SOUTHERN CALIFORNIA EDISON
(AS INTERCONNECTION CUSTOMER)

[redacted]

INDEPENDENT STUDY PROCESS
SYSTEM IMPACT STUDY

October 5, 2016

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

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SYSTEM IMPACT STUDY

October 30, 2016

1. INTRODUCTION

Southern California Edison Company (SCE), as Interconnection Customer, applied to SCE, as Distribution Provider, for interconnection of the proposed [redacted] pursuant to Section 5 of Attachment 1 (Generator Interconnection Procedures) of Southern California Edison's Wholesale Distribution Access Tariff (WDAT). The Project consists of installing a battery energy storage source (BESS) at the existing [redacted] Peaker Generating Station and a [redacted] increase to the maximum MW capacity output from the existing gas-fired peaking unit. The requested a Point of Interconnection (POI) is SCE's Etiwanda-Ameron-[redacted]Pipe 66 kV line.

SCE has performed a System Impact Study (SIS) to determine the adequacy of SCE's electrical system to accommodate the Project and to identify system limitations that would require Distribution Upgrades on the subtransmission system to mitigate any identified impacts. The SIS considered various levels of load demand with maximum generation dispatch. In addition, maximum charging of energy storage facilities was evaluated under a minimal generation within the Etiwanda 66 kV Subtransmission System coupled with maximum levels of load demand. These conditions reflect the most critical expected loading conditions for the Project. The study included all queued ahead generation and storage projects in the Etiwanda 66 kV Subtransmission System regardless of the in-service dates of such prior queued projects.

The study results of the study will be used as the basis to determine the scope, cost, and schedule corresponding to any identified Distribution Upgrades needed to mitigate any adverse impacts identified. An operational study if required is performed to determine the timing need of any identified upgrade. Such timing need is directly related to actual projects moving forward as not all queued ahead generation projects have progressed towards project execution. It is important to note that withdrawals of any queued ahead projects could result in reallocating cost of any previously identified Distribution Upgrades.

The accuracy of the study results are contingent on the accuracy of the technical data provided as part of the IR. Any changes from the data provided could void the study results and would need to be evaluated as part of a Material Modification Assessment (MMA) to determine if such change results in a material impact to queued-behind generation requests. The modifications would only be allowed if the MMA determines no material impacts to queued-behind generation requests.

The study report provides the following:

- Detailed study assumptions and conditions of the Etiwanda 66 kV Subtransmission System in which the study was performed

- Subtransmission system impacts caused by the addition of the Project operating in generation or "discharge" mode
- Subtransmission system impacts caused by the addition of the Project operating as a load or in "charge" mode

To determine the system impacts caused by the addition of the Project, the following studies were considered:

- Steady State Power Flow Analyses
- Post Transient Voltage Stability Analysis
- Subtransmission and Distribution voltage level Short-Circuit Duty Analyses

2. PROJECT INFORMATION

All the equipment and facilities comprising the BESS portion of the Project are located in Rancho Cucamonga, California, as disclosed by the IC in its Interconnection Request (IR) and consists of (i) [redacted] with a rated output of [redacted] each at unity power factor for a gross output of [redacted] as measured at the inverter terminals, (ii) [redacted] (iii) the associated infrastructure, (iv) meters and metering equipment, (v) appurtenant equipment, and (vi) auxiliary loads of [redacted] In addition, as part of the IR, the Project includes a [redacted] increase in the maximum output corresponding to the existing gas-fired peaker unit resulting in increasing the net ouput from [redacted] to [redacted] Collectively, the total output from the combined gas-fired peaker unit and the BESS will be [redacted] but the output will be limited to not exceed [redacted] The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure 1 and summarized below in Table 1.

Figure 1: Project IC Facilities One-Line Diagram

[redacted]

Table 1: Project General Information

Project Location	Rancho Cucamonga, CA San Bernardino County [redacted]
Participating TO's Planning Area	SCE Metro Bulk system
Point of Interconnection (POI)	Distribution Provider's [redacted]
Interconnection Voltage	66 kV
Requested Maximum Distribution Service	[redacted]
Number and Types of Generators	[redacted]
Power Factor Range	[redacted]
Step-up Transformer(s)	[redacted]
Gen-Tie	Utilize existing gen-tie in place for gas-fired peaker unit
Generator Auxiliary Load	[redacted]
Internal Generation Facility Losses	Negligible
Maximum unrestricted Net Output as measured on high-side of the main transformer used for the existing gas-fired peaker unit.	59.62 MW
Estimated total losses on Generation Tie Line	Negligible
Maximum restricted Net Output as measured on high-side of the main transformer used for the existing gas-fired peaker unit to maintain within the requested Distribution Service amount	49.9 MW
IC Requested COD	December 31, 2016

3. STUDY ASSUMPTIONS

3.1. Planning Criteria

The generator interconnection studies were conducted utilizing SCE's Reliability Planning Criteria. More specifically, the main criteria applicable to this study are as follows:

Power Flow Analysis

The following contingencies are considered for subtransmission lines and 220/66 kV transformer banks ("A-Banks"):

- Single Contingencies (N-1) – Loss of one line or one A-Bank
- Double Contingencies (N-2) – Common-mode loss of two lines

The following reliability criteria are used:

Subtransmission Lines	Base-Case	Limiting Component Normal Rating
	N-1 and N-2	Limiting Component Emergency Rating
220/66 kV Transformer banks (A-Banks)*	Base Case	Normal Loading Rating
	Long Term Emergency Loading Limit (LTELL) & Short Term Emergency Loading Limit (STELL)	As defined by SCE Operating Bulletin

* Please note that Normal and Emergency Ratings are reduced to reflect 95% of rating for charging cases.

3.1.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating with all facilities in-service (base case), except where otherwise indicated, such as A-Bank loading for charging cases. Mitigation will be required to address any identified normal overload triggered by the inclusion of the Projects.

3.1.2 Contingency Overloads

Contingency overloads are those that exceed 100 percent of emergency ratings under outage conditions. Mitigation will be required to address any identified contingency overload triggered by the inclusion of the Projects.

3.1.3 Voltage Criteria

Voltage performance under single and double outage conditions will be limited to 5 percent and 10 percent deviation, respectively.

3.1.4 Power Factor Criteria

The Project will need to comply with SCE's Interconnection Handbook requirements.

3.2 Load Assumptions

The load assumptions used for local subtransmission system initially considered a 2016 – 2024 load forecast. The load forecast was derived using SCE's Distribution Engineering A-Bank Planning load forecast as well as the individual load serving substation (B-bank) load forecast for 2016-2024. Figure 3.1 below provides the local subtransmission load forecast values at the A-Bank level under Normal (1-in-2 year) and Criteria (1-in-5 year) Planning assumptions.

Figure 3.1
Etiwanda A-Bank Load Forecast

[redacted]

To model year hourly forecast load performance, historical A-Bank data were obtained and normalized (maximum historical load = 1.0). This was done in order to provide a means for scaling to reflect comparable hourly performance with each load forecast. Shown below, Figure 3.2., is the normalized local subtransmission system A-Bank hourly load performance.

Figure 3.2
Normalized Local Subtransmission System
A-Bank Hourly Load Performance

[redacted]

The assessment evaluating maximum generation output considered various load scenarios for this study. Utilizing the normalized hourly load performance shown above in Figure 3.2, the lowest per-unit load was applied to define two maximum generation output scenarios. The first scenario would use the minimum per-unit load during the daytime (shown as L1) while the second scenario would use the minimum value identified at any time of the day (shown as L2). In addition, the study considered a scenario representing maximum load demand (L5) with maximum generation.

For energy storage, the assessment evaluating maximum charging considered four scenarios with the maximum load. The first charging scenario would use the maximum per-unit load during the 2:00 AM – 6:00 AM time period (shown as L3). The second charging scenario would use the maximum per-unit load during the 8:00 AM – 12:00 PM time period (shown as L4). The third charging scenario would use the maximum per-unit load during the 2:00 PM – 6:00 PM time period (shown as L5). Lastly, the fourth charging scenario would use the maximum per-unit load during the 8:00 PM – 12:00 AM time period (shown as L6).

These per-unit values were used to define the specific load distribution assumptions and were used in creating the study cases developed for each load scenario. To create each study case, the per-unit value identified for the respective load scenario, L1 through L6, were multiplied with the "Normal" load distribution except for L5, which used the "Criteria" load distribution. The resulting load assumptions used in the study for year 2016 and 2021 with the existing system topology are provided below in Table 3.2.1 and Table 3.2.2 respectively. The load assumptions used in the study for year

2016 and 2021 with the inclusion of the new Etiwanda No.9 [redacted] existing system topology are provided below in Table 3.2.3 and Table 3.2.4 respectively.

Table 3.2.1
Year 2016 Load Distribution

[redacted]

Table 3.2.2
Year 2021 Load Distribution

[redacted]

Table 3.2.3
Year 2022 Load Distribution

[redacted]

Table 3.2.4
Year 2024 Load Distribution

[redacted]

3.3 Generation Assumptions

Generation dispatch of local subtransmission system generation (existing and queued) was done in a manner that would provide for a stressed export of generation in the system. In order to assess the subtransmission system and stress it to its maximum capacity, all local generation resources were dispatched and load values varied as discussed above.

3.4 Subtransmission System Assumptions

The SIS modeled the existing Etiwanda 66 kV Subtransmission System to determine if interconnection of the Project is dependent on the completion of any potentially planned subtransmission upgrades. The study also considered existing system operating bulletins and procedures, if applicable.

3.5 Study Methodology

3.5.1 Power Flow Study

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 study cases were developed to represent stressed scenarios for the subtransmission system study. For maximum generation dispatch, the power flow assessment represented maximum load conditions (L4) reflected in Table 3.2.2 and minimum load conditions (L1 and L2) reflected in Table 3.2.1. For maximum charging conditions, the power flow assessment represents the maximum load conditions (L3 through L4) reflected in Table 3.2.2. Study cases without the inclusion of the Project (pre-project) and study cases with the inclusion of Project (post-project) were modeled for the applicable load conditions reflected. Mitigation measures are recommended for any power flow criteria violation identified to be triggered with the inclusion of the Project. Based on the Project's specifics, the critical outage conditions evaluated are provided below in Table 3.5.1.

Table 3.5.1
List of Contingencies Evaluated

[redacted]

3.5.2 Post Transient Voltage Study

The power flow study voltage results were used as a screen to identify those contingencies that may require additional post-transient voltage studies. Contingencies identified in the power flow to have a voltage drop in excess of 5% were selected for post-transient voltage analysis. The post-transient voltage studies compare voltage deviations to the reliability requirements for contingency outages on the subtransmission system. Mitigation measures are recommended for any criteria violation identified to be triggered with the inclusion of the Project.

3.5.3 Short-Circuit Duty Study

To determine the impact on short-circuit duty within the subtransmission system after inclusion of the Project, the study calculated the maximum symmetrical three-phase-to-ground (3PH) and single-line-to-ground (SLG) short-circuit duties. Generation and transformer data represented in the generator and transformer data sheets provided by the customers were utilized. Bus locations where short-circuit duty is increased with the inclusion of the Project 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, mitigation will be identified for circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities. Mitigation measures can involve circuit breaker upgrade, circuit breaker replacement, system reconfiguration to lower short-circuit duty, or the use of operating procedures. Cost for short-circuit duty mitigation will be allocated to the Project if the study identifies that the upgrades are triggered by the inclusion of the Project. It is important to note that costs for any previous mitigation measures that may have been triggered by queued ahead projects may ultimately be reallocated if the triggering entities ultimately withdraw and the need for the upgrades is still required and triggered by the inclusion of the Project.

3.5.4 Ground Grid Analysis

The short-circuit studies are used to determine substations within the subtransmission where the inclusion Project can potentially cause the need for upgrade to the existing station ground grid. The assessment will flag substations where single-phase-to-ground short-circuit duty is increased by 0.25 kA or more and seek further engineering review.

4. POWER FLOW RESULTS

Given that the Projects is seeking interconnection under ISP, no power flow impacts are identified on the CAISO controlled system since all ISP SIS are performed assuming an Energy Only Interconnection. However, the Project will be included in a Deliverability Study performed as part of a future cluster. Under Energy Only Interconnection, all power flow impacts to the CAISO controlled system are subject to mitigation via the use of congestion management protocols and no network upgrades are required to address any identified power flow impacts.

4.1 Maximum Generation Coupled with Maximum Load Conditions

Under maximum generation coupled with maximum load conditions, the inclusion of the Project, limited to 49.9 MW as requested, did not result in any identified power flow system impacts under base case or outage conditions.

4.2 Maximum Generation Coupled with Minimum Daytime Load Conditions

Under maximum generation coupled with minimum daytime load conditions, the inclusion of Project, limited to 49.9 MW as requested, did not result in any identified power flow system impacts under base case or outage conditions.

4.3 Maximum Generation Coupled with Minimum Anytime Load Conditions

Under maximum generation coupled with minimum anytime load conditions, the inclusion of the Project, limited to 49.9 MW as requested, did not result in any identified power flow system impacts under base case or outage conditions.

4.4 Maximum Energy Storage Coupled with Minimum Generation Dispatch

The storage facility charging study was performed using the load assumptions for years 2016 and 2021 outlined above in Table 3.2.1 and Table 3.2.2 with today's system topology. In addition, the charging assessment considered the addition of the new Etiwanda 9A 220/66 kV transformer bank planned to be in-service in 2022 and modeled load for years 2022 and 2024 as outlined above in Table 3.2.3 and Table 3.2.24 Study results for are as follows:

4.4.1 Existing System Topology

Prior to the inclusion of the Etiwanda 9A 220/66 kV transformer bank, a single Etiwanda 220/66 kV transformer bank is in place serving the portion of the Etiwanda 66 kV Subtransmission System which connects the Project. This single 220/66 kV transformer bank is rated at 280 MVA which provides adequate capacity for year 2021 peak criteria load of 243.2 MW and the 10 MW of charging corresponding to the Project. Under outage condition, the sectionalizing circuit breaker will be closed resulting in a total of 746 MW served via two 220/66 kV transformer banks, which combined have a short term emergency rating of 896 MW. Consequently, no restrictions are anticipated with the existing system topology.

4.4.2 Addition of Etiwanda 9A Coupled with Load Transfers

In year 2022, SCE has planned to install the new Etiwanda 9A 220/66 kV transformer bank and transfer loads served from other 220/66 kV transformer banks. Based on the current forecast, the total load to be served by the combined Etiwanda 8A and 9A transformer banks will increase to 449.1 MW by year 2024. This load is in excess of the 448 MW short-term emergency rating corresponding to the existing of Etiwanda 8A transformer bank and will likely also exceed the ratings for the planned 9A transformer banks. It is important to note that this condition is only expected during peak periods corresponding to time block L5 (2PM to 6PM). Study results during this time block for years 2022 and 2024 are provided below in Figure 4.4.2.1 and Figure 4.4.2.2, respectively.

Figure 4.4.2.1
Etiwanda A-Bank 2022 Loading Results

[redacted]

4.5 Subtransmission Assessment Power Flow Mitigations

4.5.1 Maximum Generation

Based on the study results obtained under maximum generation dispatch conditions, no mitigation is required to accommodate the Project under discharge operation.

4.5.2 Maximum Energy Storage Coupled with Minimum Generation Dispatch

Based on the study results obtained under maximum energy storage "charging", the Etiwanda 66 kV Subtransmission System was found to be adequate to accommodate the Project without mitigation during years 2016 through 2021. However, the planned addition of a new 220/66 kV transformer bank at Etiwanda coupled with load transfers in year 2021 will result in the need to install a storage management system at that point in time. The use of the storage management system would address the incremental impacts corresponding to the Project by limiting or restricting charging based on loadings on the Etiwanda 220/66 kV transformer banks.

4.6 Subtransmission System Energy Storage Restrictions

Based on the load forecast used in this study, current system configuration, and the amount of Energy Storage (MW) seeking interconnection as part of this ISP, the estimated restrictions and arming of the storage management system assuming year 2024 load forecast is illustrated below in Figure 4.6.1.

Figure 4.6.1
Charging Restrictions Assuming Year 2016 Load Forecast
Limitation: Existing Etiwanda No.8 and Future No.9 A-Banks

[redacted]

A summary of the hourly performance for each month assuming future load performance mimics historical load performance (same load shape pattern) is shown below in Figure 4.6.2 reflecting year 2024 load forecast. The performance takes into account the use of the storage management system and therefore summarizes the time periods where charging is expected to be restricted (cells highlighted in red with the number of hours where restriction is expected shown in the cell).

Figure 4.6.2
Monthly Time of Day Performance Expectations
Charging Restrictions Assuming Year 2024 Forecast

[redacted]

These values are specific to restrictions associated with loadings on the Etiwanda No.8 and future No.9 A-Banks. It is important to note that incremental charging restrictions beyond the estimates identified in this study may occur in the future under the following conditions, but not limited to:

- Incremental load growth beyond forecasts
- Additional energy storage interconnection requests beyond this ISP
- Maintenance and/or unplanned outage conditions

The storage management system will serve to ensure system reliability is maintained by addressing future increases to charging restrictions. Interconnection of the Project without the storage management system in year 2016 does not require limitations to charging operation as restrictions are not anticipated until the new Etiwanda No.9 220/66 kV transformer bank is installed.

5. POST TRANSIENT VOLTAGE STABILITY ASSESSMENT RESULTS

Review of the power flow study results did not identify any outage contingency resulting in a voltage deviation that exceeded the screening criteria discussed above. As a result, no further post-transient voltage stability analysis was performed.

6. SHORT-CIRCUIT DUTY ASSESSMENT RESULTS

Meaningful contributions to short-circuit duty were identified to be limited to the Etiwanda 66 kV Subtransmission System. Consequently, the Projects did not impact the Bulk Electric System.

6.1 Application Queue

6.1.1 Subtransmission Level (66 kV)

The breaker evaluations identified that the inclusion of the Project did not trigger the need for any short-circuit duty mitigation at the subtransmission level. The application queue three-phase-to-ground fault currents for the Etiwanda 66 kV Subtransmission System are shown below in Table 6.1. Short-Circuit Duty results did not identify any increase in the Single-Phase-To-Ground fault currents.

Table 6.1
Application Queue Three-Phase-To-Ground Short-Circuit Duty Results
Etiwanda 66 kV Subtransmission System

[redacted]

Detailed review of this single location determined that the incremental 0.1 kA contribution does not increase short-circuit duty in excess of the breaker ratings requiring circuit breaker replacements beyond those already required to support the installation of the Etiwanda No.9 220/66 kV transformer bank.

6.1.2 Distribution Level (less than 66 kV)

The breaker evaluations identified that the inclusion of this project did not trigger the need for short circuit duty mitigation at the low-voltage (less than 66 kV) distribution level within the Etiwanda 66 kV Subtransmission System.

6.2 Operational Queue

An operational study was performed to determine if circuit breaker replacements required to support the installation of the Etiwanda No.9 220/66 kV transformer bank are advanced to an earlier need date as a result of the Project. The operational queue three-phase-to-ground fault currents for the Etiwanda 66 kV Subtransmission System are shown below in Table 6.2. Short-Circuit Duty results did not identify any increase in the Single-Phase-To-Ground fault currents.

Table 6.2.
Operational Queue Three-Phase-To-Ground Short-Circuit Duty Results
Etiwanda 66 kV Subtransmission System

[redacted]

Detailed review of this single location determined that the Project does not advance the need for any of the circuit breaker replacements identified in support of the new transformer bank. Consequently, no short-circuit duty impacts requiring mitigation are assigned to the Project.

6.2 Ground Grid Evaluation

The study did not identify any substation in the Etiwanda 66 kV Subtransmission System where the single line to ground short-circuit duty contribution from the Project increased duty in excess of 0.25 kA. Therefore, no further ground grid evaluation for substations served out of the Etiwanda 66 kV Subtransmission System is required.

7. SCOPE, COST, AND SCHEDULE

Based on the study results, interconnection of the Project will utilize all existing Interconnection Facilities and Distribution Upgrades installed in support of the [redacted] Peaker Project (WDT230). Additional scope is required to enable Interconnection of the Project. The following sections provide the high-level scope description corresponding to the incremental scope and include an estimated cost and discussion addressing the schedule. Specific scope details, including the existing Interconnection Facilities and Distribution Upgrades installed in support of the Grapeland Peaker Project (WDT230), are provided in Attachment 1.

7.1 Scope

7.1.1 Relay Coordination Study

The inclusion of the Project will require a relay coordination study to review current relay settings and make any necessary setting adjustments to accommodate the Project.

7.1.2 Point Additions to existing RTU

The inclusion of the Project will require adding points to the existing RTU to properly account for the new Project.

7.1.3 Storage Management System

The inclusion of the Project will require the installation of a storage management system in year 2021 to address potential thermal overload problems on the Etiwanda B-Section A-Banks. The storage management system should monitor total bank flow on Section B (Etiwanda 8A and future 9A) and limit charging to 95% of the minimum STELL between Etiwanda 8A and future 9A. Based on the existing A-Bank technical details, this would be 95% of the STELL corresponding to Etiwanda 8A bank. The storage management system should account for the existing [redacted] Peaker Project turning off "restriction" if the [redacted] Peaker Project is running and producing more than the charging amount.

7.2 Cost

Cost estimates for the scope of work itemized above is provided in the table below.

Element-	Distribution Upgrades	One-Time Cost	Total
Substation			
Relay Coordination Study		$87,327	$87,327
Power System Control			
Point additions at generation substation		$26,630	$26,630
Storage Management System (Req'd Yr 2021)	$500,069	$26,860	$526,929
Total	$500,069	$140,817	$640,886

Assumptions: Project is exempt from Retail Metering and from ITTC.

7.3 Schedule

Because this project is progressing forward towards interconnection via an Engineering and Design Letter Agreement, construction is already in progress and is anticipated to be complete to meet the required In-Service Date.

8. CONCLUSION

Based on the study results, the Project will require a storage management system in year 2021 which would restrict charging based on total loading on the Etiwanda 220/66 kV No.8 and future No.9 transformer banks. The storage management system will serve to ensure system reliability is maintained and will address future increases to charging restrictions due to increases to load demand. Temporary interconnection of the Project without the storage management system is permitted without restriction as the identified problems will not occur until the planned Etiwanda No.9 220/66 kV transformer bank is placed in-service.

Attachment 1

Interconnection Facilities, Network Upgrades and Distribution Upgrades[1]

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

1. **Interconnection Facilities.**

(a) **Existing Interconnection Customer's Interconnection Facilities.**

[redacted]

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

(i) [redacted]

(ii) Utilize 66 kV generation tie-line from the Interconnection Customer's Large Generating Facility dead-end rack to the Distribution Provider's [redacted] 66 kV Substation.

(iii) Utilize fiber optic cable between Interconnection Customer's Large Generating Facility and Distribution Provider's [redacted] 66 kV Substation to provide both telecommunication paths required for the line protection scheme and the Remote Terminal Unit ("RTU").

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

(v) Provide required data signals and associated dedicated electrical circuits within a secure building having suitable environmental controls to the existing Distribution Provider's RTU in accordance with the Distribution Provider's Interconnection Handbook.

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[1] Nothing in this document is intended to supersede or establish terms/conditions specified in the Large Generator Interconnection Agreement between the parties.

(vi) Install all required CAISO-approved compliant metering equipment at the Generating Facility, in accordance with Section 10 of the CAISO Tariff.
(vii) Utilize existing relay protection for the generation tie-line.

(c) **Existing Distribution Provider's Interconnection Facilities.**

(i) **[redacted] 66 kV Substation.**

1. 66 kV Switchrack equipped as follows:
   - [redacted]
2. Mechanical-Electrical Equipment Room (MEER) housing the following equipment:
   - 60 cell batteries and battery charger
   - Circuit breaker controls and metering
   - Remote Terminal Unit (RTU IR 8600)
   - Station Light and Power Panel
   - AC & DC Distribution panels
   - Protection Relays
3. Protection Relays located in the [redacted] MEER:
   - [redacted]

[redacted]

6. Conduit and control cable to connect the circuit breaker controls and metering to the MEER.
7. Ground Grid covering an approximate area of 711 feet x 81 feet (3 feet outside the fence)

(ii) **66 kV Subtransmission.**

[redacted] tap connection to the [redacted] line utilizing the following facilities:

- [redacted]

(iii) **Power System Controls.**

Utilize the existing full size real-time Remote Terminal Unit at the Large Generating Facility to monitor the following elements:

- Net and Gross MW
- MVAR
- Amps on each phase
- Voltage at the Generator Bus
- Unit Status
- Unit Circuit Breaker Status

(iv) **Telecommunications.**

- [redacted]

(d) **New Distribution Provider's Interconnection Facilities.** The Distribution Provider shall:

(i) [redacted] **66 kV Substation.**

Perform a relay coordination study and reset/testing of protection relays will need to be performed, as required, to account for the new Generating Facility interconnection.

(ii) **Power System Controls.**

Add points to the existing RTU at the Large Generating Facility to monitor the following elements:

- Net and Gross MW
- MVAR
- Amps on each phase
- Voltage at the Generator Bus
- Unit Status
- Unit Circuit Breaker Status

2. **Network Upgrades.**
   (a) **Stand Alone Network Upgrades.** None
   (b) **Other Network Upgrades.** None

3. **Existing Distribution Upgrades.**
   (a) **66 kV Subtransmission**

   Replacement and relocation of one 66 kV line switch (Switch 336) on the existing [redacted] Pipe 66 kV line to accommodate the interconnection of the [redacted] Substation to this line. The switch was relocated to the north of the [redacted] Substation and south of the Pipe Substation tap.

   (b) **Ameron Substation.**

   Balancing Resistor installed on the PilotWire Protection Scheme of the Etiwanda-Pipe 66 kV line to enable [redacted] interconnection to the line resulting in the [redacted] 66 kV line and updates to all station drawings and data base to show the new line name.

4. **New Distribution Upgrades.**
   (a) **Install Storage Management System (estimated need is Year 2021)**
      (i) Create and program Storage Management System (SMS) to support charging restriction aspect of energy storage project
      (ii) Service and test SMS.

5. **Not Used**

6. **Point of Change of Ownership.**
   (a) 66 kV Gen-tie: The Point of Change of Ownership shall be the point where the 66 kV gen-tie conductors are attached to the Distribution Provider's Dead-End Rack at the [redacted] Substation. The Distribution Provider shall own and maintain the [redacted] Dead-End Rack and all insulators attached thereto.

7. **Point of Interconnection.** The Distribution Provider's [redacted] 66 kV tap connection on the [redacted] 66 kV line.

8. One-Line Diagram of Interconnection to the [redacted] Pipe 66 kV line.

[redacted]