1. Equip one (1) 220 kV position

11.4 Delivery Upgrades

No Delivery Upgrades were identified.

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11.5 Distribution Upgrades

Short Circuit Duty (SCD) Mitigation

Windhub Substation
Split the bus by performing the following:
2. Equip one (1) 66 kV position
3. Install one (1) 220/66 kV transformer

Antelope – Bailey Area Distribution Upgrades
See individual Appendix A reports

Vestal Area Distribution Upgrades
See individual Appendix A reports

12. Environmental Evaluation / Permitting

12.1 CPUC General Order 131-D

The California Public Utilities Commission's (CPUC) General Order 131-D (GO 131-D) sets for the permitting requirements for certain electrical and generation facilities. GO 131-D was established by the CPUC to be responsive to: the requirements of the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the CPUC; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Electric facilities between 50 and 200 kV are subject to the CPUC's Permit to Construct (PTC) review specified in GO 131-D, Section III.B. For facilities subject to PTC review, or for over 200 kV electric facilities subject to Certificate of Public Convenience and Necessity (CPCN) requirements specified in GO 131-D, Section III.A, the CPUC reviews utility PTC or CPCN applications pursuant to CEQA and serves as Lead Agency under CEQA. Section IX of GO 131-D discusses the requirements for PTC and CPCN applications.

Generally, SCE takes approximately a minimum of 6-18 months to assemble a CPCN or PTC application, the majority of which time is involves by developing a required Proponent's Environmental Assessment (PEA). The CPUC review of such applications may take anywhere from 8 – 36 months depending on the specific.

12.2 CPUC General Order 131-D – Permit to Construct/Exemptions

GO 131-D provides for certain exemptions from the CPUC PTC requirements for facilities between 50 and 200 kV. For example, Exemption f of GO 131-D (Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations between 50 - 200 kV to be constructed or relocated that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation. Note, GO 131-D, Section III.B.2, discusses the conditions under which PTC exemption shall not apply (consistent with CEQA Guidelines).

After lead agency approval of the final CEQA document which confirms there are no significant environmental impacts associated with the SCE scope of work, SCE may be eligible to use Exemption f, and in doing so would follow certain limited public noticing requirements, including filing an informational Advice Letter at the CPUC, posting the project site/route, providing notice to the local jurisdicition(s) planning director and the executive director of the California Energy Commission (CEC), and advertising the project notice, for once a week for two weeks successively in a local newspaper. As part of an agreement with the CPUC Energy Division, SCE informally provides a copy of the final CEQA document to the CPUC Energy Division for reference when the Advice Letter is pending before the CPUC.

Note, the CPUC rules for Advice Letters consider an Advice Letter to be in effect on 30th calendar day after the date filed, and GO 131-D specifies a minimum period of 45-days between advertising the notice for the project and when construction can occur.

Typically, SCE may proceed with construction 45-days after it has filed its Advice Letter and has posted and advertised the project notice unless a protest is filed and/or CPUC staffs suspend the Advice Letter. If protests are filed, they must address whether SCE has properly claimed the exemption. SCE has 5 business days to respond to the protest and the CPUC will typically take a minimum of 30 days to review the protest and SCE's response, and either dismiss the protests or require SCE to file a Permit to Construct. SCE has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, SCE may then need to apply for a formal permit to construct the project (i.e., Permit to Construct).

If SCE facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption due to significant, unavoidable environmental impacts, or if the exemption is subject to the "override" provision in GO 131-D, Section III.B.2, SCE may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Mitigated Negative Declaration or Environmental Impact Report).

Note, for projects undergoing no CEQA review but instead only undergoing a review under the National Environmental Policy Act (NEPA) due to the lead agency being a federal agency (such as the BLM), GO 131-D technically does not allow for the use of Exemption f when the environmental review is conducted only pursuant to NEPA and does not have a CEQA component. As such, SCE would need to review such projects on a case-by-case basis with the CPUC to determine if the CPUC would allow the project to proceed under Exemption f or instead allow SCE to proceed under an "expedited" PTC application by attaching the NEPA document in lieu of a PEA.

For projects that are not eligible for Exemption f, but have already undergone CEQA or NEPA review, SCE may be able to file an "expedited" PTC application, which typically takes the CPUC approximately 4-6 months to process.

12.3 CPUC General Order 131-D – Certificate of Public Convenience & Necessity (CPCN) Exceptions

When SCE's T/Ls are designed for immediate or eventual operation at 200 kV or more, GO 131-D requires SCE to obtain a Certificate of Pubic Convenience and Necessity (CPCN) from the CPUC unless one of the following exceptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

Unlike Exemption f relating to the exemptions allowed from a Permit to Construct for electric facilities between 50 – and 200 kV, no such exemption exists for electric facilities over 200 kV T/Ls that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation. Accordingly, SCE would need to consult on a case-by-case basis with the CPUC for such projects CPUC would allow the project to proceed "exempt" or instead allow SCE to proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a SCE Proponent's Environmental Assessment. Such an expedited CPCN with the environmental review already completed by the lead agency that permitted the Interconnection Customer's generator project, typically may take from only 4-6 months for the CPUC to process.

12.4 CPUC General Order 131-D – General Comments Relating to Environmental Review of SCE Scope of Work as Part of the Larger Generator Project

For the benefits and reasons stated above, It is assumed that the Interconnection Customer will include SCE's Interconnection Facilities and Network Upgrades work scope (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental reports/applications submitted to the lead agency permitting the Interconnection Customer's larger generator project (e.g., California Energy Commission or applicable local, state or federal permitting agency, such as the Bureau of Land Management), and that such agencies will review the potential environmental impacts associated with SCE's work scope in any environmental document issued. This may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the generator tie line and Network Upgrades work associated with the Interconnection Customer's Project. SCE may also be required to obtain other authorizations for its interconnection facilities and network upgrades. Hence, the SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit. The cost for obtaining any of this type of permitting is not included in the cost estimates.

Please see General Order 131-D. This document can be found in the CPUC's web page at:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

12.5 CPUC Section 851

Because SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires SCE to obtain CPUC approval of leases and licenses to use SCE property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the California Environmental Quality Act (CEQA). SCE recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

12.6 SCE scope of work NOT subject to CPUC General Order 131-D

Certain SCE facilities and scope of work may not be subject to CPUC's G.O. 131-D. In such instances, SCE will follow the requirements of all applicable environmental laws and regulations and issue an in-house environmental clearance before commencement of construction activities.

13. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on initial engineering scope as described in Section 11 of this report. Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate report, specific only to that generation project, containing the details of the IC's cost responsibilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in the Phase II are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

The estimated cost of **Reliability Network Upgrades** identified in this Group Study is assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request.

The estimated cost of all **Delivery Network Upgrades** identified in the Deliverability Assessment are assigned to all Interconnection Requests selecting Full Capacity Deliverability Status based on the flow impact of each such Large Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

The estimated cost of all **Interconnection Facilities** is assigned to each Interconnection Request individually. The cost estimates for the Interconnection Facilities are all site specific and details are provided in each individual project report.

The estimated costs of **Distribution Upgrades** and **non-CAISO transmission upgrades** are assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request. Distribution Upgrades and non-CAISO transmission upgrades are non-refundable.

Table 13.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade	Description	Estimated Cost x 1,000	Estimated Cost x 1,000 Constant Dollar (OD Year)		Estimated Time to Construct *(Note 1)*
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for QC1 projects in the Northern Bulk System are discussed in detail in each individual project report (Appendix A).		See Appendix A			See Appendix A
Reliability Network Upgrades	Replace Wavetraps on Lugo – Vincent No.1 & No.2 500 kV	Replace three 3,000A Rated 500kV Wave Traps at each Vincent No.1 and No.2 500kV T/L Positions with new 4,000A Rated (total of six Wave			2014	24 months
	Northern Area 500 kV SPS	Multiple N-2 500 kV line outages			2014	24 months
	Modify Existing Whirlwind SPS (AA Bank N-1)	Loss of AA Bank Transformer at Whirlwind Sub			2014	24 months
	Modify Existing Windhub SPS (AA Bank N-1)	Loss of AA Bank Transformer at Windhub Sub			2014	24 months
	Eastern Antelope 66 kV Area Upgrades	See Section 11 for description			2018	72 Months
	Windhub Area 66 kV Upgrades	See Section 11 for description			2018	72 Months
	Western Antelope Area Upgrades	See Section 11 for description			2017	60 Months
	Fiber Optic Backbones	See Section 11 for description			2014	24 Months
	Short-Circuit Duty (SCD) Mitigation	See Section 11 for description			2014	24 Months
Delivery Network Upgrades	None	No Delivery Network Upgrades were identified	$0	$0		
Distribution Upgrades *(Note 2)*	SCD Mitigation	See Section 11 for description			2014	24 Months
	Other Antelope-Bailery Upgrades	See individual Appendix A reports			2018	72 Months
	Other Vestal Upgrades	See individual Appendix A reports			2017	60 Months

Total	**$338,096**		**72 Months**

Note1: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

Note 2: These upgrades are not part of the CAISO Controlled Grid and are not reimbursable.

Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.

14. Coordination with Affected Systems

ISO LGIP tariff Appendix Y section 3.7 requires coordinating with any affected systems that have any potential impact of Phase II projects. No affected system was identified in the Phase II study for the Northern Bulk System.