

(REVISED 07-01-2025)

**DRAFT**  
**REQUEST FOR PROPOSALS**  
**FOR**  
**RENEWABLE DISPATCHABLE GENERATION**  
**AND**  
**ENERGY STORAGE**  
**ISLANDS OF O‘AHU AND HAWAI‘I**

July 1, 2025

*Appendix H – Interconnection Facilities Cost  
and Schedule Information*



**Hawaiian  
Electric**

Hawaiian Electric Company  
Company-Owned Interconnection Facilities Cost and Schedule Information

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To assist Proposers in estimating costs of potential projects, the information provided in this document can be used to approximate the cost for Company-Owned Interconnection Facilities (“COIF”), including substation, telecommunications, security, transmission and distribution lines, and project management. The Company notes that the information provided here is not a guarantee of what the costs included in the Facility Study will be. The information is based on typical assumptions but may not exactly match the COIF costs required for a particular Proposal depending on the location and facility design.

Tariff Rule No. 19, approved by the PUC, establishes provisions for Interconnection and Transmission Upgrades (<https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/>). The tariff provisions are intended to simplify the rules regarding who pays for, installs, owns, and operates interconnection facilities in the context of competitive bidding. Tariff Rule No. 19 and applicable RFP requirements will be utilized as the basis for addressing interconnection and transmission upgrades for any projects developed. Proposers will comply with the terms and conditions as specified therein.

## **SECTION 1 – COMPANY AND PROPOSER RESPONSIBILITIES**

The purpose of Section 1 is to clearly define the responsibilities to plan, design, procure, and construct COIF and system upgrades in compliance with Tariff Rule No. 19 and this RFP. The Company may determine in the Facility Study that responsibilities listed in this section need to be changed based on project specifics. If there is a conflict, the requirements in the Facility Study shall take precedence.

Please note that ownership of Proposer-built COIF cannot be transferred to the Company prior to all work being completed and all permits associated with the COIF being closed. If COIF is covered under the same permit as SOIF and Project facilities, ownership of the COIF cannot be transferred until the entire facility is completed and the permit is closed. If Proposer plans to transfer ownership as construction is completed for COIF, then the COIF needs to be permitted separately from any other facilities so that the permits can be closed when COIF construction is complete. The Company will not perform construction on equipment/assets that is not owned by the Company.

The Proposer will be responsible for all costs related to COIF and system upgrades, subject to any limitations, as described in Section 1.

### **1.1 – DEFINITIONS**

1. Betterment – Any upgrading to a facility made solely for the benefit of and at the election of the Company and is not required by applicable laws, codes, Company Standards, and the interconnection requirements in accordance with Tariff Rule No. 19.
2. Company – Hawaiian Electric, Maui Electric, or Hawai‘i Electric Light.
3. Company-Owned Interconnection Facilities – The equipment and devices owned by Company between the Point of Interconnection and the Grid Connection Point that are required to permit a generating facility to operate in parallel with and deliver

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electric energy to Company's system and provide reliable and safe operation of, and power quality on, Company's system.

4. Grid Connection Point – The point that the new interconnection facilities associated with the Proposer's project interconnects to the Company's existing electrical grid.
5. Interconnection Agreement – The executed contract between the Company and Proposer (e.g., Power Purchase Agreement, Standard Interconnection Agreement, etc.).
6. Point of Interconnection – The point of delivery of energy supplied by Proposer to Company, where the Facility owned by the Proposer interconnects with the facilities owned or to be owned by the Company.
7. Proposer – The developer proposing a renewable project in response to a Company RFP.

## 1.2 – ABBREVIATIONS

1. ADSS – All Dielectric Self-Supporting
2. COIF – Company-Owned Interconnection Facilities
3. CT – Current Transformer
4. DFR – Digital Fault Recorder
5. DTT – Direct Transfer Trip
6. FS – Facility Study
7. GCP – Grid Connection Point
8. HVAC – Heating, Ventilation, and Air Conditioning
9. IRS – Interconnection Requirements Study (includes both SIS and FS)
10. NDA – Non-Disclosure Agreement
11. OPGW- Optical Ground Wire
12. POI – Point of Interconnection
13. PT – Potential Transformer
14. RTU – Remote Terminal Unit
15. SCADA – Supervisory Control and Data Acquisition
16. SIS – System Impact Study
17. UFLS – Under-Frequency Load Shed

## 1.3 – FACILITIES IN A PROPOSER-OWNED SUBSTATION/SITE

1. Proposer will perform the following:
  - a. Obtain all permitting and land rights.
  - b. Design, procurement, and construction of all facilities at the Proposer's site, except as listed in Item 2 below. All COIF shall comply with applicable Company standards and utilize Company design templates, where applicable. This may include, but is not limited to:
    - i. Site development and civil infrastructure work (e.g., grading, trenching, manholes/handholes, conduits, cable trench, concrete pads/foundations, fencing, roadways/driveways, ground grid, lighting, etc.).

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- ii. Substation structures, design, and configuration (i.e., breaker and a half, ring bus, etc.).
- iii. Control equipment enclosure/cabinet.
- iv. Equipment (circuit breakers, transformers, relays, switches, arresters, batteries, HVAC, RTU, DFR, DTT, meters, PTs, CTs, etc.).
- v. Telecommunication equipment (See Telecommunication Facilities section below).
- vi. Electrical work (bussing, wiring, lightning protection, fiber optic cable, etc.).
- vii. Security systems/equipment (See Section 2.6A).
- c. Support the Company in performance of its scope of work. This may include but is not limited to:
  - i. Providing as-built drawings prior to acceptance testing.
- 2. Company will perform the following:
  - a. Review and approval of Proposer drawings and material selection.
  - b. Inspection of Proposer COIF construction.
  - c. Programming and functional testing of digital devices (e.g., DFR, RTU, etc.).
  - d. Acceptance testing.
  - e. Procurement, installation, and testing of revenue meters.
  - f. Support of Proposer's Control System Acceptance Test (CSAT).
- 3. Company shall be responsible for Betterment costs.

#### **1.4 – EXISTING COMPANY SUBSTATIONS**

- 1. Company will perform all engineering, procurement, and construction for work at existing Company-owned substations except as described below.
  - a. For an OH termination into an existing substation, Proposer is responsible for design, procurement, and construction of the OH T&D facilities from the project site up to and including the last pole/foundation before the substation termination structure. Proposer shall coil enough OH conductor and shieldwire on the last pole for Company to string and terminate the last span of conductor to the termination structure in the substation.
  - b. For a 138kV UG termination into an existing substation, Proposer is responsible for design, procurement, and construction of the UG T&D lines and associated civil infrastructure up to the termination on the riser structure.
- 2. Company will be responsible for the following costs:
  - a. Betterment.
  - b. Changes to the Under-Frequency Load Shed (UFLS) scheme.

#### **1.5 – NEW COMPANY-OWNED SWITCHING STATION**

- 1. Proposer will perform the following:
  - a. Obtain all permitting and land rights.
  - b. Provide vehicular access to the new switching station.
  - c. Design, procurement, and construction of all facilities at the switching station, except as listed in Item 2 below. All COIF shall comply with applicable

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Company standards and utilize Company design templates. This may include, but is not limited to:

- i. Site development and civil infrastructure work (e.g., grading, trenching, manholes/handholes, conduits, cable trench, concrete pads/foundations, fencing, roadways/driveways, ground grid, lighting, etc.).
  - ii. Substation structures, design, and configuration (i.e., breaker and a half, ring bus, etc.).
  - iii. Control equipment enclosure/cabinet.
  - iv. Equipment (circuit breakers, transformers, relays, switches, arresters, batteries, HVAC, RTU, DFR, DTT, meters, PTs, CTs, etc.).
  - v. Telecommunication equipment (See Section 1.10).
  - vi. Electrical work (bussing, wiring, lightning protection, fiber optic cable, etc.).
  - vii. Security systems/equipment (See Section 2.6B).
- d. Support the Company in performance of its scope of work. This may include, but is not limited to:
- i. Pulling wiring between RTU and IPP interface cabinet and coiling up on both ends for Company to terminate.
  - ii. Providing as-built drawings prior to acceptance testing.
2. Company will perform the following:
- a. Review and approval of Proposer drawings and material selection.
  - b. Inspection of Proposer construction.
  - c. Programming and functional testing of digital devices (i.e., DFR, RTU, etc.).
  - d. Termination of wiring between RTU and IPP interface cabinet.
  - e. Acceptance testing.
  - f. Procurement, installation, and testing of revenue meters.
3. Company shall be responsible for Betterment costs.

**1.6 – PROPOSER FACILITY SERVICE POWER AND COMPANY SWITCHING STATION POWER**

1. Facility service power is NOT a part of COIF, but Proposers should account for it in the total costs to build the project. Please note the following:
  - a. Auxiliary loads for a grid-charged BESS shall not receive service power from the grid charging power.
  - b. The Company will not perform construction on equipment/assets (poles, conduit, pads, etc.) that is not owned by the Company, except when connecting to a Proposer-owned primary metered pole. The Company will terminate at the pole, not beyond.
  - c. Ownership of Proposer-built equipment/assets must be transferred before the Company is able to schedule the installation of Company-owned equipment on those facilities.
  - d. If temporary power is required before the completion and turnover of facilities, a separate temporary line extension is required.

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2. Station power is required if a new Company switching station or substation is built to allow the interconnection of the Proposer's project.
  - a. Options for primary station power sources for the Company's various switching station voltages are:
    - i. Tap off the bus through a step-down transformer for 23kV through 69kV.
    - ii. 12kV line extension and service transformer for 23kV through 138kV.
    - iii. Gensets are not an allowable substitute for the above options.
3. For all new service requests, Proposer is responsible for submitting an Electrical Service Request Form via [www.hawaiianelectric.com](http://www.hawaiianelectric.com). Please refer to the [Large Customer New Service Request brochure](#) for milestones and estimated timeline.
4. New service requests are not included in the Interconnection Agreement and will be covered under a separate agreement that will identify responsibilities for work.
5. Typically, requesters for service would perform the following:
  - a. Obtain all permitting and land rights.
  - b. Provide infrastructure plans showing the proposed OH and/or UG route, including locations of all Company facilities (poles, MHs, HHs, vaults, conduits, equipment, etc.)
  - c. Civil infrastructure work (survey, design, grading, trenching, conduits, manholes/handholes, concrete pads, etc.)
  - d. Support the Company in performance of its scope of work. This may include, but is not limited to:
    - i. Survey/stakeout of poles and anchors in accordance with the Company-approved design drawings and in advance of Company construction.
    - ii. Vegetation trimming/removal.
    - iii. Providing vehicular access.
6. Typically, the Company would be responsible for performing the following:
  - a. Review and approval of Proposer Drawings.
  - b. Inspection of Proposer construction.
  - c. Design, procurement, and construction of electrical facilities.

### 1.7 – NEW COMPANY-OWNED T&D LINES

1. Proposer will perform the following:
  - a. Obtain all permitting and land rights.
  - b. Design, procurement, and construction of all T&D facilities required to interconnect the project facility, except as listed in Item 2 below. All COIF shall comply with applicable Company standards and specifications. This may include, but is not limited to:
    - i. The OH and/or UG route, including locations of all Company facilities (poles, MHs, HHs, vaults, conduits, equipment, etc.).
    - ii. Civil infrastructure.
    - iii. Electrical facilities up to and including the last pole or manhole/vault prior to the interconnection to existing Company facilities.

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- a. **For OH tap to existing OH lines:** Coil enough OH conductor on the last pole for Company to string and terminate the last span of conductor to the GCP.
  - b. **For UG tap to existing OH lines:** Stub-up the riser conduit above ground level at the bottom of the riser pole. Pull cable to the last MH/HH/vault prior to the riser. Provide enough cable for Company to make the last pull up the riser and terminate the cables.
  - c. **For UG tap to existing UG lines:** Install conduit to up to the interception point of the Company's existing facilities (coordinate with Company to break into facilities at interception point). Pull cable to the last MH/HH/vault prior to intercepting Company's existing facilities. Provide enough cable for Company to make the last pull to the interception point.
- c. Support the Company in performance of its scope of work. This may include, but is not limited to:
    - i. Survey/stakeout of poles and anchors in accordance with the Company-approved design drawings and in advance of Company construction.
    - ii. Vegetation trimming/removal.
    - iii. Providing vehicular access.
2. The Company will perform the following:
    - a. Review and approval of Proposer Drawings.
    - b. Inspection of Proposer construction.
    - c. Design, procurement, and construction of electrical facilities for the final tap at the GCP.
    - d. Design, procurement, and construction of electrical facilities within Company's existing energized corridor.
    - e. Procurement does not include the conductors or cable required for the last span as discussed in Item 1 above.
    - f. Break into Company's existing UG facilities for interception point (e.g., at an existing MH/HH/vault).
  3. The Company will be responsible for Betterment costs.

## **1.8 – UPGRADES TO EXISTING T&D LINES**

1. Company will perform all engineering, procurement, and construction for upgrades of existing Company lines to accommodate the Proposer's project (e.g., re-conductoring or recircuiting of existing lines that do not have the required ampacity, re-fusing or re-programming of protective devices on the system, etc.).

## **1.9 – COMPANY-OWNED FIBER**

1. Proposer will perform the following:
  - a. Obtain all permitting and land rights.























































### Estimate Breakdown (O’ahu)

[ENTER COIF SCOPE AND ASSUMPTIONS]

Example:

1. New 3-bay, 9-breaker BAAH switchyard.
2. OH to OH interconnections to Waiau-Ewa Nui 1 and Waiau-Ewa Nui 2 138kV circuits. Waiau-Ewa Nui 1 line extension includes 0.25mi of new OH line, and 0.2mi of overbuild on existing 46kV. Waiau-Ewa Nui 2 line extension includes 0.45mi of new OH line. Line extensions are accessible by truck.
3. Primary communication: Fiber to nearest splice point 0.5mi away. Fiber line will be underbuilt on existing lines. Backup communication: Leased line with Hawaiian Telcom.
4. System upgrades: None.

Appx H Item / Description	Qty	Unit	Unit Price	Total Cost
<b>Company COIF/System Upgrade Costs</b>				
<b>Section 2.1 - Substation &amp; Meter Baseline</b>				
<b>Subtransmission</b>				
[16] 46kV Interconnection		EA	\$1,435,000	\$0
[21] Remote sub work for 46kV circuits		SITE	\$570,000	\$0
<b>Transmission</b>				
[32] 138kV interconnection (2 circuits)		EA	\$2,668,000	\$0
[36a] Remote sub - 138kV line relay upgrades		EA	\$566,000	\$0
[36b] Remote sub - 138kV CB replacement		EA	\$701,000	\$0
[36c] Remote sub - 138kV DTT for anti-islanding		EA	\$156,000	\$0
<b>Section 2.2 - Interconnection to Specific Company Sites</b>				
[61a] Ewa Nui - work at Project site		EA	\$561,000	\$0
[61b] Ewa Nui - work at existing sub		EA	\$3,344,000	\$0
[62a] Kahe 5-8 - work at Project site		EA	\$561,000	\$0
[62b] Kahe 5-8 - work at existing sub		EA	\$3,344,000	\$0
[63a] Hoohana - work at Project site		EA	\$561,000	\$0
[63b] Hoohana 1st Termination		EA	\$1,440,000	\$0
[64a] CEIP - work at Project site		EA	\$561,000	\$0
[64b] CEIP - work at existing sub		EA	\$3,344,000	\$0
[65a] Koolau - work at Project site		EA	\$561,000	\$0
[65b] Koolau - work at existing sub		EA	\$2,880,000	\$0
[66a] AES - work at Project site		EA	\$561,000	\$0
[66b] AES - work at existing sub		EA	\$566,000	\$0
[69] Reuse 138kV termination for existing IPP connections		EA	\$610,000	\$0
<b>Section 2.3 - T&amp;D Baseline and Line Extension Costs</b>				
<b>Subtransmission</b>				
[120-1] 46kV OH to OH final tap (1st tap)		EA	\$98,000	\$0
[120-2] 46kV OH to OH final tap (2nd tap)		EA	\$60,000	\$0
[121-1] 46kV OH to UG final tap (1st tap)		EA	\$256,000	\$0
[121-2] 46kV OH to UG final tap (2nd tap)		EA	\$218,000	\$0
[122-1] 46kV UG to UG final tap (1st tap)		EA	\$275,000	\$0
[122-2] 46kV UG to UG final tap (2nd tap)		EA	\$237,000	\$0

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<b>Transmission</b>				
[133] 138kV OH to OH final tap		CKT	\$1,009,000	\$0
[135] 138kV OH final span for termination to existing substation		EA	\$111,000	\$0
[136] 138kV UG termination to existing substation		EA	\$37,000	\$0
<b>Line Extensions and Upgrades</b>				
[160] 46kV Add'l 100ft OH line extension (Proposer-built)		EA	\$3,600	\$0
[161] 46kV Add'l 100ft UG line extension (Proposer-built)		EA	\$6,400	\$0
[165] 46kV overbuild on existing accessible 12kV		MI	\$1,543,000	\$0
[166] 46kV overbuild on existing inaccessible 12V		MI	\$2,470,000	\$0
[170] Upgrade existing 46kV OH lines		MI	\$1,100,000	\$0
[175] 138kV Add'l 100ft OH line extension (Proposer-build)		EA	\$6,000	\$0
[176] 138kV Add'l 100ft UG line extension (Proposer-build)		EA	\$8,000	\$0
[180] 138kV overbuild on existing accessible 46kV		MI	\$6,570,000	\$0
[183] Upgrade existing 138kV OH lines		MI	\$1,897,000	\$0
[184] 138kV Steel Pole Replacement		EA	\$732,000	\$0
<b>Section 2.4 - Project Management Baseline Costs</b>				
<b>Subtransmission</b>				
[196E] PM - Engineering Phase		MO	\$25,400	\$0
[196C] PM - Construction Phase		MO	\$34,100	\$0
[196T] PM - Testing/Closeout		MO	\$15,100	\$0
<b>Transmission</b>				
[197E] PM - Engineering Phase		MO	\$25,400	\$0
[197C] PM - Construction Phase		MO	\$34,100	\$0
[197T] PM - Testing/Closeout		MO	\$15,100	\$0
<b>Section 2.5 - Telecommunication Baseline Costs</b>				
[201] Comm cabinet (≥ 1MW and ≤ 3MW)		SITE	\$127,000	\$0
[202] Comm cabinet (> 3MW)		SITE	\$284,000	\$0
[205] LTE Cellular or Lease Line		EA	\$0	\$0
[207] Licensed 900MHz Radio		LINK	\$152,000	\$0
[212] 200ft of new fiber-optic cable (Proposer-built)		EA	\$700	\$0
[213] Fiber termination or splice		EA	\$23,000	\$0
[215] Point to point Microwave link (backbone)		LINK	\$785,000	\$0
[216] Microwave link (last mile)		LINK	\$333,000	\$0
[217] 50ft Microwave tower		EA	\$801,000	\$0
[218] 100ft Microwave tower		EA	\$1,072,000	\$0
[220] Fiber from "meet point" to termination in Company switching station		EA	\$43,000	\$0
<b>Section 2.6 - Security Costs</b>				
[251] Oahu substation security		SITE	\$114,000	\$0
<b>ESTIMATED TOTAL COMPANY COIF COSTS =</b>				<b>\$0</b>
<b>ESTIMATED TOTAL COMPANY COIF COSTS (ADJUSTED FOR ESCALATION) =</b>				

Appendix H, Attachment 1

Description	Total Cost
<b>Proposer-Built COIF/System Upgrade Costs</b>	
Substation	
T&D	
Telecom	
Security (\$0 if these costs are included in Substation costs)	
<b>ESTIMATED TOTAL PROPOSER-BUILT COIF COSTS =</b>	<b>\$0</b>
<b>ESTIMATED TOTAL PROPOSER-BUILT COIF COSTS (ADJUSTED FOR ESCALATION) =</b>	
<b>ESTIMATED TOTAL COIF COSTS =</b>	<b>\$0</b>
<b>ESTIMATED TOTAL COIF COSTS (ADJUSTED FOR ESCALATION) =</b>	<b>\$0</b>

### Estimate Breakdown (Hawai'i Island)

[ENTER COIF SCOPE AND ASSUMPTIONS]

Example:

1. New 2-bay, 4-breaker BAAH switchyard.
2. OH to OH interconnection to L7100. Line extension includes 0.25mi of new OH line. Line extensions is accessible by truck.
3. Primary communication: Fiber to nearest splice point 0.5mi away. Fiber line will be underbuilt on existing lines. Backup communication: Leased line with Hawaiian Telcom.
4. System upgrades: 2 miles of 69kV reconductoring.

Appx H Item / Description	Qty	Unit	Unit Price	Total Cost
<b>Company COIF Costs</b>				
<b>Section 2.1 - Substation &amp; Meter Baseline</b>				
[30] 69kV Interconnection		EA	\$1,312,000	\$0
[34a] Remote sub - 69kV line relay upgrades		EA	\$284,000	\$0
[34b] Remote sub - Circuit switcher & differential protection per tsf/swgr		EA	\$365,000	\$0
[34c] Remote sub - 69kV circuit breaker replacement		EA	\$424,000	\$0
[34d] Remote sub - 3ph line PTs required for Synch Check		EA	\$142,000	\$0
<b>Section 2.2 - Interconnection to Specific Company Sites</b>				
[43a] Kanoelehua - work at Project site		EA	\$561,000	\$0
[43b] Kanoelehua - work at existing sub		EA	\$1,346,000	\$0
[46a] Poopomino - work at Project site		EA	\$561,000	\$0
[46b] Poopomino - work at existing sub		EA	\$2,046,000	\$0
[47] Kamaoa - upgrade existing interconnection		EA	\$503,000	\$0
[55] Reuse 69KV termination for existing IPP connections		EA	\$503,000	\$0
<b>Section 2.3 - T&amp;D Baseline and Line Extension Costs</b>				
[130] 69kV OH to OH final tap		EA	\$170,000	\$0
[131] 69kV OH final span for termination to existing substation		EA	\$66,000	\$0
<b>Line Extensions and Upgrades</b>				
[160] 69kV Add'l 100ft OH line extension (Proposer-build)		EA	\$3,600	\$0
[161] 69kV Add'l 100ft UG line extension (Proposer-build)		EA	\$6,400	\$0
[165] 69kV overbuild on existing accessible 12kV		MI	\$1,543,000	\$0
[166] 69kV overbuild on existing inaccessible 12V		MI	\$2,470,000	\$0
[170] Upgrade existing OH lines		MI	\$1,100,000	\$0
<b>Section 2.4 - Project Management Baseline Costs</b>				
[197E] PM - Engineering Phase		MO	\$25,400	\$0
[197C] PM - Construction Phase		MO	\$34,100	\$0
[197T] PM - Testing/Closeout		MO	\$15,100	\$0
<b>Section 2.5 - Telecommunication Baseline Costs</b>				
[201] Comm cabinet (≥ 1MW and ≤ 3MW)		SITE	\$127,000	\$0
[202] Comm cabinet (> 3MW)		SITE	\$284,000	\$0

Appendix H, Attachment 1

[205] Lease Line		EA	\$0	\$0
[207] Licensed 900MHz Radio		LINK	\$152,000	\$0
[212] 200ft of new fiber-optic cable (Proposer-built)		EA	\$700	\$0
[213] Fiber termination or splice		EA	\$23,000	\$0
[215] Point to point Microwave link (backbone)		LINK	\$785,000	\$0
[216] Microwave link (last mile)		LINK	\$333,000	\$0
[217] 50ft Microwave tower		EA	\$801,000	\$0
[218] 100ft Microwave tower		EA	\$1,072,000	\$0
[220] Fiber from "meet point" to termination in Company switching station		EA	\$43,000	\$0

**Section 2.6 - Security Costs**

[250] Hawaii substation security		SITE	\$72,000	\$0
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<b>ESTIMATED TOTAL COMPANY COIF COSTS =</b>				<b>\$0</b>
<b>ESTIMATED TOTAL COMPANY COIF COSTS (ADJUSTED FOR ESCALATION) =</b>				

Description	Total Cost
<b>Proposer-Built COIF and System Upgrade Costs</b>	
Substation	
T&D	
Telecom	
Security (\$0 if these costs are included in Substation costs)	
<b>ESTIMATED TOTAL PROPOSER-BUILT COIF COSTS =</b>	
<b>\$0</b>	
<b>ESTIMATED TOTAL PROPOSER-BUILT COIF COSTS (ADJUSTED FOR ESCALATION) =</b>	

<b>ESTIMATED TOTAL COIF COSTS =</b>		<b>\$0</b>
<b>ESTIMATED TOTAL COIF COSTS (ADJUSTED FOR ESCALATION) =</b>		<b>\$0</b>

### PROJECT EXAMPLES (O’AHU) - APPENDIX H UNIT COST TABLE

Examples provided for illustrative purposes only and is not binding for actual facility costs.

Estimated costs represent Company costs charged to the Proposer.

#### Projects interconnecting to a 46kV circuit

##### Example 1

15MW project interconnecting to two (2) 46kV circuits. Proposer will construct a new 46kV Company-owned substation per Attachment S1 of this Appendix H. Proposer will construct separate line extensions to two (2) separate 46kV circuits. The first line extension is 900ft OH and the second is 800ft OH and 100ft UG (not including the 100ft span at the GCPs). The second line tap is at a riser (OH to UG type). Company will complete the final taps. Relay upgrades required on one of the circuits. Proposer to install 1000ft of ADSS fiber from the nearest splice point to the new substation for primary communications. Company to install Company-owned equipment in Proposer-provided communications cabinet. Proposer to provide leased line for backup telecommunications. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[16] 46kV Interconnection	1	EA	\$1,435,000	\$1,435,000
[21] Remote sub work	1	SITE	\$570	\$570
[120-1] 46kV OH to OH Final Tap (1st tap)	1	EA	\$98,000	\$98,000
[121-2] 46kV OH to UG Final Tap (2nd tap)	1	EA	\$218,000	\$218,000
[160] Additional 100ft OH Line Extension	17	EA	\$3,600	\$61,200
[161] Additional 100ft UG Line Extension	1	EA	\$6,400	\$6,400
[196E] PM - Engineering Phase	18	MO	\$25,400	\$457,200
[196C] PM - Construction Phase	10	MO	\$34,100	\$341,000
[196T] PM - Testing/Closeout	6	MO	\$15,100	\$90,600
[202] Comm Cabinet (> 3MW)	1	LS	\$284,000	\$284,000
[205] Lease Line	1	LS	\$0	\$0
[212] 200ft of new fiber-optic cable	5	EA	\$700	\$3,500
[213] Fiber termination or splice	2	EA	\$23,000	\$46,000
[251] Oahu substation security	1	LS	\$114,000	\$114,000
<b>Proposer-Built COIF Costs</b>				
Substation (ring bus)				\$10,315,000
T&D (OH/UG lines)				\$575,000
Telecom (ADSS fiber, leased line)				\$70,000
Security (system for substation)				\$275,000
			<b>ESTIMATED TOTAL =</b>	<b>\$14,390,470</b>

**Projects interconnecting to transmission**

**Example 2**

100MW project interconnecting to existing 138kV OH circuits. Proposer to build a new Company-owned 4-bay BAAH switching station per Attachment T2 of this Appendix H. Line extension includes interception of existing circuits and a 1500ft extension of four (4) new 138kV OH lines to new Company switching station (not including the 100ft spans at the tap). All lines are accessible. Proposer to construct the new OH lines between the termination structures at the substation and the last poles/structures before intercepting the existing lines. Company will construct the final tap from the last poles/structures to the GCP. Line relay upgrades and 3ph line PTs are required on both circuits and a breaker replacement is required on one circuit. Proposer to install 1300 ft of ADSS fiber to the new Company switching station. Company to install Company-owned equipment in Proposer-provided communications cabinet. Proposer to provide leased line for backup telecommunications. Proposer's substation is adjacent to Company's switching station. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[32] Company work at new substation	1	EA	\$2,668,000	\$2,668,000
[36a] Remote sub - 138kV line relay upgrades	2	EA	\$566,000	\$1,132,000
[36b] Remote sub - 138kV CB replacement	1	EA	\$701,000	\$701,000
[133] 138kV OH to OH Final Tap	2	EA	\$1,009,000	\$2,018,000
[175] Additional 100ft OH Line Extension	60	EA	\$8,000	\$480,000
[197E] PM - Engineering Phase	18	MO	\$25,400	\$457,200
[197C] PM - Construction Phase	10	MO	\$34,100	\$341,000
[197T] PM - Testing/Closeout	6	MO	\$15,100	\$90,600
[205] Lease Line	1	LS	\$0	\$0
[202] Comm Cabinet (> 3MW)	1	LS	\$284,000	\$284,000
[212] 200ft of new fiber-optic cable	5	EA	\$700	\$3,500
[213] Fiber termination or splice	2	EA	\$23,000	\$46,000
[251] Oahu substation security	1	LS	\$114,000	\$114,000
<b>Proposer-Built COIF Costs</b>				
Substation (3-bay, 9-bkr BAAH)				\$24,000,000
T&D (OH lines)				\$8,700,000
Telecom (ADSS fiber, leased line)				\$77,000
Security (system for substation)				\$500,000
			<b>ESTIMATED TOTAL =</b>	<b>\$41,612,300</b>

**Example 3**

100MW project interconnecting at Kahe 5-8 substation. Proposer to run an OH gen-tie line (1,000ft each, not including 100ft span into sub) from Proposer's site to Kahe 5-8. Termination into Kahe 5-8 will be overhead, and Company to string final OH span from last pole to termination structure at Kahe 5-8. Proposer to run fiber between Proposer's substation and meet point near Kahe 5-8 since substation is not adjacent to existing sub. A comm cabinet is required at the Proposer's substation. Company to install Company-owned equipment in Proposer-provided communications cabinet. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[62a] Kahe 5-8 - work at Project site	1	EA	\$561,000	\$561,000
[62b] Kahe 5-8 - work at existing sub	1	EA	\$3,344,000	\$3,344,000
[135] 138kV OH termination to existing sub	1	EA	\$111,000	\$111,000
[197E] PM - Engineering Phase	18	MO	\$25,400	\$457,200
[197C] PM - Construction Phase	10	MO	\$34,100	\$341,000
[197T] PM - Testing/Closeout	6	MO	\$15,100	\$90,600
[202] Comm Cabinet (> 3MW)	1	LS	\$284,000	\$284,000
[220] Fiber meet point	1	EA	\$43,000	\$43,000
<b>Proposer-Built COIF Costs</b>				
Substation (existing substation so nothing needed)				\$0
T&D (Gen-tie is Proposer-owned)				\$0
Telecom (fiber between Proposer sub and meet point is Proposer-owned)				\$0
Security (existing substation so nothing needed)				\$0
			<b>ESTIMATED TOTAL =</b>	<b>\$5,231,800</b>

**Electrical service to Proposer Facility**

**Example 4**

Proposer requests service from existing 12kV line 0.5 miles away from the facility (new OH line for 0.4 miles and 0.1 miles underbuilt on the Company-owned interconnection lines). The OH line risers down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[188] Facility or Station Power	1	EA	\$104,000	\$104,000
[189] 12kV OH accessible	0.4	MI	\$835,000	\$334,000
[190] 12kV underbuild	0.1	MI	\$510,000	\$51,000
[193] 12kV 3ph riser	1	EA	\$47,000	\$47,000
Proposer-built civil infrastructure	1	LS	\$0	\$0
		<b>ESTIMATED TOTAL =</b>		<b>\$536,000</b>

**Electrical service to Proposer Facility and Primary station service for Company-owned switching station**

**Example 5**

Proposer requests service from existing 12kV line 0.2 miles away from the facility. Line extension is a new OH accessible line. The OH line riser down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Primary station service for the Company-owned switching station will be tapped off of the facility service line extension, riser underground, with 2 feeders going to a padmount station service transformer in the switching station located 300ft away from the tap point. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[188] Facility or Station Power	2	EA	\$104,000	\$208,000
[189] 12kV OH accessible	0.2	MI	\$835,000	\$167,000
[193] 12kV 3ph riser	1	EA	\$47,000	\$47,000
[193] 12kV 3ph riser (station svc)	1	EA	\$47,000	\$47,000
[192] 12kV UG dbl feeder (station svc)	0.04	MI	\$1,253,000	\$47,462
Proposer-built civil infrastructure	1	LS	\$0	\$0
		<b>ESTIMATED TOTAL =</b>		<b>\$516,462</b>

### PROJECT EXAMPLES (HAWAI'I) - APPENDIX H UNIT COST TABLE

Examples provided for illustrative purposes only and is not binding for actual facility costs.

Estimated costs represent Company costs charged to the Proposer.

#### Projects interconnecting to a 69kV circuit

##### Example 1

20MW PV system on Hawai'i interconnecting to an existing 69kV OH circuit. Proposer to build a new Company-owned 2-bay (4 breaker) BAAH switching station per Attachment T1 of this Appendix H. Proposer's substation is adjacent to new Company switching station. Line extension includes interception of existing line and 1000ft extension of two (2) new 69kV OH lines to new Company switching station. All lines are accessible. Proposer to construct the new OH lines between the termination structure at the substation and the last pole/structure before intercepting the existing lines. Company will construct the final tap from the last pole/structure to the GCP and remove existing 69kV OH lines. Existing lines connect to two (2) remote subs. One (1) circuit switcher and differential protection required for one transformer/switchgear at one remote sub. Line relay upgrades, replacement of one (1) 69kV circuit breaker, and 3ph line PTs for synch check required at the other remote sub. Proposer to install 1000ft of new ADSS fiber to the new Company switching station. Company installs Company-owned equipment in Proposer-provided communications cabinet and terminates fiber at both ends. Proposer to provide leased line for backup telecommunications. Assumed durations: Engineering = 18 months, Construction = 10 months, Testing/closeout = 6 months.

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[30] 69kV Interconnection	1	EA	\$1,312,000	\$1,312,000
[34a] Remote sub - 69kV line relay upgrades	1	EA	\$284,000	\$284,000
[34b] Remote sub - Circuit switcher & differential protection per tsf/swgr	1	EA	\$365,000	\$365,000
[34c] Remote sub - 69kV circuit breaker replacement	1	EA	\$424,000	\$424,000
[34d] Remote sub - 3ph line PTs required for Synch Check	1	EA	\$142,000	\$142,000
[130] 69kV OH to OH final tap	1	EA	\$170,000	\$170,000
[160] 69kV Add'l 100ft OH line extension (Proposer-build)	18	EA	\$3,600	\$64,800
[197E] PM - Engineering Phase	18	MO	\$25,400	\$457,200
[197C] PM - Construction Phase	10	MO	\$34,100	\$341,000
[197T] PM - Testing/Closeout	6	MO	\$15,100	\$90,600
[202] Comm cabinet (> 3MW)	1	EA	\$284	\$284
[205] Lease Line	1	LS	\$0	\$0
[212] 200ft of new fiber-optic cable	5	EA	\$700	\$3,500
[213] Fiber termination or splice	2	EA	\$23,000	\$46,000
[250] Hawaii substation security	1	LS	\$72,000	\$72,000
			<b>ESTIMATED TOTAL =</b>	<b>\$3,772,384</b>

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**Electrical service to Proposer Facility**

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**Example 2**

Proposer requests service from existing 12kV line 0.5 miles away from the facility (new OH line for 0.4 miles and 0.1 miles underbuilt on the Company-owned interconnection lines). The OH line risers down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[188] Facility or Station Power	1	EA	\$104,000	\$104,000
[189] 12kV OH accessible	0.4	MI	\$835,000	\$334,000
[190] 12kV underbuild	0.1	MI	\$510,000	\$51,000
[193] 12kV 3ph riser	1	EA	\$47,000	\$47,000
Proposer-built civil infrastructure	1	LS	\$0	\$0
			<b>ESTIMATED TOTAL =</b>	<b>\$536,000</b>

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**Electrical service to Proposer Facility and Primary station service for Company-owned switching station**

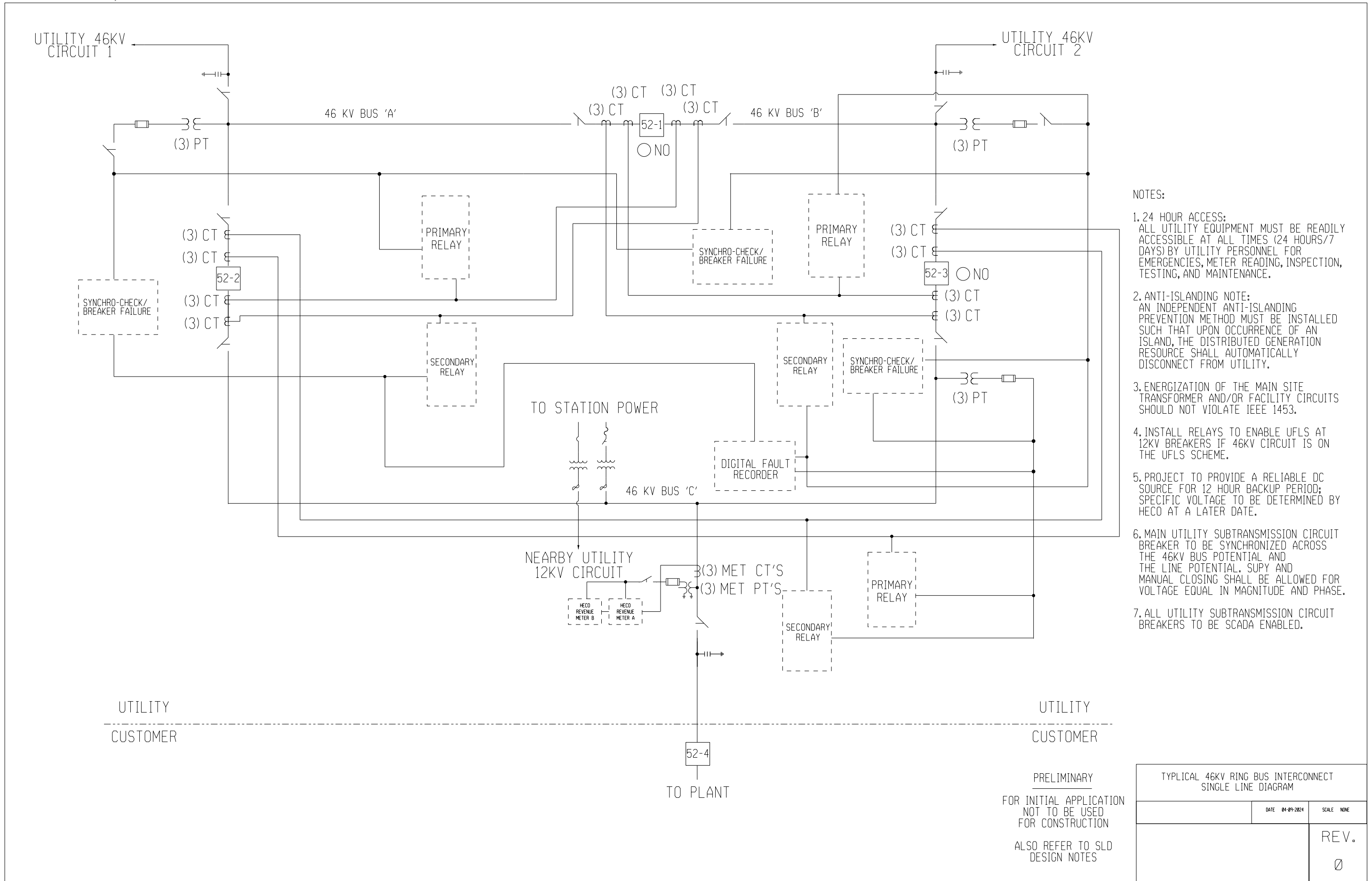
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**Example 3**

Proposer requests service from existing 12kV line 0.2 miles away from the facility. Line extension is a new OH accessible line. The OH line riser down and 2 feeders will serve a padmount transformer 100ft away from the riser pole. Primary station service for the Company-owned switching station will be tapped off of the facility service line extension, riser underground, with 2 feeders going to a padmount station service transformer in the switching station located 300ft away from the tap point. Proposer to install civil infrastructure (ductlines, MH/HH/vaults, equipment pads, etc.).

Appx H Item / Description	Quantity	Unit	Unit Price (\$)	Total Cost (\$)
[188] Facility or Station Power	2	EA	\$104,000	\$208,000
[189] 12kV OH accessible	0.2	MI	\$835,000	\$167,000
[193] 12kV 3ph riser	1	EA	\$47,000	\$47,000
[193] 12kV 3ph riser (station svc)	1	EA	\$47,000	\$47,000
[192] 12kV UG dbl feeder (station svc)	0.04	MI	\$1,253,000	\$47,462
Proposer-built civil infrastructure	1	LS	\$0	\$0
			<b>ESTIMATED TOTAL =</b>	<b>\$516,462</b>

(REVISED 07-01-2025)



- NOTES:
- 24 HOUR ACCESS:  
ALL UTILITY EQUIPMENT MUST BE READILY ACCESSIBLE AT ALL TIMES (24 HOURS/7 DAYS) BY UTILITY PERSONNEL FOR EMERGENCIES, METER READING, INSPECTION, TESTING, AND MAINTENANCE.
  - ANTI-ISLANDING NOTE:  
AN INDEPENDENT ANTI-ISLANDING PREVENTION METHOD MUST BE INSTALLED SUCH THAT UPON OCCURRENCE OF AN ISLAND, THE DISTRIBUTED GENERATION RESOURCE SHALL AUTOMATICALLY DISCONNECT FROM UTILITY.
  - ENERGIZATION OF THE MAIN SITE TRANSFORMER AND/OR FACILITY CIRCUITS SHOULD NOT VIOLATE IEEE 1453.
  - INSTALL RELAYS TO ENABLE UFLS AT 12KV BREAKERS IF 46KV CIRCUIT IS ON THE UFLS SCHEME.
  - PROJECT TO PROVIDE A RELIABLE DC SOURCE FOR 12 HOUR BACKUP PERIOD; SPECIFIC VOLTAGE TO BE DETERMINED BY HECO AT A LATER DATE.
  - MAIN UTILITY SUBTRANSMISSION CIRCUIT BREAKER TO BE SYNCHRONIZED ACROSS THE 46KV BUS POTENTIAL AND THE LINE POTENTIAL. SUPY AND MANUAL CLOSING SHALL BE ALLOWED FOR VOLTAGE EQUAL IN MAGNITUDE AND PHASE.
  - ALL UTILITY SUBTRANSMISSION CIRCUIT BREAKERS TO BE SCADA ENABLED.

PRELIMINARY  
FOR INITIAL APPLICATION  
NOT TO BE USED  
FOR CONSTRUCTION  
ALSO REFER TO SLD  
DESIGN NOTES

TYPICAL 46KV RING BUS INTERCONNECT SINGLE LINE DIAGRAM		
	DATE 04-09-2024	SCALE NONE
		REV. Ø

## Template notes to be added to the 46kV Variable Generation Project Single Line Diagram

Additional requirements may be added based on project design.

<u>PROPOSED PROJECT NAME:</u>	
<u>PROPOSED PROJECT SIZE:</u>	
<u>CUSTOMER SLD REVISION NUMBER AND DATE:</u>	
<u>UTILITY SLD REVISION NUMBER AND DATE:</u>	
<u>UTILITY SUBSTATION 1:</u>	
<u>UTILITY 46kV CIRCUIT 1:</u>	
<u>UTILITY 46kV CIRCUIT BREAKER 1 #:</u>	
<u>UTILITY SUBSTATION 2:</u>	
<u>UTILITY 46kV CIRCUIT 2:</u>	
<u>UTILITY 46kV CIRCUIT BREAKER 2 #:</u>	

### Section A: Planning Notes

1. By operation procedure(s), the Project shall be paralleled with the utility system only when the     (46kV circuit name)     46 kV circuit 1 is in normal operating configuration served via breaker     (utility breaker #)     at     (utility substation name)     Substation or when the     (46kV circuit name)     46 kV circuit 2 is in normal operating configuration served via breaker     (utility breaker #)     at     (utility substation name)     Substation.
2. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 1, upon receipt of direct transfer trip signal from     (utility substation name)     Substation opening of breaker     (utility breaker #)    , trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
3. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 2, upon receipt of direct transfer trip signal from     (utility substation name)     Substation opening of breaker     (utility breaker #)    , trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
4. Upon receipt of direct transfer trip signal from     (utility substation name)     Substation for the following conditions, trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
  - a. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 1 opening of breaker 52-2     (utility breaker #)
  - b. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 2 opening of breaker 52-3     (utility breaker #)

5. All DTT loss of comm greater than or equal to 6 seconds:
  - a. Utility to provide signal to Customer to initiate Customer performed ramp down and tripping of Customer's 46 kV breaker 52-4 (utility# XXXX).
  - b. Utility to initiate trip and block close of Customer's 46 kV breaker 52-4 (utility# XXXX) after \_\_\_ (Project size MW/2 MW per minute ramp down) minutes, assuming maximum Customer output of \_\_\_ (Project size) MW and a 2.0 MW/min ramp down rate.
6. Customer to ensure manual closing of Customer's 46 kV breaker 52-4 (utility# XXXX) shall be allowed only for hot line (\_\_\_(utility 46kV line) 46 kV line-side) and dead bus (Customer-side). There shall be no auto reclosing on Customer's 46 kV breaker 52-4 (utility# XXXX).
7. Utility breaker 52-1 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'A' potential and bus 'B' potential. Closing shall be allowed for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'A' and dead bus 'B'
    - ii. Hot bus 'A' and dead bus 'B'
    - iii. Hot bus 'B' and dead bus 'A'
    - iv. Voltages equal in magnitude and phase
8. Utility breaker 52-2 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'A' potential and bus 'C' potential. Closing shall be allowed after load dispatch confirms that Customer's 46 kV breaker 52-4 (utility# XXXX) is open and for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'A' and dead bus 'C'
    - ii. Hot bus 'A' and dead bus 'C'
    - iii. Voltages equal in magnitude and phase
9. Utility breaker 52-3 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'B' potential and bus 'C' potential. Closing shall be allowed after load dispatch confirms that Customer's 46 kV breaker 52-4 (utility# XXXX) is open and for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'B' and dead bus 'C'
    - ii. Hot bus 'B' and dead bus 'C'
    - iii. Voltages equal in magnitude and phase
10. Synch-check/breaker failure relays (SEL-700GT+) require 3-phase PTs on both sides of the breaker.

11. (If applicable) Disable Under Frequency Load Shed (UFLS) at \_\_\_\_ (46kV circuit 1 name) 46kV CB \_\_\_\_ (utility Breaker #). Install relays to enable UFLS at \_\_\_\_ (12kV circuit name(s)) 12kV CB \_\_\_\_ (utility Breaker #(s)).
12. (If applicable) Disable Under Frequency Load Shed (UFLS) at \_\_\_\_ (46kV circuit 2 name) 46kV CB \_\_\_\_ (utility Breaker #). Install relays to enable UFLS at \_\_\_\_ (12kV circuit name(s)) 12kV CB \_\_\_\_ (utility Breaker #(s)).
13. Utility shall own a harmonics monitor and associated equipment at the point of interconnection. The monitor will be in continuous service and on a rolling window basis, monitor sub-cycle voltage and currents, and be capable of remote interrogation. The harmonics monitor shall comply with IEEE STD 1159-2019 and IEEE STD 519-2014. PTs and CTs need to meet relaying and harmonic monitoring applications capable of measuring up to the 50th harmonic. Developer to submit specifications of PTs/CTs to Utility to confirm application. The following inputs shall be provided:
  - a. 46kV line current (3 phase) at point of interconnection; and
  - b. 46kV line-to-neutral voltage (3 phase) at point of interconnection

#### **Section B: System Operation Notes**

1. Customer to provide raw count (DNP 3.0) for analog and status points to the Utility or other formats as specified in the following notes. Customer to provide hardwired dry contact pairs for certain status points to the Utility and accept hardwired and DNP 3.0 control points from the Utility as categorized in the following notes.
2. Utility load dispatcher shall be enabled to issue the following Control signals to the Customer:
  - a. Digital Controls - Hardwire Dry Contact Pair controls
    - i. Trip control over Customer's 46kV breaker 52-4 (Utility# XXXX);
    - ii. Block circuit 1 and/or 2 DTT Control Function to Customer's 46kV breaker 52-4;
      1. Required to Block DTT from the current backup circuit, to prevent tripping of the plant for when the backup Circuit feeder opens.
    - iii. Reset control of Utility remotely-resettable lockouts
    - iv. All Inverter On/Off control signal
    - v. [As Applicable] Isochronous Mode Enable/Disable control signal – Disabling of Isochronous mode should revert to droop frequency response mode
    - vi. Primary Frequency Response Droop – Enable/Disable
    - vii. [As Applicable] FFR – Enable/Disable
  - b. Analog Controls - DNP 3.0 – Customer is not allowed to override Utility's control
    - i. Maximum Power Import Limit
    - ii. Maximum Power Export Limit

- iii. Power Reference Setpoint (analog MW dispatch setpoint; can be negative value for grid-charging capable batteries);
  - iv. Line to Line Voltage Setpoint Target (analog kV);
  - v. MVAR Setpoint Target (analog MVAR +/-);
  - vi. Power factor setpoint target (analog pf +/-);
  - vii. [As Applicable] Normal Operating Day Limit
  - viii. [As Applicable] Normal Operating Night Limit.
  - ix. [As Applicable] Isoch Target Frequency Setpoint (Hz)
  - x. Frequency Droop Settings (% and deadband)
  - xi. [As Applicable] FFR Settings (% and deadband)
  - xii. Dispatchable Ramp Rate (MW/min)
  - xiii. Heartbeat Counter (increments up, to allow PPC to understand when there is no more communications from Utility)
  - xiv. AVR/PF/VAR/Disable
  - xv. Energy to reserve for blackstart
3. All control values must be retained in non-volatile memory such that they will be restored immediately upon return from a control systems restart, power outage, loss of communication, etc.
4. The following signals shall be telemetered to Utility SCADA/EMS:
- a. Analog Points – Hardwired Directly to Utility RTU
    - i. 46kV line amps (B phase), 46kV voltage (A-B phase), NET MW, and NET MVAR at point of interconnection through use of Utility approved non-programmable analog transducers or other Utility approved means of providing unaltered data set of voltages and currents. Data to be provided in analog format (+/- 1mA) directly from the analog transducers;
  - b. Analog Points – DNP 3.0
    - i. 46kV line amps (A phase, B phase, and C phase), 46kV voltage (A phase L-N, B phase L-N, and C phase L-N), frequency, NET MW, NET MVAR, and NET power factor at point of interconnection. Power factor to be a calculated value;
    - ii. Latest received Maximum Power Import Limit and Maximum Power Export Limit Setpoints Feedback;
    - iii. Power Reference Setpoint Feedback. Power Reference Setpoint Feedback can be negative for grid-charging capable batteries;
    - iv. Latest received Voltage Setpoint Feedback;
    - v. Latest received MVAR Setpoint Feedback;
    - vi. Latest received Power Factor Setpoint Feedback;
    - vii. PV Gross MW [As Applicable to AC/DC coupled Facilities: and MVAR] output;
    - viii. BESS Gross MW [As Applicable to AC/DC coupled Facilities: and MVAR] output/charge;
    - ix. [Solar Projects] PV Inverters Available;

- x. [As Applicable] BESS Inverters Available;
  - xi. [Wind Projects] Number of WTGs Available;
  - xii. Ramp Rate (MW/min);
  - xiii. Ramp Rate Limit Up (MW/min);
  - xiv. Ramp Rate Limit Down (MW/min);
  - xv. Total Facility Power Possible (MW);
  - xvi. PV Power Possible (MW);
  - xvii. BESS Power Possible (MW);
  - xviii. BESS Charge Possible (MW);
  - xix. Primary Frequency Droop percent and deadband settings;
  - xx. [As Applicable] FFR percent and deadband settings;
  - xxi. BESS State of Charge (%), Minimum Usable MWh Capacity, and Maximum Usable MWh Capacity, and BESS Usable Energy Remaining (MWh), must account for derates, outages, and battery degradation;
  - xxii. Time Remaining at Current MW Output (hours or minutes at Utility discretion);
  - xxiii. Time remaining at BESS Power Possible (hours or minutes at Utility discretion);
  - xxiv. Year to Date BESS Usage Counter (cycles and/or MWh)
  - xxv. Year to Date Daily Average BESS Usage Counter (MWh)
  - xxvi. Wind Speed (MPH) and Wind Direction (degrees from true north);
  - xxvii. [Wind Projects] Barometric Pressure at MMT (mbar);
  - xxviii. Ambient Air Temperature (Celsius);
  - xxix. [Solar Projects] Plane of Array Irradiance on same axis as array (Watts/m<sup>2</sup>);
  - xxx. [As Applicable] Normal Operating Day Limit Control Feedback;
  - xxxi. [As Applicable] Normal Operating Night Limit Control Feedback;
  - xxxii. [As Applicable] Normal Operating Limit In Effect (MW);
  - xxxiii. Total Facility Auxiliary Load (Power Demand) (MW & MVAR);
  - xxxiv. [As Applicable] Isoch Target Frequency (Hz).
  - xxxv. Heartbeat Counter Feedback (echoback the Heartbeat Counter so Utility understands when there is no more communications from PPC).
  - xxxvi. Black Start Capability (MW)
  - xxxvii. Black Start Plant State (Specific Modes to be discussed with Customer)
    - 1. 0 – Shutdown
    - 2. 1 – Grid-Tied
    - 3. 2 – Islanded
    - 4. 3 – Shutting down
    - 5. 4 – Stopped in Grid tied
    - 6. 5 – Running Blackstart
    - 7. 6 – Synchronizing
  - xxxviii. Energy to reserve for blackstart
- c. Accumulator Points

- i. Total KWh From Utility
    - ii. Total KWh To Utility
    - iii. Total KVARh From Utility
    - iv. Total KVARh To Utility
  - d. Indication Points – Hardwired Dry Contact Pairs
    - i. Status of Customer’s 46kV breaker 52-4 (Utility# XXXX);
    - ii. [As Applicable] Status of Customer’s 46kV MOS switches;
    - iii. [As Applicable] Status of Customer’s medium-voltage feeder breakers;
    - iv. Status of Utility remotely-resettable lockouts;
    - v. Protection/DTT communication failure (Loss of Pilot Alarm);
    - vi. 48VDC and/or 125VDC Charger Trouble. Specific alarms to be determined by Utility at a later date [can be DNP for HI/Maui];
    - vii. Trouble alarm for loss of VDC source(s)
  - e. Indication Points – DNP 3.0
    - i. Status of Customer’s medium voltage feeder breakers;
    - ii. Violation of Maximum Ramp Rate Upward (Performance Standard);
    - iii. Violation of Maximum Ramp Rate Downward (Performance Standard);
    - iv. Status Indicating when Maximum Power Import Limit is in effect - Normal or Alarm;
    - v. Status Indicating when Maximum Power Export Limit is in effect – Normal or Alarm;
    - vi. Active Power Control Interface Control Status indicating who has control over dispatch and voltage (Local/Customer vs Remote/Utility);
    - vii. Frequency Response Status – Normal or Alarm (On or Off);
    - viii. Status for each inverter (On or Off);
    - ix. Grid Following/Grid Forming Status;
    - x. Inverter Enable / Disable Feedback Status;
    - xi. [As Applicable] Isochronous Mode Enable / Disable Status;
    - xii. Heartbeat Counter Status – Normal or Alarm; and
    - xiii. Heartbeat Counter Feedback Status – Normal or Alarm.
    - xiv. [As Applicable] Ready to Close Breaker Utility Black Start
- 5. Utility requires 24-hour access to Utility-owned SCADA/RTU, communication, and Utility-owned relaying and monitoring equipment.
- 6. Utility shall own a high-speed power quality device (e.g., Tesla Model No. 4000) near the point of interconnection, which shall be in continuous service and on a rolling window basis, monitoring sub-cycle voltages and currents, as well as disturbance events, and capable of remote interrogation following an event. Utility requires 24-hour access to this equipment. The digital fault recorder must be provided with a GPS time synchronized clock signal set to local time. Customer to provide the following hard-wired inputs to Utility’s power quality device:
  - a. Status of Customer’s 46kV breaker 52-4 (Utility# XXXX) from 52a contact only;

- b. Status of Customer's medium or low voltage breakers that will be used to sequence plant connection to prevent voltage issues upon energization/connection to the grid (as needed per IRS);
  - c. Status of all remotely-resettable lockouts;
  - d. 46kV line amps (3 phase and neutral);
  - e. 46kV voltage (A phase L-N, B phase L-N, and C phase L-N)
7. [For RDG Contracts] Each of the following quantities need to be logged locally for Utility review upon request:
- a. Status of each inverter/WTG
  - b. MW output of each inverter/WTG
  - c. MW setpoint of each inverter/WTG
  - d. MVAR output of each inverter/WTG
  - e. MVAR setpoint of each inverter/WTG
  - f. [Solar Projects] Global Horizontal Irradiance (Watts/m2)
  - g. [Solar Projects] Back of panel temperature (Celsius)

### **Section C: Telecommunication Notes**

1. Customer to provide a reliable DC Source for 12 hour backup period; specific voltage to be determined by utility at a later date.
2. Customer to provide a source of station service power for its facility that will remain available when Customer's 46 kV breaker 52-1 (utility# XXXX) is opened and the facility is separated from utility's system.
3. For DTT communication channel failure:
  - a. Signal to Customer to initiate Customer performed ramp down and tripping of Customer's 46 kV breaker 52-4 (utility# XXXX) shall be utility-owned SEL-2411. Utility SEL-2411 signal is to be a continuous signal while communication channel is failed.
  - b. Trip and block close of Customer's 46 kV breaker 52-4 (utility# XXXX) shall be utility-owned SEL-2411 via utility-owned SCADA resettable lockout relay ("86/LOSS COMM").
4. Secure and reliable communication is required for the following:
  - a. Direct transfer trip from \_\_\_(utility 46kV circuit) 46kV CB \_\_\_(utility Breaker #);
  - b. SCADA to/ from Customer's facility;
  - c. Back-up SCADA to/from Customer's facility;
  - d. Revenue metering for power export and consumption readings;
  - e. Power quality and fault recording and retrieval; and
  - f. Phone circuits as required.
5. All DTT loss of comm greater than or equal to 6 seconds shall cause the site to ramp down and trip (applies to both primary and backup).

**Section D: Metering Notes**

1. Customer to design revenue metering facilities in accordance with the requirements in Chapter 6 of the Hawaiian Electric Company's Electric Service Installation Manual.

**Section E: Design Notes**

1. PTs and CTs for Tesla and RTU transducers should be the same quality as the PTs and CTs for the 46kV protective relaying.
2. Customer to provide raw count (DNP 3.0) for analog points to utility (as identified in Section B). Customer to provide hardwired dry contact pairs for status points to utility and accept hardwired control points from utility (as identified in Section B).
3. Relay operation shall trip and block close breakers 52-2, 52-3, and utility owned DTT lockout relay. Customer breaker 52-4 tripped and block closed via separate dedicated lockout relay owned by the Customer.

## Template notes to be added to the 46kV Firm Project Single Line Diagram

Additional requirements may be added based on project design.

<b>PROPOSED PROJECT NAME:</b>	
<b>PROPOSED PROJECT SIZE:</b>	
<b>CUSTOMER SLD REVISION NUMBER AND DATE:</b>	
<b>UTILITY SLD REVISION NUMBER AND DATE:</b>	
<u>UTILITY SUBSTATION 1:</u>	
<u>UTILITY 46kV CIRCUIT 1:</u>	
<u>UTILITY 46kV CIRCUIT BREAKER 1 #:</u>	
<u>UTILITY SUBSTATION 2:</u>	
<u>UTILITY 46kV CIRCUIT 2:</u>	
<u>UTILITY 46kV CIRCUIT BREAKER 2 #:</u>	

### Section A: Planning Notes

1. By operation procedure(s), the Project shall be paralleled with the utility system only when the     (46kV circuit name)     46 kV circuit 1 is in normal operating configuration served via breaker     (utility breaker #)     at     (utility substation name)     Substation or when the     (46kV circuit name)     46 kV circuit 2 is in normal operating configuration served via breaker     (utility breaker #)     at     (utility substation name)     Substation.
2. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 1, upon receipt of direct transfer trip signal from     (utility substation name)     Substation opening of breaker     (utility breaker #)    , trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
3. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 2, upon receipt of direct transfer trip signal from     (utility substation name)     Substation opening of breaker     (utility breaker #)    , trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
4. Upon receipt of direct transfer trip signal from     (utility substation name)     Substation for the following conditions, trip and block close Customer's 46 kV breaker 52-4 (utility# XXXX).
  - a. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 1 opening of breaker 52-2     (utility breaker #)
  - b. When the Project is paralleled with the utility system via     (46kV circuit name)     46 kV circuit 2 opening of breaker 52-3     (utility breaker #)
5. All DTT loss of comm greater than or equal to 6 seconds:
  - a. Utility to provide signal to Customer to initiate Customer performed ramp down and tripping of Customer's 46 kV breaker 52-4 (utility# XXXX).

- b. Utility to initiate trip and block close of Customer's 46 kV breaker 52-4 (utility# XXXX) after \_\_\_ (Project size MW/2 MW per minute ramp down) minutes, assuming maximum Customer output of \_\_\_ (Project size) MW and a 2.0 MW/min ramp down rate.
6. Customer to ensure manual closing of Customer's 46 kV breaker 52-4 (utility# XXXX) shall be allowed only for hot line (\_\_\_ (utility 46kV line) 46 kV line-side) and dead bus (Customer-side). There shall be no auto reclosing on Customer's 46 kV breaker 52-4 (utility# XXXX).
7. Utility breaker 52-1 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'A' potential and bus 'B' potential. Closing shall be allowed for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'A' and dead bus 'B'
    - ii. Hot bus 'A' and dead bus 'B'
    - iii. Hot bus 'B' and dead bus 'A'
    - iv. Voltages equal in magnitude and phase
8. Utility breaker 52-2 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'A' potential and bus 'C' potential. Closing shall be allowed after load dispatch confirms that Customer's 46 kV breaker 52-4 (utility# XXXX) is open and for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'A' and dead bus 'C'
    - ii. Hot bus 'A' and dead bus 'C'
    - iii. Voltages equal in magnitude and phase
9. Utility breaker 52-3 \_\_\_ (utility Breaker #), shall be syncro-checked across bus 'B' potential and bus 'C' potential. Closing shall be allowed after load dispatch confirms that Customer's 46 kV breaker 52-4 (utility# XXXX) is open and for the following conditions:
  - a. No auto reclosing
  - b. Manual closing
    - i. Dead bus 'B' and dead bus 'C'
    - ii. Hot bus 'B' and dead bus 'C'
    - iii. Voltages equal in magnitude and phase
10. Synch-check/breaker failure relays (SEL-700GT+) require 3-phase PTs on both sides of the breaker.
11. (If applicable) Disable Under Frequency Load Shed (UFLS) at \_\_\_ (46kV circuit 1 name) 46kV CB \_\_\_ (utility Breaker #). Install relays to enable UFLS at \_\_\_ (12kV circuit name(s)) 12kV CB \_\_\_ (utility Breaker #(s)).

12. (If applicable) Disable Under Frequency Load Shed (UFLS) at \_\_\_\_ (46kV circuit 2 name) 46kV CB \_\_\_\_ (utility Breaker #). Install relays to enable UFLS at \_\_\_\_ (12kV circuit name(s)) 12kV CB \_\_\_\_ (utility Breaker #(s)).

### **Section B: System Operation Notes**

1. Customer to provide raw count (DNP 3.0) for analog and status points to Utility or other formats as specified in the following notes. Customer to provide hardwired dry contact pairs for status points to Utility, and accept hardwired and DNP 3.0 control points from Utility as categorized in the following notes.
2. Utility load dispatcher shall be enabled to issue the following Control signals to the Customer:
  - a. Digital Controls - Hardwire Dry Contact Pair controls
    - i. Trip control over Customer's 46kV breaker 52-4 (Utility# XXXX);
    - ii. Block circuit 1 and/or 2 DTT Control Function to Customer's 46kV breaker 52-4;
      1. Required to Block DTT from the current backup circuit, to prevent tripping of the plant for when the back-up Circuit feeder opens.
    - iii. Reset control of Utility-owned remotely-resettable lockouts.
    - iv. [As Applicable] Isochronous Mode Enable/Disable control signal – Disabling of Isochronous mode should revert to droop frequency response mode
  - b. Analog Controls - DNP 3.0 – Customer is not allowed to override Utility's control
    - i. For each generator:
      1. EMS MW Target (MW Setpoint Control);
      2. Frequency Droop Settings (% and deadband)
      3. Dispatchable Ramp Rate (MW/min)
    - ii. Line to Line Voltage Setpoint Target (analog kV);
    - iii. MVAR Setpoint Target (analog MVAR +/-);
    - iv. Power factor setpoint target (analog pf +/-);
    - v. AVR/PF/VAR/Disable (Analog value to signal which voltage control mode project is currently in)
    - vi. [As Applicable] Isoch Target Frequency Setpoint (Hz)
3. All control values must be retained in non-volatile memory such that they will be restored immediately upon return from a systems restart, power outage, loss of communication, etc.
4. The following signals provided by the Customer shall be telemetered to Utility load dispatch office:
  - a. Analog Points – Hardwired Directly to Utility RTU
    - i. 46kV line amps (B phase), 46kV voltage (A-B phase), NET MW, and NET MVAR at point of interconnection through use of Utility approved non-programmable analog transducers or other Utility approved means of

providing unaltered data set of voltages and currents. Data to be provided in analog format (+/- 1mA) directly from the analog transducers;

- b. Analog Points – DNP 3.0
  - i. 46kV line amps (A phase, B phase, and C phase), 46kV voltage (A phase L-N, B phase L-N, and C phase L-N), frequency, NET MW, NET MVAR, and NET power factor at point of interconnection. Power factor to be a calculated value;
  - ii. For each generator, as needed based on plant design:
    - 1. EMS MW Target (MW Setpoint Control) Feedback;
    - 2. Load Frequency Control (LFC) High and Low MW Setpoint Limits Feedback;
    - 3. MW, MVAR, 46kV voltage (A phase L-N, B phase L-N, and C phase L-N), frequency,
    - 4. Normal Ramp Rate Up/Down;
    - 5. Emergency Ramp Rate Up/Down;
    - 6. Frequency Droop percent and deadband settings;
    - 7. Fuel type
    - 8. Turbine RPM
    - 9. Aux load MW
    - 10. Aux load MVAR
    - 11. Start up MW
    - 12. Start up MVAR
    - 13. Start up MWH
  - iii. Plant Power Possible (MW);
  - iv. Latest received Voltage Setpoint Feedback;
  - v. Latest received MVAR Setpoint Feedback;
  - vi. Latest received Power Factor Setpoint Feedback;
  - vii. [As Applicable] Isoch Target Frequency (Hz).
- c. Accumulator Points
  - i. Total KWh From Utility
  - ii. Total KWh To Utility
  - iii. Total KVARh From Utility
  - iv. Total KVARh To Utility
- d. Indication Points – Hardwired Dry Contact Pairs
  - i. Status of Seller’s 46kV breaker 52-4 (Utility# XXXX);
  - ii. [As Applicable] Status of Customer’s 46kV MOS switches;
  - iii. [As Applicable] Status of Customer’s medium-voltage feeder breakers;
  - iv. DTT and PPC Loss of Communication;
  - v. Customer-owned 48VDC and/or 125VDC Charger Trouble. Specific alarms to be determined by Utility at a later date;
  - vi. Trouble alarm for loss of Customer-owned VDC source(s); and
  - vii. Status of Utility-owned resettable lockouts;
- e. Indication Points – DNP 3.0
  - i. Status of Customer’s medium voltage feeder breakers;

- ii. Violation of Maximum Ramp Rate Upward (Performance Standard); and
  - iii. Violation of Maximum Ramp Rate Downward (Performance Standard).
  - iv. EMS Control Status indicating who has control over dispatch (Local vs HECO);
  - v. Health check DCS/TCS – Alarm/Normal
  - vi. Raise block - Alarm/Normal
  - vii. Lower block – Alarm/Normal
  - viii. Frequency Response Status – Normal or Alarm (Will be in Alarm state when the plant is responding to frequency outside of deadband);
  - ix. [As Applicable] Isochronous Mode Disable / Enable Status;
5. Utility requires 24-hour access to Utility-owned SCADA/RTU, communication, and Utility-owned relaying and monitoring equipment.
6. Utility shall own a high-speed power quality device (i.e., Tesla Model No. 4000) near the point of interconnection, which shall be in continuous service and on a rolling window basis, monitoring sub-cycle voltages and currents, as well as disturbance events, and capable of remote interrogation following an event. Utility requires 24-hour access to this equipment. Customer to provide the following direct hard-wired inputs to Utility’s power quality device:
- a. Status of Customer’s 46kV breaker 52-4 (Utility# XXXX) from 52a contact only;
  - b. Status of Customer’s medium or low voltage breakers that will be used to sequence plant connection to prevent voltage issues upon energization/connection to the grid from 52a contact only;
  - c. Status of all remotely-resettable lockouts;
  - d. 46kV line amps (3 phase and neutral);
  - e. 46kV voltage (A phase L-N, B phase L-N, and C phase L-N)

**Section C: Telecommunication Notes**

- 1. Customer to provide a reliable DC Source for 12-hour backup period; specific voltage to be determined by utility at a later date.
- 2. Customer to provide a source of station service power for its facility that will remain available when Customer’s 46 kV breaker 52-4 (utility# XXXX) is opened and the facility is separated from utility’s system.
- 3. For DTT communication channel failure:
  - a. Signal to Customer to initiate Customer performed ramp down and tripping of Customer’s 46 kV breaker 52-4 (utility# XXXX) shall be utility-owned SEL-2411. Utility SEL-2411 signal is to be a continuous signal while communication channel is failed.
  - b. Trip and block close of Customer’s 46 kV breaker 52-4 (utility# XXXX) shall be utility-owned SEL-2411 via utility-owned SCADA resettable lockout relay (“86/LOSS COMM”).

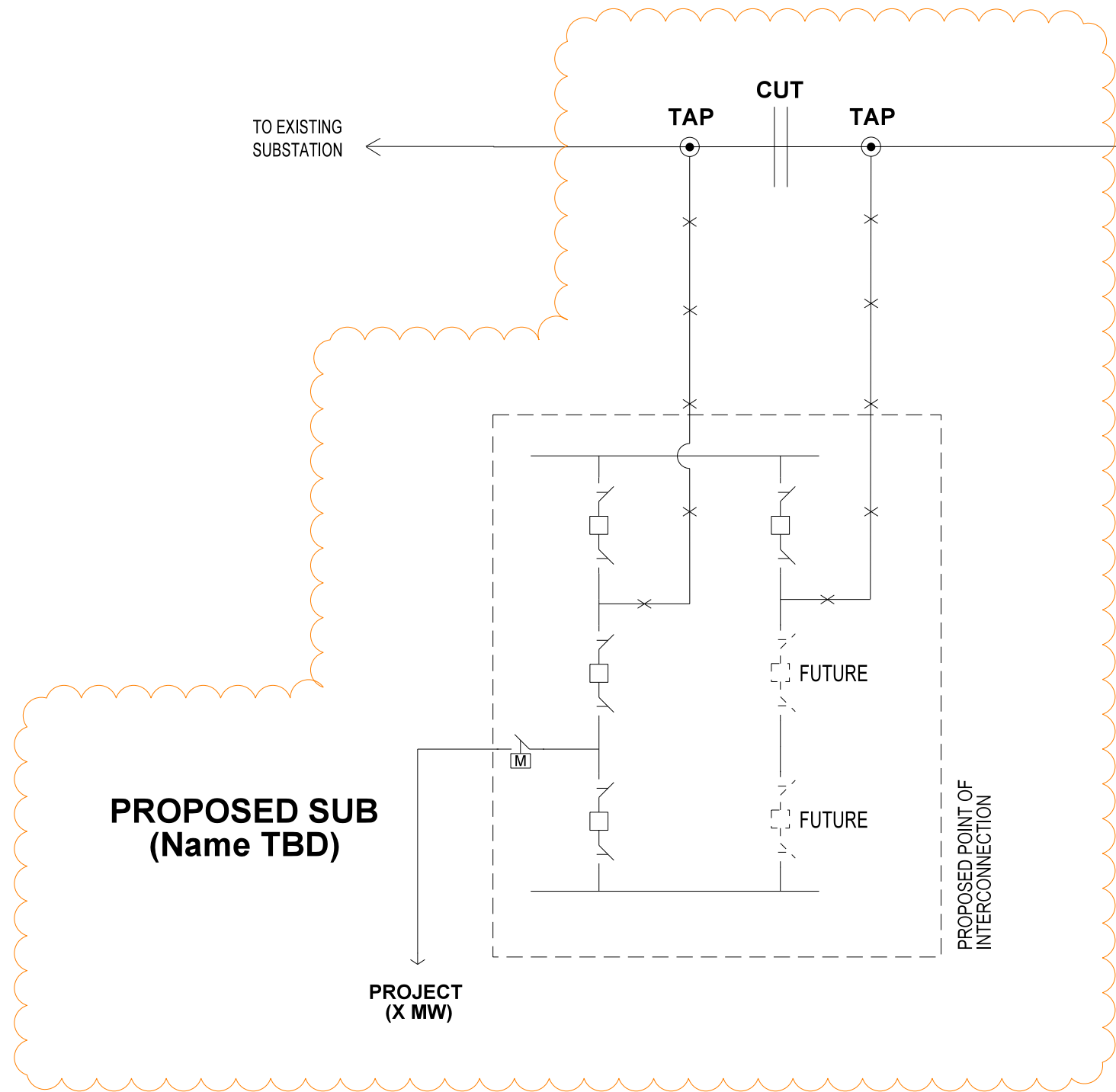
4. Secure and reliable communication is required for the following:
  - a. Direct transfer trip from \_\_\_ (utility 46kV circuit) 46kV CB \_\_\_ (utility Breaker #);
  - b. SCADA to/ from Customer's facility;
  - c. Back-up SCADA to/from Customer's facility;
  - d. Revenue metering for power export and consumption readings;
  - e. Power quality and fault recording and retrieval; and
  - f. Phone circuits as required.
  
5. All DTT loss of comm greater than or equal to 6 seconds shall cause the site to ramp down and trip (applies to both primary and backup).

**Section D: Metering Notes**

1. Customer to design revenue metering facilities in accordance with the requirements in Chapter 6 of the Hawaiian Electric Company's Electric Service Installation Manual.

**Section E: Design Notes**

1. PTs and CTs for Tesla and RTU transducers should be the same quality as the PTs and CTs for the 46kV protective relaying.
  
2. Customer to provide raw count (DNP 3.0) for analog points to utility (as identified in Section B). Customer to provide hardwired dry contact pairs for status points to utility, and utility and accept hardwired control points from utility (as identified in Section B).
  
3. Relay operation shall trip and block close breakers 52-2, 52-3, and utility owned DTT lockout relay. Customer breaker 52-4 tripped and blocked closed via separate dedicated lockout relay owned by the Customer.



**LEGEND**

- EXISTING 69KV LINE
- X— INSTALL 3-PHASE 69KV, 715A MIN (NORMAL) OVERHEAD CONDUCTOR

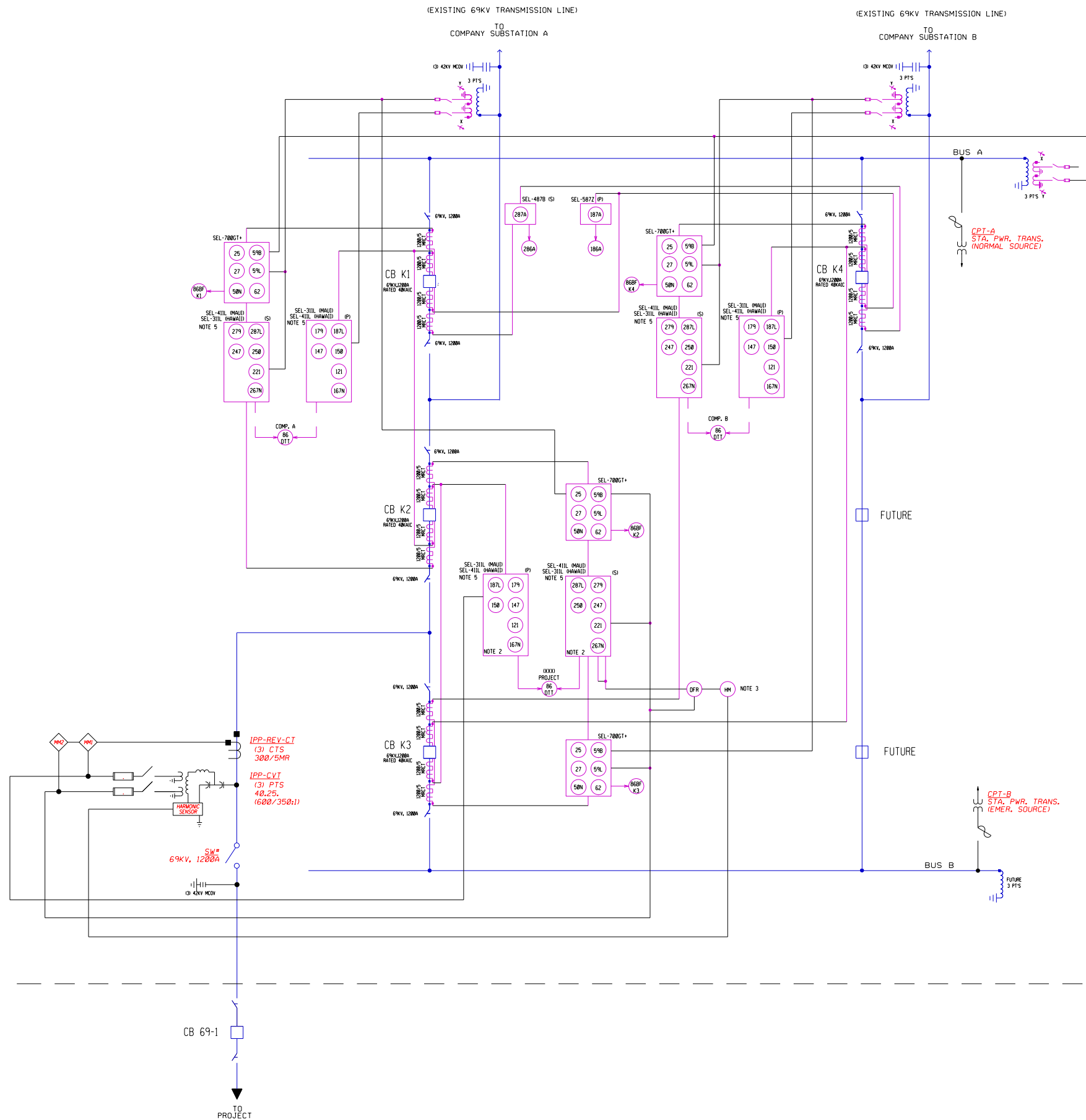
**NOTES**

1. THE 69KV BUS EQUIPMENT, MAIN AND TIE BREAKERS SHALL BE RATED 1200A CONTINUOUS, AND SHALL BE DESIGNED TO WITHSTAND A SHORT CIRCUIT CURRENT OF 40 KAIC AT 72.5KV.
2. ALL 69KV GCB'S, DISCONNECT SWITCHES, STATION POST INSULATORS, AND INSTRUMENT TRANSFORMERS ARE TO BE DESIGNED FOR 350KV BIL.
3. OTHER REQUIREMENTS ARE IN DEVELOPMENT AND WILL BE PROVIDED

**DRAFT**

**FOR ESTIMATING  
PURPOSES ONLY**

A	xx/xx/2022	DISTRIBUTED FOR COMMENTS & REVISIONS	-		
NO.	DATE	REVISIONS	BY	CHK'D	APP'D
PROJECT 69kV INTERCONNECTION T&D PLANNING SINGLE LINE					
DESIGNED	DRAWN	DATE xx/xx/2022	SCALE	NONE	
CHECKED	ELEC.	MECH.	STRUC.	TRANSMISSION & DISTRIBUTION PLANNING DEPARTMENT HAWAIIAN ELECTRIC HONOLULU, HAWAII	
APPROVAL			DRAWING NUMBER	REV	
			PRELIMINARY	A	



NOTES

1. OTHER REQUIREMENTS ARE IN DEVELOPMENT AND WILL BE PROVIDED.
2. PROTECTION RELAYS ARE DEPENDENT ON APPROXIMATE LOCATION OF SWITCHING STATION RELATIVE TO DEVELOPER SUBSTATION
3. (RDG/BESS ONLY) INSTALL HARMONICS MONITOR AND ASSOCIATED EQUIPMENT AT COMPANY-OWNED SUBSTATION MONITORING THE PROJECT POINT OF INTERCONNECTION. HARMONICS MONITORING SHALL COMPLY WITH IEEE STD 1159-2019 OR LATEST VERSION AND IEEE STD 519-2014 OR LATEST VERSION. HARMONICS MONITOR SHALL BE CONNECTED TO COMPANY PT TO ALLOW FOR BASELINE MEASUREMENTS. PTS AND CTS CONNECTED TO THE HARMONICS MONITOR SHALL BE CAPABLE OF MEASURING UP TO AT LEAST 50TH ORDER HARMONICS.
4. DIGITAL FAULT RECORDER AND MULTIMETERS TO BE INSTALLED CLOSEST TO PROJECT POINT OF INTERCONNECTION. FINAL PT AND CT CONNECTIONS TBD.
5. CT AND PT WIRING AS SHOWN IS TYPICAL FOR MAUI WHO HAS STANDARDIZED ON 311L AS PRIMARY LINE DIFFERENTIAL RELAY AND 411L AS SECONDARY LINE DIFFERENTIAL RELAY. THE CT AND PT WIRING WILL DIFFER FOR HAWAII ISLAND WHO HAS STANDARDIZED ON THE 411L AS PRIMARY, 311L AS SECONDARY.

COMPANY SWITCHYARD PROJECT

DRAFT  
FOR COST ESTIMATE ONLY  
FOR REVIEW & COMMENT ONLY

NO.	DATE	REVISIONS	BY	CHK'D	APP'D
[NAME TBD] INTERCONNECTION PLANNING SINGLE LINE					
DESIGNED		DATE	XX/XX/XX	SCALE	NONE
CHECKED	ELEC.	MECH.	STRUC.	TRANSMISSION & DISTRIBUTION PLANNING DEPARTMENT HAWAIIAN ELECTRIC HONOLULU, HAWAII	
APPROVAL	DRAWING NUMBER				REV
PRELIMINARY				A	

Notes apply to RDG, Standalone BESS, and Firm Generation Projects unless otherwise noted.

### Notes to be added to the 69kV Company Substation Single Line Diagram

<b>COMPANY SUBSTATION:</b>	
<b>COMPANY SLD REVISION NUMBER AND DATE:</b>	
<b>NOTES DATE:</b>	

1. 69kV bus equipment and breakers shall be rated 1200A continuous and shall be designed to withstand a short circuit current of 40 KAIC @ 72.5kV.
2. All 69kV Gas Circuit Breakers (GCB), disconnect switches, station post insulators, and instrument transformers are to be designed for 350kV BIL.
3. Voltage checks shall be across three phases unless otherwise specified.
4. 69kV breaker K1 and K4 to be synchro-checked across its 69kV Bus A and line potentials and allowed to close only under the following conditions:
  - A. Automatic Reclosing
    - i. [TBD by IRS]
  - B. Manual and Supy Closing:
    - i. Voltage magnitude, frequency, and phase angle difference within acceptable limits
    - ii. Dead-line and dead-bus
    - iii. Dead-line and hot-bus
    - iv. Hot-line and dead-bus
5. 69kV breaker K2 to be synchro-checked across its line potentials on both sides of the 69kV breaker and allowed to close only under the following conditions:
  - A. Automatic Reclosing
    - i. Voltage magnitude, frequency, and phase angle difference within acceptable limits
  - B. Manual and Supy Closing:
    - i. Voltage magnitude, frequency, and phase angle difference within acceptable limits
    - ii. dead-line and dead-line
    - iii. dead-line and hot-line
    - iv. hot-line and dead-line
6. 69kV breaker K3 to be synchro-checked across its line potentials on both sides of the 69kV breaker and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    - i. Voltage magnitude, frequency, and phase angle difference within acceptable limits
    - ii. dead-line and dead-line
    - iii. dead-line and hot-line
    - iv. hot-line and dead-line

(REVISED 07-01-2025)

7. All trips from developer to Company shall trip and block close breakers K2 and K3 depending on the trip.
8. [RDG/BESS Only] Install a harmonics recorder and associated equipment at each project point of interconnection, which will be in continuous service and on a rolling window basis monitor sub-cycle voltage and currents and capable of remote interrogation. Harmonics monitoring shall comply with IEEE Std 1159-2019 or latest version and IEEE Std 519-2014 or latest version. Harmonics monitor shall be connected to company-side PT to allow for baseline measurements. PTs and CTs connected to the harmonics monitor shall be capable of measuring up to at least 50<sup>th</sup> order harmonics. The following inputs shall be provided:
  - A. 69kV voltage (3-ph) at or near the point of interconnection for Project
  - B. 69kV current (3-ph) at or near the point of interconnection measuring total current from Project

**Design Notes:**

9. Substation to be built as functional ring bus in formation of breaker-and-half as shown on Planning SLD. Space should be left for two additional breakers to be installed to complete the second breaker-and-half bay.
10. SEL 700GT+ relays shall be connected to 3-phase line PTs and 3-phase bus PTs.
11. All 69kV CT's are to be MRCT's with relaying accuracy class C800 unless noted otherwise. MRCT's are to have full distributed windings on all taps and a minimum thermal rating factor of 2.0. (Provide the Protection Department with CT saturation, ratio correction factor curves, and continuous thermal rating factors.)
12. All 69kV circuit breakers are to be dead tank design with a rated interrupting time of 3 cycles, and have dual trip coils with independent tripping circuits.

**Protection Notes:**

13. Bus A differential relays operation shall trip and block close breakers K1 and K4 via manual lockout relays.
14. Line current differential relay operation shall trip and block close breakers K2 and K3, via Company lockout relay. Developer breaker 69-1 tripped and blocked closed via separate dedicated lockout relay owned by the Developer.
15. Line differential relays subject to telecom requirements as specified in the RFP for renewable dispatchable generation and energy storage, Appendix H, Section 2.5
16. The local breaker failure scheme shall trip and block close all adjacent breakers via non-electrically resettable lockout relays.
17. 69kV breaker K2 or K3 breaker failure function provided by SEL-700GT+.
18. All trips going to Developer sub shall go through dedicated Company lockout relays. Company lockout relays will be owned by Company, SCADA resettable, and shall trip a separate, dedicated developer-owned lockout relay in Developer substation. All trips from Developer to Company shall

go through a dedicated Developer-owned lockout relay and trip a separate, dedicated Company-owned lockout relay.

19. The following local 69kV breaker failure conditions shall initiate a direct transfer trip (DTT) to trip and block close the respective 69kV breakers at the remote substation via a dedicated remotely resettable lockout relay at the remote substation:

<u>Local Breaker Failure Condition</u>	<u>Breaker Failure DTT to Remote Substation</u>
Company Sub A BKR1 Fail	Trip [Name TBD] Sub Bkrs K1 & K2
Company Sub A BKR2 Fail	Trip [Name TBD] Sub Bkrs K1 & K2
Company Sub B BKR1 Fail	Trip [Name TBD] Sub Bkrs K3 & K4
Company Sub B BKR2 Fail	Trip [Name TBD] Sub Bkrs K3 & K4
Project Sub Bkr 69-1 Fail	Trip [Name TBD] Sub Bkrs K2 & K3
[Name TBD] Sub Bkr K1 Fail	Trip Company Sub A BKR1 & BKR2
[Name TBD] Sub Bkr K2 Fail	Trip Company Sub A BKR1 & BKR2 & Project Sub bkr 69-1
[Name TBD] Sub Bkr K3 Fail	Trip Project Sub Bkr 69-1
[Name TBD] Sub Bkr K4 Fail	Trip Company Sub B BKR1 & BKR2

**System Operations Notes:**

20. All 69kV breakers are controlled and supervised by Company System Operator via supervisory equipment and have control switches in the control house.
21. Install a digital fault recorder near point of interconnection, which will be in continuous service and on a rolling window basis monitor sub-cycle voltage and currents, as well as disturbance events and capable of remote interrogation following an event. The following inputs shall be provided and direct hard wired to the recorder:
- a. Status of [Project] (Developer) 69kV breaker
  - b. Status of all 69kV [Name TBD] substation breakers
  - c. Status of all lockouts for 69kV [Name TBD] substation breakers
  - d. 69kV voltage (A phase L-N, B phase L-N, and C phase L-N)at the point of interconnection
  - e. 69kV current (A phase, B phase, and C phase) at the point of interconnection measuring total Project individual phase currents from the Project
  - f. [AS Applicable, when there is a gen tie line] 69kV line fault distance (miles)
22. Phasor Measurement Unit (PMU) phasor data measuring at minimum frequency, voltage, and current is to be provided from PMU capable relays at each point of interconnection and each line termination.

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23. Each of the following control and status points for 69kV breakers, motor operated disconnect switches, the associated transmission lines and equipment shall be remotely controlled and supervised by HECO system operator:
  - a. Trip/Close and status of all 69kV breakers
  - b. All 69kV breakers automatic reclosing status (Auto / Block)
  - c. Open/Close and status of all 69kV disconnect switches
  - d. [As Applicable, if using remote reset LOs] Status and control of each remotely resettable lockout
  - e. Status of each manual-reset lockout
24. Each of the following analog points for 69kV breakers, 69kV motor operated switches, the associated transmission and equipment shall be telemetered to HECO system operator:
  - a. All 69kV line amps (A phase, B phase, and C phase), voltages (A phase L-L, B phase L-L, and C phase L-L), watts, and vars
  - b. All 69kV bus voltages (A phase L-L, B phase L-L, and C phase L-L)
  - c. Fault Distance for all 69kV Lines
  - d. [As Applicable depending on location of generation POI metering] kWh and kVARh values via Revenue Meter "A"
25. For 69kV breakers, motor operated disconnect switches, the associated transmission lines and equipment, each of the following initiates an alarm to HECO system operator:
  - a. DTT Status (Normal/Trip) for CB XXX and XXX (*breakers to Project*) (BF DTT,[and Anti Islanding DTT As Applicable])
  - b. 125V DC battery low voltage (both primary and backup battery)
  - c. 125V DC charger trouble (both primary and backup battery)
  - d. Loss of 125V DC circuit (for each 125V DC circuit)
  - e. 48V DC battery low voltage
  - f. 48V DC charger trouble
  - g. Loss of normal AC station power source
  - h. Loss of emergency AC station power source
  - i. Operation of AC station power auto-transfer switch to emergency source
  - j. Loss of 69kV line and synchro-check potential

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- k. Low SF6 gas pressure for all GCB (individual alarm for each GCB)
- l. Block operation due to SF6 low gas pressure for all GCB (individual alarm for each GCB)
- m. Spring discharge alarm for all GCB (individual alarm for each GCB)
- n. Trip Coil Loss of DC for all GCB (individual alarm for each GCB)
- o. All 69kV lockout relay (86) operation
- p. All 69kV digital protective relay trouble alarm
- q. Loss of 69kV line relay primary & backup potential
- r. Loss of DC for each lockout relay (86)
- s. Comm Trouble and Loss of Comm alarms for all comm circuits
- t. RTU communication failure

Notes apply to RDG, Standalone BESS, and Firm Generation Projects unless otherwise noted.

### Notes to be added to the 69kV Project Single Line Diagram

<b>PROPOSED PROJECT NAME:</b>	
<b>PROPOSED PROJECT SIZE:</b>	
<b>DEVELOPER SLD REVISION NUMBER AND DATE:</b>	
<b>MECO SLD REVISION NUMBER AND DATE:</b>	
<b>COMPANY SUBSTATION:</b>	

1. The Project shall install point-on-wave breakers, specifically independent pole operated (IPO) breakers with residual flux calculation capability, when more than five energizations are expected or observed in any 12-month period after commercial operations. Energizations is only to occur in coordination with the Company system operator. The voltage deviation at the point of interconnection (POI) must be limited to +/- 6% when energizing the Project. [TBD by IRS]
2. Opening of 69kV breakers K2 and K3 shall trip Developer’s 69kV breaker CB 69-1 via Company-owned lockout relay.
3. Developer to ensure manual closing of breaker CB 69-1 shall be allowed for the following conditions under coordination with the Company system operator:
  - a. Hot line (company-side) and dead bus (project-side).
  - b. Hot line (company-side) and hot bus (project-side) with supervised synchro-check for self-energization using grid forming capabilities.
    - i. Voltage magnitude, frequency, and phase angle difference within acceptable limit
  - c. Dead line (company-side) and hot bus (project-side), for black start provided by grid forming capabilities.
4. There shall be no auto-reclosing on Project 69kV breaker CB 69-1.

#### **Protection Notes**

5. Line current differential relay operation shall trip and block close Company 69 kV breakers K2 and K3 at Company Substation via Company lockout relay. Developer breaker 69-1 tripped and blocked closed via separate dedicated lockout relay owned by the Developer.
6. Line differential relays subject to telecom requirements as specified in the RFP for renewable dispatchable generation and energy storage, Appendix H, Section 2.5
7. Breaker failure of Company 69kV breakers K2 or K3 at Company Substation shall trip separate Company lockout relays which will trip and block close Developer’s 69kV breaker 69-1 via separate dedicated lockout relays owned by the Developer.
8. Breaker failure of 69kV breaker K2 or K3 at Company Substation shall trip a Company lockout relay which will trip and block close Project 69kV breaker 69-1 via separate dedicated lockout relay.
9. Breaker failure of Project 69kV breaker 69-1 shall trip developer-owned dedicated lockout relay

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which will trip dedicated lockout relay in Company substation. Dedicated breaker failure lockout relay in Company substation will trip and block close Company 69kV breakers K2 and K3.

10. All trips going to Developer sub shall go through dedicated Company lockout relays. Company lockout relays will be owned by Company, SCADA resettable, and shall trip a separate, dedicated developer-owned lockout relay in Developer substation. All trips from Developer to Company shall go through a dedicated Developer-owned lockout relay and trip a separate, dedicated Company-owned lockout relay.

#### **Design Notes**

11. All 69kV CT's are to be 1200/5 MRCT's with relaying accuracy class C800 unless noted otherwise. MRCT's are to have full distributed windings on all taps and a minimum thermal rating factor of 2.0. (Provide the Protection Department with CT saturation, ratio correction factor curves, and continuous thermal rating factors.)
12. All microprocessor relays, instruments, CT's, and PT's are to have test switches.

#### **System Operations Notes:**

13. HECO shall have SCADA trip control over Seller's 69 kV breaker CB 69-1 (HECO# XXXX).
14. Seller to provide raw count (DNP 3.0) for analog and status points to HECO or other formats as specified in the following notes. Seller to provide hardwired dry contact pairs for certain status points to HECO, and accept hardwired and DNP 3.0 control points from HECO as categorized in the following notes.
15. HECO SCADA/EMS shall be enabled to issue the following Control signals to the Seller Facility:
  - a. Digital Controls - Hardwire Dry Contact Pair controls
    - i. Trip control over Seller's 69kV breaker
    - ii. [As Applicable] All Inverter On/Off control signal
    - iii. [As Applicable] Isochronous Mode Enable/Disable control signal – Disabling of Isochronous mode should revert to droop frequency response mode
  - b. Analog Controls - DNP 3.0 – Seller is not allowed to override HECO's control
    - i. [As Applicable] Maximum Power Import Limit
    - ii. [As Applicable] Maximum Power Export Limit
    - iii. Power Reference Setpoint (analog MW dispatch setpoint; can be negative value for grid-charging capable batteries; Facility level control for RDG and BESS; Unit level control for Firm facilities comprised of multiple units);
    - iv. Line to Line Voltage Setpoint Target (analog kV);

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- v. MVAR Setpoint Target (analog MVAR +/-);
  - vi. [As Applicable] Normal Operating Day Limit
  - vii. [As Applicable] Normal Operating Night Limit.
  - viii. [As Applicable] Isoch Target Frequency Setpoint (Hz)
  - ix. [As Applicable] Frequency Droop Settings (% and deadband)
  - x. [As Applicable] FFR Settings (% and deadband)
  - xi. [As Applicable] Dispatchable Ramp Rate (MW/min)
- c. Digital Controls – DNP 3.0
- i. Primary Frequency Response Droop – Enable/Disable
  - ii. [As Applicable] FFR – Enable/Disable
  - iii. AVR/VAR Enable/Disable
  - iv. [As Applicable] Reset control of remotely-resettable lockouts
  - v. [As Applicable] Engine Start/Stop (Unit level control for Firm facilities comprised of multiple units);
16. All control values must be retained in non-volatile memory such that they will be restored immediately upon return from a control systems restart, power outage, loss of communication, etc.
17. The following signals provided by the Seller shall be telemetered to HECO SCADA/EMS:
- a. Analog Points – DNP 3.0
- i. 69kV line amps (A phase, B phase, and C phase), 69kV voltage (A phase L-L, B phase L-L, and C phase L-L, frequency, NET MW, NET MVAR, NET MVA and NET power factor at point of interconnection. Power factor and MVA can be a calculated values;
  - ii. [As Applicable] Latest received Maximum Power Import Limit and Maximum Power Export Limit Setpoints (Echo);
  - iii. Power Reference Setpoint (Echo). Power Reference Setpoint can be negative for grid-charging capable batteries; from each unit for Firm Facilities comprised of multiple units
  - iv. Latest received Voltage Setpoint Feedback;
  - v. Latest received MVAR Setpoint Feedback;
  - vi. [Solar Projects] PV Gross MW [As Applicable to AC coupled Facilities: and MVAR] output;

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- vii. [Projects w/BESS] BESS Gross MW [As Applicable to AC coupled Facilities: and MVAR] output/charge;
- viii. [As applicable, DC coupled Solar+BESS] Total Inverters Gross MW and MVAR output;
- ix. [AC-Coupled Solar Projects] PV Inverters Available (count)
- x. [As Applicable] BESS Inverters Available (count)
- xi. [Wind Projects] number of WTGs Available (count)
- xii. Ramp Rate (MW/min, Maximum Dispatchable Up & Down, Feedback As Applicable);
- xiii. Ramp Rate Limit Up (MW/min, absolute limit, from each unit for Firm Facilities comprised of multiple units, provide Normal and Emergency As Applicable);
- xiv. Ramp Rate Limit Down (MW/min, absolute limit, from each unit for Firm Facilities comprised of multiple units; provide Normal and Emergency As Applicable);
- xv. Capacity Available for Dispatch (MW; Total Facility for RDG, for each unit for Firm Facilities comprised of multiple units);
- xvi. [As Applicable] PV Power Possible (MW);
- xvii. [As Applicable] BESS Power Possible (MW);
- xviii. Primary Frequency Droop percent and deadband settings;
- xix. [As Applicable] FFR percent and deadband settings;
- xx. [As Applicable] BESS State of Charge (%), Minimum Usable MWh Capacity, and Maximum Usable MWh Capacity, and BESS Usable Energy Remaining (MWh), must account for derates, outages, and battery degradation;
- xxi. [As Applicable, BESS] Time Remaining at Current MW Output (minutes);
- xxii. [As Applicable, BESS] Time remaining at BESS Power Possible (minutes)
- xxiii. [As Applicable, BESS] Year to Date BESS Usage Counter (cycles and/or MWh)
- xxiv. [As Applicable, BESS] Year to Date Daily Average BESS Usage Counter (MWh)
- xxv. Minimum transient Power Limit (MW) (Ifcmin, typically 0 for inverter-based technology, can be less than 0 for energy storage allowed to charge from grid, from each unit for Firm Facilities comprised of multiple units)
- xxvi. [Solar or Wind Projects] Wind Speed in (MPH) and Wind Direction (degrees from true north);
- xxvii. [Wind Projects] Barometric Pressure at MMT (mbar);

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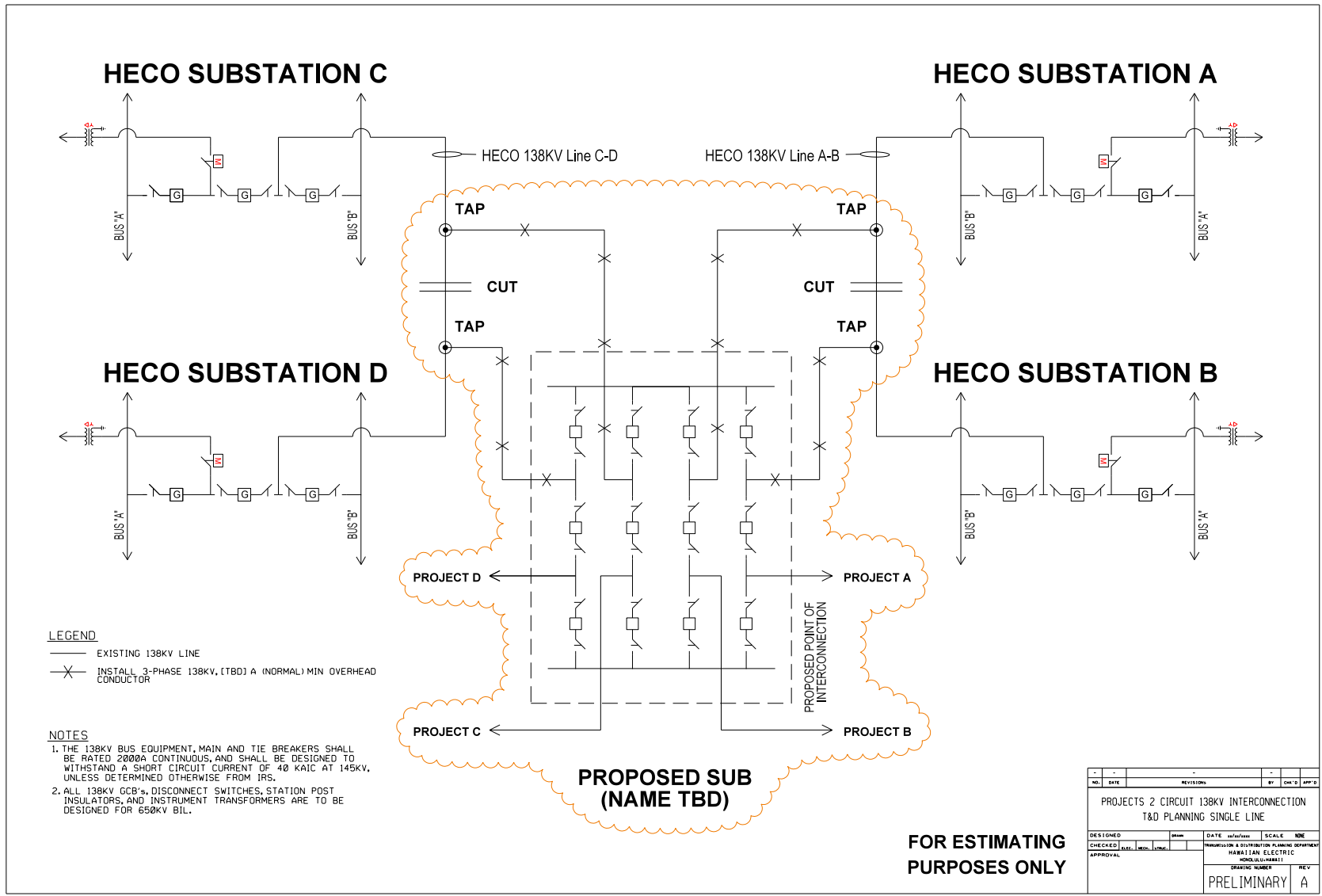
- xxviii. [Solar or Wind Projects] Ambient Air Temperature in Celsius;
  - xxix. [Solar Projects] Plane of Array Irradiance on same axis as array (Watts/m2);
  - xxx. [Solar Projects] Global Horizontal Irradiance (Watts/m2)
  - xxxi. [As Applicable] Normal Operating Day Limit Control Feedback
  - xxxii. [As Applicable] Normal Operating Night Limit Control Feedback
  - xxxiii. [As Applicable] Normal Operating Limit In Effect (MW)
  - xxxiv. Total Facility Auxiliary Load (Power Demand) (MW & MVAR)
  - xxxv. [As Applicable] Isoch Target Frequency (Hz)
  - xxxvi. Black Start Capability (MW)
  - xxxvii. Black Start Plant State (Specific Modes to be discussed with Seller; could be done in indication points if less status/modes expected)
    - 1. 0 – Shutdown
    - 2. 1 – Grid-Tied
    - 3. 2 – Islanded
    - 4. 3 – Shutting down
    - 5. 4 – Stopped in Grid tied
    - 6. 5 – Running Blackstart
    - 7. 6 – Synchronizing
  - xxxviii. [As Applicable] Energy Reserve for Blackstart (MWh)
  - xxxix. [Fueled Facilities] Fuel Type
- b. Accumulator Points
- i. Total KWh From HECO
  - ii. Total KWh To HECO
  - iii. Total KVARh From HECO
  - iv. Total KVARh To HECO
- c. Indication Points – Hardwired Dry Contact Pairs
- i. Status of Seller’s 69kV breaker CB 69-1 (HECO# XXXX);
  - ii. Status of all MOS switches;
  - iii. Status of all lockouts;
  - iv. Protection/DTT communication failure (Loss of Pilot Alarm)

- d. Indication Points – DNP 3.0
  - i. Status of Seller’s medium voltage feeder breakers (and generating unit breakers as applicable);
  - ii. [As Applicable] Status Indicating when Maximum Power Import Limit is in effect - Normal or Alarm;
  - iii. [As Applicable] Status Indicating when Maximum Power Export Limit is in effect – Normal or Alarm;
  - iv. Active Power Control Interface Control Status indicating who has control over dispatch and voltage (Local/Seller vs Remote/HECO);
  - v. Voltage Regulation Status – Normal/AVR or Alarm/VAR/PF (regular On or Off)
  - vi. Frequency Response Status – Normal or Alarm (On or Off);
  - vii. Status for each inverter (on/off);
  - viii. Grid Following/Grid Forming Status;
  - ix. Inverter Enable/Disable Feedback Status;
  - x. Isochronous Mode Enable/Disable Status;
  - xi. Black Start Mode Enable/Disable Status (if analog modes not provided);
  - xii. PPC Heartbeat/Communication Status – Normal or Alarm (On or Off)
  - xiii. APCI to RTU communication failure
  - xiv. 48VDC and/or 125VDC Charger Trouble. Specific alarms to be determined by HECO at a later date;
  - xv. Trouble alarm for loss of VDC source(s) (this is one “specific alarm”, but could include more in detailed design);
- 18. HECO requires 24 hour access to HECO-owned SCADA/RTU, communication, and HECO-owned relaying and monitoring equipment.
- 19. Seller shall install adequate equipment to comply with Section 11 (Measurement data for performance monitoring and validation) of IEEE 2800-2022 (or latest version) and make such data available to the Company upon request.
- 20. [For RDG Contracts] Each of the following quantities need to be logged locally for Company review upon request:
  - a. Status of each inverter/WTG
  - b. MW output of each inverter/WTG

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- c. MW setpoint of each inverter/WTG
- d. MVAR output of each inverter/WTG
- e. MVAR setpoint of each inverter/WTG
- f. [Solar Projects] Back of panel temperature (Celsius)

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**LEGEND**

- EXISTING 138KV LINE
- ✕ INSTALL 3-PHASE 138KV, (TBO) A (NORMAL) MIN OVERHEAD CONDUCTOR

**NOTES**

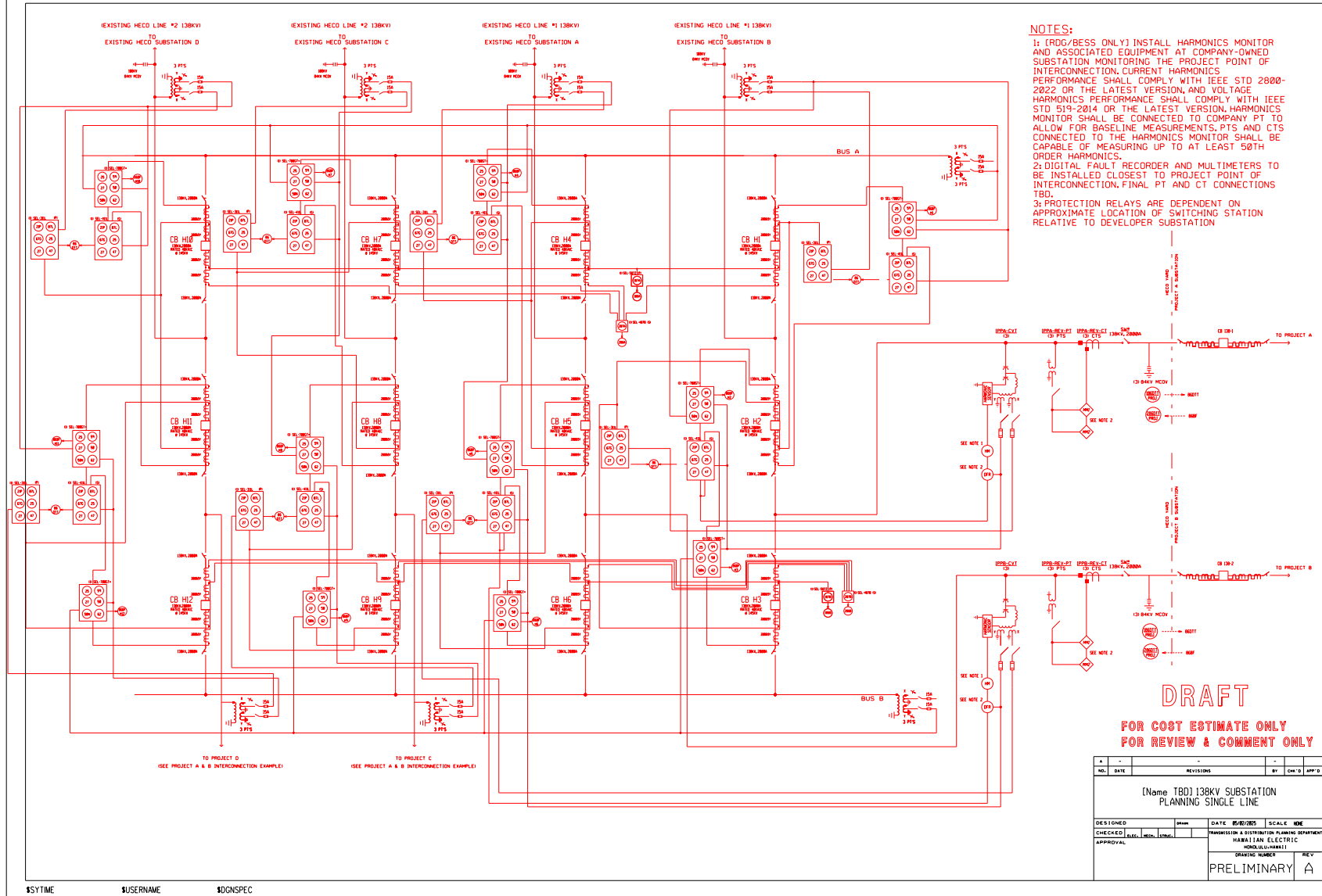
1. THE 138KV BUS EQUIPMENT, MAIN AND TIE BREAKERS SHALL BE RATED 2000A CONTINUOUS, AND SHALL BE DESIGNED TO WITHSTAND A SHORT CIRCUIT CURRENT OF 40 KAIC AT 145KV, UNLESS DETERMINED OTHERWISE FROM IRS.
2. ALL 138KV GCB'S, DISCONNECT SWITCHES, STATION POST INSULATORS, AND INSTRUMENT TRANSFORMERS ARE TO BE DESIGNED FOR 650KV BIL.

**PROPOSED SUB  
(NAME TBD)**

**FOR ESTIMATING  
PURPOSES ONLY**

NO.		DATE		REVISIONS		BY	CHK'D	APP'D
PROJECTS 2 CIRCUIT 138KV INTERCONNECTION T&D PLANNING SINGLE LINE								
DESIGNED	DATE	SCALE	NONE					
CHECKED	REV.	DATE	TRANSMISSION & DISTRIBUTION PLANNING DEPARTMENT					
APPROVAL	HAWAIIAN ELECTRIC		PROJECT NUMBER					
DRAWING NUMBER							REV	A
PRELIMINARY								

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- NOTES:**
- 1: (RDG/BESS ONLY) INSTALL HARMONICS MONITOR AND ASSOCIATED EQUIPMENT AT COMPANY-OWNED SUBSTATION MONITORING THE PROJECT POINT OF INTERCONNECTION. CURRENT HARMONICS PERFORMANCE SHALL COMPLY WITH IEEE STD 2800-2022 OR THE LATEST VERSION, AND VOLTAGE HARMONICS PERFORMANCE SHALL COMPLY WITH IEEE STD 519-2014 OR THE LATEST VERSION. HARMONICS MONITOR SHALL BE CONNECTED TO COMPANY PT TO ALLOW FOR BASELINE MEASUREMENTS. P.TS AND C.TS CONNECTED TO THE HARMONICS MONITOR SHALL BE CAPABLE OF MEASURING UP TO AT LEAST 50TH ORDER HARMONICS.
  - 2: DIGITAL FAULT RECORDER AND MULTIMETERS TO BE INSTALLED CLOSEST TO PROJECT POINT OF INTERCONNECTION. FINAL PT AND CT CONNECTIONS TBD.
  - 3: PROTECTION RELAYS ARE DEPENDENT ON APPROXIMATE LOCATION OF SWITCHING STATION RELATIVE TO DEVELOPER SUBSTATION

**DRAFT**  
**FOR COST ESTIMATE ONLY**  
**FOR REVIEW & COMMENT ONLY**

NO.	DATE	REVISIONS	BY	CHK'D	APP'D
[Name TBD] 138kV SUBSTATION PLANNING SINGLE LINE					
DESIGNED	DATE	REV'D/2025	SCALE	IDE	
CHECKED	DATE	DATE	TRANSMISSION & DISTRIBUTION PLANNING DEPARTMENT		
APPROVAL	HARRISIAN ELECTRIC				
DRAWING NUMBER					REV
PRELIMINARY					A

Notes apply to RDG, Standalone BESS, and Firm Generation Projects unless otherwise noted.

**Notes for Typical Project 138kV Substation Electrical Single Line (2 Existing Circuit Interconnection)**

1. 138kV bus equipment and breakers shall be rated 2000A continuous and shall be designed to withstand a short circuit current of 40 KAIC @ 145kV.
2. All 138kV Gas Circuit Breakers (GCB), disconnect switches, station post insulators, and instrument transformers are to be designed for 650kV BIL.
3. Voltage checks shall be across three phases unless otherwise specified.
4. 138kV breaker H1 to be synchro-checked across its 138kV Bus A and line potentials and allowed to close only under the following conditions:
  - A. Automatic Reclosing:
    1. [TBD by IRS]
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
5. 138kV breaker H2 to be synchro-checked across its line potentials on both sides of the 138kV breaker and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-line
    3. Dead-line and hot-line
    4. Hot-line and dead-line
5. 138kV breaker H3 to be synchro-checked across its 138kV Bus B and line potentials and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
6. 138kV breaker H4 to be synchro-checked across its 138kV Bus A and line potentials and allowed to close only under the following conditions:
  - A. Automatic Reclosing:
    1. [TBD by IRS]
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus

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3. Dead-line and hot-bus
4. Hot-line and dead-bus
7. 138kV breaker H5 to be synchro-checked across its line potentials on both sides of the 138kV breaker and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-line
    3. Dead-line and hot-line
    4. Hot-line and dead-line
8. 138kV breaker H6 to be synchro-checked across its 138kV Bus B and line potentials and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
9. 138kV breaker H7 to be synchro-checked across its 138kV Bus A and line potentials and allowed to close only under the following conditions:
  - A. Automatic Reclosing:
    1. [TBD by IRS]
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
10. 138kV breaker H8 to be synchro-checked across its line potentials on both sides of the 138kV breaker and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-line
    3. Dead-line and hot-line
    4. Hot-line and dead-line
11. 138kV breaker H9 to be synchro-checked across its 138kV Bus B and line potentials and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus

4. Hot-line and dead-bus
12. 138kV breaker H10 to be synchro-checked across its 138kV Bus A and line potentials and allowed to close only under the following conditions:
  - A. Automatic Reclosing:
    1. [TBD by IRS]
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
13. 138kV breaker H11 to be synchro-checked across its line potentials on both sides of the 138kV breaker and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-line
    3. Dead-line and hot-line
    4. Hot-line and dead-line
14. 138kV breaker H12 to be synchro-checked across its 138kV Bus B and line potentials and allowed to close only under the following conditions:
  - A. No Automatic Reclosing
  - B. Manual and Supy Closing:
    1. Voltage magnitude, frequency, and phase difference within acceptable limit
    2. Dead-line and dead-bus
    3. Dead-line and hot-bus
    4. Hot-line and dead-bus
15. All trips from Project #1 to HECO shall trip and block close breakers H2 and H3.
16. All trips from Project #2 to HECO shall trip and block close breakers H5 and H6.
17. All trips from Project #3 to HECO shall trip and block close breakers H8 and H9.
18. All trips from Project #4 to HECO shall trip and block close breakers H11 and H12.
19. [RDG/BESS Only] Install a harmonics recorder and associated equipment at each project point of interconnection, which will be in continuous service and on a rolling window basis monitor sub-cycle voltage and currents and capable of remote interrogation. Current harmonics performance shall comply with IEEE Std 2800-2022 or the latest version, and voltage harmonics performance shall comply with IEEE Std 519-2014 or the latest version. Harmonics monitor shall be connected to company-side PT to allow for baseline measurements. PTs and CTs connected to the harmonics monitor shall be capable of measuring up to at least 50th order harmonics. The following inputs shall be provided:
  - A. 138kV voltage (3-ph) at or near the point of interconnection for Project
  - B. 138kV current (3-ph) at or near the point of interconnection measuring total current from Project

- 20. Opening of 138kV breakers H2 and H3 shall trip HECO lockout relay which will trip and block close Project #1 138kV breaker 138-1 via separate dedicated lockout relay owned by the Developer.
- 21. Opening of 138kV breakers H5 and H6 shall trip HECO lockout relay which will trip and block close Project #2 138kV breaker 138-2 via separate dedicated lockout relay owned by the Developer.
- 22. Opening of 138kV breakers H8 and H9 shall trip HECO lockout relay which will trip and block close Project #3 138kV breaker 138-3 via separate dedicated lockout relay owned by the Developer.
- 23. Opening of 138kV breakers H11 and H12 shall trip HECO lockout relay which will trip and block close Project #4 138kV breaker 138-4 via separate dedicated lockout relay owned by the Developer.

Design Notes:

- 24. SEL 700GT+ relays shall be connected to 3-phase line PTs and 3-phase bus PTs. New CT's are to be MRCT's with relaying accuracy class C800 unless noted otherwise. MRCT's are to have full distributed windings on all taps and a minimum thermal rating factor of 2.0. (Provide the Protection Department with CT saturation, ratio correction factor curves, and continuous thermal rating factors.)

Protection Notes:

The following is only for Project A. The Projects B, C, & D documents would have similar notes with the following changes in breaker number/letter.

Project	Project Breaker #	Switching Station Breakers
A	138-1	H2 & H3
B	138-2	H5 & H6
C	138-3	H8 & H9
D	138-4	H11 & H12

- 25. Bus A differential relay operation shall trip and block close breakers H1, H4, H7, and H10 via manual lockout relay.
- 26. Bus B differential relay operation shall trip and block close breakers H3, H6, H9, and H12 via manual lockout relay
- 27. Line current differential relay operation shall trip and block close breakers H2 and H3, via HECO lockout relay. Developer breaker 138-1 tripped and blocked closed via separate dedicated lockout relay owned by the Developer.
- 28. Line differential relays subject to telecom requirements as specified in the RFP for renewable dispatchable generation and energy storage, Appendix H, Section 2.5
- 29. The local breaker failure scheme shall trip and block close all adjacent breakers via non-electrically resettable lockout relays.

- 30. 138kV breaker H2 or H3 breaker failure function provided by SEL-700GT+.
- 31. All trips going to Developer sub shall go through dedicated Company lockout relays. Company lockout relays will be owned by Company, SCADA resettable, and shall trip a dedicated lockout relay in Developer substation. All trips from Developer to Company shall go through a dedicated Developer owned lockout relay and trip a dedicated lockout relay in Company substation.
- 32. The following local 138kV breaker failure conditions shall initiate a direct transfer trip (DTT) to trip and block close the respective 138kV breakers at the remote substation via a dedicated remotely resettable lockout relay at the remote substation:

<u>Local Breaker Failure Condition</u>	<u>Breaker Failure DTT to Remote Substation</u>
Company Sub A BKR1 Fail	Trip [Name TBD] Sub Bkrs H4 & H5
Company Sub A BKR2 Fail	Trip [Name TBD] Sub Bkrs H4 & H5
Company Sub B BKR1 Fail	Trip [Name TBD] Sub Bkrs H1 & H2
Company Sub B BKR2 Fail	Trip [Name TBD] Sub Bkrs H1 & H2
Company Sub C BKR1 Fail	Trip [Name TBD] Sub Bkrs H7 & H8
Company Sub C BKR2 Fail	Trip [Name TBD] Sub Bkrs H7 & H8
Company Sub D BKR1 Fail	Trip [Name TBD] Sub Bkrs H10 & H11
Company Sub D BKR2 Fail	Trip [Name TBD] Sub Bkrs H10 & H11
Project Sub A Bkr 138-1 Fail	Trip [Name TBD] Sub Bkrs H2 & H3
Project Sub B Bkr 138-2 Fail	Trip [Name TBD] Sub Bkrs H5 & H6
Project Sub C Bkr 138-3 Fail	Trip [Name TBD] Sub Bkrs H8 & H9
Project Sub D Bkr 138-4 Fail	Trip [Name TBD] Sub Bkrs H11 & H12
[Name TBD] Sub Bkr H1 Fail	Trip Company Sub B BKR1 & BKR2
[Name TBD] Sub Bkr H2 Fail	Trip Company Sub B BKR1 & BKR2 & Project Sub A Bkr 138-1
[Name TBD] Sub Bkr H3 Fail	Trip Project Sub A Bkr 138-1
[Name TBD] Sub Bkr H4 Fail	Trip Company Sub A BKR1 & BKR2
[Name TBD] Sub Bkr H5 Fail	Trip Company Sub A BKR1 & BKR2 & Project Sub B Bkr 138-2
[Name TBD] Sub Bkr H6 Fail	Project Sub B Bkr 138-2
[Name TBD] Sub Bkr H7 Fail	Trip Company Sub C BKR1 & BKR2
[Name TBD] Sub Bkr H8 Fail	Trip Company Sub C BKR1 & BKR2 & Project Sub C Bkr 138-3
[Name TBD] Sub Bkr H9 Fail	Project Sub C Bkr 138-3
[Name TBD] Sub Bkr H10 Fail	Trip Company Sub D BKR1 & BKR2
[Name TBD] Sub Bkr H11 Fail	Trip Company Sub D BKR1 & BKR2 & Project Sub D Bkr 138-4
[Name TBD] Sub Bkr H12 Fail	Project Sub D Bkr 138-4

System Operations Notes

The following is only for Project A. The Projects B, C, & D documents would have similar notes with the following changes in breaker number/letter.

Project	Project Breaker #	Switching Station Breakers
A	138-1	H2 & H3
B	138-2	H5 & H6
C	138-3	H8 & H9
D	138-4	H11 & H12

33. All 138kV breakers are controlled and supervised by load dispatch via supervisory equipment and have control switches in the control equipment enclosure.
34. Install a digital fault recorder near point of interconnection, which will be in continuous service and on a rolling window basis monitor sub-cycle voltage, currents, as well as disturbance events and capable of remote interrogation following an event. The digital fault recorder must be provided a GPS time synchronized clock signal set to local time. The following inputs shall be provided and direct hard wired to the recorder:
  - a. Status of all Developer’s 138kV breaker
  - b. Status of all Developer’s medium voltage breakers
  - c. Status of all Developer’s lockouts
  - d. Status of all 138kV Substation Breakers (if Company Substation is located adjacent to project)
  - e. Status of all lockouts for 138kV Substation Breakers (if Company Substation is located adjacent to project)
  - f. 138kV voltage (3-ph) at point of interconnection
  - g. 138kV current (3-ph) at point of interconnection measuring total current from [Project] project
  - h. 138kV line fault distance (miles)
35. Each of the following control and status points shall be remotely controlled and supervised by HECO load dispatcher:
  - a. Trip/Close and status of all 138kV breakers
  - b. All 138kV breakers automatic reclosing status (Auto / Block)
  - c. Open/Close and status of all 138kV disconnect switches
  - d. Status and control of each remotely resettable lockout
  - e. Status of each manual-reset lockout

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36. Each of the following analog points shall be telemetered to HECO load dispatcher:
  - a. All 138kV line amps (A phase, B phase, and C phase), voltages (3 phase), watts, and vars
  - b. All 138kV bus voltages (3 phase)
  - c. Fault Distance for all 138kV
  - d. kWh and kVARh values via Revenue Meter "A"
  
37. Each of the following initiates an alarm to HECO load dispatcher:
  - a. DTT for CB H2 and H3 (*breakers to Project*)
  - b. 125V DC battery low voltage (both primary and backup battery)
  - c. 125V DC charger trouble (both primary and backup battery)
  - d. Loss of 125V DC circuit (individual alarm for each 125V DC circuit)
  - e. 48V DC battery low voltage
  - f. 48V DC charger trouble
  - g. Loss of normal AC station power source
  - h. Loss of emergency AC station power source
  - i. Operation of AC station power auto-transfer switch to emergency source
  - j. Loss of 138kV line and synchro-check potential
  - k. Low SF6 gas pressure for all GCB (individual alarm for each GCB)
  - l. Block operation due to SF6 low gas pressure for all GCB (individual alarm for each GCB)
  - m. Spring discharge alarm for all GCB (individual alarm for each GCB)
  - n. Trip Coil Loss of DC for all GCB (individual alarm for each GCB)
  - o. Each 138kV lockout relay (86) operation
  - p. Each 138kV digital protective relay trouble alarm
  - q. Loss of 138kV line relay primary & backup potential
  - r. Loss of DC for each lockout relay (86)
  - s. Comm Trouble and Loss of Comm alarms
  - t. RTU communication failure

Notes apply to RDG, Standalone BESS, and Firm Generation Projects unless otherwise noted.

The following Project Notes document is only for Project A. The Projects B, C, & D documents would have similar notes with the following changes in breaker number/letter.

Project	Project Breaker #	Switching Station Breakers
A	138-1	H2 & H3
B	138-2	H5 & H6
C	138-3	H8 & H9
D	138-4	H11 & H12

### Notes to be added to the 138kV Project Single Line Diagram

<b>PROPOSED PROJECT NAME:</b>	-
<b>PROPOSED PROJECT SIZE:</b>	-
<b>DEVELOPER SLD REVISION NUMBER AND DATE:</b>	-
<b>HECO SLD REVISION NUMBER AND DATE:</b>	-
<b>HECO SUBSTATION:</b>	-

1. The Project shall install point-on-wave breakers [TBD—For Projects without self-energization], specifically independent pole operated (IPO) breakers with residual flux calculation capability. Energizations is only to occur in coordination with the Company system operator. The voltage deviation at the point of interconnection (POI) must be limited to +/- 5% when energizing the Project. [TBD by IRS]
2. Opening of 138kV breakers H2 and H3 shall trip Developer’s 138kV breaker 138-1 via Company-owned lockout relay.
3. Project breaker 138-1 shall be allowed to close only under the following conditions:
  - a. No Automatic Reclosing
  - b. Manual Closing shall be allowed for the following conditions under the coordination of the Company system operator:
    - i. Hot line (company-side) and dead bus (project-side).
    - ii. Hot line (company-side) and hot bus (project-side) [TBD—For Projects with self-energization]
      - Active synchronization control (i.e., an active synchronizer) on the generation facility shall be used to limit the disturbance, caused by closing, to a minimum. If synchronization parameters, such as voltage magnitude, angle and frequency difference are used during this process, these parameters shall be reviewed and approved by Company.
    - iii. Dead line (company-side) and hot bus (project-side), for black start provided by grid forming capabilities.

### Protection Notes

4. Line current differential relay operation shall trip and block close Company 138 kV breakers H2 and H3 at Company Substation via Company lockout relay. Developer breaker 138-1 tripped and blocked closed via separate dedicated lockout relay owned by the Developer.
5. Line differential relays subject to telecom requirements as specified in the RFP for renewable dispatchable generation and energy storage, Appendix H, Section 2.5 Breaker failure of Company 138kV breakers K2 or K3 at Kahe Substation shall trip separate Company lockout relays which will trip and block close Developer's 138kV breaker 138-1 via separate dedicated lockout relays owned by the Developer.
6. Breaker failure of Company 138kV breaker H2 or H3 shall trip a Company lockout relay which will trip and block close Project 138kV breaker 138-1 via separate dedicated lockout relay.
7. Breaker failure of Project 138kV breaker 138-1 shall trip developer-owned dedicated lockout relay which will trip dedicated lockout relay in Company substation. Dedicated lockout relay in Company substation will trip and block close Company 138kV breakers H2 and H3.
8. All trips going to developer sub shall go through dedicated Company lockout relays. Company lockout relays will be owned by Company, SCADA resettable, and shall trip a separate, dedicated lockout relay in Developer substation. All trips from Developer to Company shall go through a dedicated Developer-owned lockout relay and trip a separate, dedicated Company-owned lockout relay.
9. The local breaker failure scheme shall trip and block close all adjacent breakers via non-electrically resettable lockout relays.

#### **System Operations Notes**

10. HECO shall have SCADA trip control over Seller's 138 kV breaker CB 138-1 (HECO# XXXX).
11. Seller to provide raw count (DNP 3.0) for analog and status points to HECO or other formats as specified in the following notes. Seller to provide hardwired dry contact pairs for certain status points to HECO, and accept hardwired and DNP 3.0 control points from HECO as categorized in the following notes.
12. HECO SCADA/EMS shall be enabled to issue the following Control signals:
  - a. Digital Controls - Hardwire Dry Contact Pair controls
    - i. Trip control over Seller's 138kV breaker
    - ii. Reset control of HECO remotely-resettable lockouts
    - iii. [As Applicable] Isochronous Mode Enable/Disable control signal – Disabling of Isochronous mode should revert to droop frequency response mode
    - iv. [As Applicable] FFR – Enable/Disable
    - v. RDG / BESS Only:
      - All Inverter On/Off control signal
      - Primary Frequency Response Droop – Enable/Disable
  - b. Analog Controls - DNP 3.0 – Seller is not allowed to override HECO's control

- i. Line to Line Voltage Setpoint Target (analog kV);
- ii. MVAR Setpoint Target (analog MVAR +/-);
- iii. Power factor setpoint target (analog pf +/-);
- iv. AVR/PF/VAR/Disable (Analog value to signal which voltage control mode project is currently in)
- v. [As Applicable] Isoch Target Frequency Setpoint (Hz)
- vi. Frequency Droop Settings (% and deadband)
- vii. RDG / BESS Only:
  - Dispatchable Ramp Rate (MW/min)
  - Maximum Power Import Limit
  - Maximum Power Export Limit
  - Power Reference Setpoint (analog MW dispatch setpoint; can be negative value for grid-charging capable batteries);
  - [As Applicable] FFR Settings (% and deadband)
  - Heartbeat Counter (increments up, to allow PPC to understand when there is no more communications from HECO)
  - [As Applicable] Energy Reserve for Blackstart (MWh)
- viii. Firm Only:
  - For each generator:
    - a. EMS MW Target (MW Setpoint Control);
    - b. Frequency Droop Settings (% and deadband)
    - c. Dispatchable Ramp Rate (MW/min)

13. All control values must be retained in non-volatile memory such that they will be restored immediately upon return from a control systems restart, power outage, loss of communication, etc.

14. The following signals shall be telemetered to HECO SCADA/EMS:

- a. Analog Points – Hardwired Directly to HECO RTU
  - i. 138kV line amps (B phase), 138kV voltage (A-B phase), NET MW, and NET MVAR at point of interconnection through use of HECO approved non-programmable analog transducers or other HECO approved means of providing unaltered data set of voltages and currents. Data to be provided in analog format (+/- 1mA) directly from the analog transducers;
- b. Analog Points – DNP 3.0
  - i. 138kV line amps (A phase, B phase, and C phase), 138kV line voltages (A phase, B phase and C phase), frequency, NET MW, NET MVAR, NET MVA and NET power factor at point of interconnection. Power factor and MVA can be a calculated values;
  - ii. Latest received Voltage Setpoint Feedback;
  - iii. Latest received MVAR Setpoint Feedback;
  - iv. Latest received Power Factor Setpoint Feedback;
  - v. [As Applicable] Isoch Target Frequency (Hz).
  - vi. RDG / BESS Only:
    - Latest received Maximum Power Import Limit and Maximum Power Export Limit Setpoints Feedback;
    - Power Reference Setpoint Feedback. Power Reference Setpoint Feedback can be negative for grid-charging capable batteries;

- PV Gross MW [As Applicable to AC/DC coupled Facilities: and MVAR] output;
  - BESS Gross MW [As Applicable to AC/DC coupled Facilities: and MVAR] output/charge;
  - [Solar Projects] PV Inverters Available;
  - [As Applicable] BESS Inverters Available;
  - [Wind Projects] Number of WTGs Available;
  - Ramp Rate (MW/min);
  - Ramp Rate Limit Up (MW/min);
  - Ramp Rate Limit Down (MW/min);
  - Total Facility Power Possible (MW);
  - PV Power Possible (MW);
  - BESS Power Possible (MW);
  - BESS Charge Possible (MW);
  - Primary Frequency Droop percent and deadband settings;
  - [As Applicable] FFR percent and deadband settings;
  - BESS State of Charge (%), Minimum Usable MWh Capacity, and Maximum Usable MWh Capacity, and BESS Usable Energy Remaining (MWh), must account for derates, outages, and battery degradation;
  - Time Remaining at Current MW Output (hours or minutes at HECO discretion);
  - Time Remaining at BESS Power Possible (hours or minutes at HECO discretion);
  - Year to Date BESS Usage Counter (cycles and/or MWh)
  - Year to Date Daily Average BESS Usage Counter (MWh)
  - Wind Speed (MPH) and Wind Direction (degrees from true north);
  - [Wind Projects] Barometric Pressure at MMT (mbar);
  - Ambient Air Temperature (Celsius);
  - [Solar Projects] Plane of Array Irradiance on same axis as array (Watts/m<sup>2</sup>);
  - [As Applicable] Normal Operating Day Limit Control Feedback;
  - [As Applicable] Normal Operating Night Limit Control Feedback;
  - [As Applicable] Normal Operating Limit In Effect (MW);
  - Total Facility Auxiliary Load (Power Demand) (MW & MVAR);
  - Heartbeat Counter Feedback (echoback the Heartbeat Counter so HECO understands when there is no more communication from PPC).
  - Black Start Capability (MW)
  - Black Start Plant State (Specific Modes to be discussed with Seller)
    - 0 – Shutdown
    - 1 – Grid-Tied
    - 2 – Islanded
    - 3 – Shutting down
    - 4 – Stopped in Grid tied
    - 5 – Running Blackstart
    - 6 – Synchronizing
  - [As Applicable] Energy Reserve for Blackstart (MWh)
- vii. Firm Only:
- For each generator, as needed based on plant design:
    - a. EMS MW Target (MW Setpoint Control) Feedback;

- b. Load Frequency Control (LFC) High and Low MW Setpoint Limits Feedback;
  - c. MW, MVAR, 46kV voltage (A phase L-N, B phase L-N, and C phase L-N), frequency,
  - d. Normal Ramp Rate Up/Down;
  - e. Emergency Ramp Rate Up/Down;
  - f. Frequency Droop percent and deadband settings;
  - g. Fuel type
  - h. Turbine RPM
  - i. Aux load MW
  - j. Aux load MVAR
  - k. Start up MW
  - l. Start up MVAR
  - m. Start up MWH
  - Plant Power Possible (MW);
- c. Accumulator Points
- i. Total KWh From HECO
  - ii. Total KWh To HECO
  - iii. Total KVARh From HECO
  - iv. Total KVARh To HECO
- d. Indication Points – Hardwired Dry Contact Pairs
- i. Status of Seller’s 138kV breaker CB 138-1 (HECO# XXXX);
  - ii. [As Applicable] Status of Seller’s MOS switches;
  - iii. Status of HECO remotely-resettable lockouts;
  - iv. Protection/DTT communication failure (Loss of Pilot Alarm);
  - v. 48VDC and/or 125VDC Charger Trouble. Specific alarms to be determined by HECO at a later date [can be DNP for HI/Maui];
  - vi. Trouble alarm for loss of VDC source(s)
- e. Indication Points – DNP 3.0
- i. Status of Seller’s medium voltage feeder breakers;
  - ii. Violation of Maximum Ramp Rate Upward (Performance Standard);
  - iii. Violation of Maximum Ramp Rate Downward (Performance Standard);
  - iv. Active Power Control Interface Control Status indicating who has control over dispatch and voltage (Local/Seller vs Remote/HECO);
  - v. Frequency Response Status – Normal or Alarm (On or Off);
  - vi. [As Applicable] Isochronous Mode Enable / Disable Status;
  - vii. Watchdog Timer: RTAC Loss of Communication
  - viii. RDG / BESS Only:
    - Status Indicating when Maximum Power Import Limit is in effect - Normal or Alarm;
    - Status Indicating when Maximum Power Export Limit is in effect – Normal or Alarm;
    - Status for each inverter (On or Off);
    - Grid Following / Grid Forming Status;
    - Inverter Enable / Disable Feedback Status;
    - Heartbeat Counter Status – Normal or Alarm; and
    - Heartbeat Counter Feedback Status – Normal or Alarm.

- [As Applicable] Ready to Close Breaker Utility Black Start
- ix. Firm Only:
- Health check DCS/TCS – Alarm/Normal
  - Raise block - Alarm/Normal
  - Lower block – Alarm/Normal
15. HECO requires 24 hour access to HECO-owned SCADA/RTU, communication, and HECO-owned relaying and monitoring equipment.
16. HECO shall own a high-speed power quality device (e.g., Tesla Model No. 4000) near the point of interconnection, which shall be in continuous service and on a rolling window basis, monitoring sub-cycle voltages and currents, as well as disturbance events, and capable of remote interrogation following an event. HECO requires 24 hour access to this equipment. The digital fault recorder must be provided with a GPS time synchronized clock signal set to local time. Seller to provide the following hard wired inputs to HECO's power quality device:
- a. Status of Seller's 138kV breaker CB 138-1 (HECO# XXXX) – 52a contacts only;
  - b. Status of Seller's medium or low voltage breakers that will be used to sequence plant connection to prevent voltage issues upon energization/connection to the grid (as needed per IRS);
  - c. Status of all remotely-resettable lockouts;
  - d. 138kV line amps (3 phase);
  - e. 138kV voltage (3 phase).
17. [RDG/BESS Only] Each of the following quantities need to be logged locally for Company review upon request:
- a. Status of each inverter/WTG
  - b. MW output of each inverter/WTG
  - c. MW setpoint of each inverter/WTG
  - d. MVAR output of each inverter/WTG
  - e. MVAR setpoint of each inverter/WTG
  - f. [Solar Projects] Global Horizontal Irradiance (Watts/m<sup>2</sup>)
  - g. [Solar Projects] Back of panel temperature (Celsius)

**Design Notes**

18. All 138kV CT's are to be MRCT's with relaying accuracy class C800 unless noted otherwise. MRCT's are to have full distributed windings on all taps and a minimum thermal rating factor of 2.0. (Provide the Protection Department with CT saturation, ratio correction factor curves, and continuous thermal rating factors.)
19. All microprocessor relays, instruments, CT's, and PT's are to have test switches.