SEL Engineering Services, Inc.

Distributed Restart Zone Controller FEED

National Grid UK

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ACRONYMS AND ABBREVIATIONS

BESS	battery energy storage system
CB	circuit breaker
CFEP	central front-end processor
CLR	current-limiting reactor
CLS	contingency-based load shedding
CLSP	contingency-based load-shedding processor
DRZ	distributed restart zone
DRZC	distributed restart zone controller
EWS	engineering workstation
F	frequency
FEED	front-end engineering design
FEP	front-end processor
GTG	gas turbine generator
GW	gateway
ICS	island control system
IRM	incremental reserve margin
KVM	keyboard, video, and mouse
LAN	local-area network
LSP	load-shedding processor
LLS	load-shedding system
ms	milliseconds
MGCS	microgrid control system
NGVL	Network Global Variable List
OT-SDN	operational technology software-defined networking
OWS	operator workstation
P	real power
PLS	progressive overload shedding
PMS	power management system
PV	photovoltaic
s	seconds
Q	reactive power
SEL	Schweitzer Engineering Laboratories, Inc.
SEL ES	SEL Engineering Services, Inc.
SER	Sequential Events Recorder
STG	steam turbine generator
UFLS	underfrequency-based load shedding
UFLSP	underfrequency-based load-shedding processor

V	voltage
VPN	virtual private network

SECTION 1 INTRODUCTION

This front-end engineering design (FEED) study report provided by SEL Engineering Services, Inc. (SEL ES) describes the POWERMAX® Power Management and Control System distributed restart zone controller (DRZC) for the National Grid UK project. National Grid UK requested SEL ES to perform a FEED study to propose methods to improve system reliability by implementing a DRZC to assist in black start and stability of the system with minimal impact to the system in operation. The following functionalities are part of the DRZC POWERMAX system:

- Distributed restart system
- Load-shedding system (LSS)
  - Contingency-based load shedding (CLS)
  - Underfrequency-based load shedding (UFLS)
  - Undervoltage-based load shedding (UVLS)
  - Load bank control (LBC) for increasing block load pickup capability and frequency stabilization
  - Progressive overload shedding (PLS)
- Distributed energy resource (DER) and generator control system (GCS)
- Overfrequency-based generation shedding system (GSS)

Note: The distributed restart zone controller (DRZC) will be implementing some of the SEL microgrid control system (MGCS) philosophies and algorithms to control the power system.

1.1 SEL ES Scope of Supply

The following services are proposed by SEL ES for deployment in the distributed restart project.

1.1.1 DRZC POWERMAX System

The DRZC POWERMAX system is comprised of hardware and software components configured to provide control for electrical power systems. The POWERMAX algorithms are proven and proprietary control function libraries that run on a single SEL-3555 Real-Time Automation Controller (RTAC) platform. The SEL-3555 RTAC running the POWERMAX is called a DRZC for the scope of this project. The functionalities of the system will be split between three conceptual groups of algorithms, Load-shedding system (LSS), Generation control system (GCS) and the Overfrequency-based generation shedding (GSS).

The functionalities of the POWERMAX logic running in the LSS will include:

- Distributed restart system that starts DER assets and picks up loads within the distributed restart zone (DRZ) to re-energize the distribution network and bring the DRZ online with the transmission grid. This includes management of LBC to effectively increase the block load capability of the DERs available in the distributed restart zone (DRZ).
- A CLS algorithm that sheds load based on a predicted power deficit. The CLS attempts to reduce the total load to less than or equal to the calculated available capacity after a contingency occurs. The individual plant loads are selected for shedding based on modifiable priorities on the POWERMAX DRZC human-machine interface (HMI) and power system topology.

- A UFLS algorithm that sheds load based on underfrequency events. The UFLS will serve as a backup for the CLS in the scenario that a loss of generation or sudden addition of load occurs without sending a contingency trigger to the CLS system. The UFLS sheds loads using the same priorities as the CLS.
- A UVLS algorithm that sheds load based on undervoltage events. The UVLS will shed load to preserve the system from voltage collapse by shedding loads local to the detected undervoltage event based and considering user settable priorities in the HMI.
- A PLS algorithm sheds load based on overload of generation assets. This will serve to protect the generation assets from exceeding a safe percentage of their maximum output.

The functionalities of the POWERMAX logic running in the GCS will include:

- Generator and DER starting control.
- Generator and DER frequency control to maintain system frequency during islanded restart operation of the distribution network.
- Generator and DER voltage control to maintain system voltage during islanded restart operations of the distribution network.
- Tie line control to control the import and export of MW and MVAR at the coupling point with the transmission grid.
  - Tie line control is only intended for use after the DRZ is restarted during transmission grid re-energization. This control lets the DRZC operate the distribution system in a “power plant” mode, which controls all DERs to provide real and reactive power to the grid.

The functionalities of the POWERMAX logic running in the GSS will include:

- An over frequency-based generation shedding algorithm that aggressively controls the load bank, runs back generation, or sheds generation from the system entirely in response to overfrequency events.

The POWERMAX DRZC will be installed at a central control building and will collect real-time data from front end processors (FEPs) which collect field data physically and through intelligent electronic devices (IEDs) located at various substations in the DRZ.

SECTION 2 DISTRIBUTED RESTART PROJECT NETWORK

This section of the report overviews the Chapelcross 33 kV grid supply point (GSP) network and covers the single-line diagram (SLD), communications architecture, and the POWERMAX DRZC system requirements. Consideration is given to generalize this substation for DRZC applicability in other future substations.

Details of the Chapelcross DRZ configuration can be found in APPENDIX A. The main anchor generation station is Stevens Croft Biomass Generating Unit. The anchor generator is the most important asset the DRZC uses to drive the restart process.

Major substations on the simplified SLD include Chapelcross Substation 33 kV, which consists of the following equipment:

- Two Chapelcross buses (Bus A and Bus B), nominally rated at three phase 50 Hz and 33 kV.
- One 33 kV connection to Stevens Croft substation that connects to the Stevens Croft biomass anchor generator and load bank (can also be located at the 33 kV bus).
- One 33 kV connection to substation Middlebie that interconnects to Ewe Hill Wind Farm.
- One 33 kV connection to substation Minsca Wind Farm.
- Two 33 kV connections to load substations:
  - Annan
  - Lockerbie
  - Moffat
  - Gretna
  - Langholm (interconnection through Middlebie to Chapelcross Bus A)

Note: Lockerbie, Moffat, Gretna, and Langholm are not considered in this case study. Only Annan Substation is being considered for restoration and load shedding.

Major DER assets are shown in Table 2.1:

Table 2.1: DERs Under Consideration

DER Name	Type	Location	Rating/Voltage
Stevens Croft Anchor Generator	Biomass	Stevens Croft	53 MVA/11 kV
Ewe Hill Wind Farm	Wind farm	Ewe Hill	12 MW/11 kV
Minsca Wind Farm	Wind farm	Minsca	37 MW/11 kV
Battery energy storage system (BESS) (Example)	TBD	Chapelcross	TBD/33 kV
Photovoltaic (PV) (Example)	TBD	Chapelcross	TBD/33 kV

Through Chapelcross 33 kV bus, Stevens Croft biomass generator, EWE Hill Wind Farm, and Minsca Wind Farm serve loads at multiple substations including Annan, Lockerbie, Gretna, Langholm, etc. There are wind farms at the 11 kV level as well, but these are not considered as part of this FEED. Additionally, a BESS and PV substation is being considered to demonstrate how the DRZC would control these DERs if they were available in the system. For the current DRZC load-shedding scheme the load substations in Table 2.2 are selected for preliminary design based on the communications availability.

Table 2.2: Load Substations

Load Substation Number	Name	Voltage Level (kV)
1	Annan	33 kV/11 kV

2.1 OPERATION PHILOSOPHY CONSTRAINTS

The FEED will explore the feasibility and design of the DRZC to restore power using DERs in the event of a shutdown of the National Electricity Transmission System. Once a distribution power island is restored, it will be expanded to energize the transmission network using a “bottom up” strategy. It is being considered that multiple DRZC may communicate to an external grid controller for executing the “bottom up” strategy on a wide scale. The DRZC will enable the monitoring, control, and coordination of a range of DER and network resources to provide black start services, load restoration, and transmission grid reenergization while maintaining stability of the distribution power island.

SEL ES proposed design for the DRZC are summarized in this document along with APPENDIX B.

2.2 PHYSICAL NETWORK CONNECTIONS

The APPENDIX B communication architecture drawing shows the physical network and device connections. The current architecture includes a branching network from the central Chapelcross Substation out to each 33 kV substation necessary for the control system. Due to the possibility of individual substations being vulnerable to cyber intrusion, VPN tunneling and security hardware firewalls for each connection between the central Chapelcross Substation and the other substations are implemented.

The communication architecture shows the ideal, fully featured, top-to-bottom communication network solution by SEL ES. However, SEL ES understands that the full design presented here may not be practical for every application required by a distribution network operator (DNO). To assist with the general design understanding SEL ES describes the minimum requirements of the communication network in Section 4.2. Please keep in mind, SEL hardware can be configured to form a secure “bolt on” solution to any existing communication hardware that National Grid UK desires, if the existing communication network can support the minimum bandwidth requirements.

2.3 COMMUNICATION ARCHITECTURE

The physical architecture of the DRZC and supporting system consists of the central devices that provide core control functions and the peripheral devices that provide metering, status, and control data. APPENDIX B, the communication architecture, illustrates the physical architecture of the distributed restart controller system. APPENDIX C, the data flow diagram, shows details of the data flow between devices such as protocols and conceptual communication paths. In this section, the roles of each device in the communication architecture are briefly covered. Reference APPENDIX B to see devices in the communication architecture.

The SEL-2240 Axion® acts as a substation FEP by collecting I/O data from breakers and DER using its modular I/O cards. The modular I/O of the Axion make it a good choice for various data acquisition roles.

The Axion field data are transmitted to the SEL-3555 RTAC central front-end processor (CFEP). The CFEP collects data from each Axion FEP, concentrating all field data before sending it to the central controller, offloading the communications burden from the controller.

Concentrated field data are sent from the CFEP to the SEL-3555 DRZC for analysis and decision making. The DRZC performs logical operations at high speed and sends out control signals to the FEPs where they are routed to specific field control points.

SEL-3355 Computers are used in the system to firewall and run IPSEC VPN connections between distributed substations and the central Chapelcross Substation. SEL-3355 Computers are also implemented in the Chapelcross Substation as the HMI operator workstation (OWS) and the engineering workstation (EWS).

The backbone of the communication network is the SEL-2740S Software-Defined Network Switch. These switches use operational technology software-defined networking (OT-SDN) technology implementing a deny by default network configuration. All network flows will need to be explicitly defined for these switches. This ensures a high level of security within each substation local area network (LAN), especially when combined with the SEL-3355 Computers that act as firewalls and encrypt traffic via VPN across the links between the substation switches.

Please reference Section 4, which describes the data layers, paths, and cybersecurity features in further detail and gives an example of how they are applied throughout the communication architecture.

2.3.1 Equipment by SEL ES

SEL ES proposes the following equipment to the DNO who operates the DRZ:

- Two fully configured NEMA 12 POWERMAX panels for installation at the Chapelcross GSP Substation with the following hardware installed:
  - Two (2) SEL-2740S Software-Defined Network Switch
  - Two (2) SEL-2730M Managed Network Switch
  - One (1) SEL-3355 Computer (firewall and VPN concentrator)
  - One (1) SEL-3355 Computer (HMI-OWS)
  - One (1) SEL-3355 Computer (EWS)
  - One (1) SEL-3555 RTAC (DRZC)
  - One (1) SEL-3555 RTAC (gateway)
  - One (1) SEL-3555 RTAC (CFEP)
  - One (1) SEL-2488 Satellite-Synchronized Network Clock
  - Two (2) SEL-451 Protection, Automation, and Bay Control System
  - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
  - One (1) 19″ LCD monitor with keyboard and mouse (HMI and workstation)
- Loose equipment for installation at each substation with controlled assets:
  - Annan
    - Two (2) SEL-2740S Software-Defined Network Switch
    - One (1) SEL-3355 Computer (firewall and VPN)

        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - EWE Hill
        - Two (2) SEL-2740S Software-Defined Network Switch
        - One (1) SEL-3355 Computer (firewall and VPN)
        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - Minsca
        - Two (2) SEL-2740S Software-Defined Network Switch
        - One (1) SEL-3355 Computer (firewall and VPN)
        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - Stevens Croft
        - Two (2) SEL-2740S Software-Defined Network Switch
        - One (1) SEL-3355 Computer (firewall and VPN)
        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - Middlebie
        - Two (2) SEL-2740S Software-Defined Network Switch
        - One (1) SEL-3355 Computer (firewall and VPN)
        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - Lockerbie
        - Two (2) SEL-2740S Software-Defined Network Switch
        - One (1) SEL-3355 Computer (firewall and VPN)
        - One (1) SEL-2240 Axion I/O module and RTAC (FEP)
    - All additional controlled substations will have similar equipment to what is shown for the substations listed here.

Note: Existing customer panels would need to be altered to accommodate new wiring for power, networking, hardwired I/O, and equipment mounting. Please refer to APPENDIX B for hardware requirements.

2.3.2 Documentation by SEL ES

SEL ES identifies the following documentation deliverables as part of project execution to the customer:

- An initial set of drawings for the customer to review, comment, and approve consisting of the following:
    - Drawing index or drawing transmittal sheet that includes drawing number, revision number, and description
    - AC/DC elementary drawings
    - Wiring drawings
    - Bill of Materials (BOM) including revised part numbers and quantities

- Panel layout drawings, including revised placement and numbers
- Nameplate list, including revised device numbers

- A final set of the drawings after customer approval
- A relay instruction manual for each relay provided in either electronic or bound format
- Functional Design Specification (FDS) document
- Data flow diagram
- Communications architecture drawing
- I/O list
- Factory acceptance test (FAT) plan
- Site acceptance test (SAT) plan
- User's manual
- An electronic copy of all drawings and BOMs furnished by SEL ES

Note: All drawings will be provided in AutoCAD format (.dwg) version or in portable document format (.pdf) unless otherwise agreed during design stage.

2.4 Overview of Restart Control Philosophy

The SEL DRZC POWERMAX system will use the distributed hardware explained in the previous section to control the distribution system during restart. The hardware interfaces with DERs and circuit breakers (CBs) throughout the distribution system. The general concepts for how the DRZC will perform the restart process is described in this section. For more detailed descriptions of the control algorithms and DER strategies, please see Section 6.

An important concept of the DRZC is that it can operate in both an Automatic and a Manual Mode. In automatic it will perform its own control function and only require operator intervention if an alarm flag is asserted. In manual mode the DRZC still runs some basic controls which maintain system stability, but the restarting process will require operator input to continue moving forward. For example, load restoration and starting DER will be initiated with a button click in manual, but in automatic the DRZC will perform both without any operator intervention.

One important term that will be used in this section and throughout the document is incremental reserve margin (IRM). IRM, or block load pick up capability, is defined as the amount of step increase in load that a generation asset can provide within the tuning time response to keep the frequency within acceptable limits. The IRM is different from spinning reserve, which is the capacity of the generator minus the current operating point of the generator.

2.4.1 Basic Distributed Restart Process

Restart begins when a full blackout occurs within the DRZ. The SEL DRZC will initiate commands to start the anchor generator and use it to energize 33 kV lines and busbars following a predefined pattern. Because the Chapelcross anchor generator is black start capable, the DRZC will send a control signal to the generator interface to initiate startup. Next, all available DERs will be brought online and connected to form a single power island. Consideration will be given for transmission line energization and transformer energization by arming the generators prior to each event. Remote control of circuit breakers and DERs is performed by DRZC commands to the SEL-2240 Axions in each substation.

Load restoration for the Annan Substation will occur once the DERs and generator are running in a stable configuration. The available load bank will be charged to just above the expected restoration demand of the given feeder then switched off at the same moment the system load feeder is closed. If a load bank is not available load would be restored only in sections smaller than the total block load pick up capability of the anchor generator and DERs.

During the process of growing the power island, the stability of the network must be maintained. The SEL GCS algorithms running inside of the DRZC will be used to maintain the frequency and voltage by dispatching the DERs. This includes control to maintain steady state limits and optimizing different assets by enforcing load sharing and active and reactive power participation. Control includes intelligent loading of the DERs, keeping in mind the available capacity of each and considering the potential for a cold load pickup to be greater or less than expected. See Section 6 for detailed control strategies.

Stability during events that cause load generation mismatch on any given island is achieved by shedding load or generation. This shedding could be for active or reactive power to regulate frequency or voltage. Load will shed when a contingency breaker is opened under load or underfrequency or undervoltage conditions are detected. This is accomplished using the contingency-based load shedding (CLS), underfrequency-based load shedding (UFLS), and undervoltage-based load-shedding (UVLS) algorithms that run in the DRZC.

The DRZC will also respond to overfrequency events by adding load to the load bank, if available, and/or curtailing DER output. In the more extreme overfrequency cases the overfrequency-based generation shedding (GSS) algorithm will runback generators and/or shed generation. Details of the load-shedding algorithms can be found in Section 7.

Note: Anchor generator shall always be blocked from shedding. The frequency & voltage thresholds shall be coordinated with existing protection systems to avoid any mis operation.

2.4.2 Transmission Grid Re-Energization or Synchronization

Once the DRZ is maintaining stable operation after restarting all the available DERs and load substations, it will change its focus to grid re-energization mode. In grid re-energization mode the DRZC will monitor the voltage of the transmission grid while providing total available DRZ MW and MVAR capacity, system block load pickup capability, and a "ready to support" signal to the external grid controller. The DRZC will also accept external commands over secure channels from the external controller to change export to the grid.

The grid controller is an assumed source of external control during grid re-energization. This external grid controller shall be communicating to multiple DRZC at different location to manage this process. This is required because the DRZC does not have hardware monitoring at the transmission grid level and is unaware of the assets connected to the transmission grid. An external control input, either an operator or grid controller, is needed to coordinate the output of the DRZC with the grid. Linking with a controller external to the DRZ during re-energization comes with inherent risk but can be managed using secure connection. To understand SEL's recommendation on how to securely connect to external networks, refer to Section 4.

If the grid voltage and frequency are within healthy limits (live-grid condition) the DRZC will automatically synchronize with the grid upon an external close to grid command. The DRZC will operate the DERs in Droop/grid following mode. If the grid is not healthy (dead-grid condition) the DRZC will wait for the external close to grid command and begin re-energization. If the source in the DRZ is the only source of generation after closing to the dead grid then DRZC will operate the DERs in ISOC/grid forming mode. Once the grid controller provides feedback signals to the DRZC that it will be paralleling with additional grid sources the DRZC switches DERs into the Droop/grid following mode. When grid-connected, GCS algorithms control the system DERs and anchor generator to achieve the desired tie line power flow. Detailed descriptions of the control algorithms used to accomplish tie line control are found in Section 6.

Note: SEL recommends a transient stability analysis to be performed prior to field deployment. SEL also recommends a voltage stability analysis to be performed prior to field deployment. This type of simulation can be part of SEL's hardware-in-the-loop (HIL) testing during the project execution for any given site.

2.4.3 Minimum DER Control Requirements

For effective control of the system with the DRZC, some minimal control interface requirements must be met for the DERs:

- DER must provide a hardwired and/or communication-based interface such as Modbus to an SEL device.
  - I/O interface allows control of MW and MVAR output (or demand in case of load bank).
  - I/O interface allows DERs to be started and synchronized remotely by the DRZC.
  - I/O interface allows DERs to be controlled remotely by the DRZC and have voltage and frequency regulation capability.
  - I/O interface provides available capacity or spinning reserve of the DER.
- Interface must provide DER alarms to inform the DRZC that the DER is not controllable.
- Interface should provide P, Q, V, and F at the DER. If any of these are not available, SEL ES will install metering at the DER.
  - Analog metering can be slow speed, updating once every 500 ms or less.

2.4.4 Minimum Breaker Control Requirements

The DRZC must control breakers to connect the system islands and DERs in addition to picking up and shedding load. SEL DRZC breaker designations are defined as follows in the APPENDIX A Single Line Diagram:

- Contingency Breaker (Yellow on SLD): Contingency breakers are essential links to a source. Unexpected opening of a contingency breaker results in an immediate loss of generation.
- Load Breaker (Blue on SLD): Load breakers connect to demand.
- Topology Breaker (Green on SLD): Topology breakers provide connections that do not link directly to a source of generation or load. Topology breaker status must be monitored to know the configuration of the network, but metering is not required.

The required interface for any breaker is the following:

- Close and open control contacts
- 52A or 52B status (pickup of both statuses is preferred, but not required)
- P, Q, V, and F metering at the load and contingency breakers
- Truck-operated contact (TOC) or rack out status

2.4.5 Minimum Grid Energization Requirements

For the DRZC to support the re-energization of the transmission grid, some minimum requirements must be established:

- Transmission system voltage and frequency must be monitored upstream of the distribution network PCC transformers.
- Minimum demand requirement in terms of MVAR and MW for re-energization should be available, either through operator input or by calculation from data made available to the controller. The estimate should be accurate for the portion of the transmission grid the DRZC is helping to energize.
  - The DRZC will provide the block load pickup capability and MVAR capacity the DRZ can provide to the transmission grid. This value must meet or exceed re-energization requirements before attempting re-energization.
- A relay with a synchronism-check element across each PCC must be available to close the PCC breaker into a live grid.

With these requirements met the DRZC should be able to support re-energization of the transmission grid regardless of the grid being alive or dead.

SECTION 3 OPERATIONAL SCENARIOS

The operational scenarios described here consider the following assets. Details of each sequence is also shown in the DRZC flow chart APPENDIX D.

DER Name	Status	DER Type	Location	Rated (MVA)
Stevens Croft Anchor Generator	Available	Biomass	Stevens Croft	53 MVA/11 kV
EWE Hill Wind Farm	Available	Wind farm	EWE Hill	12 MVA/11 kV
Minsca Wind Farm	Available	Wind farm	Minsca	37 MVA/11 kV
BESS (Future)	Not available	TBD	Chapelcross	TBD/33 kV
PV Future	Not available	TBD	Chapelcross	TBD/33 kV
Load Bank	Available	Load bank	Stevens Croft	20 MVA/11 kV
Annan	Available	Load substation	Annan	33 kV/11 kV

3.1.1 Distributed Restart – Black Start Sequence

Step 1. The DRZC detects the blackout condition based on Undervoltage (27) condition and performs the following actions:

a. Open transmission grid incomers to the DRZ, if closed.

b. Open all Chapelcross 33 kV Substation feeder breakers.

c. Verify load bank is off and set to the lowest value possible.

d. Send a black start signal to the anchor generator and connect it to the 11 kV bus.

e. Energize the 11 kV bus.

Step 2. Monitor system voltage and frequency for stable operation. Once stable, wait for the stability timer to expire before proceeding to the next step. The voltage and frequency shall be regulated within 2% of nominal for frequency and 5% of nominal for voltage. The rate of change of frequency is within 0.5 Hz/sec and rate of change of voltage is within 2%/sec.

a. The voltage and frequency limits and the stability timer are configurable in the DRZC HMI.

Step 3. The DRZC performs the following actions:

a. Verify that all feeder breakers at the Chapelcross 33 kV bus are open.

b. Adjust the mode of the Stevens Croft anchor generator to Island mode if necessary.

c. Close breakers starting at the anchor generator to energize the Stevens Croft feeder and then finally Chapelcross 33 kV Bus A.

d. DRZC shall control the exciter of the anchor generator to regulate the voltage at Chapelcross 33kV Bus.

Step 4. The DRZC system will now retrieve expected P and Q restoration demand for first available load substation (Anan in this case). Load profile for the given time of year, if available, will be compared against the 15-minute average P and Q from when the load was last closed and healthy. The maximum of the two will be the expected demand. An operator enterable MW setpoint can be entered for the DRZC to use instead, for manual operation. The DRZC will not restore a load which exceeds the current island capacity unless manually forced to by the operator.

Step 5. The DRZC will charge the load bank to 110 percent of the maximum load profile detected for the Annan Substation using a gradual step. The anchor generator output shall follow this load demand from the load bank. This load factor can be adjusted from the HMI and may vary depending on time of year and each individual site.

Step 6. Stability check from Step 2 is performed.

Step 7. The DRZC will issue a close command to the Annan feeder or feeders at the Chapelcross 33 kV Substation while simultaneously issuing a step-down command to the load bank such that overall load pick up remains less than the block load capability of the generator. Figure 3.1 shows the impact of the load energization using the previous steps. This was provided to SEL and demonstrates the capability of the anchor generator to pick up loads while regulating the frequency. Different options to energize the feeder are considered and listed in the following sections.

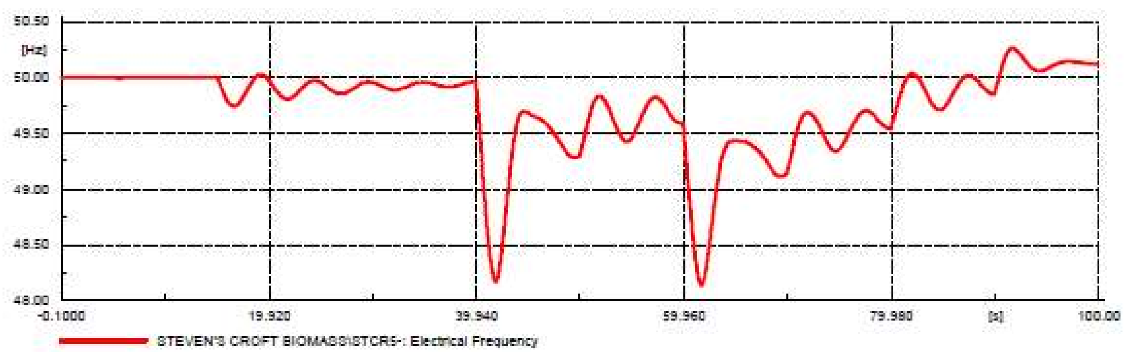

Figure 3.1: Electrical Frequency for Load Pick Up

Step 8. The Minsca WF and Ewe Hill WF and all other DERs shall be energized after receiving permissive signal from the DRZC. The DERs will synchronize with the power island with the anchor generator.

a. Prior to adding any DER to the DRZ network DRZC will perform a stability check as per step 2. If lines or transformers are excessively long or higher impedance, the generation terminal voltage will be adjusted to meet the reactive power demand.

Step 9. The DRZC will continue to regulate the islanded power system using all available assets.

Step 10. Continuously monitor system voltage and frequency and maintain stability.

Step 11. Repeat steps 4–7 for each additional load feeder until the DERs are operating at 80 percent of their total maximum capacity. Any additional load substations the steps required to restore load feeders will be an identical process as compared to Annan substation.

Step 12. Continue to Maintain voltage and frequency of the island and switch into transmission grid re-energization mode when initiated by an operator or grid controller. This is covered later in this section.

Six primary substation restoration options are considered in this document as provided by the customer. The first three options (A–C) illustrate the simultaneous energization of the primary transformer. The

11 kV busbar and load are fed from the primary substation, and these options are referred to as "load" options. The last three options (D–F) illustrate energization of the primary transformer followed by the 11 kV busbar and load fed from the primary substation; these are referred to as "No-load" options. **Option F is the recommended restoration strategy proposed by SEL ES for this system.**

Note: SEL ES will need to know about any automatic transfer schemes in the system so that they can be considered during implementation.

Note: The drawings used in the options below are taken directly from the customer's Chapelcross grid energization options document.

OPTION A

Close CB 13, energizing the T1 transformer with CB 10 closed and CB 20 open, consequently energizing a single primary transformer and taking on the full load fed from the primary substation. This option shall cause transformer energization and cold load pick up of the entire substation, if the impedance between the generation site and load is significantly long and if the generation is undersized, this may cause a voltage stability issue. SEL recommends this to be simulated prior to final implementation.

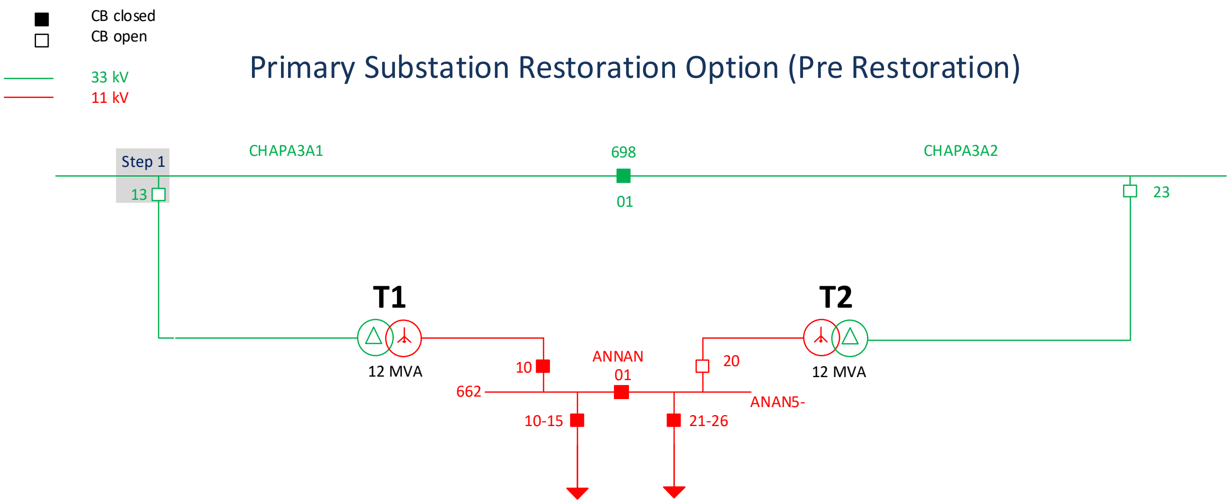

Figure 3.2: Option A - Annan substation load restoration

OPTION B

Close CB 13, energizing the T1 and T2 transformers with CB 10 and CB 20 breakers closed, consequently taking on the full load fed from the primary substation. This option shall cause transformer energization and cold load pick up of the entire substation, if the impedance between the generation site and load is significantly long and if the generation is undersized, this may cause a voltage stability issue. SEL recommends this to be simulated prior to final implementation.

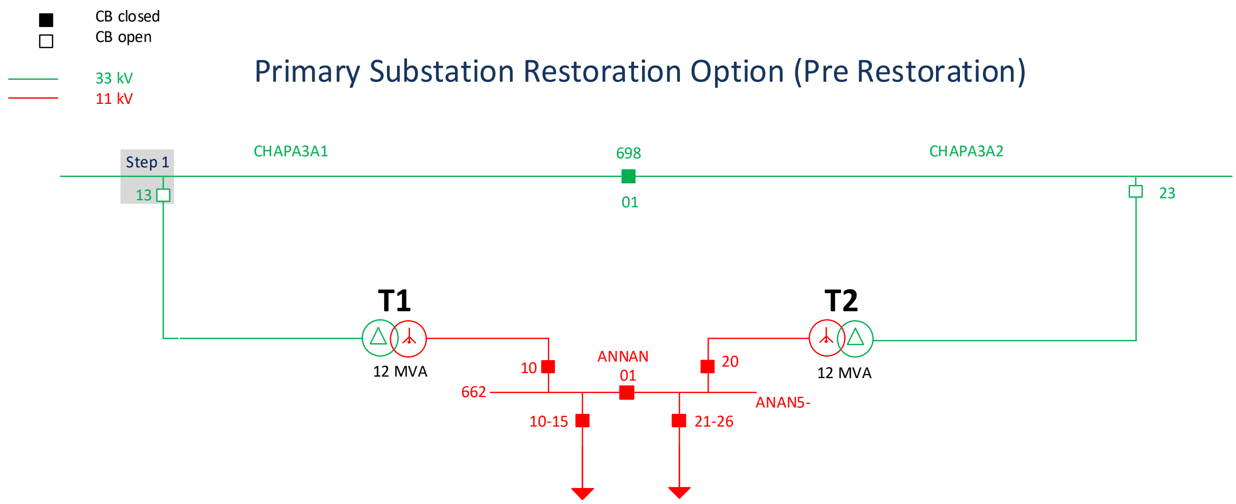

Figure 3.3: Option B - Annan substation load restoration

OPTION C

Ensure the 11 kV CB 01 bus coupler is open. Close CB 13, energizing the T1 transformer with CB 10 closed taking on half the load fed from the primary substation. Then, if applicable, close the second 33 kV primary feeder CB 23 to energize the T2 transformer, taking on the second half of the load fed from the primary substation. Finally, close the bus section to improve security of supply.

- This option should only be considered if there are no 11kV circuits which can power wheel between Annan bus A and Annan bus B.
- The 11 kV busbar that supplies the auxiliary circuits for the primary substation should be energized first (this will provide a supply to the transformer tap change motor).

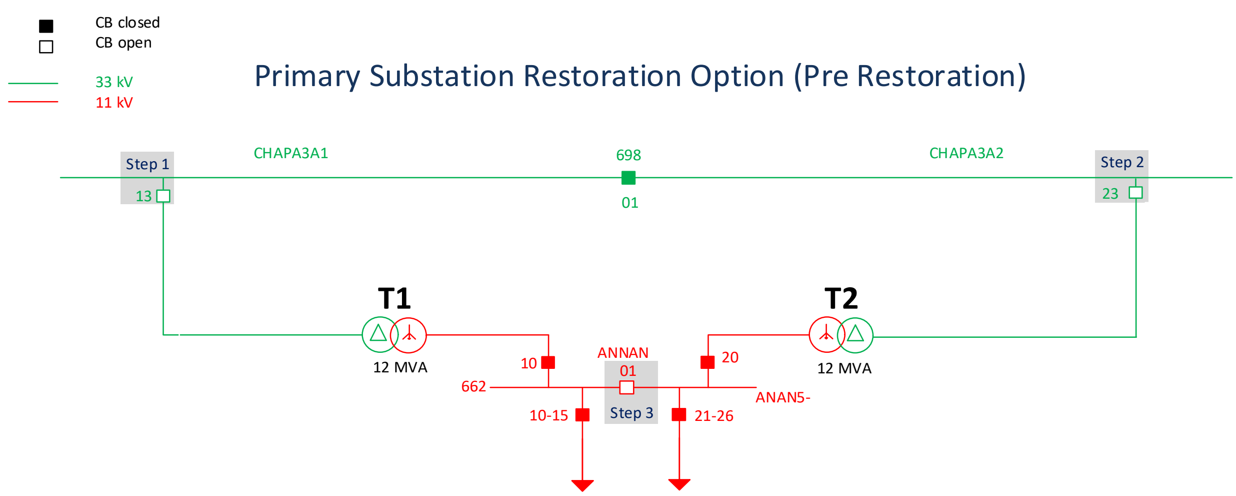

Figure 3.4: Option C - Annan substation load restoration

OPTION D

No-load, sequential energization of transformer followed by load. Close CB 13, energizing the T1 transformer with CB 10 open. Once T1 is energized, close CB 10, taking the full load fed from the primary substation.

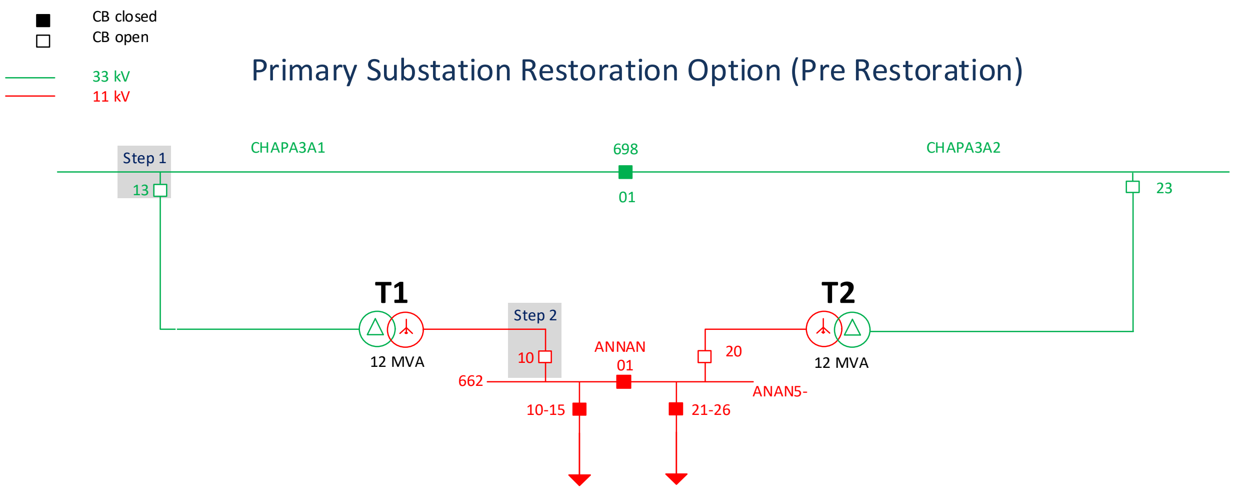

Figure 3.5: Option D - Annan substation load restoration

OPTION E

Ensure the CB 01 11kV bus coupler is open. Close CB 13, energizing the T1 transformer with CB 10 open. Once T1 is energized, close CB 10, taking on half the load fed from the primary substation. Then, close the CB 01 11kV CB bus coupler taking on the second half the load fed from the primary substation.

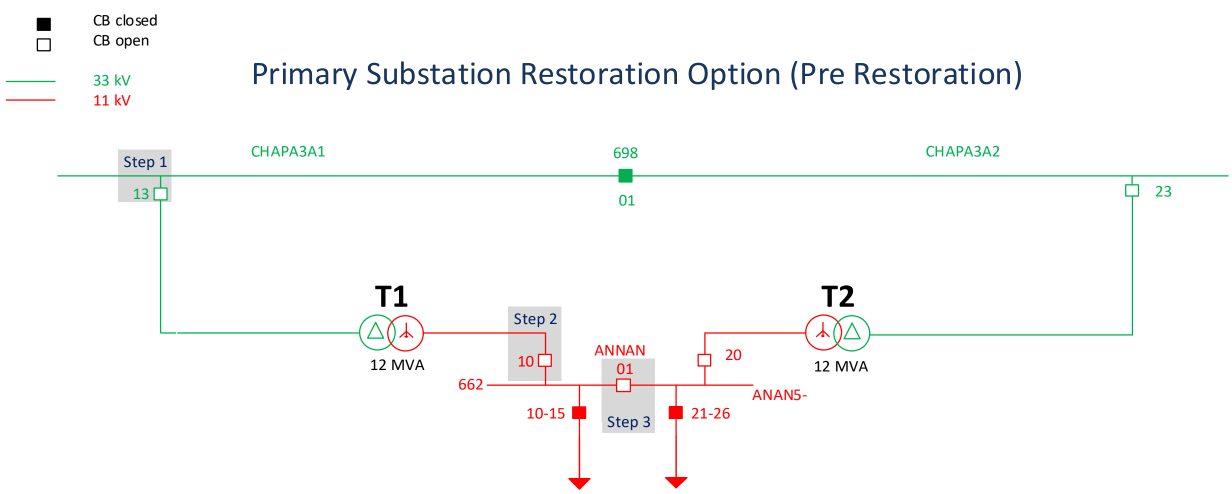

Figure 3.6: Option E - Annan substation load restoration

OPTION F

Close CB 13, energizing the T1 transformer with CB 10 open. Ensure all 11 kV feeder CBs are open, then close CB 10 to energize the 11 kV busbar. Finally, close 11 kV feeder CBs, sequentially energizing individual 11 kV feeder circuits. Between each 11kV CB restoration the DRZC will perform a stability check.

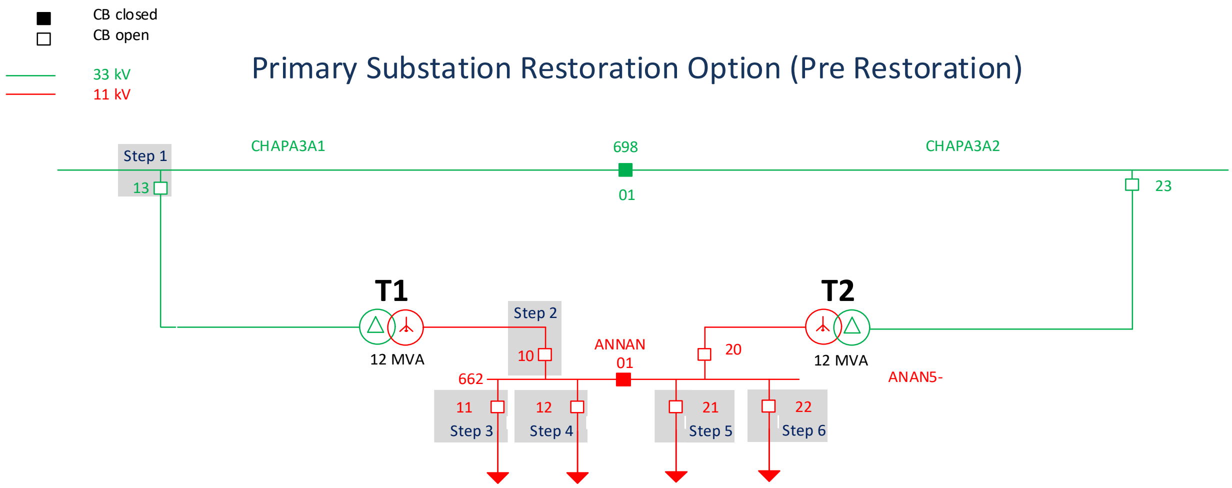

Figure 3.7: Option F – Recommended Annan substation load restoration

SEL ES highly recommends option F for implementation for more granular energization of the load substation and minimal impact to the DER and generator asset in the system. This accounts for minimal disturbance to the anchor generator.

3.1.2 Distributed Restart – Islanded Operation

Once the system restoration of all possible actions to expand the grid has been completed and the system is in automatic mode, the DRZC performs the following actions:

1. Continuously monitor the system voltage and frequency and regulate the system using the available assets.
2. Perform load management if the anchor generator output exceeds predetermined threshold using the progressive overload shedding to prevent it from tripping on overload.
3. Perform load shedding if the generation asset trips or generation asset loading exceeds the limits of the existing generation in the facility.
4. Perform load shedding if the underfrequency trigger is detected.
5. Perform load bank charging, generation runback, or shedding if an overfrequency trigger is detected or a bus fault that may clear a significant amount of loads.
6. Continuously monitor the active and reactive power loading of the available assets so that other load feeders can be energized.
7. Continuously load or unload the load bank to regulate system frequency and voltage.
    a. For example, during underfrequency reduce loads by unloading the load bank first, then progress onto other loads based on the shedding priority.
    b. For example, during overfrequency add loads by loading the load bank then progress to generation shedding or reducing.

3.1.3 Distributed Restart – Resynchronization and Grid Support

Once the system restoration has been completed, the DRZC is operating in the islanded fashion, and the grid is available, the DRZC performs the following actions:

1. Continuously monitor the distributed network system voltage and frequency and regulate using the available assets.
2. Monitor the voltage and frequency of the transmission grid side and automatically adjust the system frequency and voltage after a user-initiated command is used to synchronize to the macro grid.
3. If the grid is live, adjust the modes of the DERs in the DRZ so they are compatible for the grid-connected operation and open any needed earthing transformers.
4. If the grid is dead, keep the DERs in their islanded/grid forming operating modes to energize a grid with no additional sources connected and open any needed earthing transformers.
5. Monitor and communicate island capacity and block load pickup capability in real time for additional energization to other parts of the transmission grid outside of power island.
6. Once transmission grid is online with other generation assets in the transmission grid, accept control set points (MW and MVAR flow at tie line) from an grid controller, adjust the modes of the DERs and generators in the DRZ. Control the tie line export/import to set points provided by grid controller or user setpoint using tie flow control algorithm.
7. Once the grid is restored the DRZC will transition assets back to grid-connected mode and relinquish control. The DRZC disables and goes back to a passive monitoring mode.

SECTION 4 CYBERSECURITY

This section provides an overview of the cybersecurity concepts applied in the system, including the hardware used to implement said concepts. The high-level security features of the SEL DRZC include the following:

- An electronic security perimeter (ESP) that is maintained at all outside system interfaces.
  - Every path between the central substation and an outside substation is firewalled and VPN encrypted, and the network switches on substation LAN are running the OT-SDN deny by default architecture to only allow permitted flows through.
  - SEL-3355 will implement a VPN and firewall while the SEL-2740S switches operate using OT-SDN.
- Separate business and operational communications systems.
  - Links to the corporate network can be implemented using a SEL-3355 running SEL-UTM to provide any level of encryption, firewalling, multi-factor authentication, and a host of additional security features across the WAN link.
  - This also applies to sources of external or grid control specifically.
- Encryption for all access point connections.
- Strong password capability requiring uppercase and lowercase letters, numbers, symbols, and 12-character passwords using a 90-character alphabet.
- Multilevel access control that gives personnel access only to the functions they require.
- Port timeouts that slow and/or eliminate automated or manual password guessing attacks.
- Real-time access monitoring that notifies about access attempts.

Please refer to Figure 4.1 for a higher-level view of data security layers. The current vision of the system includes the substation LANs communicating Level 3 data (automation). Cybersecurity includes encryption and firewalling between the substation LANs, and SDN deny by default within the LANs. The following section covers more details of how data flow and are protected in the communication network.

4.1 DATA FLOW EXAMPLE

This section covers how data are managed with the proposed hardware. Please refer to the communication architecture (APPENDIX B) for clarity on hardware described in this section. If a substation name is mentioned below it refers to the similarly titled page in the communication architecture. The flow of data from low level (hardware) to high level (central controller and beyond) is envisioned as follows:

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Refer to Section 2.3 (Communication Architecture) for more descriptions of the SEL hardware mentioned in the previous steps. The communication outside of the DRZ (mentioned in step 7) allows the DRZC to provide MW and MVAR available capacity to another controller, which will leverage that capacity for transmission grid re-energization and support.

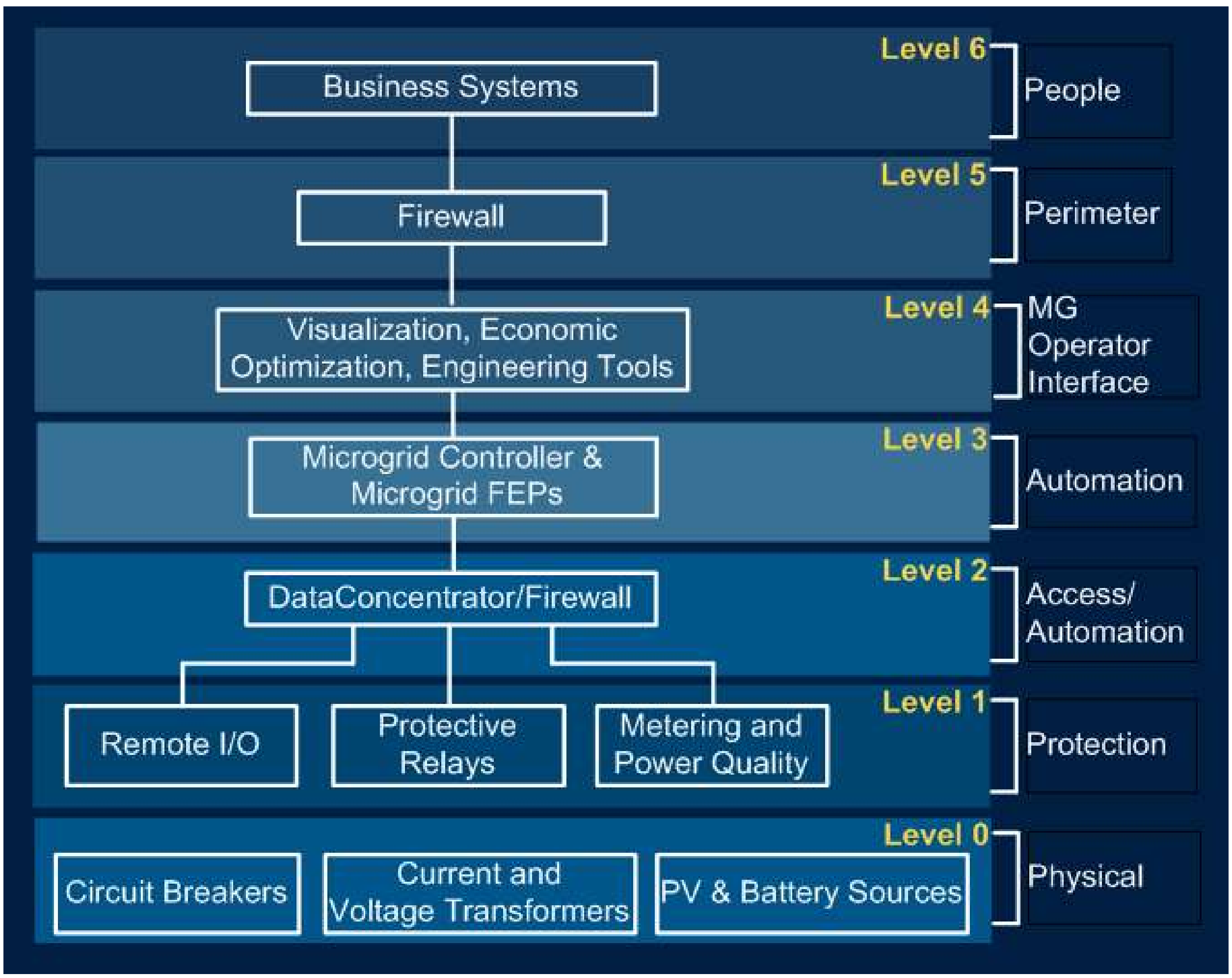

Figure 4.1: Cybersecurity Network Layers Overview

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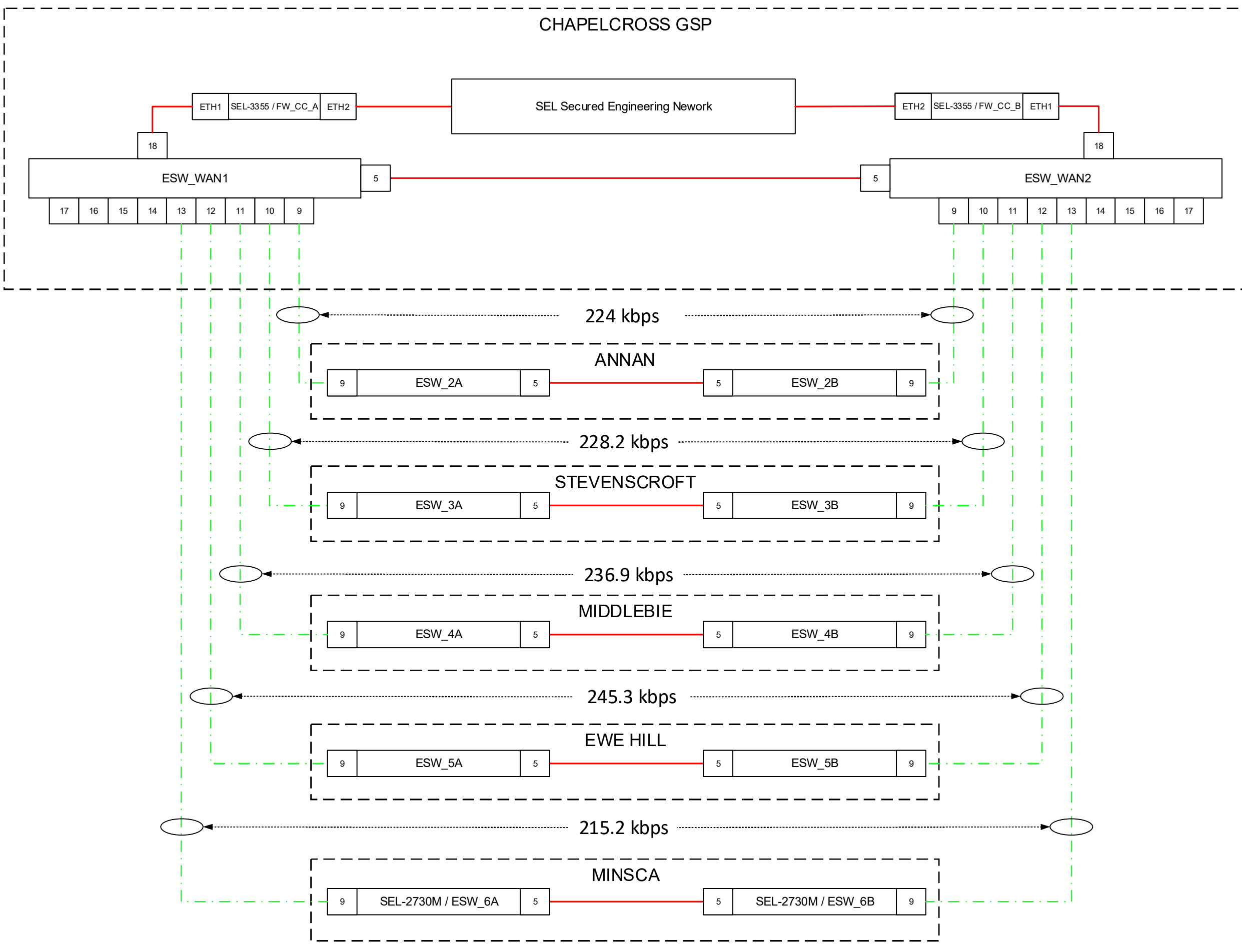

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[redacted]		Number of DER Control Interfaces					
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Number of Breakers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]		Number of DER Control Interfaces					
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SECTION 5 DER ASSETS AND POINT LISTS

The purpose of the SEL DRZC is to provide a coordinated control strategy for all DERs installed in the system to ensure resilient power delivery to loads across the system. SEL ES is providing the design and hardware for the control interfaces between the installed DERs and the SEL DRZC.

The SEL DRZC will collect system information from relays and control interfaces installed at each DER site to determine the system state and to dispatch controls. Subsequent tables show the minimum DER I/O points required by the SEL DRZC to deploy the required control strategies. The protocols used for the I/O points are flexible, but the preferred protocols are shown here.

Table 5.1 details the DER assets considered for this project.

Table 5.1: DER Assets

DER Asset Type	Location	Rating	Comments
Stevens Croft anchor generator	Stevens Croft	53 MVA	Black start capable
Wind farm	Minsca	37 MW	Grid following/voltage regulation capable
Wind farm	EWE Hill	12 MW	Grid following/voltage regulation capable
BESS	TBD	TBD	Included as an example
PV array	TBD	TBD	Included as an example

5.1 SYNCHRONOUS GENERATORS

The DRZ contains one generator at Stevens Croft with a total capacity of 53 MVA. The DRZC will monitor the active power, reactive power, voltage, and frequency of the generators. In addition, the DRZC can start and stop the generators as needed during operation. If only one synchronous generator is available on the island, which is the case for Stevens Croft anchor generator, it will run in isochronous mode for frequency regulation and voltage droop mode for voltage regulation. If multiple similarly sized generators were available in the system, all generators would run in Droop and frequency would be maintained by the DRZC issuing control setpoints. If multiple generators of varying size were available in the system the largest would operate in ISOC, and other generators in Droop mode. The DRZC shall control the operating modes of the generator while dispatching the exciter to maintain the system voltage at 33 kV busbar. Table 5.2 shows an example I/O interface between the DRZC control system and the generator control interface.

Table 5.2: Interface I/O Between DRZC and Synchronous Generators

I/O Points	DRZC Data Type	Protocol	Description
Start command	Digital output (DO)	Modbus	Start sequence command. This will cause the generator to start, sync, and go online.
Stop command	DO	Modbus	Stop sequence command. This will cause the generator to ramp down, stop, and go offline.

I/O Points	DRZC Data Type	Protocol	Description
Running Status	Digital input (DI)	Modbus	Asserts if the generator is running.
Active power	Analog input (AI)	Modbus	Active power measurement.
Reactive power	AI	Modbus	Reactive power measurement.
Frequency	AI	Modbus	Frequency measurement.
Voltage	AI	Modbus	Voltage measurement for three-phase.
Breaker Status 52A	DI	Modbus	Breaker closed indication.
Breaker Status 52B	DI	Modbus	Breaker opened indication.
Voltage lower command	DO	Hardwire	The DRZC voltage lower pulse.
Voltage raise command	DO	Hardwire	The DRZC voltage raise pulse.
Power lower command	DO	Hardwire	The DRZC power lower pulse.
Power raise command	DO	Hardwire	The DRZC power raise pulse.
Generator in local mode	DI	Modbus	Generator is not available for DRZC control.
Generator in remote mode	DI	Modbus	Generator is available for DRZC control.
Generator in ISOC mode	DI	Modbus	The generator in ISOC mode.
Generator in droop mode	DI	Modbus	The generator is in droop mode.
Generator in base mode	DI	Modbus	The generator is in base mode.
Generator to ISOC mode	DO	Modbus	The DRZC sends the generator to ISOC mode.
Generator to droop mode	DO	Modbus	The DRZC sends the generator to droop mode.
Generator to base mode	DO	Modbus	The DRZC sends the generator to Base mode. Note* This mode is only applicable if there are more than one generator available in the island.
Generator is unavailable (alarm)	DI	Modbus	The generator is offline and unavailable to the DRZC.

5.2 WIND FARMS

The system contains three wind farms, two farms at EWE Hill (12 MW), and one farm at Minsca (37 MW). The DRZC control strategy is to use wind power for energizing load substations and provide voltage support during an islanded scenario. The WF will also contribute to tie line control during transmission grid re-energization. Table 5.3 shows an example I/O interface between the DRZC control system and the wind farm control interface which would allow the DRZC to execute its WF control strategy. SEL considers these windfarms to either be Type 3 or Type 4 wind turbines and considers no inertia can be provided from these wind farms.

Table 5.3: I/O Between SEL DRZC and WF Control Interfaces

I/O Points	DRZC Data Type	Protocol	Description
Wind speed	AI	Modbus	Wind speed
Wind speed forecast	AI	Modbus	Wind speed forecast
Active power	AI	Modbus	Active power measurement
Current available capacity	AI	Modbus	Active power available from the WF
Allowed capacity	Analog output (AO)	Modbus	Percentage of available capacity to provide to the system
Voltage	AI	Modbus	Voltage measurement from WF
V setpoint	AO	Modbus	DRZC voltage setpoint to WF
Frequency	AI	Modbus	Frequency measurement
F setpoint	AO	Modbus	DRZC frequency setpoint to WF
Breaker status 52A	DI	Modbus	Breaker closed indication
Breaker status 52B	DI	Modbus	Breaker opened indication
Run command	DO	Modbus	DRZC command to run the WT
Pause command	DO	Modbus	DRZC command to pause the WT
State of wind turbine (WT)	AI	Modbus	WT in run, pause, or stop status
Contact status	DI	Modbus	WT in online or offline status
Volt/VAR Mode	DO	Modbus	Voltage regulation mode command
Volt/VAR Mode	DI	Modbus	Voltage regulation mode feedback
WF Alarm	DI	Modbus	Alarm from the WF signaling an error in the WF controller. This input could also receive error function codes over Modbus for display on the HMI.

5.3 BESS

The Chapelcross system does not contain BESS units. SEL ES has included an example BESS unit in the case study to demonstrate the BESS control strategy. The BESS unit has a primary purpose of providing frequency and voltage regulation support during islanded operation and providing smoothing for the fluctuations of the WF and PV. The BESS system shall operate in the grid forming mode (Mixed Mode) during islanded condition and can return to grid following mode after grid synchronization where the DRZ is powering the grid in parallel with other grid sources. In Mixed Mode the BESS runs in frequency droop and voltage droop mode. Mixed Mode is suitable as each DRZ generally will have an anchor generator synchronous machine running in isochronous mode. Table 5.4 shows an example I/O interface between the DRZC control system and the BESS control interface.

Table 5.4: I/O Between SEL DRZC and BESS Controller Interface

I/O Points	DRZC Data Type	Protocol	Description
Run status	DI	Modbus	Enabled

I/O Points	DRZC Data Type	Protocol	Description
Availability	DI	Modbus	Asset ready to be controlled. All conditions are met to allow the DER to be started and dispatched. (e.g., in remote, in auto, no critical alarms present)
Enable	DO	Modbus	BESS Run Command
P set point feedback	AI	Modbus	Real power set point feedback
Q set point feedback	AI	Modbus	Reactive power set point feedback
SOC	AI	Modbus	Battery state of charge
P set point	AO	Modbus	Real power set point
Q set point	AO	Modbus	Reactive power set point
Critical BESS alarm	DI	Modbus	Alarm is present that requires resetting
Island Control mode command (CMD)	DO	Modbus	Island Control mode command (Mixed Mode)
Island Control mode status	DI	Modbus	Island Control mode Status (Mixed Mode)
Active Power Direct Control mode CMD	DO	Modbus	Active Power Direct Control mode command
Reactive Power Direct Control mode CMD	DO	Modbus	Reactive Power Direct Control mode command
Reset CMD	DO	Modbus	Reset command (used to reset alarms)
F set point	AO	Modbus	Frequency set point
V set point	AO	Modbus	Voltage set point
F	AI	Modbus	Frequency measurement
V	AI	Modbus	Voltage measurement
Full charge energy	AI	Modbus	Full charge energy available
Maximum charge power	AI	Modbus	Maximum charge power available
Maximum discharge power	AI	Modbus	Maximum discharge power Available
Maximum apparent power	AI	Modbus	Maximum apparent power of BESS (required for capability tracking)

5.4 PV SYSTEMS

The Chapelcross system does not contain PV. SEL ES has included a PV unit in the case study to demonstrate PV control strategy. The inverters will generate a percentage of the maximum electrical power possible based on irradiance and temperature. The percentage of maximum generation will be limited by an allowed capacity percentage, set in the HMI, to improve the smoothness of the PV output. The PV MW output will be directed to serve the load in the DRZ while running in volt/VAR mode to provide voltage regulation during the islanded restart operation. Table 5.5 shows an example I/O interface between the DRZC control system and the PV control interface.

Table 5.5: I/O Between SEL DRZC and PV Inverter Controller Interface

I/O Points	Data Type	Interface	Description
Availability	DI	Modbus	Enabled
Run status	DI	Modbus	Asset ready to be controlled; all conditions are met to allow the DER to be started and dispatched (e.g., in remote, in auto, no critical alarms present)
Enable command	DO	Modbus	PV Array Run command
P set point feedback	AI	Modbus	Real power set point feedback
Q set point feedback	AI	Modbus	Reactive power set point feedback
Inverter name plate kW rating	AI	Modbus	Name plate rating kW
AC output limit percentage	AI	Modbus	AC output limit
P set point	AO	Modbus	Real power set point
Q set point	AO	Modbus	Reactive power set point
Volt/VAR Mode	DO	Modbus	Voltage Regulation Mode command
Volt/VAR Mode	DI	Modbus	Voltage Regulation Mode Feedback

SECTION 6 POWERMAX DRZC

This POWERMAX DRZC section is provided to give background information on current SEL algorithms that will be leveraged to help accomplish the goals of the restart controller. SEL POWERMAX is a collection of hardware and software components configured to provide intelligent and automatic control of the power system. A basic conceptual overview of the DRZC is shown in Figure 6.1. The SEL DRZC will implement many features described in this section.

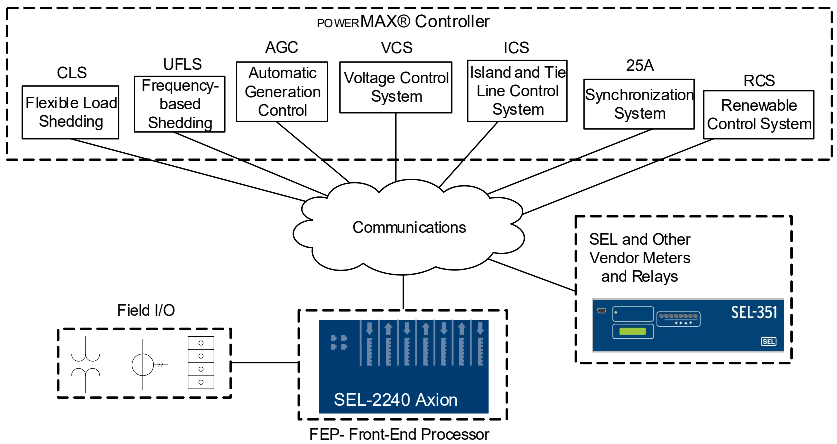

Figure 6.1: SEL POWERMAX Conceptual Overview

6.1 GENERATION CONTROL SYSTEM (GCS)

The DRZC employs the automatic generation control (AGC), voltage control system (VCS), and island control system (ICS) functions of the GCS within the DRZC to meet island frequency and voltage control objectives when islanded and restarting. The AGC, VCS, and ICS functions are used to meet frequency and voltage regulation objectives while managing the modes of DERs available in the island. Further GCS shall also dispatch the generation assets for load sharing and restore load substations by maximizing the available assets. Furthermore, the GCS system shall return control back to the grid-connected operation control system after assisting with the re-energization of the transmission system.

6.1.1 AGC Functions

- Dispatch active power set points to DERs that are under DRZC control to regulate the system frequency and share the active power load.
- Adjust the operating modes of the DER and generation assets based on the system topology.
- Control the active power output of the WF, PV, and BESS based on a priority dispatch according to the regulation range and capability of each asset.
- Dispatch generators as needed to maintain spinning reserve when islanded or during startup.
- Control the active power output of the BESS to smooth large load changes.
- Control the active power set points of the WF and/or PV to attempt to maximize WF/ PV output based on the forecast.
- Control the active power set points for the WFs and/or PV to curtail output when necessary.
- Provide island capacity (MW) during transmission grid re-energization.

- Control active power flow across the utility tie line when grid connected.

6.1.2 VCS Functions

- Regulate the voltage of the DRZ at the main bus when islanded by controlling all the assets in the DRZ.
- Adjust the operating modes of the DER and generation assets based on the system topology.
- Dispatch reactive power set points to DERs that are under DRZC control to share the reactive power load during grid-connected and islanded operation.
- Control the reactive power output of the anchor generator, WF, PV and BESS based on an equal percentage of their respective regulation bands.
- Limit the reactive power contribution of each DER to avoid violating voltage limits at the DER terminal, while maintain voltage at the load substation.
- Provide island capacity (MVAR) during transmission system re-energization.
- Control reactive power flow across the utility tie line when grid connected.

6.1.3 ICS Functions

- Determine which DERs and loads are electrically connected.
- Determine islands and grid connections.
- Control modes of generation assets based on topology.

6.1.4 Interlocks

Figure 6.2 shows the sample interlock logic used in the GCS. The primary interlock used in the GCS is a run permissive. An individual run permissive signal is generated for both the AGC and VCS for each DER under DRZC control. This signal allows set points to be sent to the DER controller to adjust the active and reactive power output of assets. An indication of all run permissive signals will be provided on the HMI.

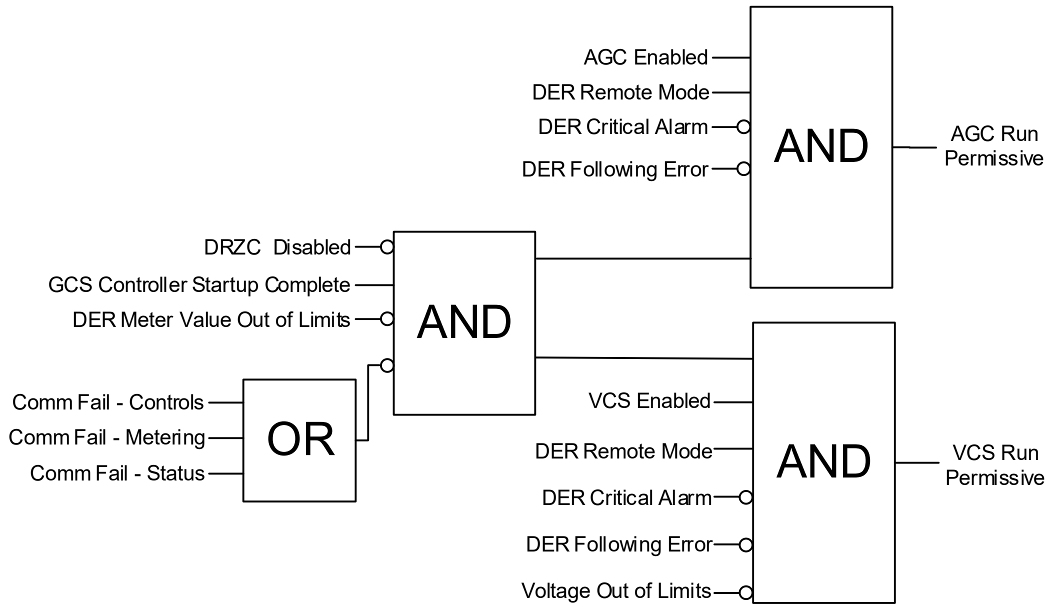

Figure 6.2: GCS Interlocks

6.2 TRADITIONAL GENERATOR STRATEGY

6.2.1 Anchor Generator Control

The anchor generator terminology comes from the DRZC specification and is intended primarily to preserve system functionality and provide black start capability in the event of a complete outage. In the event of a full outage, the DRZC will detect the loss of voltage, open the main PCC breakers, open all load feeders at the 33kV bus and provide the start command to the anchor generators to initiate the re-energization process. This is will happen automatically when set in auto mode or will wait for an operator to initiate if in manual mode. The time required for declaration of the loss of voltage to open the PCC shall be determined during the testing phase.

Once island has been established, anchor generators may also participate in the active power control of the island. The AGC function adjusts the anchor generators power output between the specified lower and upper regulation limits. The regulation limits are set to provide a wide operating region (e.g., 50 to 100 percent). The base set points of these generators are set near the lower regulation limit (50 percent). The anchor generators are used to provide frequency regulation when islanded. For the Chapelcross implementation, this anchor generator shall operate in the isochronous mode during islanded operation.

The anchor generator reactive power control can be set to operate in regulation mode or maintained mode. In regulation mode, the DRZC-VCS function adjusts the anchor generator reactive power output between the specified lower and upper regulation limits. The anchor generator regulation limits are set to provide an operating region that does not significantly degrade active power output capacity. The anchor generator reactive power regulation limits are set in terms of reactive power (MVAR) lower and upper regulation limits. This configuration ensures that the anchor generator can operate at optimal active power output while allowing it to participate in reactive power regulation to some extent. Alternately, the anchor generator can be set to operate in maintained mode; however, in the case of Chapelcross this is not recommended because in maintained mode the anchor generator will not be adjusted automatically to meet microgrid voltage regulation objective. The terminal voltage of anchor generator shall be adjusted to maintain to the 33kV bus.

6.2.2 Generator Control

If there are other generators in the island (not applicable for Chapelcross GSP) generator active power control can be set to operate in regulation mode or maintained mode while in frequency droop mode. In regulation mode, the AGC function adjusts the generator power output between the specified lower and upper regulation limits. The generation regulation limits are set to provide an operating region within the machine capacity (e.g., 80 to 100 percent). The base set point will be set near the preferred operating point. This configuration ensures that the generator power output is at the most efficient level while allowing it to participate in regulation if other assets are not available. Alternately, the generator can be set to operate in maintained mode and dispatched at a user settable power output. In maintained mode the generator will not be adjusted automatically to meet DRZ active power objectives.

The generator reactive power control can be set to operate in regulation mode or maintained mode while in voltage droop mode. In regulation mode, the VCS function adjusts the generator reactive power output between the specified lower and upper regulation limits. The generator regulation limits are set to provide an operating region that does not significantly degrade active power output capacity. Additionally, voltage override logic is applied to limit the reactive power contribution to avoid violating voltage limits at the generator terminal. The base set point will be set near zero. This configuration ensures that the generator can operate at high active power output while allowing it to participate in reactive power regulation as needed. Alternately, the generator can be set to operate in maintained mode and dispatched at a constant reactive power output. In maintained mode, the generator will not be adjusted automatically to meet DRZ reactive power objectives.

6.2.3 DER Start/Stop

The DRZC includes autostart and autostop functions for the DERs. These functions can be enabled and disabled by the operator if the DRZC control mode is changed into Manual in the DRZC HMI.

The DERs can be set in automatic mode or manual mode. In automatic mode the DRZC will command the DERs to start during the restart process. This starting action can happen at any time during the restart process when the DRZC detects a stable island and it is not actively restoring load.

The DRZC starts selected DERs one at a time until all available DERs are running. The DRZC dispatches the running DERs and generators according to the AGC and VCS functions described earlier. The DRZC continuously recalculates the total contribution that is required from the DERs and generators and evaluates which combination of available generators most closely matches the requirement to maintain system stability. The DRZC starts and stops generation assets as needed. Stopping generation assets will only occur in extreme over frequency scenarios.

6.3 Wind Farm Strategy

There are two WF systems under study at the Chapelcross DRZ. Each system should have inverters with a dedicated controller accepting the control set points from the SEL DRZC. The main intent of a wind farm is to provide autonomous operation while islanded and provide voltage support using the inverters functionality, furthermore additional power from the wind farms can be used to support energization of additional load substations.

All wind farm output will be directed to serve the load in the electrical network and maintain the system voltage. The inverters will generate maximum electrical power based on wind speed and forecast. The

SEL DRZC will attempt to maximize the wind farm output and control the utility import by regulating the output of the other DERs. Typically, the inverters for the Wind farm and PV have four main control modes, however, first two modes are selected for this control operation:

- Constant Power mode, which generates fixed real and reactive power (during grid-connected operation).
- Volt-Var mode, which regulates the grid voltage by supplying or absorbing reactive power (during islanded operation).
- Frequency-Watt mode, which limits real power in case of high frequency.
- Volt-Watt mode, which limits real power in case of overvoltage.

The SEL DRZC shall use these modes to achieve the voltage regulation during islanded condition. When islanded, the inverters shall be switched to Volt-Var mode to support the voltage at the connected terminal. The SEL DRZC may further increase or decrease the reactive power output to adjust the voltage at the main substation.

The wind farm assets may be unavailable at times due to the present operating conditions. Figure 6.3 and Figure 6.4 illustrate the decision flow for determining if the wind farm is available.

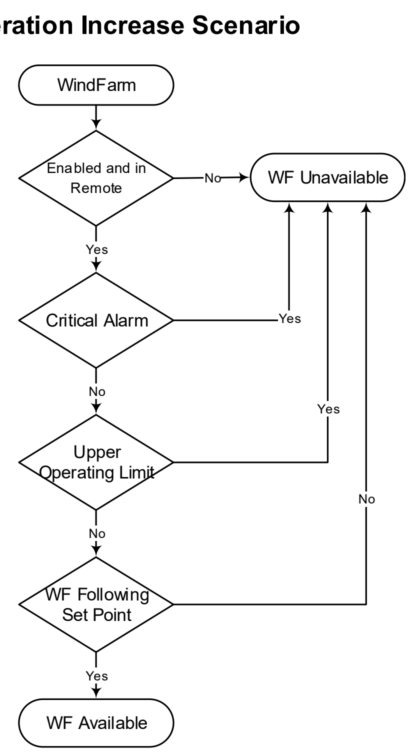

Figure 6.3: Wind Farm Availability Decision Flow for Generation Increase Scenario

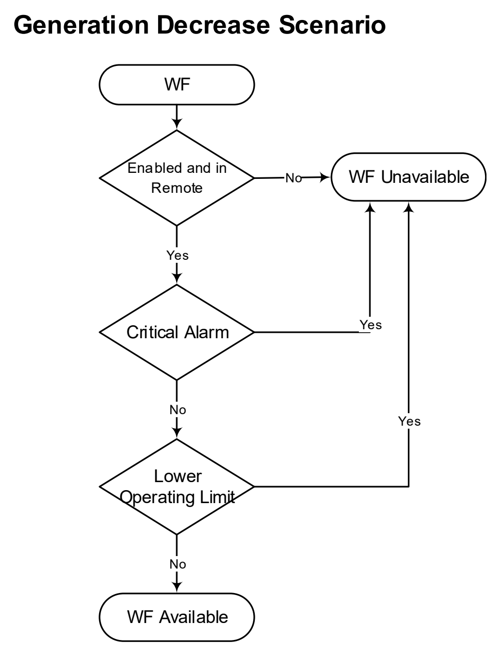

Figure 6.4: Wind Farm Availability Decision Flow for Generation Decrease Scenario

6.3.1 Maximize Contribution

The DRZC continuously attempts to increase the power output of the WF assets if there is enough margin to absorb power from the WF while maintaining the primary control. Additionally, the DRZC ensures WF participation remains less than a user-specified set point (i.e., percent of total load) during islanded operation for stability. The margin available to absorb power from the WF assets is calculated based on the sum of the margins between the present operating output and the lower regulation limit of each non-WF asset on the microgrid. This additional margin can be used to reduce the output from the anchor generator to provide additional headroom required for load substation re-energization and transmission network re-energization. The WF inverters can also provide voltage support by staying in the Volt/VAR mode.

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6.4 BESS Strategy

Currently, SEL ES understands that battery energy storage is not available within the Chapelcross network. This strategy is an example, and it will be reevaluated if the customer power system includes BESS sources. The project objective is for islanded operation and system re-energization, this document will focus on those control objectives. If available, SEL ES will control the state of charge of the battery to maintain reserve system capacity for islanded operation and control the discharge of the battery systems. Battery systems are recommended to be present at PV or WF stations or near the load substation so that local reactive power support can be provided. The BESS is intended to displace at demand during islanded operation specifically during black start energization providing additional support to the anchor generator during cold load pick up. Prior to each load substation energization, the BESS system will be primed and ready to discharge the maximum capacity while adjusting reactive power to keep main substation voltage at the nominal value. The BESS will not be discharged for a sustained period but will provide a bridge to the startup DERs. If BESS control is implemented a dedicated interface device (SEL-2240 Axion or SEL-2411 Programmable Automation Controller [PAC]) will be installed at the BESS location. BESS shall also provide voltage support at the 33 kV bus, and the added active and reactive capacity will load to increase in island capacity for re-energizing load substations and the transmission network.

The BESS control strategy is summarized in Figure 6.5. Depending on the state of energy, the BESS will have four distinct areas of operation that will in turn reflect the availability of BESS to charge or discharge energy. Each area is bounded by user-settable limits. The limits are defined as follows:

- Upper charge limit
  - Maximum SOC the battery can reach
- Grid-connected discharge limit
  - Only used during transmission grid re-energization when the DRZC is supporting the grid in parallel with additional grid sources outside the DRZ.
- Islanded discharge limit
- Reserve capacity limit
  - Minimum SOC the DRZC will discharge the BESS to. This limit will not be reached unless the DRZ is islanded and needs maximum contribution from the BESS in order to remain stable.

Note: kWh and BESS values shown in this section are for example only as BESS doesn't exists at Chapelcross.

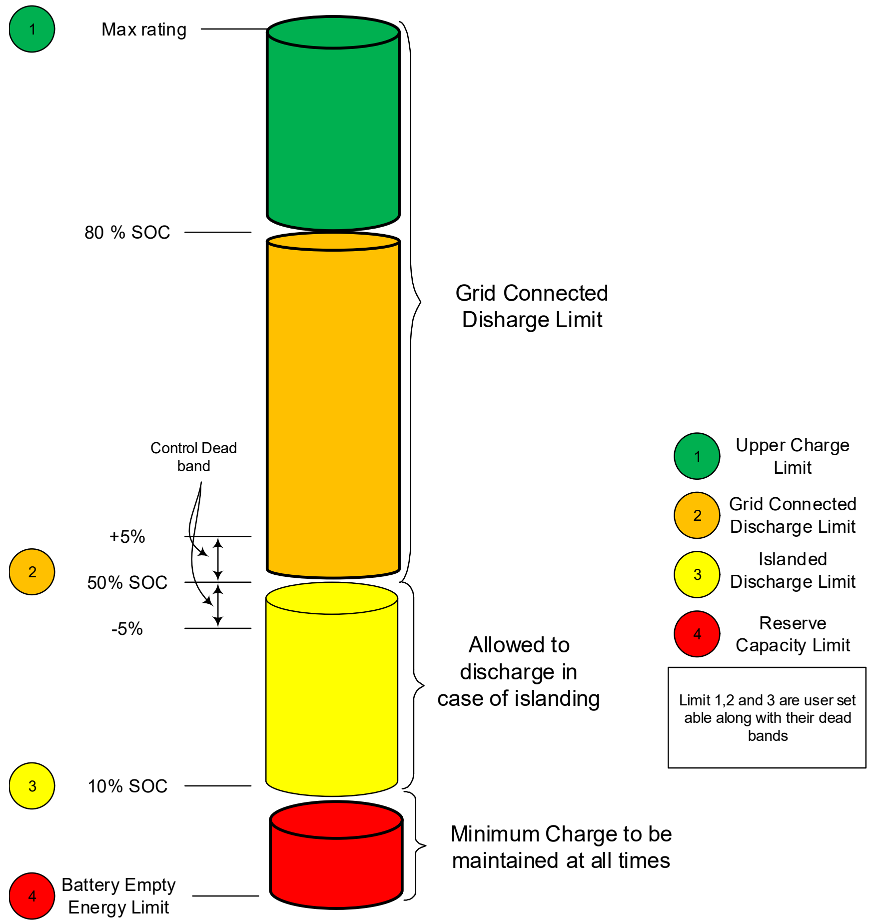


Figure 6.5: BESS Control Strategy

Limit 1 through Limit 3 will be available to set from the HMI with their control deadbands to allow granular control.

Limit 1 (upper charge limit) reflects the battery capability to charge and is limited by the available charge energy reported by the BESS controller. For example, if an inverter or battery cell fault results in the total capacity of BESS being reduced, limit one is automatically set to this reduced limit.

When the state of energy (SOC) of the BESS is below Limit 1 (Upper Charge limit) and is greater than Limit 2 (Grid Connected discharge limit) and the DRZ is grid connected with additional grid sources, the BESS will regulate its output either by charging or discharging to maintain the tie line active, reactive power/power factor set points and to absorb excessive generation.

To increase the security and resiliency of the distribution network, the BESS will reserve capacity below Limit 3 (Island discharge limit) for instances when the DRZ is islanded and needs frequency and/or voltage support. A minimum charge level (Limit 4) is set at ten percent of full charge energy.

The BESS may be unavailable to charge or to discharge at times due to the present operating conditions and system alarms.

The BESS can participate in three distinct control functions.

- Grid Forming – Mixed Mode Operation
- Grid Following
- Smoothing

Each of these functions can be enabled/disabled independently.

6.4.1 Grid Forming – Mixed Mode Operation

When islanded, the BESS system shall be in the grid forming (Mixed) mode. During this operation, the BESS will operate in voltage and frequency droop while accepting active and reactive power set points within the regulation limits defined by the operators based on the available state of charge.

When islanded, the Demand Assist function within the grid forming mode uses the available capacity of the BESS to offset excessive demand temporarily while the generators are ramping up and during initial cold load pick up or load variation. During demand assist operation, the BESS is allowed to discharge more deeply but is only limited by the upper charge limit and reserve capacity limit described in Figure 6.5.

6.4.2 Grid Following

When grid-connected and running in parallel with additional sources, the BESS system shall be in the grid-following mode and BESS power output is limited by the SOE upper charge limit and the grid-connected discharge limits described in Figure 6.5. Table 6.1 summarizes the SOE limits that are active under different operating scenarios.

Table 6.1: BESS Active SOE Limits

Operation	Lower Limit	Upper Limit
Islanded	Reserve limit	Upper charge limit
Grid connected	Grid-connected limit	Upper charge limit

Additionally, the DRZC will override the BESS base set point and regulation limits to ensure a small minimum charge power if the SOC falls below the reserve capacity limit and there is enough reserve from other assets.

6.4.3 Smoothing

The smoothing function works to meet the overall control objective quickly. When enabled, the smoothing control uses the available capacity of the BESS to quickly respond to a sudden large load change, such as cold-load pickup and discharge at maximum rate allowed. The DRZC dispatches slower responding DERs (e.g., WF) in parallel with the BESS. As the slower DERs reach their set points the

DRZC returns the BESS to its normal base set point. The smoothing function employs a deadband to avoid unnecessary changes to the BESS output for small load changes.

6.5 Photovoltaic Strategy

Currently, there are no installations of PV systems at the Chapelcross Restart Zone. This strategy is an example, and it will be reevaluated if the customer power system includes PV sources. However, for the purpose of the FEED study, it is assumed there is an installation at the Chapelcross 33 kV Zone. This is added to provide information on how a PV system would be integrated in to the DRZC strategy if one were available. The PV system has inverters that should have a dedicated controller accepting the control set points from the SEL DRZC. The main intent of PV is to provide additional active power support for load restoration and help maintain system voltage. PV inverters can also provide additional reactive power support during load re-energization and transmission re-energization. Similarly to WF, they can also participate in the tie flow control after grid synchronization.

All PV output will be directed to serve the load in the island electrical network and support frequency and provide voltage stability. The inverters will generate within a band with higher limit capped at user settable percentage of maximum electrical power based on irradiance, temperature, and forecast. In certain scenarios, the output of the PV needs to be curtailed. This condition can arise when PV generation capability exceeds the demand of the DRZ and any of the following are true:

- The PV is operating above the allowed capacity.
  - Allowed capacity set point limits the PV to less than its current available to ensure a safe buffer and reduce PV output variation.
- The anchor generator is operating at its minimum limit.
- The BESS is fully charged and cannot absorb excess PV generation or is unavailable to because of a communication outage or critical error in the BESS controller. (If there is no BESS then this does not apply)

The PV assets may be unavailable at times because of the present operating conditions. Figure 6.6 and Figure 6.7 illustrate the decision flow for determining if the PV is available. The PV system can be also used for voltage support and regulation using the voltage control mode.

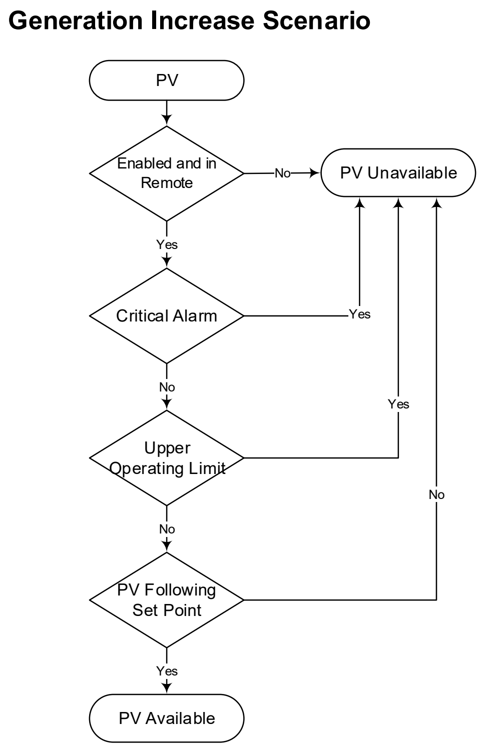


Figure 6.6: PV Availability Decision Flow for Generation Increase Scenario

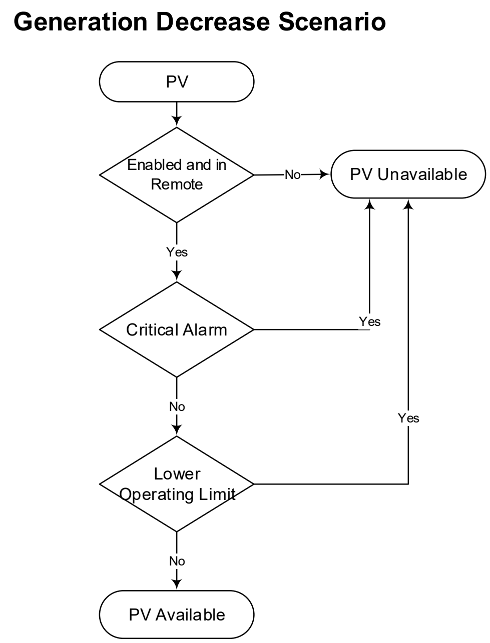


Figure 6.7: PV Availability Decision Flow for Generation Decrease Scenario

6.6 CONTINGENCY-BASED LOAD-SHEDDING SCHEME OVERVIEW

The primary CLS scheme sheds load based on a predicted power deficit in any given island when a contingency occurs. A contingency is defined as the opening of a breaker that interrupts system power flow and causes a power unbalance. This scheme reduces the total plant load to less than the calculated available capacity based on measured capacity and creates a load generation balance. The calculation to balance plant load and available capacity is completed before a contingency occurs and includes the sum of the IRM of the remaining power sources (generation). This scheme only operates on an opening of a defined contingency breaker under load. By shedding load in accordance with the available capacity, the system can restore the power balance and hence minimize the negative effects of frequency in the system; thereby, preventing blackouts and maintaining stability.

The system runs these calculations every task cycle (2–4 ms) prior to the event trigger taking place; therefore, the power deficit can be seen by the operators before an actual event occurs. If there is insufficient plant load to balance the loss of power from a contingency source, an alarm will convey this to the operator. This allows operators to take corrective action and prevent continued operation in a state that could cause a blackout.

This load-shedding scheme involves reducing load on load bank, tripping feeders or individual loads based on the user-defined priorities. Currently, there are multiple breakers that have been identified as contingencies and will initiate primary load-shedding. APPENDIX A and Table 6.2 show the contingencies identified for the Chapelcross 33 kV DRZ. All power wheeling breakers that can cause power deficit when opened under load can also be considered as contingency breakers.

Table 6.2: List of Primary Contingencies

Contingency #	Substation	Generation Equipment	Type	Description
1	Steven's Croft	Anchor generator	Traditional generator	Added for reference only – applicable for station with multiple anchor generators
2	Middle Brie	EWE Hill WF	Wind farm	
3	Minsca	Minsca WF	Wind farm	
4	TBD	BESS-1	Battery	Included as example
5	TBD	PV-1	PV	Included as example

6.6.1 Pre-Event Calculations

This system collects the following data and processes them at high speed to dynamically select the loads that will be shed for each possible contingency.

- **Status of sources**: This includes the online status of each generator and utility tie, as well as the source bus connection. Additionally, this includes the present power output of each source.
- **Topology of the power system:** This involves determining how each source and load is connected to a bus by use of the statuses of breakers and disconnect switches located throughout the distribution network.
- **Operator inputs:** This includes operator-settable parameters such as control enable signals, IRM set points, load priorities, and override load consumption values.

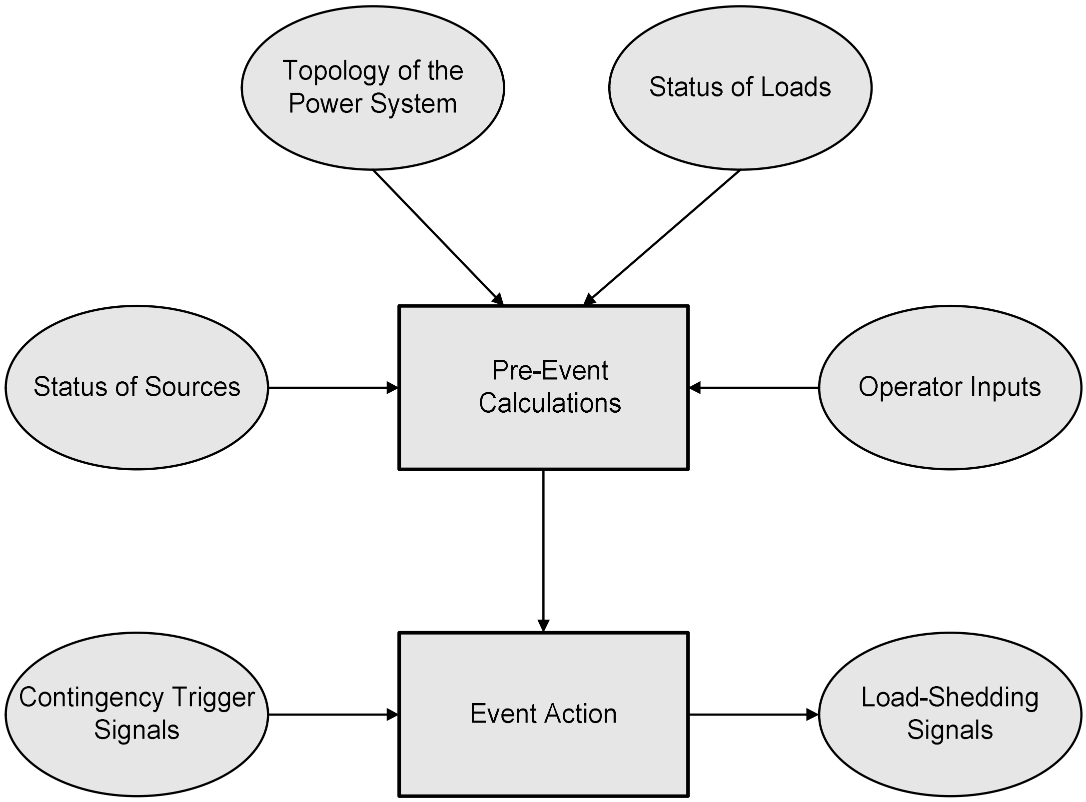


Figure 6.8: Conceptual Architecture of CLS

The pre-event conditioning of the real-time system parameters ensures that all information required by the CLS is preloaded into the event action algorithms, effectively arming the system. The event action requires high-speed and deterministic processing, as well as secure communications channels to propagate contingency triggers and load-shedding signals. The system uses a substation-grade RTAC as a POWERMAX controller to implement the pre-event calculations and post-event actions.

- **Analog data:** The pre-event calculations do not need to occur at high speed. In fact, the LSS filters all analog measurements to filter power system transients. The pre-event calculations are executed to dynamically update the load-shedding table used to select the loads that will be shed for specific contingencies and to arm the high-speed event actions. Analog measurements occur at least once every 1000 milliseconds.
- **Status of loads:** This includes the online status of each load, as well as the load bus connection. Additionally, this includes the present measured power consumption of each load.

6.6.2 Controller Calculations

As previously outlined, the load-shedding controllers perform pre-event calculations to arm the controller with load-shedding decisions based on a real-time power system state. The following subsections further describe different power system states that contribute to the pre-event calculations.

INCREMENTAL RESERVE MARGIN

The IRM, or block load pick up capability, can be defined as the amount of step increase in load that a generation asset can provide within the tuning time response of the governor to keep the frequency within specific limits (typically ±1–2 Hz). The IRM is different from spinning reserve, which is the capacity of the generator minus the current operating point of the generator.

For the POWERMAX CLS, the IRM is defined as the amount of instantaneous power that a power source can supply while maintaining the frequency within specific limits. As previously mentioned for generators, this value is limited by the response characteristic and spinning reserve of the generator.

This operator-set value can be entered through the HMI. The access for entering the IRM is password-protected and granted to only those personnel with the appropriate privilege level.

For closely timed events occurring within 10 seconds of one another, the system will consider the IRM only for the first contingencies. As subsequent contingencies occur, the IRM for the island will be reduced to zero. If a second contingency occurs more than 10 seconds after the first one, the system will again use the IRM values for the generators. If, however, the events are closely timed (within 10 seconds), the CLS will not use the IRM for the second contingency because it was already used for the first one. The recommended IRM values of every generator will be identified via Real Time Digital Simulator (RTDS) testing and will be recommended by SEL ES.

SELECTED LOAD-TO-SHED EQUATION

The theory expressed in the Contingency-Based Load-Shedding Scheme Overview section and the IRM section of this document leads to the fundamental equation of the load-shedding algorithm. The amount of load to be shed is the difference between the amount of source power lost and the sum of the instantaneous power that can be supplied by the remaining sources. This is described in Equation (1), which is performed for each island on the system; meaning that the terms of load, power disparity, and IRM are all specific to the individual islands.

$$L_n = P_n - \sum_{g=1}^{m} IRM_g$$

where:

n is the contingency event number.

m is the number of sources in the system after *n* event.

g is the generator number, 1 through *m*.

L_n is the amount of load selected for *n* event (MW).

P_n is the power disparity caused by *n* event (MW).

IRM_g is the IRM of all sources after *n* event (MW).

The system monitors all these connections and arms the analog quantities into the event calculation algorithms. With these armed values, the system can predict the power deficit that would result if that source should trip offline (contingency) and displaying the resulting loads that would be shed. The power deficit calculated is equal to the amount of generation lost on an island minus the IRM of the remaining sources. This load-to-shed calculation is run continuously in the CLS; however, the system will not initiate a load-shedding event without a trigger. When a trigger is detected, such as a sudden loss of generation on the system, the CLS will shed load according to Equation (1). The controller is also able to pre-calculate the amount of load required to shed if any event occurs. This information is important because it is compared to the available load for shedding to determine if the system will be able to shed enough load to stabilize it. These pre-calculations are then sent to the HMI for display, alerting the operators about the loads selected by the CLS to shed for each defined contingency.

It is sometimes possible that one or more of the contingencies cannot be satisfied. In this situation, the operator will receive a critical system alarm indicating that the CLS cannot shed enough load to compensate for the predicted power deficit that would occur if a particular contingency were to occur. It is the responsibility of the operator to adjust to allow the LSS to fully protect the system. In most situations during restart loss of the anchor generator will result in a black out scenario, however load shedding may be able to save the system from loss of wind farms or other generation assets.

6.6.3 Contingency Triggers

For the CLS scheme, there are two standard methods used to detect contingencies. The first is based on monitoring breakers at high speed. If a source breaker is opened under load, the system will shed load according to the calculations in Equation (1). The second method that results in a contingency trigger is a protection-based breaker trip signal. This would be from some sort of protection operation that results in opening a contingency breaker, as in the first method. The difference in these methods is that instead of the system waiting to receive the breaker open signal, the CLS directly receives the protection trip signal. This is sent to the POWERMAX DRZC at high speed and will reach the controller before the breaker status signal. This allows for even faster load shedding and less system disturbance. By the time the CLS receives a trigger from the contingency breaker status in response to the protection trip, it will already be processing the contingency and may already have sent out load-shedding signals.

If a bus tie is feeding a load bus with no additional generation from the POWERMAX DRZC perspective opening the coupler can result in shedding all load on the bus, or not shedding any load. The bus will be dead either way. However, in some situations having load breakers open on a dead bus can simplify operation. The decision to shed load in a dead bus scenario will be left up to the DNO.

CONTINGENCY BREAKER OPENING

When the POWERMAX DRZC detects the opening of a contingency breaker, several conditions must first be met for the CLS to declare it as a contingency event and enable it to shed load. First, the breaker must be without alarm for at least five seconds prior to opening for the status to be valid. If invalid 52A and 52B statuses are observed, they must remain healthy for five seconds before the system will consider the breaker for load shedding again. The trigger also cannot occur during an alarmed state and must first be healthy for at least ten seconds. These safety measures help prevent unnecessary triggering of contingencies, ensuring the breaker and monitoring equipment are functioning properly and can be used by the system. Once a valid breaker operation is detected, calculations for load required to shed begin.

CONTINGENCY-BASED LOAD-SHEDDING AUTOMATIC INHIBIT

The CLS scheme allows up to five closely timed contingencies to occur and then inhibits itself from tripping more loads for ten seconds so that the system can stabilize. The specific number of closely timed contingencies and the time interval of ten seconds is typical for power systems of this size and will be verified by the RTDS testing to ensure maximum system power balance based on the electrical model. In this way, the system does not act on too many closely timed contingencies based on data from transient conditions. Once load is shed by the CLS scheme, further load will only be shed after the ten second time-out; during that time, the UFLS scheme will protect the system. The number of closely timed contingencies will be based on typical system operating conditions and the RTDS studies performed for the DRZ.

Traditionally, the CLS scheme will also be inhibited if an underfrequency event occurs. Underfrequency events signify a system condition in which the CLS scheme was unable to prevent frequency decay. Frequency fluctuations can cause many cascading events and can be made worse by shedding additional load.

6.6.4 Event Actions

Event actions occur at high speed in response to contingency trigger signals. When the LSS detects a contingency trigger (e.g., a generator that trips), the system trips a set of preselected loads to restore power balance. All information pertinent to the load-shedding decision is read into the system prior to detecting any contingency. This means that the system can develop a matrix that predicts the outcome of given contingencies and displays this information, via HMI to the operator prior to the event occurring. The load-shedding controller computes and executes the event action at the same moment that the event is detected. Priority-based optimal load selection logic is implemented, where multiple loads might have the same priority.

6.6.5 Controller Logic

The core CLS logic can be broken down into four primary logical blocks, as shown in Figure 6.9.

- Contingency detection logic
- Load-shedding calculation logic
- Load selection logic
- Crosspoint (CPS) Advanced Applications Logic

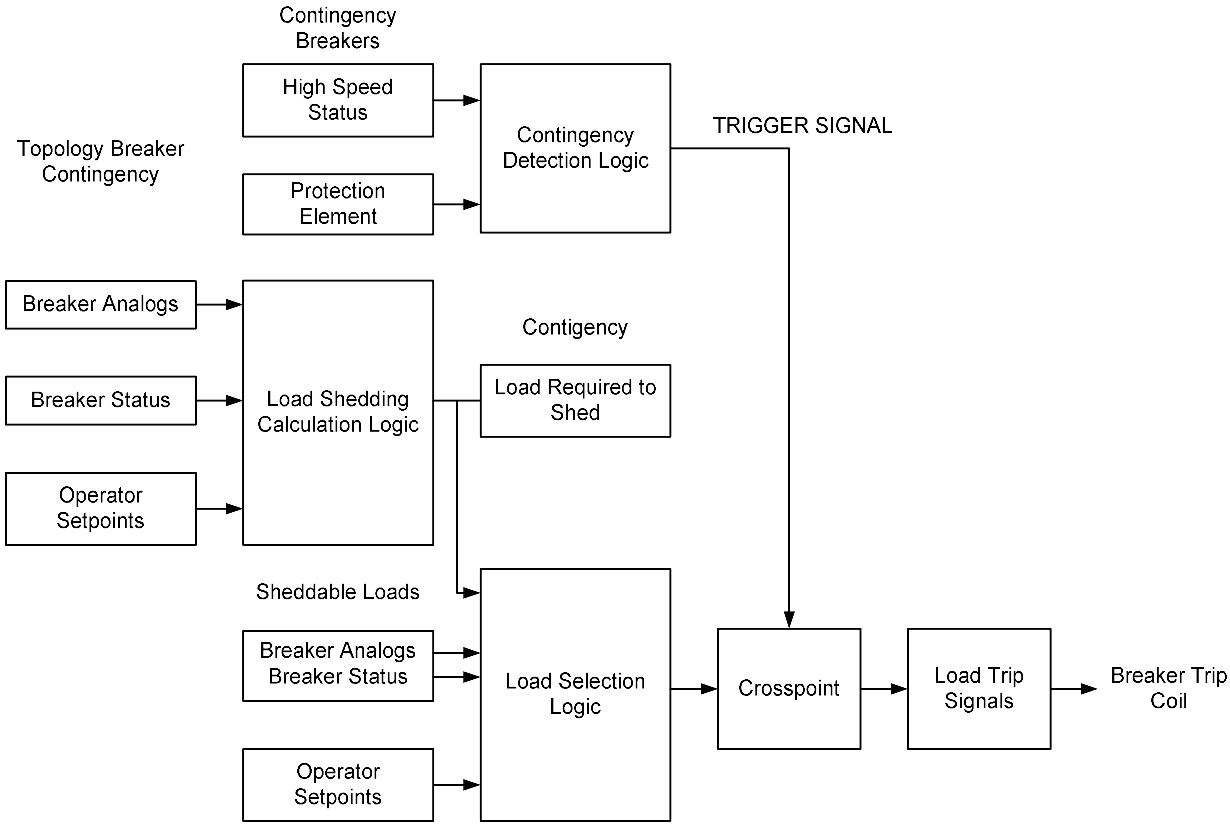


Figure 6.9: Load-Shedding Logic

Figure 6.10**Error! Reference source not found.** shows the details of the load selection logic. A list of loads to shed for each contingency is ultimately output from this block. Bus connections of loads and contingencies are compared to ensure only loads existing on the same electrical island as the contingency may be part of the load-shedding list. Load priority and active power consumed is monitored, ensuring the optimum amount and priority of load will be shed if the associated contingency is triggered. Note that this is a conceptual flow chart and does not show all details for the system.

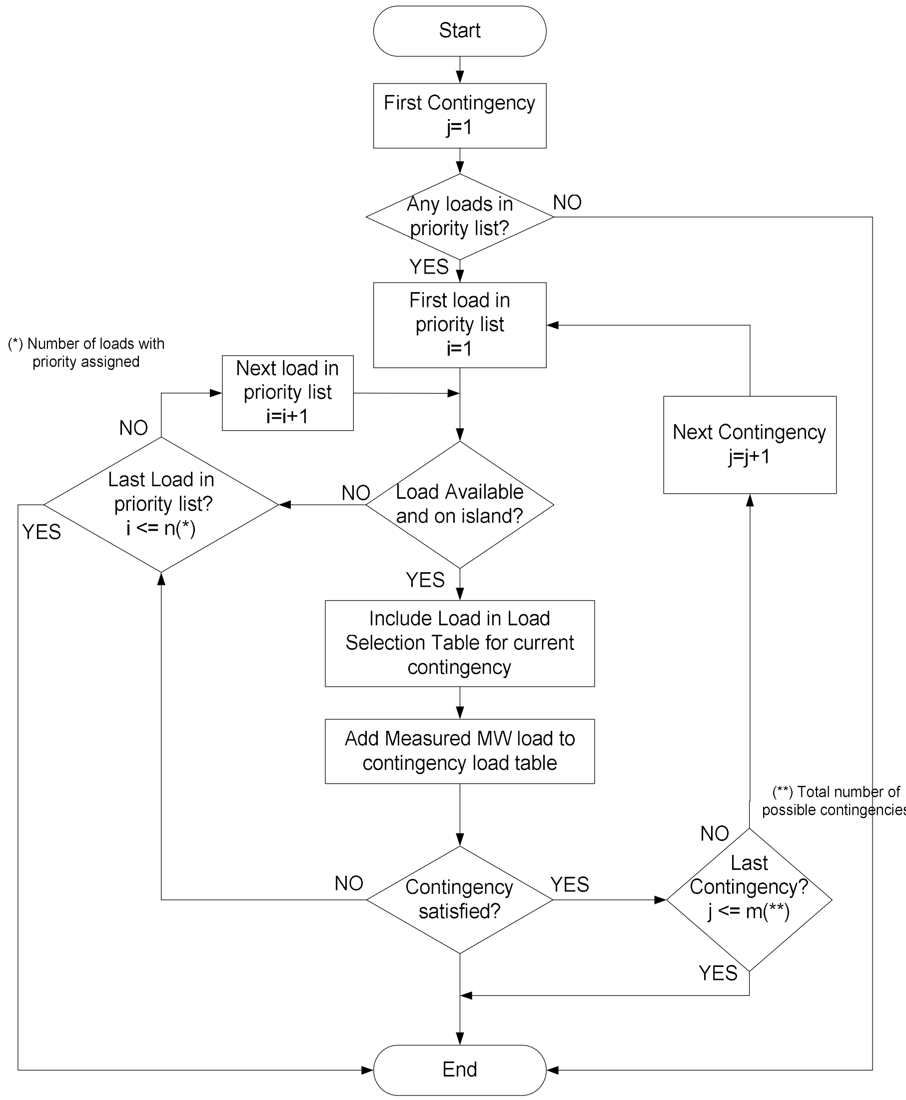


Figure 6.10: Load Selection Logic

Figure 6.11 shows a simplified version of the Crosspoint Advanced Application Logic. Each contingency has an associated trigger. Trigger 1 corresponds with Contingency 1, and so forth. Each load is selected per contingency and may be preselected for multiple contingencies. However, if a load was shed in one contingency, it will be inhibited from being selected for shedding by any other contingencies. This is done instantly and without status feedback from the circuit breaker (CB). Even if the controller processes multiple contingencies in the same process cycle, it will not attempt to select the same load for different contingencies. The load-shedding logic is executed every two milliseconds in the controller. This allows for a very quick and continuous calculation to update the load-shedding Crosspoint. If a contingency is triggered, the same contingency will be blocked for a system-specified amount of time; thereby, avoiding erroneous triggers and resultant load-trip output signals. The result of the Crosspoint switch multiplication is trip signals that are sent directly to the substation FEPs at various locations and from there, to the mitigation devices whose output contacts are wired to the trip coil for each load.

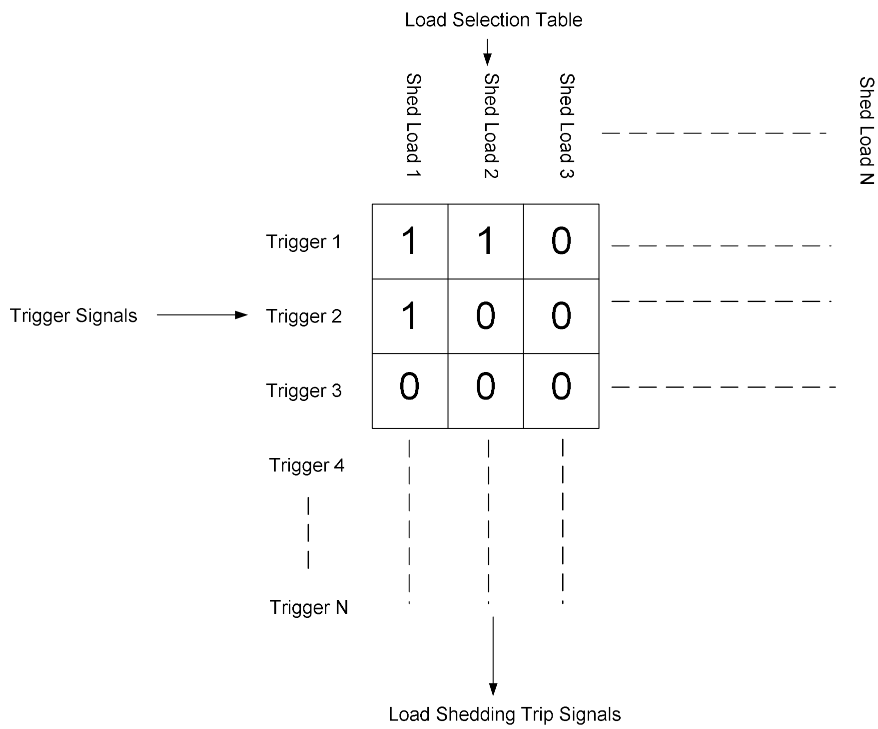


Figure 6.11: Crosspoint Logic

As shown in the Figure 6.12, each row represents a specific contingency. The columns show the total amount selected to shed and the number of loads for each busbar. The table shown will inform the operator which loads on a specific busbar will be shed. These loads are represented in the rows by each breaker and the load classes are indicated in the columns.

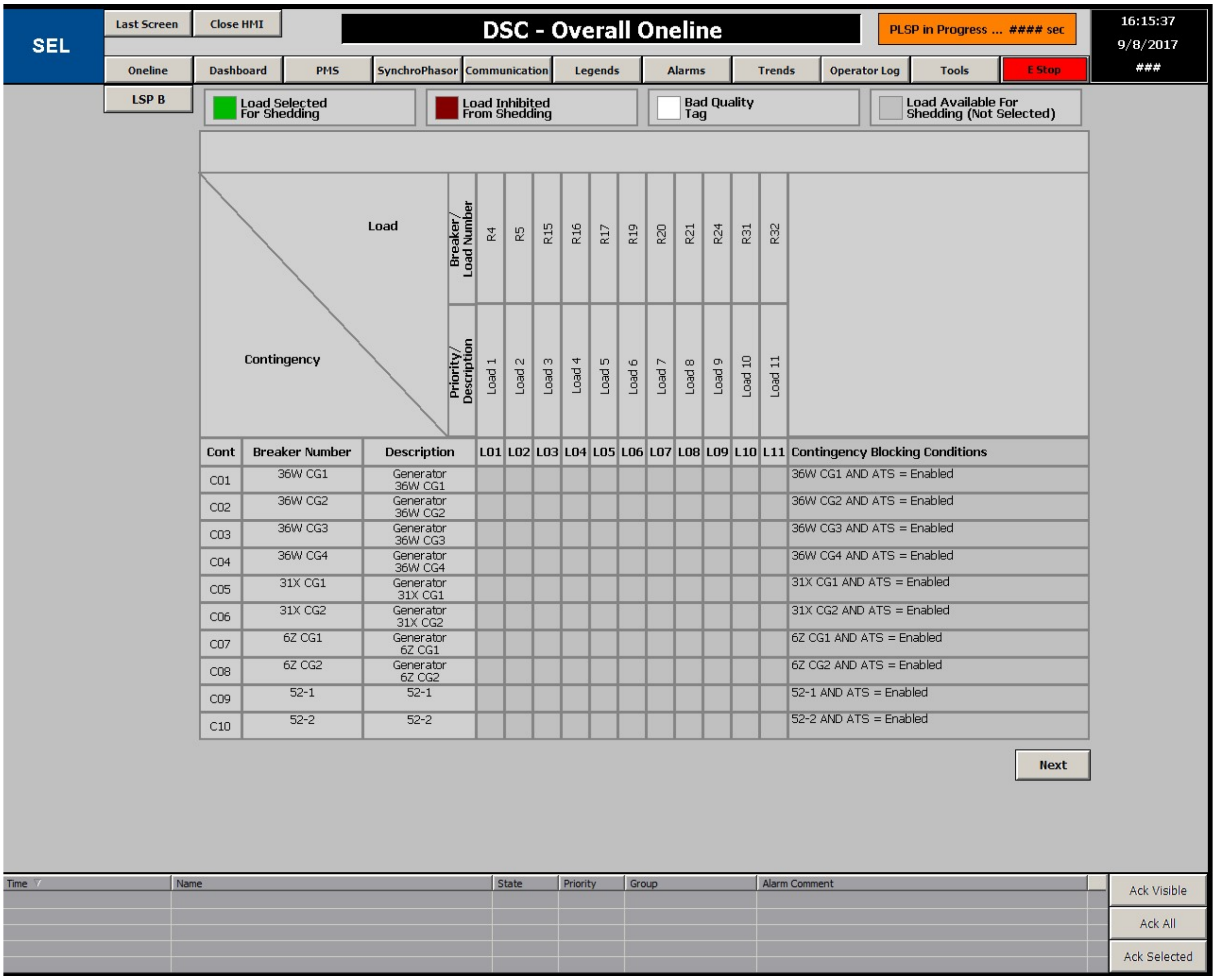


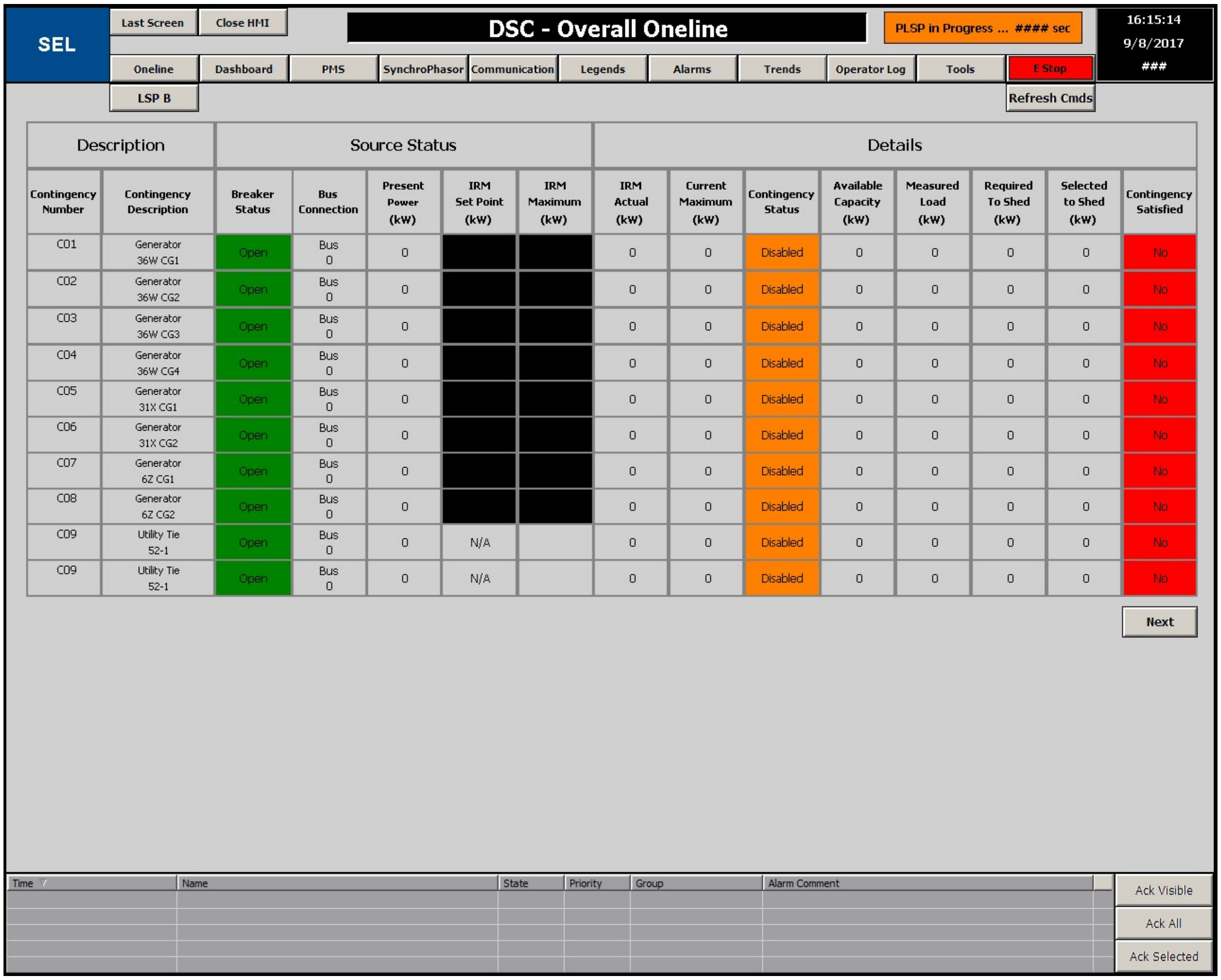
Figure 6.12: Example Crosspoint Screen

6.6.6 Post-Event Actions

Once a CLS event has occurred, all load-shedding outputs are held in their trip state. This is to ensure that trip signals reach the relays and trip coils of all loads selected for shedding. The outputs of the controllers will remain high for one minute or until the load-shedding trip is reset from the HMI. All trip coils will remain energized for one minute or an operator releases them in the HMI prior to the one-minute window.

6.6.7 Contingency Summary Screen

The Contingency Summary screen, shown in Figure 6.13, displays all contingency information used and processed by the POWERMAX CLS. It also provides the operator an interface to set parameters and enable or disable contingencies. This screen is only an example; the project specific screens will be developed for the network operator system during the design phase of the project. All screens will go through a standard approval process with the network operator and other responsible parties prior to the delivery.



Description		Source Status					Details							
Contingency Number	Contingency Description	Breaker Status	Bus Connection	Present Power (kW)	IRM Set Point (kW)	IRM Maximum (kW)	IRM Actual (kW)	Current Maximum (kW)	Contingency Status	Available Capacity (kW)	Measured Load (kW)	Required To Shed (kW)	Selected to Shed (kW)	Contingency Satisfied
C01	Generator 36W CG1	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C02	Generator 36W CG2	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C03	Generator 36W CG3	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C04	Generator 36W CG4	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C05	Generator 31X CG1	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C06	Generator 31X CG2	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C07	Generator 6Z CG1	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C08	Generator 6Z CG2	Open	Bus 0	0			0	0	Disabled	0	0	0	0	No
C09	Utility Tie 52-1	Open	Bus 0	0	N/A		0	0	Disabled	0	0	0	0	No
C09	Utility Tie 52-1	Open	Bus 0	0	N/A		0	0	Disabled	0	0	0	0	No

Figure 6.13: Contingency Summary Screen

6.6.8 Alarms and Bad Status Handling

The LSS monitors the health of all communications channels and deals with errors in a variety of ways. The following are the basic types of alarms that are detected by the system with an explanation of their negative impact.

- **Device Alarm:** An alarm to any IED monitoring an asset within the electrical system. This includes IEDs monitoring breaker (52A or 52B) statuses or metering data.
- **Status Alarm:** An alarm of the status information for any breaker. Mismatch of 52A and 52B statuses for breakers or disconnect switches can trigger this alarm.
- **Metering Alarm:** An alarm on any of the metering quantities for ties, generators, bus couplers, or loads. These alarms are generated when the meter values are outside of the typical operating range. Typical operating ranges are specific to each system asset.
- **Contingency Alarm:** Any alarm generated for a contingency breaker, such as an IED alarm, status alarm, or metering alarm. Contingency alarms will prevent the triggering and load shedding for that contingency.
- **Load Alarm:** Any alarm generated for a load breaker, such as an IED alarm, status alarm, or metering alarm. Load alarms inhibit the load from being selected for shedding.

If a communications failure to a device is detected, the system will immediately switch data paths to use the redundant device, if one exists on the system, and alert the operator via the HMI. If both devices are lost on any level and an alarm is declared, this alarm is then sent to each system asset being handled by the device. These alarms omit the associated assets from all load-shedding calculations. For an alarm on a relay providing metering of one or more loads, those loads will be declared unavailable for load shedding. If the device monitors metering values on a contingency breaker is in alarm, that contingency will be disabled. If an alarm is detected for any device within the system and there is no backup data source, all assets (contingency breakers, load breakers, and switches) associated with the device are declared to be in alarm and are suppressed from any calculations. These inhibits take place because without valid power system information the POWERMAX DRZC cannot make the correct decision. The system then relies on the selection of alternate load breakers or the backup UFLS scheme to protect the electrical system.

Invalid information for contingencies or loads can also result in alarmed conditions for assets throughout the system. The two primary types of information alarms that can affect assets are breaker statuses and metering values.

If any breaker in the system has both 52A and 52B contacts being monitored, they must always be in opposing states. A 52A contact indicates a closed breaker, while a 52B contact indicates an open breaker. If both are detected to be in the asserted state at the same time, then something has gone wrong, and breaker status is not valid. Either the breaker or the monitoring equipment has malfunctioned. Because of this, a bad status alarm is declared for that breaker. POWERMAX controllers use real power-supervised breaker-status conditioning logic. A breaker with a bad status alarm, but with real power flow that is more than a predefined threshold, is considered closed by the CLSs. All breakers with a bad status and less than the threshold real power flow will be considered open by the CLSs. The POWERMAX DRZC control actions (contingency detection/shedding) are inhibited for breakers in a bad status or IEDs in alarm condition. Any action by the CLS involving a breaker with an unknown state puts the system at risk for mis-operation and plant blackout. For example, even if the breaker still has a power reading, a bad status may indicate that all control and metering for the breaker is unsure. It must be inhibited from all calculations. For contingencies, this means being inhibited from triggering load-shedding events and for load breakers, it means being declared unavailable for shedding.

A similar inhibition is applied for bad metering statuses. Bad metering statuses are declared when a controller detects values outside of the bounds for a specific breaker. These bounds are hard-coded to filter out erroneous data. This is a safety feature that can detect bad relay settings (CT or PT ratios), line-to-ground faults, and other situations that can result in inaccurate metering. The only difference in how the controllers process bad metering and bad breaker statuses is that the metering alarms do not affect the topology.

6.7 UNDERFREQUENCY-BASED LOAD-SHEDDING SCHEME OVERVIEW

The backup UFLS scheme shed loads based on underfrequency thresholds, which are set in the protection relays located where the generators connect to the busbar. This scheme sheds load corresponding to the frequency response characteristic (FRC) of the system and the predicted power deficit for varying levels of frequency excursion. This scheme backs up the primary load-shedding scheme by detecting frequency decay that was not prevented by the CLS scheme because of an alarmed breaker opening, overestimated IRM, load-shedding failure because of wiring/trip coil issues, or overestimated MW values for loads. Relays on the generation buses and other defined locations, as listed in Table 6.3, send triggers to the CLS when an underfrequency threshold has been crossed. In addition to frequency triggers, relays also provide rate-of-change of frequency (df/dt) measurements to indicate how quickly the frequency of the system is decaying. These df/dt values further dictate the amount of load to shed with higher values corresponding to more load being shed. This is to be determined based on the RTDS underfrequency study. When the UFLS declares an underfrequency event, it will select an amount of load to shed based on the frequency threshold and the df/dt of the island. Each underfrequency level sheds progressively more load. If the system fails to recover and the next level is triggered via threshold detection, additional load is shed based on the set point.

As with the CLS, the UFLS selects load for shedding based on the high-speed algorithms that determine loads to shed based on required amount, operator-defined priorities, and electrical system topology. An added benefit of this centralized UFLS is the ability to isolate events on an island-by-island basis. This ensures that only relevant loads are shed for frequency excursions throughout the system and that other islands remain unaffected.

6.7.1 System Topology

Topology refers to the interconnection of assets throughout the electrical system. By analyzing the connections between devices, the POWERMAX DRZC can form islands consisting of any variety of sources, buses, or loads within the given distributed restart zone. By identifying these electrically separate groups of islands, the system is then able to process control algorithms individually for each one. This is important because of the variance of devices, such as generators or utility connections, throughout the system.

The UFLS gathers data to perform these calculations for load shedding. It will map each load in the system to buses and determine the interconnections using topology breakers. Collectively, this information will make up the system topology. In contrast to the CLS, the UFLS requires slightly less information. The primary concern of the UFLS is the connection of loads and the interconnection of buses. The following are the three categories of information required by the UFLS for load shedding:

- **Topology Information:** Includes breaker (52A and/or 52B) and breaker racked-in statuses (TOC). It does not contain metering data because it is not required to perform the load-shedding calculation. These status points are used to determine system topology and allocate loads and sources to electrical islands.
- **Load Information:** Includes breaker statuses and metering values of the sheddable loads.
- **Underfrequency Triggers:** Includes protection-based underfrequency trigger signals from relays on the 33 kV buses.

With this information, the UFLS then process all underfrequency triggers and shed load according to the topology of the system. This means that only loads electrically connected to the bus that detected the underfrequency trigger will be shed.

Note: The underfrequency (UF) required-to-shed (MW) calculation is a percentage-based value based on the system generation capacity at the given instance. This algorithm is dynamic and will consider system capacity to select the loads required to shed. SEL ES and network operators will finalize the required-to-shed values after detailed system studies, simulation, and testing. The proposed UF and df/dt trigger locations for Chapelcross are listed as follows:

Table 6.3: Underfrequency and df/dt Trigger Locations

Substation	Relays	Type
Chapelcross Bus A 33 kV	SEL-451 Protection, Automation, and Bay Control System or existing SEL device	UF and df/dt trigger

Chapelcross Bus B 33 kV	SEL-451 Protection, Automation, and Bay Control System or existing SEL device	UF and df/dt trigger

6.7.2 Underfrequency-Based Load-Shedding Automatic Inhibit

The UFLS allows for tripping of loads for an underfrequency level trigger one time for any bus. When a frequency-level trigger has been processed, the system will wait until the frequency recovers above that level before allowing that same trigger to shed load again. This prevents the system from acting on transient characteristics and allows the electrical system to stabilize prior to initiating further load shedding. Underfrequency conditions are tracked for each bus. If an underfrequency trigger is detected for any bus on an island, all other buses on that island are inhibited from triggering that particular level because of their electrical connection. This prevents additional tripping in case of the system topology changing during closely timed events.

The UFLS frequency thresholds are coordinated with the generator protection frequency set point to minimize excess load shedding. When the CLS operates, the UFLS will be disabled for 300 milliseconds (this will be confirmed during RTDS testing). The temporary disable condition will only occur if the CLS is active and load shedding is enabled. Inhibiting the UFLS for a short period of time when the CLS is active allows for the system frequency to recover after load shedding.

6.7.3 Post-Event Actions

As with the LSS scheme, the outputs of controllers will remain high for one minute or until released from the HMI. All trip coils will remain energized until an operator releases them in the HMI, locally in the relay, or when the DRZC system deasserts the output contacts. In addition to holding the load-trip signals in the asserted state, the specific underfrequency events are also latched. The latches for the underfrequency system are only temporary. They will prevent the same level of underfrequency event from occurring until the latch is reset. The latch will reset when the frequency has risen above the level for the trigger. The trigger will be reset in the SEL relay using a hysteresis calculation. This allows the system to stabilize prior to shedding additional load. This also prevents unnecessary load shedding because of fluctuating frequency within the electrical system. The latches for the UFLS apply to all buses that are part of an island that receive an underfrequency trigger. Any bus that was part of an island where a underfrequency event occurred will be inhibited from triggering that same level of underfrequency event until the frequency has recovered.

6.8 Overfrequency-Based Gen-Shedding Scheme Overview

The GSS scheme shed generation or adds loads to the load bank based on overfrequency thresholds, which are set in the protection relays located where the generators connect to the busbar. This scheme performs load generation balance corresponding to the frequency response characteristics of the system and the predicted excess power for varying levels of frequency excursion. Relays on the generation buses and other defined locations, as listed in Table 6.3, send triggers to the DRZC when an overfrequency threshold has been crossed. In addition to frequency triggers, relays also provide df/dt measurements to indicate how quickly the frequency of the system is rising. These df/dt values further dictate the amount of load bank charging or generation to runback or shed, with higher values corresponding to more generation being reduced. The exact values will be be determined based on the dynamic simulation study. When the GSS declares an over frequency event, it will select an amount of load to be added on the load bank or generation to shed or runback based on the frequency and df/dt trigger on the island. Each overfrequency level progressively reduces more generation. If the system fails to recover and the next level is triggered via threshold detection, additional action is taken.

As with the UFLS, the GSS selects amount of load to be added via load bank or generation shedding based on the high-speed algorithms that determine load rebalancing, required amount, operator-defined priorities, and electrical system topology. An added benefit of this centralized GSS is the ability to isolate events on an island-by-island basis. This ensures that only relevant generation is shed for frequency excursions throughout the system and that other islands remain unaffected.

6.9 Progressive Overload Shedding Scheme Overview

A slow-speed, progressive overload-based load-shedding signal (PLS) is generated by the local protective relay and provided to the DRZC. This overload-based load shedding can be implemented at Steven's Croft feeding the Chapelcross 33 kV Substation. The primary objective of this PLS to prevent the anchor generator from tripping due to overload scenario by keeping it operating within the safe percentage of the maximum output and increasing the reliability of the overall of DRZ.

Note: This scheme is an optional scheme, but not a requirement.

In summary, the DRZC PLS performs the following specific functions:

- Dynamically calculates the quantity of load to shed for overload conditions.
- Dynamically selects individual loads to shed based on user-set priorities, measured power consumption, and the present topology of the power distribution system. Each load will have its own unique priority.
- Inhibits load for shedding if the breaker status is already open; if there is communications loss from the device; if the signal quality of the breaker status or running load (MW), or both, is bad; or if the breaker is out of service (racked out/test position).
- Keeps the protected asset from tripping due to overload condition.

6.10 Undervolage-Based Load-Shedding Scheme Overview

A voltage or reactive power-based load-shedding scheme is required due the nature of the DRZ. When energizing transformers, transmission lines, or load substations, a significant amount of voltage drop may be observed due to additional demand for the reactive power. If already in the process of restoration, this may cause an outage on the DRZ. To mitigate this, an undervoltage signal is generated by the SEL-451 relays at Chapelcross and provided to the POWERMAX DRZC. This undervoltage-based load shedding can be implemented at the Chapelcross 33 kV Substation.

The primary objective of this undervoltage-based LSS to prevent the overall system voltage collapse during system re-energization. This load-shedding functionality follows similar logic as the load-shedding systems. However, specific undervoltage detection will be programmed into the relays to trigger load shedding and only load at the buses where undervoltage is trigged will be shed.

In summary, the POWERMAX DRZC performs the following specific functions:

- Dynamically calculates the quantity of load to shed for each contingency based on the voltage pick up and reactive power consumption of the load.
- Dynamically selects individual loads to shed based on user-set priorities, measured reactive power consumption, and the present topology of the power distribution system. Each load will have its own unique priority.
- Shed load on the location where undervoltage triggers are generated as voltage is a local phenomenon.

- Responds to a voltage based contingency trigger in less than 50 ms, excluding circuit breaker opening time.

6.11 Load Bank Control Scheme Overview

A high-speed Load Bank Control (LBC) scheme is implemented by the DRZC. This signal is generated by the POWERMAX DRZC and provided to an I/O module to the load bank to adjust the load at the load bank. This LBC is implemented at Steven's Croft feeding the Chapelcross 33 kV Substation. This LBC scheme charge the load bank and will quickly reduce loads when attempting to energize the load feeder so that there is minimal disturbance to the anchor generator. This LBC scheme will also incorporate controls from LSS and GSS for charging or discharging the load bank based on contingency or frequency triggers.

In summary, the POWERMAX LBC performs the following specific functions:

- Dynamically calculates the quantity of load to shed on load bank for each substation being energized.
- Performs load reduction and increase based on the DRZC LSS / GSS logic.
- Responds to a contingency trigger in less than 50 ms, excluding circuit breaker opening time.
- Supervises all signals with communications-quality indications.
- Inhibits load for shedding if the breaker status is already open; if there is communications loss from the device; if the signal quality of the breaker status or running load (MW), or both, is bad; or if the breaker is out of service (racked out/test position).

6.12 Load Processing

All load-shedding schemes within the POWERMAX DRZC use a priority-based load selection. Loads are selected for shedding based on their present power and their predefined priority. Loads with a priority of zero are inhibited from shedding. Operators may set load priorities to zero to intentionally inhibit them from shedding. Loads with lower numerical priorities are selected for shedding first, starting with one and moving up the list as loads are available, until the total amount of load selected for shedding matches or exceeds the amount of load required for shedding. After each load is selected, the algorithm sums the total load selected for shedding to determine if the required-to-shed amount has been reached. Loads with a power value of zero will not be selected for shedding. If all loads available are selected and the required-to-shed amount is not reached, the contingency is declared unsatisfied and an alarm is sent to the operator during pre-event calculations.

Load-shedding signals are sent out by the CLS, propagated through both the central FEPs, and sent to the load-trip relays, and then to the load-trip coils or VSD controllers. Figure 6.14 illustrates this process.

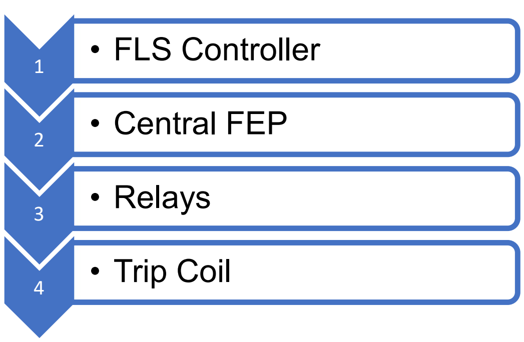


Figure 6.14: Load-Shedding Signal

When a load is selected for shedding, the load-trip signal is sent out by the controller and held for 60 seconds. This ensures that the signal is propagated through all devices and reaches the load. The trip signal is then transmitted through the load-specific relay as the breaker trip coil signal. Load-trip coils will only be de-energized after 60 seconds or with the HMI reset command.

The following sheddable load list in Table 6.4 is considered for the distributed restart project.

Table 6.4: Sheddable Load List

Site	Location	Substation	Switchboard	Voltage	Incomer/ Feeder
Annan	Annan	Annan	Anna A	11 kV	A
Annan	Annan	Annan	Anna B	11 kV	B

6.12.1 Load Status Screen

The Load Status screen, shown in Figure 6.15, displays all load information used and processed by the DRZC. It also provides the operator an interface to set various load parameters, such as class distribution and shed priority. This screen is only an example; the project specific screens will be developed for the DNO during project design stage.

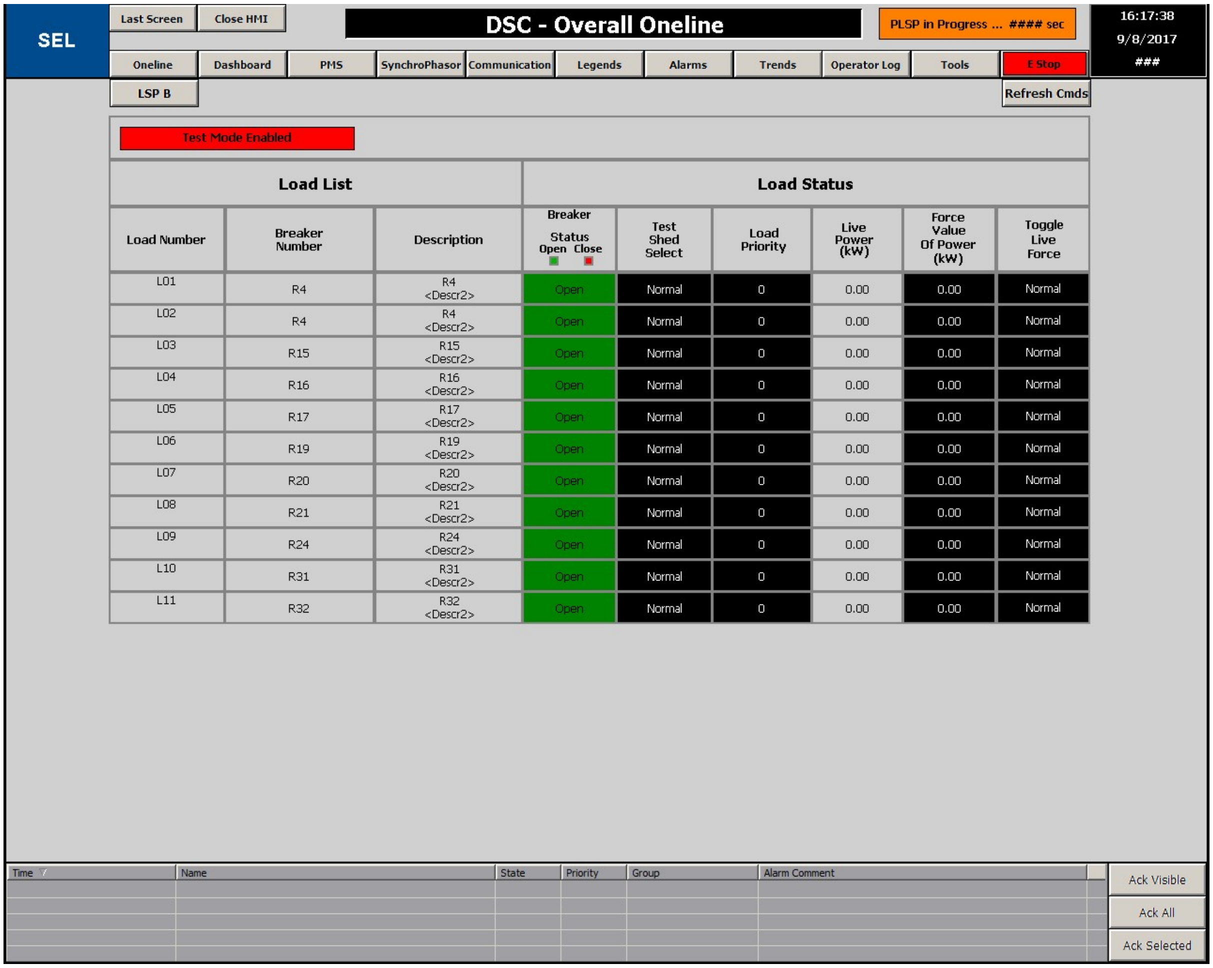


Figure 6.15: Load Status Screen

6.12.2 Load Status Commands

- **Test Shed Select** displays the state of the test shed option for the breaker. This is selectable between Normal and ON/OFF. This field is password protected.
- **Toggle Live Force** displays the present state of the kW value being used for load-shedding calculations. The operator may toggle to force and override the live value.
- **Force Value of Power (kW)** indicates the desired forced kW value for load.
- **Load Priority** displays the priority entered for each load. This is operator settable and will automatically sort to ensure that there are no duplicate entries or gaps in the priorities.
- **Breaker Number** displays the feeder CB number.
- **Description** displays the description (or client) for the feeder breaker.
- **Breaker Status** shows the current open or closed state of the feeder breaker. Red indicates Close and green indicates Open.
- **Live Power (kW)** shows the preset power flow through the feeder breaker.

6.12.3 Load Restoration Logic

The DRZC will restore system loads based on the restoration priority of the loads, the expected restoration demand, available system IRM, and available system capacity. Usually, the restoration priority of the loads is opposite to the shedding priority, with the most important load restored first and shed last. The DRZC will attempt to restore as much load as possible to the system while staying within a percentage of the total capacity of all DERs in the island. In the case study only Annan Substation is considered but the other loads would be restored in a similar manner.

The load restoration process will move through the loads from highest number priority to lowest. For each load, the estimated MW and MVAR required for restoration will be compared to the current IRM and MVAR capacity of the system. If the capacity exceeds the expected requirement then the load will be picked up cold into the system. The pickup process is assisted by the adding load to the load bank and switching it out as the substation load is picked up.

If the DRZ capacity is less than the expected P and Q requirement then the DRZC will skip that restorable load and restore the next load in the priority list.

When restoring load, it must be considered that the reactive power (Q) metered at the load is not a perfect representation of the Q requirement to restore the load. Because the restored load's real power (P) will cause additional Q absorption in the system. Inhibiting restoration for loads that would increase the reactive demand, based on load metered Q, above a certain percentage of the DRZ Q capacity should minimize this risk. In summary, a reserve of Q capacity in the system will be allocated to account for system Q absorption during load restoration. The amount of Q capacity to be reserved will be determined during the final design stage.

Under voltage shedding will also be actively protecting against unexpected voltage drops during restoration see Section 6.10 for more details.

Between the restoration of each load the voltage and frequency of the system will be required to return to a healthy level within deadbands of nominal for a settable period. After the system is stable for this amount of time the DRZC will move onto restoring the next load. This process continues until all possible loads have been restored.

If the DRZC is set to manual mode, the operator will be responsible for selecting the loads to be restored. The load restoration priorities will not be followed.

LOAD RESTORATION HMI

The restorable loads will have a few controls and statuses available in the HMI. Standard for every load will be breaker status, manual restore command, automatic restore priority, system stability status and set points, alarms, last healthy P and Q demand, P and Q from load profile, and manual expected P and Q demand set points. Manual operator intervention will be required to clear alarm flags that may assert during restoration.

The HMI details covered here are specific to load restoration. Separate load controls and statuses are available for load shedding, this is covered in Section 6.12.1.

Breaker Status: This field will indicate the open or closed status of the load breaker. 52A/B contacts are read from the field and the status is communicated to the HMI. This field will also display alarms.

Manual Restore Command: This command allows the operator to manually close the load for restoration. This command can only be used when the restart system is in "Manual" mode. The operator must ensure that the system is running in a stable state with enough reserve to pick up the load before issuing this restoration command.

Automatic Restore Priority: This field shows the priority order for loads to be automatically restored. The DRZC will automatically follow this priority list from lowest to highest number when automatically restoring loads. If a load should not be restored during restart, an operator or engineer can simply set the restore priority to zero. The priorities can be modified if necessary, but in general the priorities will be set once in the desired order. A load with expected demand that exceeds the current available capacity or spinning reserve may be bypassed during automatic restoration, and have an alarm asserted.

System Stability Status and Set Points: System stability statuses will be shown in a group of fields on the load restoration page. The voltage and frequency of the Chapelcross bus will be displayed as well as the available capacity of the system. The stability set points include voltage and frequency limits and timer seconds. The voltage and frequency must be within the V and F limit until the timer expires before restoring the next load automatically.

Last Healthy P and Q Status: These fields show the last healthy real and reactive power metered on the load. This is generally a 15-minute average but can be tailored to meet any requirements.

Load Profile P and Q Status: These fields show expected real and reactive power based on the load profile provided by the DNO. This is optional data.

Expected P and Q Set Point: These fields allow the operator or engineer to enter the expected real and reactive power required to restore the load. This is the manual override of the last healthy and load profile estimations. It should be left at zero unless a manual override of the load power is needed for some reason, such as an analog metering failure prior to the blackout causing bad data for the average.

Note: It will be up to the customer whether the system stability status and set points need to be followed during a manual restoration, they will always be followed during automatic restoration.

6.13 DER HMI

SEL HMI systems provide graphical representations of systems, access to real-time data, the ability to override points in a system, an interface with external management systems, and access to all supervisory monitoring and control functions. For the distributed restart controller, the HMI will allow the operators and engineers to intervene and manipulate the restart process if desired. Some important features which may be required in the restart controller like manual DER or load pickup inhibits, import/export limits while running in “Power Plant” mode during grid restart, PF and voltage deadbands before load restoration, etc..., will be available from the HMI for users with proper authentication credentials.

Figure 4.1 shows a higher-level overview of the DRZC network layers. The HMI operates at Layer 4 and do not influence the protection, control, and metering systems at lower levels. These systems display Sequential Events Recorder (SER) information, alarms, communications statuses, oscillography data, and trending provide for set point administration.

All necessary documentation, configuration information, configuration tools, programs, drivers, and other software are licensed to the end user. This allows the end user to repair, replace, upgrade, and expand the HMI system without dependence on SEL. Software licenses supplied by SEL do not require periodic fees and are valid in perpetuity.

6.13.1 Sample DER Asset Status and Control

The DERs will have a host of controls and statuses available in the HMI. Standard for every DER will be enable/disable control, alarms, remote DRZC control status, control in progress status, DER Allowed Capacity (this is the percent of current available capacity that the restart system will leverage to ensure a safety buffer is maintained), all control can be switched from automatic to manual and back again at any point in the restart process. Manual operator intervention will be required to clear the alarm flags which may assert during restart.

SYNCHRONOUS GENERATOR

This section describes the HMI functionality for a synchronous (anchor) generator. The following are descriptions of each command and indication that will be available for a generator.

Generator Start Control sends a command to start the generator. This provides a manual starting option for an operator, if the DRZC is in manual mode.

Generator Stop Control sends a command to stop the generator. This provides a manual stop option for an operator, if the DRZC is in manual mode.

ISOC/Droop Status displays whether the generator is operating in ISOC or Droop mode.

Generator in Remote displays if the generator is operating in remote mode and ready to receive commands from the DRZC.

Breaker Status displays the status of the generator breaker as Open, Closed, or in alarm.

Frequency (Hz) displays the frequency of each turbine generator.

Present Power (MW) is the present active power output of the turbine generator.

Voltage (kV) displays the voltage of the generator.

Present Q (MVAR) is the present reactive power output of the generator.

MW Enable Control enables or disables AGC functionality for each individual turbine generator. AGC only controls the turbine if it is not in ISOC mode.

MW Control Mode displays the present control mode of the unit MW controller within the AGC algorithm. Clicking this cell allows the user to change the control mode. Each unit MW controller can be set in Regulation or Maintain mode. It is only applicable if it is not in ISOC mode.

Lower Regulation Limit (MW), **Base Set Point (MW)**, and **Upper Regulation Limit (MW)** are the three user set points for the AGC. The user can change any of these set points by clicking on an associated cell.

Requested Set point (MW) is the destination set point of the unit MW control in the AGC algorithm.

Governor Under DRZC Control indicates whether DRZC detects the required conditions for AGC control, enabling the AGC unit MW control when on.

Governor Control in Progress indicates whether the DRZC is presently sending control pulses to raise/lower the MW set point of the turbine generator.

MVAR Enable Control displays the present enable or disable status of the unit MVAR controller in the VCS algorithm. Clicking this cell allows users to enable or disable VCS functionality for each individual turbine generator.

MVAR Control Mode displays the present control mode of the unit MVAR controller within the VCS algorithm. Clicking a cell in this column allows the user to change the control mode. Each unit MVAR controller can be set in Regulation or Maintained mode.

Lower Reg Limit (MVAR), **Base Set Point (MVAR)**, and **Upper Reg Limit (MVAR)** are the three user set points for the VCS. The user can change any of these set points by clicking on an associated cell.

Requested Set point (MVAR) is the destination set point of the unit MVAR control in the VCS algorithm.

Exciter Under DRZC Control indicates whether DRZC detects the required conditions for VCS control, enabling the VCS unit MVAR control when on. The exciter must be running in voltage Droop mode for this status to be true.

Exciter Control in Progress indicates whether the DRZC is presently sending control pulses to raise/lower the MVAR set point of the turbine generator.

WIND FARM

This section describes the HMI functionality for a WF. The following are descriptions of each command and indication that will be available for a WF.

Run Command: This command will allow the user to enable the WF inverter.

Pause Command: This command will allow the user to temporarily disable the WF inverter.

Control Enable Disable: This command allows the user to enable or disable DRZC control of the WF inverter. When control is disabled, no manual or automatic commands can be issued to the inverter by the DRZC system. This command is made available so that when an outage or fault occurs, or maintenance is needed, the user can disable the WF inverter to ensure that the DRZC system takes no control action.

Control Status: This status will be the feedback from the controller indicating whether the WF inverter is enabled or disabled for DRZC control.

Communication Status: The communication status between the DRZC system and the WF inverter is monitored. If the communication channel is unhealthy the DRZC will stop attempting control until communication is returned.

Asset Available to Dispatch: Apart from communication monitoring, the DRZC system will also monitor internal failures and errors of the inverter. If the inverter is unable to produce power because of an internal failure or error, the DRZC system will disable it and not control it.

Active Power Control Mode Command: All renewable assets will be able to operate either in Manual mode or in Automatic mode from the DRZC system in terms of active power. In Manual mode, the user can provide a set point from the DRZC system HMI, whereas in Automatic mode the DRZC system calculates the set point for an asset based on system requirements. This command allows the user to place an inverter in Automatic mode or Manual mode.

Active Power Control Status: This status will be the feedback from the DRZC system indicating whether the WF inverter is in Automatic mode or Manual mode for active power production.

Present Active Power: This field will indicate the current active power output of the inverter.

Active Power Set Point Command: This field will allow the user to enter the active power set point for the inverter if the inverter is operating in Manual mode. The minimum and maximum allowable value in this field will be 0 (zero) or the value displayed in active power limit field, respectively.

Active Power Set Point: This field will indicate the set point that the DRZC system issued to the inverter. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Active Power Set point Command field if in Manual mode.

Active Power Limit: This field will show the maximum active power limit based on wind speed and rating of the WF inverter.

Allowed Capacity Limit: This set point limits the output of the WF to a percent of its active power limit. This will increase stability of the WF output negating small wind speed fluctuations.

Reactive Power Control Mode Command: All renewable assets will be able to operate either in Manual mode or in Automatic mode for DRZC reactive power control. In Manual mode, the user can provide a set point from the DRZC system HMI. In Automatic mode, the DRZC calculates the set point for an asset based on system requirements. This command allows the user to place an inverter into Automatic mode or Manual mode.

Reactive Power Control Status: This status will be the feedback from the DRZC system controller indicating whether the WF inverter is in Automatic mode or Manual mode for reactive power production.

Present Reactive Power: This field will indicate the current reactive power output of the inverter.

Reactive Power Set Point Command: This field will allow the user to enter the reactive power set point for the inverter if the inverter is operating in Manual mode. The minimum and maximum allowable value in this field will be 0 (zero) or the value displayed in reactive power limit field, respectively.

Reactive Power Set Point: This field will indicate the set point that the DRZC system issued to the inverter. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Reactive Power Set point Command field if in Manual mode.

Reactive Power Limit: This field will show the DRZC system calculated reactive power limit imposed on the inverter.

Wind Speed: This field will show the current wind speed for the WF.

Wind Speed Forecast: This field will show the forecast wind speed for the WF.

BESS

This section describes the HMI functionality for a BESS. The following are descriptions of each command and indication that will be available for a BESS.

Control Command: Through this command, the user can enable or disable the BESS. When the BESS is disabled, no control command, manual or automatic, can be issued to the BESS controller by the DRZC system. This command will be available so that when an alarm or fault occurs, or maintenance is needed, the user can disable the BESS to ensure that no control action is issued by the DRZC system.

Control Status: This status will be the feedback from the DRZC system indicating whether the BESS is enabled or disabled. When an asset is disabled for the DRZC system, it is not included in the DRZC system control algorithms.

Communication Status: The communication status between DRZC system and BESS. If the communication channel is unhealthy, the DRZC will not attempt control of the BESS until communication is restored.

Breaker Status displays the status of the battery breaker as Open, Closed, or in alarm.

Reset Alarm Command resets alarms stored by the DRZC and shown on the HMI.

Asset Available to Dispatch: Apart from communication monitoring, the DRZC system will also monitor the BESS internal failures and errors. If the inverter cannot produce power because of an internal failure or error, causing the maximum charge and maximum discharge power to go to 0 (zero), the DRZC system will disable it and remove it from the active and reactive power control loops.

Active Power Control Mode Command: All renewable assets will be able to operate in either Manual mode or Automatic mode from the DRZC system in terms of active power. In Manual mode, the user can provide a set point from the DRZC system HMI, whereas in Automatic mode the DRZC system calculates the set point for an asset based on the system requirements. This command allows the user to place the BESS into Automatic mode or Manual mode.

Active Power Control Status: This status is the feedback from the DRZC system that will indicate whether the BESS is in Automatic mode or Manual mode for active power.

Present Active Power (kW): This field will indicate the present active power output of BESS.

Active Power Set Point Command: This field will allow the user to enter the active power set point for the BESS if the BESS is operating in Manual mode. Because the BESS can source or sink active power, the user can use this field to input a charge (negative value) or discharge (positive value) set point for the BESS. The input value of this field is limited by the value displayed in the **DRZC system calculated charge** and **discharge power fields**.

Operating Active Power Set Point: This field will indicate the set point that the DRZC system has issued to the BESS. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Active Power Set Point Command field if in Manual mode.

Active Power Discharge Limit: The DRZC system will read the maximum possible discharge rate from the BESS local controller and show it here. A reduced discharge power from the battery rating is an indication of battery cell failure or failure of an inverter. It is recommended that during restart the battery's maximum safe discharge rate is used to provide the most help with load pickup.

DRZC Calculated Discharge Limit: This field will display the DRZC calculated discharge limit imposed on the BESS. The DRZC system has the functionality to curtail the discharge power for the BESS if it is approaching the minimum acceptable state of energy for during the restart process.

Reactive Power Control Mode Command: All DER assets will be able to operate in either Manual mode or Automatic mode from the DRZC system in terms of reactive power. In Manual mode, the user can provide a set point from the DRZC system HMI. In Automatic mode, the DRZC system calculates the set point for an asset based on the system requirements. Through this command, the user can put the BESS into Automatic mode or Manual mode. If an asset is in Manual mode for reactive power, it will be removed from the reactive power control loop.

Reactive Power Control Status: This status will be the feedback from the DRZC system indicating whether the BESS is in Automatic mode or Manual mode for reactive power

Present Reactive Power: This field will indicate the present reactive power output of the BESS.

Reactive Power Set Point Command: This field will allow the user to enter the reactive power set point for the BESS if the BESS is operating in Manual mode. Because the BESS can source or sink reactive power, the user can use this field to input a value for sinking (negative value) or sourcing (positive value) reactive power from the BESS. The input value of this field is limited by the value displayed in the **Reactive Power Limit field**.

Operating Reactive Power Set Point: This field will indicate the set point that the DRZC system has issued to the BESS. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Reactive Power Set Point Command field if in Manual mode.

V Setpoint: This setpoint allows manual control of the voltage output of the BESS.

F Setpoint: This setpoint allows manual control of the frequency output of the BESS.

Present State of Charge: This field will display the present SOC read from the BESS controller.

Full Charge Energy Available: This field will display the capacity of the BESS. Along with charge and discharge power, this value is also an indicator of the health of the BESS; a value lower than nominal in this field indicates unhealthy battery cells or inverters.

Energy Limit Commands, Deadband Values, and Control Deadbands: The SEL DRZC system will allow the user to limit the BESS charge or discharge. On the DRZC system HMI, the following SOE limits can change the BESS behavior for different operation scenarios:

- **Full Charge Energy Limit Command:** This limit will define the upper extreme for charging the battery. The maximum allowable value in this field will be limited by the value shown in the full charge energy available field, whereas minimum allowable value could be 90 percent of full charge energy available. This limit will come into effect only if the BESS is charging, e.g., if there is a requirement to charge the battery because of a tie line control error; it will be available to charge until the present SOE hits this limit.
- **Minimum Charge Energy Limit Command:** This limit will define the extreme for discharging the battery. The maximum allowable value in this field will be limited by 50 percent of the full charge energy limit command field. The minimum allowable value will be defined by the manufacturer minimum healthy charge level. This limit will stop discharge once the present SOC hits this limit.
- **Minimum Charge Energy Limit Command:** This limit is similar to Minimum charge energy limit but is a more conservative limit used only if the DRZC is operating during transmission grid re-energization and there are additional sources connected to the transmission grid outside the DRZ. It can also be set on the HMI

PHOTOVOLTAIC

This section describes the HMI functionality for one PV unit. The following are descriptions of each command and indication that will be available for a PV.

Control Command: This command will allow the user to enable or disable the PV inverter. When the PV inverter is disabled, no manual or automatic control command can be issued to the inverter by the DRZC system. This command is made available so that when an outage or fault occurs, or maintenance is needed, the user can disable the PV inverter to ensure that the DRZC system takes no control action.

Control Status: This status will be the feedback from the controller indicating whether the PV inverter is enabled or disabled. When an asset is disabled for the DRZC system, it is not considered to be in the DRZC system control loops.

Communication Status: The communication status between the DRZC system and the PV inverter is monitored. If the communication channel is unhealthy the DRZC will stop attempting control until communication is returned.

Asset Available to Dispatch: Apart from communication monitoring, the DRZC system will also monitor internal failures and errors of the inverter. If the inverter is unable to produce power because of an internal failure or error, the DRZC system will disable it and remove it from the active and reactive power control loops.

Active Power Control Mode Command: All renewable assets will be able to operate either in Manual mode or in Automatic mode from the DRZC system in terms of active power. In Manual mode, the user can provide a set point from the DRZC system HMI, whereas in Automatic mode the DRZC system calculates the set point for an asset based on system requirements. This command allows the user to place an inverter in Automatic mode or Manual mode.

Active Power Control Status: This status will be the feedback from the DRZC system indicating whether the PV inverter is in Automatic mode or Manual mode for active power production.

Present Active Power: This field will indicate the current active power output of the inverter.

Active Power Set Point Command: This field will allow the user to enter the active power set point for the inverter if the inverter is operating in Manual mode. The minimum and maximum allowable value in this field will be 0 (zero) or the value displayed in active power limit field, respectively.

Active Power Set Point: This field will indicate the set point that the DRZC system issued to the inverter. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Active Power Set point Command field if in Manual mode.

Active Power Limit: This field will show the maximum active power limit based on irradiance, temperature, and rating of the PV inverter.

Reactive Power Control Mode Command: All renewable assets will be able to operate either in Manual mode or in Automatic mode for DRZC reactive power control. In Manual mode, the user can provide a set point from the DRZC system HMI. In Automatic mode, the DRZC calculates the set point for an asset based on system requirements. This command allows the user to place an inverter into Automatic mode or Manual mode.

Reactive Power Control Status: This status will be the feedback from the DRZC system controller indicating whether the PV inverter is in Automatic mode or Manual mode for reactive power production.

Present Reactive Power: This field will indicate the current reactive power output of the inverter.

Reactive Power Set Point Command: This field will allow the user to enter the reactive power set point for the inverter if the inverter is operating in Manual mode. The minimum and maximum allowable value in this field will be 0 (zero) or the value displayed in reactive power limit field, respectively.

Reactive Power Set Point: This field will indicate the set point that the DRZC system issued to the inverter. This field will show either the set point calculated by the DRZC system if in Automatic mode, or the set point entered in the Reactive Power Set point Command field if in Manual mode.

Reactive Power Limit: This field will show the DRZC system calculated reactive power limit imposed on the inverter.

Note: the user access level (ex. Operator vs. Engineer vs. Administrator) required to change the set points throughout the HMI section is decided by the customer.

6.13.2 Alarm Management and Operator Logs

Active alarm screens visually indicate the state of alarms, including time stamp, acknowledged, and return-to-normal indications.

Operator action log screens contain tabular display that documents every action a user takes while logged in to the system, including security items such as incorrect password entries or attempted unauthorized actions.

SECTION 7 OVERVIEW OF SEL HARDWARE COMPONENTS

7.1.1 SEL-3355 Computer

Designed as a server-class computer, the tough SEL-3355 Computer is built to withstand harsh environments in utility substations and industrial control and automation systems. By eliminating all moving parts, including rotating hard drives and fans, and using error-correcting code (ECC) memory, SEL computers have over ten times the mean time between failures (MTBF) of typical industrial computers. Designed, manufactured, and tested to the same standards as our protective relays, every SEL-3355 comes with an unprecedented ten-year, worldwide SEL warranty.

Table 7.1: SEL-3355 Implementation

Node	Description	Comment
SEL-3355 as Engineering workstation	This node deploys all configuration software from various suppliers for entire microgrid control system and any other software required to change the configuration of various components like relays, inverters, BMS, etc. With proper user access, one can change/edit the settings.	
SEL-3355 as Operator workstation	This node deploys DRZC/DRZC HMI software to view real-time data/alarms/trends of entire distributed restart zone. Operator can view/change set points on real-time basis. ACSELERATOR TEAM® SEL-5045 Software is used to collect Sequence of Events (SOEs) from the DRZC and each protective relay. Engineers can use these data for any post-event analysis. This node will also deploy MS SQL-based historian to collect data from each IED/DER and DRZC controller that can be retrieved by any SQL client or SQL queries for business analysis. SEL ES can provide either Microsoft Windows workstation (64 bit) or Microsoft Windows server-based operating system.	

Node	Description	Comment
SEL-3355 as Firewall and VPN security gateway	The SEL-3355 configured with SEL-Unified Threat Management (UTM) is a state-of-the-art firewall and advanced routing platform. The SEL-3355 offers flexible hardware options with the ability to have redundant power supplies and up to 10x1 gigabit Ethernet ports with built-in diagnostic capabilities. SEL-3355 supports high availability using Common Address Resolution Protocol for resilient multi-WAN connections, load balancing, and failover modes. The SEL-3355 has advanced VPN capabilities and captive portal support for secure authorization and access control. Moreover, the support for IPsec enables secure and encrypted message exchange between the SEL-3355 and other devices. Additionally, built-in intrusion detection/prevention systems secure operational technology networks against advanced cyberattacks using rules and signature matching. Core features are listed below. • Dynamic routing • Stateful inspection firewall • Multi-factor authentication • Captive portal • Web proxy and access control list • Traffic shaper • Advanced virtual private network • High availability • Intrusion detection and prevention • Build-in reporting and monitoring tools • Centralized network flow monitoring • DHCP server and relay • Encrypted configuration backup • Granular control over state table • Network address translation	

7.1.2 SEL-3555 RTAC

The SEL-3555 RTAC is a powerful automation platform that combines the best features of the high-performance 64-bit architecture, embedded microcomputer, embedded real-time operating system, and secure communications framework with IEC 61131-3 PLC programmability.

Table 7.2: SEL-3555 Implementation

Node	Description	Comment
SEL-3555 as DRZC	This device is the heart and brain of the entire DRZ. It runs powerful algorithms to maintain voltage and frequency stability during islanded mode, active/reactive power sharing, load shedding, load restoration, etc.	

Node	Description	Comment
SEL-3555 as Central front end processor	This FEP provides great flexibility for the scalability of the entire microgrid distribution network by taking communication burden off of the DRZC, allowing more devices to be controlled. It is the primary interface device for all communications/data concentrating/traffic segregation of high-speed and low-speed data.	
SEL-3555 as HMI Gateway	The HMI GW receives and transmits data between the DRZC and the HMI. It changes protocols between the two devices from NGVL to DNP3 and preforms some HMI interface functions.	

7.1.3 SEL-2240 Axion I/O Interface

The Axion will be implemented as an FEP for the DRZC system. The Axion is a fully integrated, modular I/O and control solution ideally suited for utility and industrial applications. It combines the communications, built-in security, and IEC 61131 logic engine of the SEL RTAC family with a durable suite of I/O modules that provide high speed, deterministic control performance. Whether your application calls for a remote terminal unit (RTU) or an ultra-rugged PLC, the SEL-2240 will be a good match. All Axion modules are rated from –40 degrees to +85 degrees Celsius and can optionally include conformal coating. The system is designed to be flexible; use the right combination of modules and nodes in almost any arrangement to suit the job. The SEL-2244-3 Digital Output Module has substation duty contacts (30 A make, 6 A carry capacity) to provide reliable operation and flexible application.

At present SEL ES has assumed one 10-slot chassis and a few DI/DO cards at each site. Requirement of these modules can be optimized after receipt of complete engineering details and the I/O needs of each substation, etc.

7.1.4 SEL-2740S Software-Defined Network Switch

The SEL-2740S Software-Defined Network Switch operate on OT-SDN technology implementing a deny by default architecture. The flow table configuration allows matching rules on fields in Layer 1 through Layer 4 of the packet. Only configured flows are forwarded. Software-defined networking (SDN) improves cybersecurity by eliminating attack-prone networking features like MAC tables, the Rapid Spanning Tree Protocol (RSTP), and cast types. SDN also improves failover performance and can be managed and validated simply, using the SEL-5056 Software-Defined Network Flow Controller software. The switch offers the same reliability found in SEL protective relays and is designed for harsh environments. The SEL-2740S has IEEE 1613 compliance, KEMA certification and –40° to +85°C (–40° to +185°) operating range.

7.1.5 SEL-2730M Managed 24-Port Ethernet Switch

The SEL-2730M Managed 24-Port Ethernet Switch is designed for the harsh conditions found in the energy and industrial environments. The switch supports communications infrastructure built for engineering access, supervisory control and data acquisition (SCADA), and real-time data communications, while offering the same reliability found in SEL protective relays. The SEL-2730M meets or exceeds the IEEE 1613 (Class 2), IEC 61850-3, and IEC 60255 industry standards for vibration, electrical surges, fast transients, extreme temperatures, and electrostatic discharge for communications devices in electrical substations. Details on SEL-2730M functionality is discussed in Section 7.

7.1.6 SEL-3060 Ethernet Radio

The SEL-3060 Ethernet Radio is a multipurpose Ethernet radio for distribution automation wireless applications, including SCADA and engineering access. The SEL-3060 provides communications within a 15-mile range, operating in the 900 MHz license-free industrial, scientific, and medical (ISM) frequency band. The SEL-3060B has a 10-mile range and operates in the 2.4 GHz license-free ISM band. The SEL-3060 offers unmatched ruggedness and is backed by the SEL ten-year, worldwide product warranty. This radio supports advanced encryption standard (AES) 128-bit encryption for secure data transfer and IEC 61850 GOOSE messages with 6–12 ms point-to-point latency.

Note: The SEL-3060 is not currently included in the design but could be implemented for systems lacking communication infrastructure as an alternative to fiber optics.

7.1.7 SEL-2488 Satellite-Synchronized Network Clock

The SEL-2488 Satellite-Synchronized Network Clock receives Global Navigation Satellite System (GNSS) time signals and distributes precise time via multiple output protocols, including IRIG-B and the Network Time Protocol (NTP). The SEL-2488 provides Parallel Redundancy Protocol (PRP) support as a dual-attached node (DAN) device for NTP time distribution. With an optional upgrade, the SEL-2488 can serve as a Precision Time Protocol (PTP) grandmaster clock, as defined by IEEE 1588. The advanced capabilities of the SEL-2488 make it well-suited for demanding applications, like synchrophasors, and for substations with multiple time synchronization requirements.

7.1.8 SEL-2407 Satellite-Synchronized Clock

The SEL-2407® Satellite-Synchronized Clock receives GNSS time signals and distributes precise time via IRIG-B. The SEL-2407 provides time synchronization, allowing precisely time stamped actions to be recorded in Sequential Event Recorders (SER) and SOEs for devices in the system.

SECTION 8 RISKS AND MITIGATION PLANS

Table 3 summarizes the risks observed by SEL ES, the cause for risk, and the mitigation plan that the project implementation teams should be aware of.

Table 3: Risks and Mitigation Plans

Risk	Impact	Priority	Description	Mitigation Plan
Voltage Support	Technical	High	The voltage support at the load substation is concern especially after the first substation is energized and during subsequent load substation energization, significant voltage drop may cause system wide outage.	1. A voltage-based load-shedding scheme is proposed, along with transient stability study for transformer energization and HIL testing is recommended.
Mock testing	Technical and Schedule	High	Availability of third-party equipment (WF models, generator models, inverters,) for testing.	SEL ES will actively work with partners involved for the Mock testing (Integration and communication testing with other systems). National Grid and DNO support will also be required.
Finalization of DERs, other assets and one-line diagram	Technical	High	The DER and other asset capabilities and requirements of other assets like BEMS are yet to be confirmed. Lack of this information or incomplete information (assumptions) will have impact on final design during implementation which might lead to changes to the overall design.	SEL ES can work with generation owners and other partners in reviewing, identifying, and defining the DER and generator assets during the 100% design stage.
Networking	Technical	High	Some of the control applications might require high-speed signals. Future projects requiring seamless islanding and/or high-speed load shedding in response to island event or DER loss after islanding will require high-speed communications.	SEL ES will work with National Grid and DNO in defining the use cases for the DRZC. Once the use cases are defined SEL will work with National Grid and DNO to weigh-in and distinguish between the existing network and the proposed network identifying the pros and cons of each.
RTDS modeling – data availability	Technical and schedule	High	Incomplete information or assumptions made in gathering data required for the RTDS model development can lead to inaccurate dynamic power system model.	SEL ES will share all the data required for RTDS model development and validation. These data will need to be collected from the responsible parties/partners during phase 2.

Schedule control	Commercial	High	Some aspects of the schedule are out of SEL control Certain schedule items are contingent upon contributors or partners other than SEL to provide information or perform tasks that can affect the SEL schedule.	SEL, National Grid UK and other partners must work collaboratively to achieve the overall project schedule goals. National Grid UK and DNOs should make sure all partners know and are responsible for deliverables deadlines.
Liquidated Damages	Commercial	High	Liquidated damages are an SEL risk due to some aspects of the schedule being out of SEL control. SEL deliverables can only be on time if all predecessors are on time. Some of the predecessors are for other partners to deliver.	National Grid UK and DNOs must protect SEL and all partner's interests with respect to others affecting the schedule.

SECTION 9 HARDWARE-IN-THE-LOOP TESTING

9.1 SYSTEM OVERVIEW

All SEL POWERMAX control systems with generation control features are tested using an HIL testing with RTDS system. The RTDS is a fully digital power system simulator capable of continuous real-time operation. It performs electromagnetic power system transient simulations with a typical time step of 50 microseconds using a combination of custom software and hardware. The RTDS is an ideal tool for thorough design, study, and testing of protection and control schemes. With a large capacity for both digital and analog I/O, physical protection and control devices can be connected to the RTDS to interact with the simulated power system for closed-loop testing. For this project, the SEL DRZC system shall be connected directly to the RTDS at SEL headquarters in Pullman, Washington.

For this project scope, SEL ES will perform HIL testing for SEL DRZC functions, and 25A scheme using RTDS.

Testing relay protection settings are not part of this scope of work. The following sections review RTDS hardware, testing philosophy, model development, and model validation.

9.2 HARDWARE

The RTDS hardware was designed specifically to perform hundreds of thousands of calculations in a real-time environment. To operate in real time, a 50-microsecond time step would require that all computations for the system solution be completed in less than 50 microseconds. The overall network solution technique employed in the RTDS is based on nodal analysis. The underlying solution algorithms are those developed by H. W. Dommel. The Dommel Algorithm allows two levels of parallel processing:

- Level One: Parallel processing of components connected to a common admittance matrix (i.e., within one subsystem).
- Level Two: Parallel processing of subsystems (i.e., decoupled admittance matrices).

The RTDS mimics the first level by using tightly-coupled processors within a rack to solve components connected to a common admittance matrix. The second level is implemented by using separate racks to solve different simulation subsystems.

In addition to being designed to execute the Dommel Algorithm in real time, the RTDS was designed to test physical protection and control equipment. One of the main considerations in testing physical devices is the I/O structure. To maximize the communications bandwidth and minimize the time required, the RTDS was designed to provide the most direct route possible for I/O to be passed from the processors performing the simulation to the I/O channels.

9.3 TESTING PHILOSOPHY

RTDS testing is performed to validate the SEL DRZC functionality as designed. The RTDS is connected to the SEL DRZC, as shown in Figure 9.1, allowing for closed-loop validation during the customer FAT. The test results can be used to achieve the following:

- Validate different DER control strategies employed by the SEL DRZC.
- Verify that system stability is maintained during different contingency events and modes of operation.

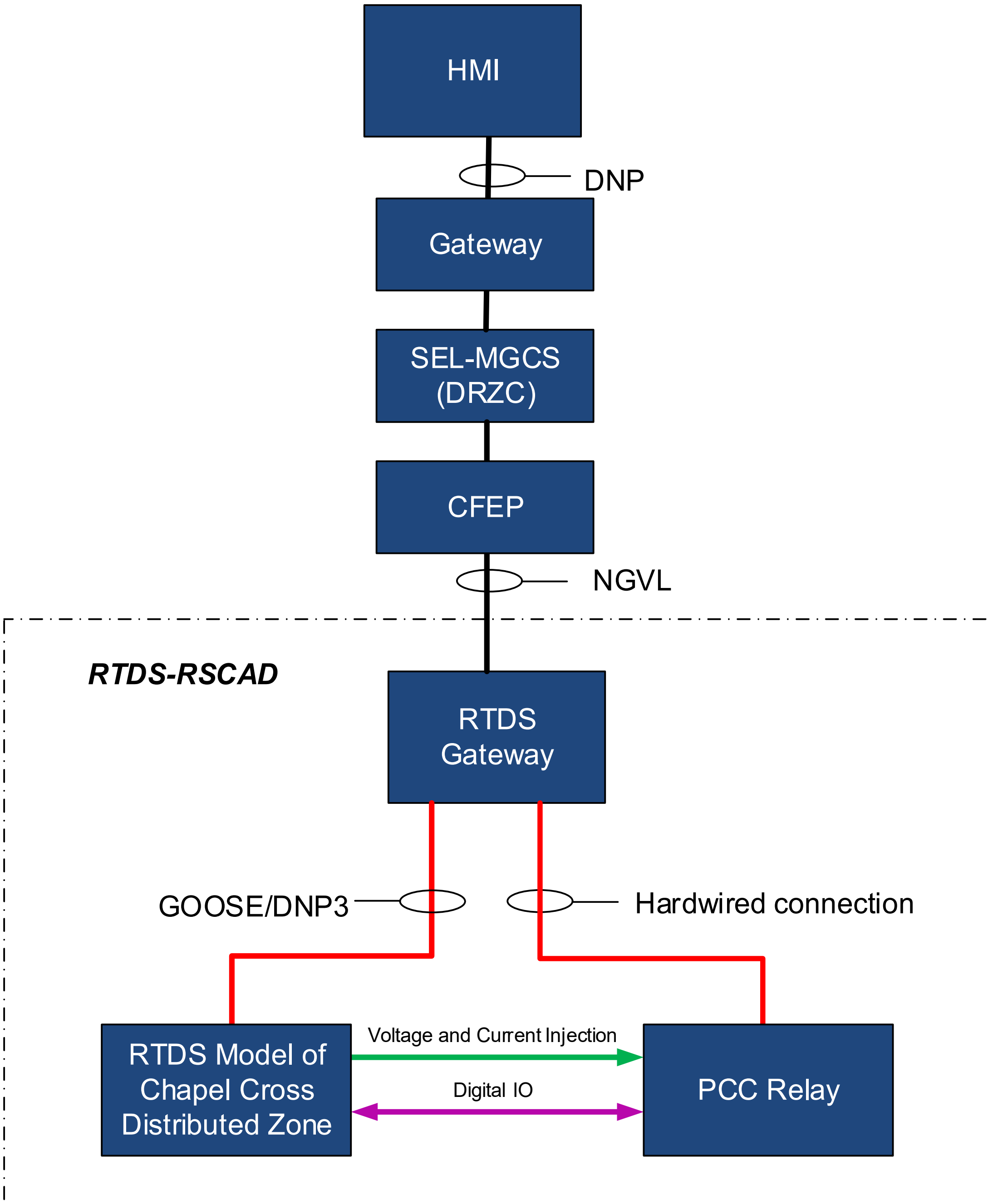


Figure 9.1: Closed-Loop Simulation

9.4 Model Development

The model developed for RTDS testing will represent the complete system based on the simplified one-line drawing approved for the case study. For Chapelcross the RTDS model may be provided by National Grid, but SEL ES will run and verify the model in house at SEL. The data required for modeling different power system components (generators, transformers, distribution lines and cables, and loads) shall be provided by National Grid or the network operator. SEL ES makes appropriate assumptions based on its previous modeling experience at places where there is insufficient data. The RTDS has certain limitations with the total number of nodes and total number of power system components that can be fit into the model. Because of these limitations, wherever necessary, certain components of the system will be grouped with the least loss of accuracy for model development. To create an RTDS model, SEL ES will use customer-provided data from any existing power system software model.

For this project, SEL ES shall use the following data provided for the RTDS model:

- Approved simplified one-line drawing of the Chapelcross system
- Data provided as per the Request for Information (RFI)
- Data sheets provided for different equipment
- Any short-circuit or electrical model and report

Transformer models are available in two- or three-winding configurations and are based on the theory of mutual coupling. The windings can be modeled as either wye-grounded, wye-ungrounded, or delta. Automatic online tap changers are also available for use. The transformers can be modeled as either an ideal or non-ideal type. Ideal will have no magnetizing inductance and will be represented by the specific leakage reactance and the non-ideal will include a magnetizing branch.

DER models are custom built based on the DER equipment manufacturer specifications and will be finalized once 100 percent of the design is completed.

The various loads throughout the system can be modeled in several ways depending on the type of load. They can be modeled as a static ZIP (constant impedance, constant current, constant power) load or as a physical machine load if it is an induction motor or a synchronous motor. Induction or synchronous motor loads are based on generalized machine theory. Because of the limitations of nodes and available computational power, certain loads will be grouped, as necessary.

9.5 MODEL VALIDATION

Model validation is a very critical step in the process of model development. SEL ES performs the model validation on a base-case topology, which is the typical customer power system topology.

SEL ES performs the following for model validation:

- Steady-state load flow: This includes comparison of the power flow (active power [P], reactive power [Q], bus voltage magnitude [V], and phase angle [θ]) between the RTDS model and the customer-provided model, or the actual power flow observed on the customer system for a base-case topology.
- Dynamic study validation: This includes comparison of the dynamic response of different generators (generator speed, rotor angle, P, Q, and V) between the RTDS model and the customer-provided model for a base-case topology when exposed to different faults.

APPENDIX A SIMPLIFIED SINGLE-LINE DRAWING

021416.000.00_NationalGrid_SLD_20200901.pdf

APPENDIX B COMMUNICATIONS ARCHITECTURE

021416.000.00_National_Grid_Comm_Arch_20200901.pdf

APPENDIX C DATA FLOW DIAGRAM

021416.000.00_National_Grid_DFD_20200901.pdf

APPENDIX D DRZC FLOW CHART

Attachment#4_021416.000.00_National_Grid_Flow_Chart