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Functional Specification

Protection, Control and Metering

Revision History						
Revision	**Date**	**Description**	**Originator**	**Reviewer**	**Checker**	**Approver**
R0	30-05-2022	First Issue, for industry feedback	A R Perkin DNV	Vitali Garon, Ray Doyle, Daniele Giustini, Martin Kavanagh	James Staunton Leon Notkevich, Neil Cowap	Aidan Corcoran, Richard Blanchfield
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1 SCOPE

This specification describes the functional requirements for protection, control and metering (PCM) devices and systems associated with offshore windfarms to be owned and operated by EirGrid.

This specification should be read in association with the project specific contestable works pack and project documentation and all other relevant functional specifications as issued by EirGrid.

For the purpose of this specification the term Customer shall refer to Offshore Wind Power Developers, Independent Power Producers responsible for the design and build of assets to be handed over to EirGrid.

The Customer shall submit a completed set of the appropriate Technical Schedules for EirGrid review. Note that most parameters of the Technical Schedule shall be completed during the design by Customer in consultation with EirGrid.

Each windfarm project is divided into distinct location-based sections, according to which the protection, control and metering shall be similarly delineated:

- Windfarm, thus the turbines and array cables
- Offshore platform (OSP), including the offshore substation (OSS)
- Export cable, linking the OSP with the onshore installation
- Onshore compensation compound (OCC), at which certain terminal equipment is located, and where power produced is injected into the ESB Networks grid

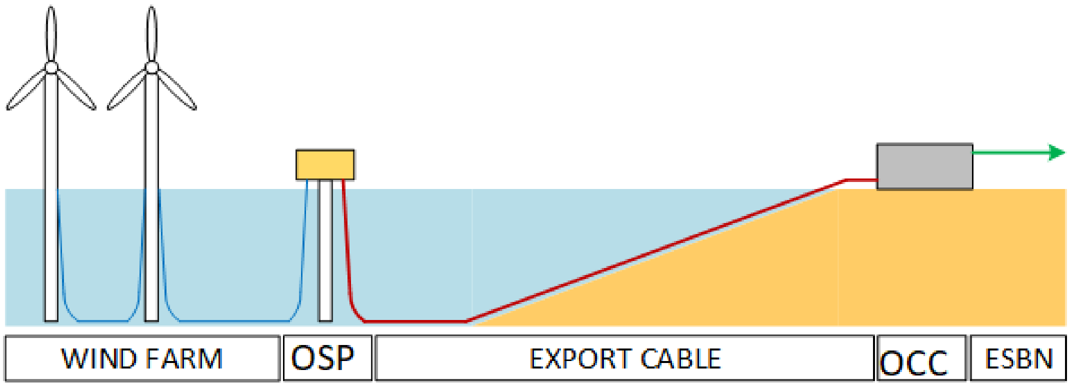

Figure 1 – Windfarm Project Delineation

1.1 ABBREVIATIONS

AC	Alternating current
AIS	Air Insulated Switchgear
ALF	Accuracy Limit Factor
AR	Auto-reclose
AVR	Automatic Voltage Regulator
BBP	Busbar Protection
BCP	Bay Control Point
BCU (or BYC)	Bay Control Unit (or Bay Controller)

CB	Circuit Breaker
CBF	Circuit Breaker Fail
CT	Current Transformer
CVT	Capacitor Voltage Transformer
DC	Direct current
E/F	Earth Fault
EHV	Extra High Voltage (220kV or above in this document)
FAT	Factory Acceptance Test
GIS	Gas Insulated Switchgear
GOOSE	Generic Object-Oriented Substation Event
GWY	Gateway
HMI	Human Machine Interface
HV	High Voltage (above 52kV but below transmission voltage like 220kV in this document)
IED	Intelligent Electronic Device
ITP	Inspection and Test Planning
IT	Instrument Transformer
LAN	Local Area Network
LCC	Local Control Cabinet
MCB	Miniature Circuit Breaker
MCCB	Moulded Case Circuit Breaker
MMS	Manufacturer Messaging Specification
N/C	Normally Closed
N/O	Normally Open
OCC	Onshore Compensation Compound
OEM	Original Equipment Manufacturer
OSP	Offshore Platform
OSS	Offshore Substation
OT	Operational Technology
O/C	Overcurrent
PCM	Protection, Control, Metering
PCP	Plant Control Point
POTT	Permissive Overreach Transfer Trip
PUTT	Permissive Underreach Transfer Trip
RCD	Residual Current Detection
RCP	Remote Control Point
RDRE	R = protection Related DRE = Disturbance Recorder
RPT	Repeater
SAT / SIT	Site Acceptance / Integration Test
SCADA	Supervisory Control and Data Acquisition

SCP	Substation Control Point
SCS	Substation Control System
SSS	Shore Substation (the same as onshore compensation compound)
VT	Voltage Transformer
VTS	Voltage Transformer Selection
WTG	Wind Turbine Generator

2 Reference Information

2.1 Definitions

2.2 Governing legislative documents

Listing of governing legislative documents, EirGrid specifications and standards in sections 2.2; 2.3 and 2.4.

The list below is non-exhaustive and offshore specific:

Document Number	Document Title
Act No. 18/1987	Safety, Health and Welfare (Offshore Installations) Act, 1987
S.I. No. 274/1990	Safety, Health and Welfare (Offshore Installations) Act, 1987 (Commencement) Order, 1990.
S.I. No. 16/1991	Safety, Health and Welfare (Offshore Installations) (Operations) Regulations, 1991.
S.I. No. 15/1991	Safety, Health and Welfare (Offshore Installations) (Life-Saving Appliances) Regulations, 1991.
S.I. No. 14/1991	Safety, Health and Welfare (Offshore Installations) (Emergency Procedures) Regulations, 1991.
S.I. No. 13/1991	Safety, Health and Welfare (Offshore Installations) (Installation Managers) Regulations, 1991.
S.I. No. 429/1997	Petroleum and Offshore Exploration (Transfer of Departmental Administration and Ministerial Functions) Order, 1997
S.I. No. 110/2000	Petroleum and Offshore Exploration (Transfer of Departmental Administration and Ministerial Functions) Order, 2000.
S.I. No. 389/2001	Petroleum and Offshore Exploration (Transfer of Departmental Administration and Ministerial Functions) Order, 2001.
S.I. No. 358/2009	European Communities (Control of Dangerous Substances from Offshore Installations) Regulations 2009
S.I. No. 819/2004	Organisation of Working Time (Inclusion of Offshore Work) Regulations 2004

2.3 EirGrid Specifications

This functional specification shall be read in conjunction with other EirGrid functional specifications.

2.4 International and Irish Standards, Codes and Industry Practices

Document Number	Document Title
IEC 60255	Measuring relays and protection equipment
IEC 60529	Degrees of protection offered by enclosures (“IP Code”)
IEC 60617	Graphical symbols for drawings
IEC 60870-5	Telecontrol equipment and systems
IEC 60947	Low voltage switchgear and controlgear
IEC 61000	Electromagnetic compatibility
IEC 61131-3	Programmable controllers – programming languages
IEC 61850	Communications protocols for IEDs in electrical substations (Edition 2)
IEC 61869	Instrument transformers
IEC 62439	Industrial communication – high-availability automation networks
IEEE 37.94	Standard for N*64kbps optical fibre interfaces
EN 55011	Industrial, scientific and medical equipment – RF disturbance characteristics – Limits and methods of measurement

The above list of standards is not exhaustive. All relevant Irish, IEC, IEEE standards shall be complied with.

3 General Requirements

3.1 Derogation Procedure

The protection, control and metering systems (and their installation and commissioning) shall comply with this Specification. Where deviations are proposed in the design the Customer shall submit a formal Derogation Request outlining an explanation of why the non-compliance is expected and any additional information to support the request for EirGrid to consider. Further information is outlined in EirGrid’s Derogation Process OFS-GEN-24.

3.2 Control Methodology

Control and monitoring of the substations, via the protection, control and metering systems, shall be to the Substation Control System architecture, in accordance with the OFS-GEN-015 Functional Specification for SCADA and Telecommunications.

The Local Control Cubicles (LCCs) and the associated BCUs shall serve as the designated points for locking out and tagging. LCC devices shall be suitable to apply locks for Lock Out Tag Out (LOTO).

3.2.1 OPERATOR CONTROL AND MONITORING

The control levels for operators are described in OFS-GEN-015 Functional Specification for SCADA and Telecom and, comprises four levels (Equipment Level, Bay Level, Substation Level (onshore and offshore), Control Room Level (onshore).

3.2.2 NON-OPERATOR CONTROL

Certain automated commands shall be incorporated into protection and control systems, including:

- Circuit breaker protection trip
- Circuit breaker auto-reclose (if required)
- Automatic changeover
- Tap change raise / lower

The source of such commands shall be in accordance with the placement of their respective devices.

3.2.3 CONTROL POINT SELECTION

A series of selection switches, colloquially termed “Local-Remote”, shall be used to cascade control from the plant level upwards to the highest level (NCC). The principle is that in the Local state, all upstream controls shall be disabled, and in the Remote state, control is passed one level upwards. This is shown schematically:

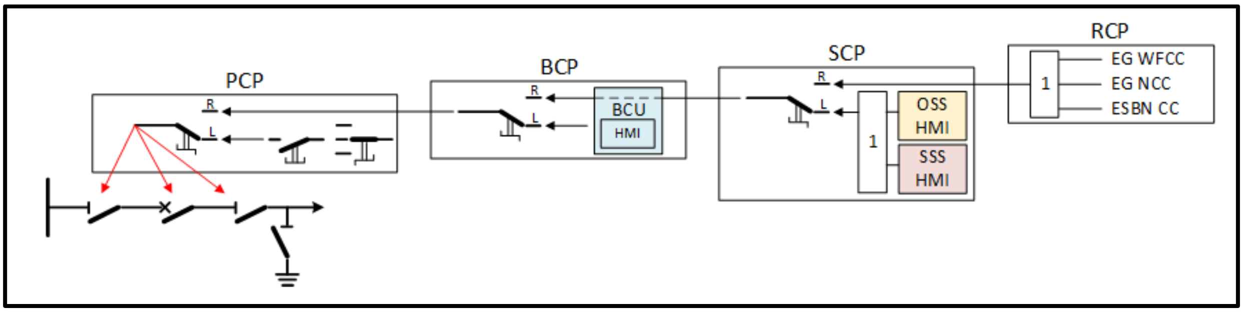

Figure 2 – Control Point Selection Philosophy

Where:

- PCP : Plant Control Point (equipment level)
- BCP : Bay Control Point (bay level)
- SCP : Substation Control Point (offshore and onshore HMIs)
- RCP : Remote Control Point (control rooms, onshore)

Note that although the symbol for a mechanical (rotary) switch is used to differentiate between Local and Remote in the diagram, the functionality may be achieved by various means, e.g., a dedicated L/R button on an IED or a programmed button on an HMI display screen.

Protection and emergency pushbutton trip commands shall not be impeded by Local-Remote switch functions. Similarly, plant status signals monitored by the BCUs and passed to the upper control levels shall not be interrupted by the position of any Local-Remote switch / function.

3.3 PROTECTION PHILOSOPHY

3.3.1 FUNDAMENTALS

Protection and control shall be arranged in discrete circuit-specific schemes. Further, the envisaged requirements of protection and control devices or schemes shall serve as inputs to the design and specification processes of related equipment, notably instrument transformers and wiring interfaces with the switchgear.

Protection and control schemes shall conform with the following fundamental principles:

- Speed – to isolate abnormal events / conditions as rapidly as possible
- Reliability – to always operate when called upon to do so
- Security – to remain stable for external / extraneous conditions
- Selectivity – to trip the least number of circuit breakers required to isolate a given abnormality

The following philosophies shall be adhered to when preparing the requirements for protection and control:

- Protection schemes shall overlap, ensuring that no section of the power system is left unprotected
- Each bay shall be provided with one or more protection IEDs and a bay control IED which together shall perform the P&C functions for that bay. This is reflected in Figure 3.
- EHV circuits shall be protected by dual-main IEDs, one-unit type and one non-unit protection function, with a number of complementary backup functions
- HV circuits (HV/LV auxiliary transformers) shall be protected by dual -main IEDs, providing unit protection as their principal function, with a number of complementary backup functions
- EHV/HV busbars, where present, shall be provided with busbar differential protection, including 2 stage circuit breaker failure protection
- Unit protection shall operate and clear in-zone faults within 100ms, including circuit breaker operating time, under normal operational conditions.
- Non-unit protection of EHV and HV circuits shall be coordinated based on the results of appropriate grading studies, such that protection closest to the fault point operates as rapidly as possible, and protection furthest from the fault point is delayed incrementally.
- Auxiliary power distribution circuits shall be protected by ACBs, MCCBs or MCBs, in accordance with the expected loading, fault levels, and criticality
- ACB / MCCB / MCB ratings and operating curves shall be coordinated to ensure protection selectivity
- The providers of emergency power sources, for example, diesel generators, shall include comprehensive protection and control, commensurate with the rating and importance of the equipment

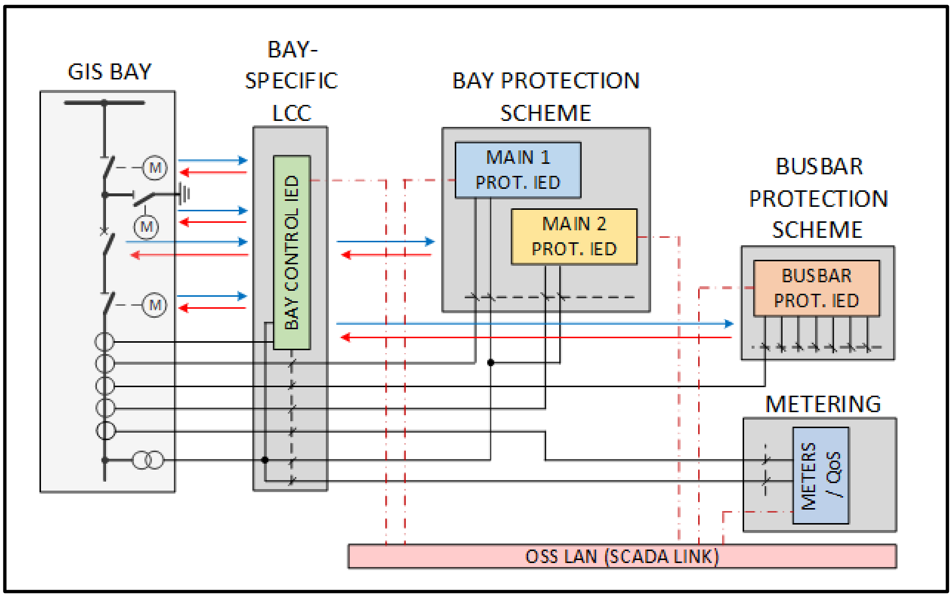

Figure 3 – Generic PCM Architecture, per Bay

Note: the diagram is generic and does not reflect EirGrid's design intent for the system or any particular bay type.

3.3.2 REDUNDANCY

Protection schemes are designed with inherent redundancy to ensure reliability of correct tripping when required. The following design practices shall be implemented:

- Dual-main plus backup architecture
  - Where the dual-main IEDs perform a materially equivalent function, they shall be supplied by unique manufacturers
- Where the feeder protection functionality is dependent on an external telecommunications system, the interfaces with any bandwidth management or multiplexing equipment shall be independent
- The presence of two fully independent trip circuits per circuit breaker
- The provision of two independent DC supplies to each scheme
- The provision of discrete current transformer cores per IED
- The provision of discrete voltage transformer windings per IED; alternatively, where single VT windings are present, sectionalised circuit arrangements shall be employed to prevent loss of voltage to multiple devices following an MCB trip
- The digital communications interface facilitating intra- and inter-bay messaging and SCADA MMS reporting shall be redundant

3.3.3 DESIGN PRINCIPLES

The design of EHV and HV protection schemes shall ensure that:

- No single failure within any protection and control system results in a loss of availability or loss of supply
- No failure within the protection and control scheme itself goes undetected and should be alarmed, including in SCADA.

The following conservative design practices that shall be followed:

- Application of thermostatically controlled panel heating to prevent formation of condensation

- Specification of IED circuit boards to be tropicalised (also known as “conformal coating”)
- Application of IEDs with comprehensive self-monitoring / diagnostic features
- Supervision of VT MCB statuses
- Supervision of CT circuits
- Supervision of DC supplies by application of auxiliary relays and IED binary inputs
- Application of a third auxiliary power supply (230Vac) for global alarm indication
- Adoption of test blocks or test terminal modules where disconnection of a circuit may readily be detected
- Monitoring of IED watchdogs and active alarm contacts

3.3.4 SUMMARY OF PROTECTION AND CONTROL FUNCTIONS

A summary of protection and control functions, based on the principles listed above, is provided in tabular and diagrammatic format, in Appendix A.

3.4 SYNCHRONISM CHECK

Synchronism check shall be applied to the closure of all circuit breakers where there exists the potential to couple two asynchronous systems, for example:

- Array cable feeder CB (*customer* responsibility)
- EHV/HV transformer
- Busbar coupling bays (only when applied)
- EHV export cable (both ends)

Synchronism check shall be performed by the applicable protection relays.

The synchronism check function shall include settable elements for delta voltage magnitude, delta voltage phase angle and delta frequency. A CB close command shall only be issued when all delta values are within the parameters set, for a set time period, and if system coincidence occurs within the overall window time.

Synchronism check shall be automated, not reliant on any intentional selection by an operator.

Synchronism check shall be bypassed under [live line, dead bus], [deadline, live bus] and [deadline, dead bus] conditions. The thresholds above which the line or bus are deemed to be live, and below which the line or bus are deemed to be dead, shall be settable. The BCU shall not interpret reactor ringdown on a de-energised line as a live condition. Declaration of any line / bus dead condition shall be supervised by the status of the relevant VT MCB.

3.5 INTERLOCKING

Interlocking shall be implemented to prevent operating / switching which has the potential to cause equipment damage, a safety hazard to personnel or violations of EirGrid operating protocols. A combination of hardwired and digital message-based interlocking, inter- and intra-bay, shall be implemented in each BCU, each LCC.

Hard-wired interlocks for inter-bay and station levels shall be used where they can be implemented and practical.

Interlocking shall be permissive, that is, a number of conditions shall be met to permit execution of a desired command (logical AND). (As opposed to the absence of one or more variables being sufficient to execute.) Interlocking on the basis of a single variable shall not be permitted. Where interlocking is dependent on one or more digital status bits (i.e. GOOSE messages), these shall be supervised by the GOOSE quality bit to ensure fidelity.

Where switchgear statuses are used for interlocking these shall be derived directly from the respective auxiliary contacts. Statuses shall be expressed in double-bit configuration, e.g., [52B & !52A] or [89A & !89B].

The status of interlocks shall be readily available in the BCU. In the event that a switching command is blocked by an interlock, this shall be flagged by the BCU for the benefit of the operator, logged in the device sequence of events recorder and flagged on the OSP and OCC HMIs .

Consideration shall be given to the provision of key switch-based interlock override functionality (interlock bypass). Where implemented, keys shall be safely stored by the authorised operator, and only used in exceptional circumstances, with alternative means of determining plant status conditions having been followed.

3.5.1 INTRA-BAY INTERLOCKS

The following interlocks shall be applied, over and above any mechanical means native to the switchgear:

- Switchgear shall only be permitted to operate if the unit or compartments have sufficient SF_6 gas pressure
- Circuit breakers shall only be permitted to close if:
  - The closing mechanism is fully charged. and
  - At least one trip circuit is functional (where trip circuit supervision is applied), and
  - All associated protection functions are available, and
  - The associated protection IEDs do not have any fault trip conditions present, and
  - If the CB is to be energized with the normal service voltage, the bay level Local-Remote switch is in the Remote position, or
  - If the equipment level Local-Remote switch is in the Local position, both disconnectors shall be open.
- Disconnectors shall only be permitted to close if:
  - Any adjacent earth switch is open, and
  - The CB is open.
- Disconnectors shall only be permitted to open if the associated CB is open
- Earth switches shall only be permitted to close if:
  - Disconnectors with the potential to energise the primary circuit are open, and optionally,
  - The primary circuit is potential free, when directly measured.
- Following the de-energisation of any capacitor bank, a 300s lockout timer shall commence:
  - The CB shall only be permitted to close following expiry of the lockout, and
  - Any live chamber gate key mechanism shall only permit release of the key following expiry of the lockout, and
  - When the key is removed from its mechanism, the CB shall be inviolably locked out.

3.5.2 INTER-BAY INTERLOCKS

Inter-bay interlocks shall be realized by means of hardwired contacts (preferred) and GOOSE messages between BCUs. GOOSE messages interlocking will be used only where hardwired interlocks are not practical. Interlocking concepts and programmed logic shall be submitted to EirGrid for review during design stage. A non-exhaustive list of interlocking examples is provided below:

- The EHV CB of any EHV/HV transformer shall only be permitted to close if the HV CB is open, and any earth switch on the HV side is open
- The HV CB of any HV/LV transformer shall only be permitted to close if the LV CB is open
- The HV CB of any EHV/HV transformer shall only be permitted to close if the EHV CB is closed
- The LV CB of any HV/LV transformer shall only be permitted to close if the HV CB is closed
- Transformer interlocking shall be supplemented with additional logic to permit CB operations when the respective busbar disconnectors are open, for maintenance purposes
- Any EHV/HV transformer earth switch shall only be permitted to close when the unit is disconnected from all potential points of supply
- If busbar earth switches are to be implemented:
  - These shall only be permitted to be closed if all disconnectors associated with the busbar section are open, and
  - Once the earth switch is closed, closure of any such disconnector shall be blocked.
- Conditional interlocks (i.e. “only operate circuit X if circuit Y is open / closed”) shall be determined as part of the site operating regime and programmed accordingly
- If the primary side CB of any transformer is tripped, the corresponding secondary and tertiary CBs shall be automatically tripped in response (“take with” function)

3.5.3 WIDE-AREA FUNCTIONS

When any operating command is executed by a BCU, an inhibit bit shall be set and published to the whole SCS, to prevent the execution of commands by other BCUs in the system, for a settable period (applies for both onshore and offshore).

When switching is being performed from , Remote Control Centre, OCC or OSP HMI (workstation), a prominent flag shall be set on the counterpart HMI, to alert personnel to the operating taking place at the alternate location.

3.6 INSTRUMENT TRANSFORMERS

The placement and specification of instrument transformers remains the purview of the primary equipment designers / suppliers. Nonetheless, the requirements for protection, control and metering devices shall serve as inputs to the instrument transformer (IT) selection process.

All ITs shall be in accordance with OFS-SSS-424.

3.6.1 CURRENT TRANSFORMERS (CTS)

Cabling between the CT terminal boxes and the respective PCM cubicles shall be minimum 6mm^2. In the event of an interface cubicle being provided where CT signals cross an asset split boundary, internal wiring for protection and control circuits shall be minimum 2.5mm^2. Internal wiring for revenue metering shall be 6mm^2.

Cubicles containing revenue metering CT circuits shall be able to be locked and sealed. Where the circuits are present in a cubicle shared with other applications, the portion of the cubicle pertaining to the metering CTs shall be screened off with acrylic plates to prevent unauthorised tampering.

Each CT circuit shall be earthed at a single point. In the event of an interface cubicle being used, the earth shall be applied therein, accessible by both parties. CT earths shall be affected with sliding link terminals, permitting the CT single-earth criterion to be tested.

Spare CT circuits shall be short-circuited and earthed.

5P50 protection class is standard that shall be used. Other classes of protection CTs can be used if approved by EirGrid on case-by-case basis.

3.6.2 VOLTAGE TRANSFORMERS (VTS)

VTs shall be per-phase (as opposed to be combined on a multi-limbed core). Primary voltage rating shall be in accordance with the designed system voltage. The outputs of wye-connected windings shall be per standard EirGrid values, 57.7V phase-to-neutral, resulting in line-to-line voltage of 100V. The outputs of open delta windings shall be 100/3V, when measured individually.

Each VT shall include at least two windings, one for protection applications and one for metering / measurements. For revenue metering (main and check) applications discrete metering windings shall be available for each device. In the event that zero sequence voltage polarization for directional earth fault is required, a broken delta winding shall be provided.

For VTs based on capacitor voltage division, an additional open delta winding shall be provided for damping of CVT transients.

The P-windings shall be dual-rated: when the total external burden is lower than the specified value, the VT accuracy shall be in accordance with the values stated for class 0.2M VTs; if the total external burden exceeds this lower bound, accuracy shall be in accordance with values for class 3P VTs.

The M-windings shall be rated to class 0.2M.

Cabling between the VT terminal boxes and the respective PCM cubicles, inclusive of any interface cubicles, shall be minimum 1.5mm^2.

Cubicles containing revenue metering VT circuits shall be able to be locked and sealed. Where the circuits are present in a cubicle shared with other applications, the portion of the cubicle pertaining to the metering VTs shall be screened off with acrylic plates to prevent unauthorised tampering.

Each VT circuit shall be earthed at a single point. In the event of an interface cubicle being used, the earth shall be applied therein, accessible by both parties. VT earths shall be affected with sliding link terminals, permitting the single-earth criterion to be tested.
Each VT circuit shall be protected. The ratings of such protection shall be coordinated per the following table:

Table 1– VT Protection Coordination

Location	Circuit description	Type	Ratings
PCM Cubicle	Individual shunt circuits to various devices	MCB	2A, curve B/C
Marshalling or Interface Cubicle	Distribution to multiple PCM cubicles	MCB	6A, curve B/C
VT Terminal Box	Supply to all subsidiary users	Fuse	16A (or similar)

The above table is typical to be confirmed during detailed design.

MCBs of three-phase VT circuits shall be ganged. Further, mechanically linked auxiliary contacts (1 N/O, 1 N/C) shall be provided for the signalling of any MCB trip condition.

Where revenue metering is required, separate VT secondaries are required for the Main and Check meters.

3.6.3 VT SELECTION

VT selection shall be provided where the outputs are to be provided to protection and control devices not intrinsically associated with the location of the VTs, e.g.:

- Transferring line / cable R, S, T voltage to external (e.g., transformer) P&C devices
- Providing busbar R, S, T voltage to multiple P&C devices
- Providing R-S voltage to the synch inputs of applicable BCUs

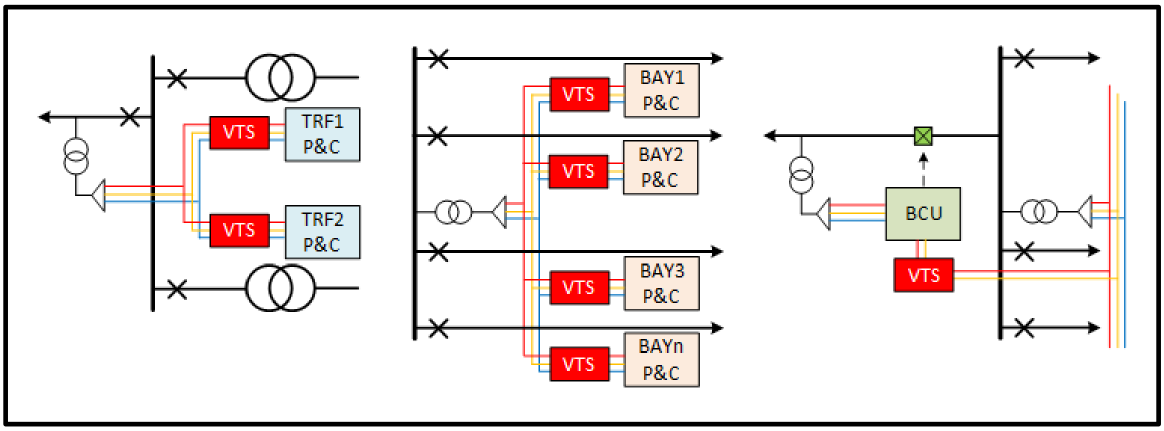

Figure 4 – Examples of Application of VT Selection

Each VTS auxiliary relay shall be energised by a contact from the respective BCU. The logic driving activation of the contact shall mimic the primary equipment statuses which would result in voltage being present at the intended point of measurement.

Where the voltage measured performs a critical function for which loss of voltage due to drop-off of the VTS auxiliary relay is not desirable, the auxiliary relay shall be of the bistable (“flip-flop”) type, with discrete operate and reset BCU contacts provided accordingly.

Any switching of VT circuits shall avoid inadvertent paralleling of VT secondary windings.

VTs for revenue metering shall not be subject to VTS switching.

4 PROTECTION AND CONTROL FUNCTIONALITY

Protection and control solutions shall be developed based on the single line diagram of each envisaged project.

All protection, control and metering scheme function block / single line diagrams and associated design documents shall be submitted to EirGrid for review.

4.1 COMMON REQUIREMENTS

This sub-section describes requirements which shall apply to all intelligent electronics (IEDs) devices offered for the projects.

4.1.1 OEMS AND IEDS

All IEDs shall be sourced from original equipment manufacturers (OEMs) with a proven track record of supplying equipment to utilities and industries of size and complexity commensurate with the Irish transmission system. All offered products shall bear the CE mark for safety.

IED manufacturers shall have:

- At least 10 years' experience in the production of protection devices of the required type
- A track record of use of the proposed devices on EHV transmission networks in at least three EU utilities
- A presence in the Republic of Ireland for support of such devices (includes a specialist being able to mobilise to site relatively quickly).

All offered IED types shall have at least 200 units of each type in EU, UK, EEA utilities for at least 2 years duration and reliable service.

4.1.2 IED STRUCTURE

Each IED shall comprise a modular chassis / case into which various cards / modules are fitted to meet the overall design requirements, including:

- The power supply
- Central processing unit
- Communications ports
- I/O modules – analogue (CT, VT, transducer) inputs, binary inputs, relay outputs, etc

It shall be possible to replace individual modules or augment the IED with additional modules. Augmentation is only relevant if required by design. Following such changes to the hardware, the IED shall either automatically detect the changes, or if a firmware update is required, this shall be possible by EirGrid's technical personnel (all necessary specialist software or tools shall be provided to EirGrid).

Modules shall be secured in the IED using a common backing plate and/or Torx © or similar screws, to prevent casual interference by unauthorised persons.

All cards / modules shall be supplied with a conformal coating / topicalization.

The scheme wiring shall interface with the IED modules via male-female connector blocks which shall be secured to each module with screws. Where removal of a connector block disconnects CT circuits, the block shall incorporate means of automatically short-circuiting these. Individual terminals shall be suitable for ring, pin or flat blade lugs. In the case of pin or blade lug terminals, compression mechanisms shall be used; it shall not be permitted for screws to act directly on the lug surfaces.

Each IED shall include an HMI, comprising a backlit LCD screen and buttons for navigation. The size and functions of LCD screens shall be dependent on the device applications. The backlight brightness shall be adjustable, and at its maximum setting be bright enough to be read in a brightly lit room. The backlight shall be provided with a timeout of settable duration.

A front port shall be provided for local interrogation of each IED from a personal computer running the device-specific operating software. Such port shall be of a non-proprietary architecture, e.g., serial, USB or RJ45.

The power supply shall preferably be universal (i.e. suitable for 48 – 250Vdc). The vendor shall state the nominal power drawn by the IED in the quiescent state.

The IEDs shall be configured to consider any cyber security risks (relays shall comply with IEC 62443 - 3-3 as an SL 1 device with the provision of hardening, local accounts, whitelisting etc).

4.1.3 Self-supervision

The IED shall continuously monitor all internal hardware, firmware and numerical (calculated) functions. In addition, the integrity and plausibility of measured signals (whether analogue or binary) shall be monitored. In the event of any abnormality the appropriate alarm bit shall be set for internal logging and reporting to the SCADA system.

A changeover contact shall be provided to serve the life (N/O) and watchdog (N/C) functions. Each watchdog in a scheme shall activate a bay-specific alarm, and in turn signal the general BCU of the substation.

4.1.4 Settings and logic

Each IED shall include user-programmable settings and logic. Programming shall be possible from the device HMI or operating software, with password protection available to ensure access only by authorised personnel.

The settings menu structure, when accessed from the HMI, shall be a replica of that displayed in the operating software. When exiting the menu, having entered new settings from the HMI, the IED shall prompt the user to save and/or enable the new values.

Settings fields in the operating software shall show the present value, the range of values permissible, and the step size. Settings ranges shall be context-sensitive, i.e., if a major parameter in the structure of the device is changed, such as from 5A to 1A CTs, the available ranges of derived settings shall be adjusted accordingly. The IED shall include error checking to prevent the saving or uploading of invalid settings to the device.

Logic may be entered in Boolean equation or graphical (continuous function chart) formats, per IEC 61131-3. The logic engine shall automatically detect and flag errors such as invalid variables, gates not allocated to functions or attempts to use output functions for multiple purposes.

It shall be possible to edit the tags / labels of user-defined variables, such as binary inputs, relay outputs and virtual bits for GOOSE messaging. When a user-edited tag is applied, the internal nomenclature of the variable shall remain visible.

4.1.5 Sequence of events recording (SER)

IEDs shall include SER of a minimum of 1,000 change-of-state events. Such events include:

- Activation of IED function elements, e.g., trip / start of protection algorithms or important intermediate logic states
- Programmed logic gate changes

- Device access by users, including changes to settings or logic files
- Flags in respect of the health of the device itself

Events shall be displayed in text form on the device HMI and in the operating software (PC). It shall be clear whether the event is active (logic high, “coming”, 1, etc) or inactive (logic low, “going”, 0, etc).

Timestamping resolution shall be 1ms or better.

Events shall be stored in non-volatile memory on a first-in, first-out basis. The highest level of user access shall be required to delete logged events, and this deletion itself shall be logged.

4.1.6 DISTURBANCE RECORDING / OSCILLOGRAPHY

IEDs shall include recording of analogue and digital quantities during faults and abnormalities. The sampling frequency of analogue channels shall be 3.2kHz (64 samples per cycle), and resolution of digital (binary) channels shall be 1ms or better.

Thirty seconds (30s) of recordings shall be possible, with the number of recordings dependent on the record length. For example, 10 records of 3s each or 20 records of 1.5s each. Records shall be stored in non-volatile memory on a first-in, first-out basis. The highest level of user access shall be required to delete records, and the deletion shall be logged by the IED. Users with lower access levels shall be permitted to extract records for analysis, leaving them intact on the device.

Analogue channels shall include all quantities directly measured by the IED and applicable derived quantities, e.g., bias and differential currents for differential IEDs.

Digital channels shall be user-selectable, and shall include internal function states, binary inputs, relay outputs, and digital messages (virtual bits). For IEDs performing complex functions, e.g., bay controllers, distance and differential IEDs, the minimum number of digital channels available shall be 64. For IEDs performing less sophisticated functions, e.g., overcurrent, the minimum number of digital channels shall be 32.

Record triggering shall be user-selectable, the logical OR of multiple criteria. Analogue triggering may be by means of threshold exceedance or excursion from a user-defined band. Binary triggering shall include rising and falling edges of the applicable signals.

The pre-trigger time and overall record time shall be independently settable. In the event of any trigger condition falling away and being reactivated within the overall record time, it shall be possible to extend the record by a further time increment.

In the case of distributed busbar protection schemes, if the central unit recording is triggered this shall be relayed to all connected bay units, so that a complete Oculographic record for the scheme can be created.

When a recording is triggered, a text-only summary shall be co-created. This summary shall include the date and time, description of the trigger quantity, all protection elements issuing a trip signal, fault duration, and in the case of line protection IEDs, distance to fault. This summary shall be displayed on the IED HMI.

Upon creation of a new record, a status bit in the RDRE logical node shall be set and included in the MMS report, to signal to the HMI and SCADA systems that a new record is available. Upon extraction of the record, the status bit shall be cleared.

The operating and settings software shall include an application for the analysis of extracted fault records. This application shall include various functions:

- Multiple cursors with time difference between cursors displayed
- RMS and peak values of analogue quantities at any given cursor position
- Vector plotting of any given cursor position

- Harmonics tabulation for any given cursor position
- Ability to zoom into analogue waveforms for analysis of high frequency phenomena
- Separate sub-windows for analogue and digital channels, such that digitals remain visible when waveforms are being zoomed into

Records may be stored in the IED in proprietary format, however when extracted, they shall be in COMTRADE format.

4.1.7 Technical requirements of Input / Output modules

4.1.7.1 Analogue inputs

All CT inputs (R, S, T, N) shall be independent, thus star points shall be realised external to the IED.

Phase (R, S, T) VT inputs may be independent or internally starred, with a single neutral terminal provided. The input for synchronising voltage shall be independent.

Table 2– Requirements for Analogue Inputs (as typical guidance)

Input	Nominal Value	Thermal Limits
CTs, phase and neutral	1A	4A Continuous 100A for 1s
CTs, neutral, for sensitive E/F measurements	0.2A	0.8A Continuous 20A for 1s
Burden, CTs	<0.1VA	-
VTs, phase-to-phase and synch quantity	100V	190V Continuous 300V for 10s
Burden, VTs	<0.05VA	-
Transducer inputs, permissible options	0-20mA 4-20mA -10 . 0 . +10V	-

4.1.7.2 Binary inputs

Sufficient binary inputs shall be included to meet the full scheme requirements, with provision of 20% spares. A combination of independent and ganged inputs shall be provided.

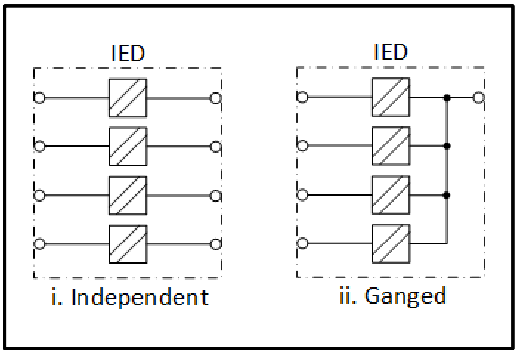

Figure 5 – Independent vs Ganged Inputs

Polarity of DC circuitry shall be clearly evident from the device schematics.

Table 3– Requirements for Binary Inputs (as typical guidance)

Parameter	Nominal Value	Thermal Limits
Operating voltage	220V	250V
Minimum pickup value	>132V Or user-settable	-
Pickup / drop-off ratio	>1.05	-
Inrush power consumption	<0.5W (~5mA)	-
Steady state power consumption	<0.2W (~2mA)	-

4.1.7.3 Digital / Relay outputs

Sufficient digital outputs shall be included to meet the full scheme requirements, with provision of 20% spares. A combination of independent and ganged outputs shall be provided. In general, ganged outputs shall always be of type A (N/O), whereas independent outputs may be of type A, type B (N/C) or type C (changeover).

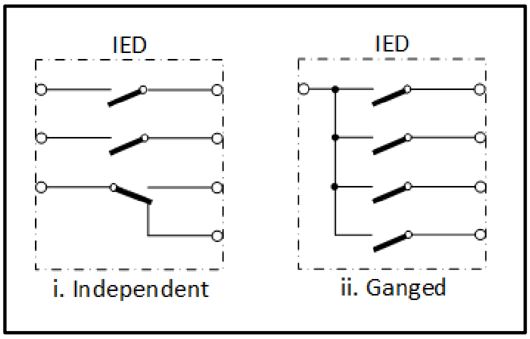

Figure 6 – Independent vs Ganged Outputs

Polarity-sensitive outputs (solid state / high speed / high break) shall have the required DC polarity clearly shown in the device schematics.

Table 4 – Requirements for Digital Outputs (as typical guidance)

Parameter	Nominal Value
Rated voltage	24 – 250Vdc
Make and carry continuously, trip contacts	6A
Make and carry, signal contacts (if different from trip)	3A
Short time carry	30A for 1s
Maximum pickup time	8ms
Conventional (reed relay) output contacts	
Break, resistive or inductive, L/R 40ms	>40W (~0.2A)
High-break / solid state outputs (if offered)	
Break, resistive or inductive, L/R 40ms	>220W (10A)

4.1.7.4 INDICATION LEDS

Each IED shall include indication LEDs for the flagging of trip, alarm and status signals. The number thereof shall depend on the device type and functions implemented.

All IEDs shall include a minimum of three fixed pattern LEDs:

- Device on / healthy – green
- Device fault – amber or red
- Protection trip – red (available, but not used on BCUs)

Programmable LEDs shall be bi-colour as a minimum, with tri-colour preferred. All LEDs shall be settable for latched, follower or flashing operation. Should an LED reset command be inputted while the underlying signal remains active, the LED shall not be extinguished.

LEDs shall be labelled, using either tab inserts or by the application of printed plastic sheets. The font size and line spacing shall be consistent with text native to the IED and the distance between the LEDs themselves.

4.1.7.5 ACCURACY OF MEASURANDS – GENERAL

Table 5 – Accuracy Limits

Error in	Better than
Directly measured quantities (V, I)	1%
Derived quantities (P, S, Q, cos-φ)	2%
Complex quantities (impedance, diff / bias currents)	5%
Frequency	10mHz
Phase angle	0.5º
Timestamping, when GPS- or NTP-synchronised	1ms

Note: more onerous accuracy values are prescribed for instruments and devices performing metering and measurements functions.

4.1.8 IED OPERATING AND SETTINGS SOFTWARE

Software to program and interrogate each IED shall be provided. Freeware is preferred, however where a licence fee is payable, the price for a multi-user / corporate licence shall be clearly evident in the commercial offer. Paid licences shall remain valid for the envisaged life of the equipment (25+ years) and be transferrable should ownership of the assets change during that time.

The software package shall be suitable for installation on personal computers with a Windows 10 (or later) operating system. The OEM shall clearly indicate the minimum hardware requirements for software installation, and if there are any limitations related to non-Intel processors or virtual operating systems (e.g. Bootcamp on Mac OS).

The package shall include all modules and applications related to the devices offered, including but not limited to:

- Settings input and transfer
- Logic programming and transfer
- IEC 61850 programming and/or IEC 60870-5 mapping
- Programming of custom bay single line diagrams (for display on the HMI)
- Visualisation of busbar protection scheme layout and status

- Visualisation of parallel transformer layout

Standard USB or LAN ports shall be used for the cable connections to each IED. Standard serial cables are preferred for IED connections; where a proprietary cable is mandated, the price per unit shall be clearly indicated in the commercial offer.

Should any IED offer wireless interfacing (WIFI or Bluetooth), such functionality shall be disabled by the OEM.

Updates to the software package shall be backwards compatible with the offered devices and made available at no cost to EirGrid. In general, a new version of the software shall first be made available to EirGrid technical specialists for testing / validation, prior to broader deployment. The OEM shall not unilaterally distribute updates to field personnel prior to review by EirGrid's specialists. See OFS-GEN-17- Cyber Security Systems for additional information.

4.2 BAY CONTROL UNITS (BCUS)

Each substation bay shall be provided with a BCU. BCUs shall be installed apart from the respective protection systems, depending on the type of substation:

- GIS – in the bay LCC
- AIS – in the kiosk or room designated for bay control units

For OSP (offshore substation platform), where space is limited, it is acceptable to have protection system (including relays) to be installed in the same room or cabinet / LCC as BCU. In this case, it must be safe and possible to work on any relay without any outages on the GIS.

The BCU serves as the means of controlling the plant at BCP level, and for executing commands issued by upstream control points. In short, upon receipt of a command instruction from a substation HMI or remote-control centre, a gateway device shall convert the command instruction to an IEC 61850 MMS report and push it to a specific BCU for execution.

In return, the BCU shall assemble the statuses of the plant, analogue and binary, into MMS reports for publication to the gateway. The gateway shall then relay the data to upstream control centres and the HMI(s).

Interlocking shall be programmed in the BCU and applied to all switching commands, whether locally initiated or received from remote.

BCUs shall include measurements functionality with an accuracy of class 1.0. Measurements data shall be reported using the MMXU and MMXN logical nodes.

The BCU HMI display shall be of the graphical type, large enough to display the complete bay single line diagram. The operating software shall include a substantial library of bay types, with the ability to customize switch device labels and incorporate additional elements, e.g., the status of the Local-Remote switch / button. It shall also be possible to program unique bay layouts. The inputs and outputs pertaining to bay layouts shall not be prescriptive.

The symbology used for switch devices shall be in accordance with IEC standards. The BCU shall display each device status based on double bit status binary inputs. In addition to open and closed states, (0, 1) or (1, 0), the BCU shall also indicate devices in the transition (0, 0) and invalid (1, 1) states.

Additional HMI pages shall be available for display of, amongst others:

- Measurements data
- Events log

- Alarm list
- States of inputs, outputs and programmed logic
- User-defined virtual pushbuttons, LEDs or signal states

It shall be possible to rotate through the HMI pages in the manner of a carousel. After a settable period without user input, the display shall revert to the home (bay layout) page.

Navigation around the bay layout for switching purposes shall be clear and intuitive. It shall not be possible to select a device for which switching is not possible. When contemplating execution of a switching action, the operator shall first select the applicable device, then confirm the selection and the intended operation, before issuing the command. If a device has been selected and no further action is performed, the selection shall be voided after a settable time period.

Touch screens should not be used. If touch screen is proposed by Customer, it shall need to be specifically approved by EirGrid. In the event of a touchscreen display being approved it shall include means of ignoring inadvertent successive touches during operating sequences. It is recommended that following selection and confirmation of a device to operate, the button for execution of the command be located apart from the device icon.

It shall be possible to set a password-protected user access level specifically for switching operations.

Table 6 – Miscellaneous BCU Requirements

Parameter	Requirements
CT Inputs – general	4 (R, S, T, N)
CT Inputs – for SSS, export cable bay only	4 (line R, S, T, N) + 4 (reactor R, S, T, N)
VT Inputs - phase	3 (R-S-T-N)
VT Input – synch	1 (R-S)
Programmable LEDs	≥12
HMI Display	Large graphical, >56k pixels
Settings groups	≥4
Control functions	Open/Close of ≥10 devices Local-Remote selection Synchronism check (if applicable) Interlocking
Optional protection functions (Unlikely to be used)	Overcurrent and Earth Fault Directional O/C E/F Negative phase sequence CB Fail

4.3 LINE DIFFERENTIAL

The principal function shall be per-phase and fourth wire biased differential protection of feeders, by numerical comparison of the magnitudes and phase angles of local (measured) and remote (received digitally) currents. A multiplexed fibre optic link shall serve as the principal communications medium between devices.

Concurrent distance protection shall be included, in accordance with the provisions of [4.4]. The medium for communications aided functions (PUTT, POTT, blocking) shall be either channels allocated from the binary signal exchange integral to the differential device, or discrete, direct interfaces with the multiplexers.

Table 7 – Line Differential IED Requirements

<table>
<tr><th>Parameter</th><th colspan="2">Requirements</th></tr>
<tr><td>CT Inputs (local) - default</td><td colspan="2">4 (R, S, T, N)</td></tr>
<tr><td>CT Inputs (local) – when shunt reactor tee-off is within the protected zone</td><td colspan="2">4 (line R, S, T, N) +
4 (reactor R, S, T, N)</td></tr>
<tr><td>VT Inputs - phase</td><td colspan="2">3 (R-S-T-N)</td></tr>
<tr><td>Optional VT Input – synch</td><td colspan="2">1 (R-S)</td></tr>
<tr><td>Programmable LEDs</td><td colspan="2">≥16</td></tr>
<tr><td>HMI Display</td><td colspan="2">Text only (≥4 lines) or small graphical</td></tr>
<tr><td>Settings groups</td><td colspan="2">≥4</td></tr>
<tr><td>Multiplexer communications interface</td><td colspan="2">Multimode fibre optic, 850nm
IEEE C37.94 protocol</td></tr>
<tr><td>Optional communications media – if ordered for specific applications</td><td colspan="2">Single mode fibre optic
1310nm (<~85km), 1550nm (>~85km)</td></tr>
<tr><td>Number of terminals</td><td colspan="2">2 – default
3 – special applications only</td></tr>
<tr><td rowspan="5">Line differential elements</td><td>Operating mode</td><td>Phase and earth fault protection</td></tr>
<tr><td>$I_{DIFF-MIN}$</td><td>Settable, 0.1 – 0.5 * I_{NOM}</td></tr>
<tr><td>Slopes, k</td><td>≥2, settable, 0.1 – 4 * I_{BIAS}</td></tr>
<tr><td>Binary channels</td><td>≥16 (for Direct Txfer Trip, etc)</td></tr>
<tr><td>In-zone transformers</td><td>Available as ordering option, with:
• Vector group compensation
• Zero sequence path settable
• Inrush blocking</td></tr>
<tr><td>Additional functions</td><td colspan="2">Backup overcurrent / earth fault (multiple stages of IDMT or DT)
Directional O/C E/F
CB Fail, two-stage
Stub fault detection (DTT Tx)
Under- and overvoltage
Under- and over frequency
Rate of Change of Frequency
Thermal characteristic
Trip circuit supervision</td></tr>
<tr><td>Tripping</td><td colspan="2">Per-phase and three-pole</td></tr>
<tr><td>Auto-reclose</td><td colspan="2">Yes, internal or external initiation
≥3 shots, multiple modes</td></tr>
<tr><td>Maximum trip times for instantaneous elements</td><td colspan="2">≤30ms when $I_{DIFF} \geq 1.2*k*I_{BIAS}$ and
$I_{BIAS} \geq 2*I_{NOM}$
≤40ms when $I_{DIFF} < 1.2*k*I_{BIAS}$ or
$I_{BIAS} < 2*I_{NOM}$</td></tr>
<tr><td>Reset time</td><td colspan="2">≤40ms</td></tr>
</table>

4.4 DISTANCE (FEEDERS)

The principal function shall be independent phase and earth fault protection of multiple fault loops and multiple zones The protection shall be communications aided (selectable between permissive, blocking, directional comparison) via a discrete interface with the fibre optic link multiplexer.

In the table that follows, parameters and requirements which are hardware-specific shall apply to standalone distance protection devices. Where distance protection is an adjunct function within the line differential device, the hardware requirements of that device shall have precedence.

Table 8 – Feeder Distance Protection Requirements

Parameter		Requirements
CT Inputs - default		4 (R, S, T, N)
CT Inputs – when shunt reactor tee-off is within the protected zone		4 (line R, S, T, N) + 4 (reactor R, S, T, N)
VT Inputs - phase		3 (R-S-T-N)
Optional VT Input – synch		1 (R-S)
Programmable LEDs		≥8
HMI Display		Text only (≥2 lines) or small graphical
Settings groups		≥4
Multiplexer communications interface		Vendor to specify
Distance elements	Operating loops	RS, ST, TR, RN, SN, TN
	Zones	≥6 phase-phase and ≥6 earth fault (Typically, 3 * forward, 2 * reverse and 1 * zone extension)
	Polarisation	Combination of self-, cross- and memory polarisation
	Zone characteristics	Selectable between Mho and quadrilateral
	Load encroachment	Availability of lenticular characteristics or blinders
	Timers per zone	Settable, 0 – 3s, 10ms steps
	Communications aids	Selectable between PUTT, POTT, directional comparison, blocking
	Starting elements	Independent of main zones
	Switch Onto Fault	Zone 1 Extension or Overcurrent
	Fuse failure detection	By MCB auxiliary contact and 3V(0)
	Additional functions	Weak infeed tripping Current reversal guard CVT Transient damping Power swing blocking (PSB)

Parameter		Requirements
	Testing tools	XRIO export for distance zones and PSB characteristic
Additional functions		Backup overcurrent / earth fault (multiple stages of IDMT or DT) Directional O/C E/F CB Fail, two-stage Under- and overvoltage Under- and over frequency Rate of Change of Frequency Trip circuit supervision
Tripping		Per-phase and three-pole
Auto-reclose		Yes, internal or external initiation ≥3 shots, multiple modes Note: Auto-reclosing will not be employed for offshore installations
Maximum trip times for instantaneous elements		≤30ms when SIR ≤ 5 & I_{FAULT} ≥ 2 * I_{SET} ≤40ms when SIR > 5 | I_{FAULT} < 2 * I_{SET}
Reset time		≤40ms

4.5 Transformer / Reactor Biased Differential

Transformer / reactor main protection shall take the form of a bespoke IED performing multiple functions. Preference is for a single product family that may be tailored depending on the configuration of the primary equipment, e.g. two- or three-winding transformers or single-winding reactors.

Table 9 – Transformer / Reactor IED Requirements

Parameter		Requirements		
		3-Wdg	*2-Wdg*	*1-Wdg*
CT Inputs - phase		9 (P, S, T)	6 (P, S)	6 (Rx, N)
CT Inputs - neutral		3	2	1
VT Inputs		≥1 minimum, ≥3 preferred		
Programmable LEDs		≥12		
HMI Display		Text only (≥2 lines) or small graphical		
Settings groups		≥4		
Transformer differential elements	Characteristic	Biased differential for phase and earth (where applicable) faults		
	$I_{DIFF-MIN}$	Settable, range sufficient to ensure stability at extreme tap positions		
	Slopes, k	≥2, settable, 0.2 – 4 * I_{BIAS}		
	Security	Settable f(2) and f(5) harmonic thresholds, inrush blocking CT saturation detection		

Parameter		Requirements
	Configuration method	User sets CT ratios, unit ratings, vector group and zero sequence path – IED derives all operating quantities
Restricted earth fault elements		1 per grounded winding >90% winding coverage
Additional functions		Sufficient binary inputs for buchholz, oil / winding temperature, pressure release, oil level alarms and trips Over fluxing Backup overcurrent / earth fault (multiple stages of IDMT or DT), per winding CB Fail, two-stage, per winding Thermal characteristic Trip circuit supervision
Tripping		Three-pole only Master trip (ANSI 86) function programmable in logic
Maximum trip times for instantaneous elements		≤25ms when $I_{DIFF} \geq 1.2*k*I_{BIAS}$ and $I_{BIAS} \geq 2*I_{NOM}$ ≤40ms when $I_{DIFF} < 1.2*k*I_{BIAS}$ or $I_{BIAS} < 2*I_{NOM}$
Reset time		≤40ms

4.6 Distance (Transformers)

Distance protection shall be applied on the primary and secondary windings of each main export transformer. To perform this function, such IEDs need not be "full feature" distance devices as per [4.4], rather, stripped down versions offering the necessary functions.

Separate distance relays are required for the export cable and transformer.

Table 10 – Transformer Distance IED Requirements

Parameter		Requirements
CT Inputs		4 (R, S, T, N)
VT Inputs - phase		3 (R-S-T-N)
Programmable LEDs		≥8
HMI Display		Text only (≥2 lines) or small graphical
Settings groups		≥2
Distance elements	Operating loops	RS, ST, TR, RN, SN, TN
	Zones	Minimum: ≥3 phase-phase and ≥3 earth fault (Typically, 1 * forward, 1 * reverse and 1 * zone extension) Preferred: ≥6 phase-phase and ≥6 earth fault (per feeder distance)
	Polarisation	Combination of self-, cross- and memory polarisation
	Zone	Selectable between mho, quadrilateral

Parameter		Requirements
	characteristics	
	Load encroachment	Availability of lenticular characteristics or blinders
	Timers per zone	Settable, 0 – 3s, 10ms steps
	Communications aids	Optional
	Starting elements	Independent or switched
	Switch Onto Fault	Zone 1 Extension or Overcurrent
	Fuse failure detection	By MCB auxiliary contact and 3V(0)
	Additional functions	CVT Transient damping
	Testing tools	XRIO export for distance zones
Additional functions		Sufficient binary inputs for buchholz, oil / winding temperature, pressure release, oil level alarms and trips Note: Mechanical trips should be routed directly to CB Backup overcurrent / earth fault (multiple stages of IDMT or DT) Directional O/C E/F CB Fail, two-stage Under- and overvoltage Under- and over frequency Rate of Change of Frequency Trip circuit supervision
Tripping		Three-pole only, without AR
Maximum trip times for instantaneous elements		≤30ms when SIR ≤ 5 & $I_{FAULT} \geq 2 * I_{SET}$ ≤40ms when SIR > 5 | $I_{FAULT} < 2 * I_{SET}$
Reset time		≤40ms

4.7 BUSBAR BIASED DIFFERENTIAL

Busbar protection (BBP) solutions shall be offered and developed based on the actual substation topology envisaged for each project, rather than as a universal offering. A number of architectures are possible, dependent on the number of bays to be protected and the zones to be considered:

- Centralised (1) – a single IED offers BBP for N * three-phase bays, connected to a maximum of two zones
- Centralised (3) – each IED offers BBP for a maximum of N*3 bays, connected to a maximum of two zones; one IED is required for each phase, and all binary inputs and relay outputs are connected in parallel
- Distributed – a system comprising a central unit (CU) and N * bay units (BUs) provides three-phase and earth BBP for substations with a high number of bays,

where more than two zones are considered, or where a centralised scheme with high cable interface requirements is undesired

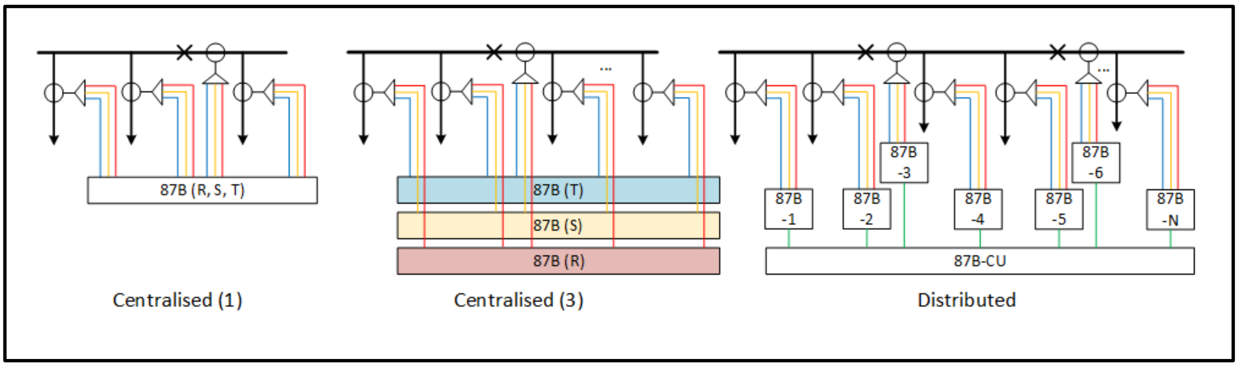

Figure 7 – Comparison of BBP Architectures

In distributed schemes, communications between bay and central units shall be by means of fibre optic patch leads, multimode, 850nm (or similar). The use of the substation LAN to facilitate data exchange shall not be permitted. Proprietary protocols shall be permitted.

Zones shall be coupled by bus coupler or section bays, including CTs, or by bus sectionalizing disconnectors. In the case of the latter, for any BBP trip event both zones shall be tripped, regardless of the origin of the abnormality, if the disconnector is closed. Only one CT set shall be provided for bus couplers and sections, with the current output provided to both zones' differential elements, albeit with an inversion of polarity.

Logic shall be included to ensure correct zone tripping for bus coupler or section stub (or 'dead zone') faults. To this end, the auxiliary contacts of the circuit breaker shall be monitored.

Stub fault detection for feeder or transformer bays shall be included, based on the monitoring of CB auxiliary contact status. When declared, stub fault may be used to delay the busbar differential elements, to allow the remote source of fault current to trip first.

Zone allocation shall be made based on the position of the busbar disconnectors, by monitoring of the auxiliary contacts. As a minimum, the drop-off of each disconnector open (89B) contact shall be monitored. If a disconnector closed (89A) contact is provided in addition, this shall be used for disconnector runtime monitoring. To maximise security, the general intent is to force bay disconnectors to close in the IED logic, in the event of any uncertainty about its status.

A minimum of two output contacts shall be provided for the tripping of each bay, with additional contacts available if stub fault trip is used to relay a transfer trip command to the applicable line differential IED.

BBPs shall be flexible with regard to interfacing with the primary plant. Different CT ratios, positions and polarities shall be settable per bay, and the user shall be free to allocate inputs and outputs to various bays as required. Use of internal or external CB Fail shall be selectable on a per-bay basis.

The following scheme controls shall be possible, effected by buttons or function keys on the devices, or by means of external rotary switches wired to binary inputs:

- Per-bay in- / out-of-service
- Per-zone differential enable / disable
- Scheme-wide CB Fail trip enable / disable
- Scheme-wide trip functions enable / disable

Table 11 – Busbar Protection Requirements

Parameter		Requirements
CT Inputs		Application dependent
VT Inputs		Optional
Programmable LEDs		≥12 for Central Units ≥8 for Bay Units
HMI Display		Text only (≥2 lines) or small graphical
Settings groups		≥4
BU-CU Communications		Vendor to specify
Binary inputs		Sufficient for application
Digital outputs		Sufficient for application
Differential elements	Characteristic	Low impedance biased differential
Differential elements	Security	Two-out-of-two tripping (discriminating zone plus check zone) Phase angle plausibility check CT Supervision by sensitive differential element, per zone Compensation for CT saturation
Differential elements	Settings	Independent $I_{DIFF-MIN}$ and slope (k) settings for each of: • Discriminating zones • CT Supervision elements • Check zone Settings shall be expressed in primary values
Circuit breaker fail		Internal / External selectable per bay Reset by undercurrent threshold, CB auxiliary contact, or both Two settable timers: • First stage, retrip own CB • Second stage, strip bus Note: CBF protection triggering to be based on current and non-current inputs.
Additional functions		Bus Coupler stub fault logic Feeder stub fault detection Per-bay backup O/C E/F (multiple stages of IDMT or DT protection)
Maximum trip times for instantaneous elements		≤25ms when $I_{DIFF} \geq 1.2*k*I_{BIAS}$ and $I_{BIAS} \geq 2*I_{NOM}$ ≤40ms when $I_{DIFF} < 1.2*k*I_{BIAS}$ or $I_{BIAS} < 2*I_{NOM}$
Reset time		≤40ms
Configuration software		To be included in the OEM's general operating / settings package "OEM-only" configuration establishment and changes shall not be permitted

Parameter	Requirements
Commissioning / monitoring tools	Visualisation software to display the complete substation in a single location, complete with per-bay and per-zone current magnitudes, disconnector states and all protection element statuses The software shall be installed on the substation HMI or user PCs Polling / refresh time ≤1s

4.8 Overcurrent and Earth Fault

The requirements apply to bespoke IEDs offering overcurrent and earth fault protection, and, where applicable, to the backup overcurrent and earth fault functions present in other main devices.

Table 12 – Overcurrent and Earth Fault Protection Requirements

Parameter		Requirements
CT Inputs		4 (R, S, T, N)
VT Inputs – for directionalising only		3 (R-S-T-N) + 1 (3V(0))
Programmable LEDs		≥8
HMI Display		Text only (≥2 lines) or small graphical
Settings groups		≥2
Overcurrent elements	Number of elements	≥3 Overcurrent and ≥3 Earth Fault (Of which one element shall be IDMT)
	Definite time settings	Pickup value Operating time
	IDMT curves	IEC – NI, VI, EI, LTI per [0]
	IDMT settings	Pickup value Time multiplier Minimum time Disk return emulation
	Directional O/C	90º RCA (for other algorithms – OEM to specify)
	Directional E/F	3V(0) Polarisation method (for other algorithms – OEM to specify)
	Directional settings	Maximum torque angle Locus of operation
	Reset ratio	>95% of pickup value
Additional functions		Directional comparison, when paired with other device(s) CB Fail, two-stage Negative sequence Trip circuit supervision
Additional functions – voltage dependent		VT Fuse failure supervision Power protection

Parameter	Requirements
	Watt metric earth fault Under- and overvoltage Under- and over frequency
Maximum trip times for instantaneous elements	≤30ms when $I_{FAULT} \geq 1.5 * I_{SET}$ ≤40ms $I_{FAULT} < 1.5 * I_{SET}$
Reset time	≤30ms

4.9 Automatic Voltage Regulator (AVR)

The AVR shall provide automated control of the main power transformer tap changer and facilitate manual control, whether local or remote. It shall be determined whether the AVR(s) shall be installed in a discrete cubicle or together with the associated protection IEDs.

The AVR shall be suitable for balanced load applications, hence one current and one voltage quantity shall be measured as a minimum. Where system studies indicate the possibility of significant unbalance, the specification shall be upgraded.

Table 13 – AVR IED Requirements

Parameter		Requirements
CT Inputs		1 (Default), 3 (Unbalanced load)
VT Inputs		1 (Default, L-L), 3 (Unbalanced load)
Programmable LEDs		≥8
HMI Display		Graphical, >24k pixels
Buttons onboard		HMI navigation Selection: Local / Remote Selection: Automatic / Manual Commands: Raise / Lower Function keys for user-defined actions
Settings groups		≥4
Regulation element	Setpoints	≥2 Voltage and ≥1 Power Each setpoint shall include a settable dead band Selection of setpoints may be time-based or dependent on configuration of the installation
	Time characteristics	Inverse or definite time
	Parallel transformers	Master / Follower / Individual Circulating current compensation: • δI*sin(φ) • cos(φ)
	Current influence	Line drop compensation Tap change blocking for overcurrent condition

Parameter	Requirements
Supervision	Motor runtime monitoring Runaway detection and blocking Out of step alarm
Tap position	Preferred: binary coded decimal, minimum 5 bits (6 preferred) Optional: • Transducer input (4-20mA) • Resistance potentiometer • GOOSE Integer from external device
External inputs	Tap change in progress TC Drive Local-Remote switch and MCB status monitoring Trip issued by external protection Miscellaneous switchgear states
Parallel transformer setup	The operating software shall include a module for the setup of parallel transformer controls, based on the statuses of various disconnectors / circuit breakers Once in service, the module shall enable the visualisation of the installation and evaluation of the control actions in real time

4.10 LV Auxiliary System

Protection of the LV Auxiliary System shall be developed in concert with the configuration of the system itself, based on protection coordination studies. Consistent curve selection shall be a key feature of the design, ensuring that curve crossing and consequent maloperations are avoided.

The main power distribution board shall feature heavy duty withdrawable or *in situ* circuit breakers, including settable protection elements. Settings shall be implemented by means of DIP switches and potentiometers, or in the case of numerical devices, programmed from the device HMI or accompanying software package. Multiple elements of overcurrent and earth fault protection shall be provided, offering inverse and definite time characteristics.

In consumer cubicles and subsidiary power distribution boards, protection shall be by means of miniature circuit breakers and moulded case circuit breakers, depending on the predicted ampacity and fault levels for each circuit. A key assumption for MCBs and MCCBs in LV circuits is that in a solidly grounded system, earth fault current magnitudes are of the same order of magnitude as phase faults, thus discrete earth fault protection is seldom required.

MCBs shall include the following elements, generally not settable by the user:

- A thermal element, designed to provide inverse time tripping for overloads and faults of moderate current magnitude, and
- A magnetic element, intended to offer fast tripping for faults of high current magnitude

MCCBs shall offer elements with greater settings flexibility:

- A thermal element with user-selectable pickup value and operating curve,
- A magnetic element with user settable pickup value and trip time, and
- A magnetic element with a high-set pickup value and instantaneous operating time

On selected circuits, in particular those supplying plug sockets, earth leakage protection shall be provided in the form of residual current devices (RCDs). The default trip setting for RCDs shall be 30mA.

4.11 External / Other Devices

4.11.1 Filter bank protection

Dual-main filter bank protection shall be provided, based on the guidance of the equipment vendor. It shall be an express commercial condition that selection of a particular vendor's primary equipment shall not mandate the use of that vendor's recommended IED(s).

Table 14 – Filter Bank IED Requirements

Parameter	Requirements
CT Inputs - phase	4 (R, S, T, N)
CT Inputs - unbalance	3 (R_{UNB}, S_{UNB}, T_{UNB})
VT Inputs - phase	3 (R-S-T-N)
VT Inputs – for voltage differential	3 (R', S', T')
Programmable LEDs	≥12
HMI Display	Text only (≥2 lines) or small graphical
Settings groups	≥4
Primary configuration	The IED shall be able to be tailored for various applications, including: • Star, earthed • Double-star, unearthed • H-bridge • C-filter
Principal protection functions	Voltage differential Duplicated capacitor unbalance Two stage overvoltage
Additional functions	Backup overcurrent / earth fault (multiple stages of IDMT or DT) CB Fail, two-stage Undervoltage Under- and over frequency Trip circuit supervision Faulted capacitor can location
Optional control functions	CB lockout following trip, ~300s Automated switching control, voltage-based
Tripping	Per-phase and three-pole
Maximum trip times for instantaneous elements	≤30ms
Reset time	≤40ms

If required by electrical system studies, (OFS-GEN-5 Network Engineering Studies Specification) it shall be required to include a point-on-wave switching controller designed to reduce the impact of transient overvoltage on the circuit breaker. Design of the filter bank protection and control scheme shall take cognizance of such a controller.

4.11.2 Static Compensator or Other FACTS system

The vendor of the Statcom shall include comprehensive protection for the transformer, switches and reactive equipment. To this end, Customer shall make CT and VT circuits available as required.

Customer shall integrate trip signals from the Statcom system into the EHV circuit breaker control scheme and applicable busbar protection (including CBF) scheme.

If other FACTS systems are used, protection and control requirements will be developed with consultation with OEM.

5 Metering Functionality

5.1 Revenue and Statistical Metering

Revenue metering locations shall be on the HV side of the EHV/HV main export transformer(s). See Figure 8 for graphical representation of metering locations.

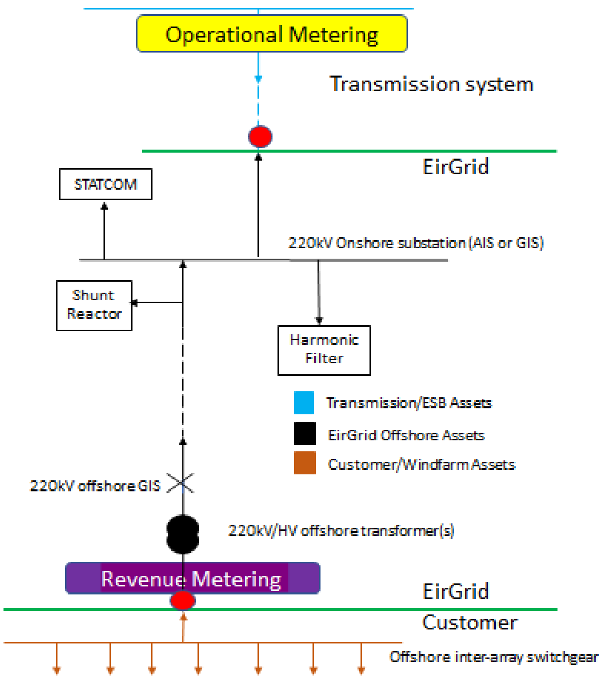

Figure 8 – Location of Metering Points (to be verified with Grid Code)

Revenue meters shall be applied in a redundant (main and check) configuration. Location of the revenue meters and the provision of anti-tampering seals shall be agreed between EirGrid and the customer.

Integration of the meters within EirGrid's metering management system shall be a key requirement.

- Operational Revenue Metering to be installed at the OCC as Main and Check Revenue Metering in a Standard EirGrid Energy Meter Cabinet, with associate Communication equipment and 48 VDC supply.

- Revenue Metering located on Offshore Platform to be installed as Main and Check Revenue Metering in an EirGrid Meter Cabinet with associated Communication Equipment and 48 VDC supply.
- EirGrid Energy Meters are compatible for IP/Ethernet communication, it would be proposed that the Primary communication would be over IP via the Fibre cable to the Offshore platform.
- EirGrid Energy Meters can operate over IP and OIP network, consideration should be taken in relation to Communication interface between EirGrid Data collection servers and the 220 KV Onshore/Offshore Substation.

Additional *statistical metering* should be applied at appropriately selected points in the installation, which when compared with the revenue metering data, would enable the determination of losses occurring throughout the system, notably the main export cable(s) and power transformers.

Operational Metering. And Revenue Metering

EirGrid Energy Meters

Accuracy Class: 0.2s Bi-directional 4 wire 3 phase, CT and VT connected

48V DC supply, Power and Earthing

A 48V DC power supply system is required to the EirGrid Energy Meter Cabinet.
The Electrical Contractor shall provide space and mounting rails in the designated Control/Communications room.
The Electrical Contractor shall provide and install the earth-bar (400mm x 60mm x 10mm 95mmsq annealed copper minimum.

5.1.1 CABINETS

EirGrid Meter Operator shall free-issue the following cabinet types as required for the sub-station:

Table 15 – Metering Cabinet Details

Cabinet Description	**Cabinet dimensions** (d*w*h)	**Access requirements**	**Cable Entry**	**Quantity required**
Energy Metering Cabinet	600*800*2200mm	Front & back access	Bottom	1

The electrical contractor shall install:
- Cabinet-mounting rails for all Telecoms cabinets
- 400 mm^2 cable tray or other suitable structured cabling containment method, under and between all cabinets.
- Cable tray/containment must be appropriately bonded to the station earth grid
- Earth bar with suitable connections for all equipment
- 2 x 95 mm^2 earth cross-bonded from different points to station earth grid and cabled to earth bar.

- 35 mm^2 earth cable from the Telecoms earth bar to cabinet.
- EirGrid Meter Operator shall free-issue Energy Metering cabinet to Electrical Contractor for installation.

5.1.2 SMPS (Operational Metering)

Table 16 – Metering48DC Cabinet

Cabinet Description	Cabinet dimensions (d*w*h)	Access requirements	Cable Entry	Quantity required
48Vdc System	600*600*1890mm	Floor standing, front-access	Bottom	1

- 400 mm^2 cable tray or other suitable structured cabling containment method, under and between all cabinets.
- Cable tray/containment must be appropriately bonded to the station earth grid
- Telecoms earth bar with suitable connections
- 2 x 95 mm^2 earth cross-bonded from different points to station earth grid and cabled to the earth bar.
- 35 mm^2 earth cable from the Telecoms earth bar to each cabinet (Note 48V DC SMPS cabinet shall require an additional 35sq earth to earth the positive pole).

Energy Metering

Energy Metering Earthing:

- 1 x 35sq earth from Telecoms Earth Bar for the Energy Metering Cabinet Frame
- 1 x minimum 35sq earth from Station Earth Mesh to the earth bar within the Energy Metering cabinet to provide CT/VT Star Point grounding.
- Provision & termination of CT/VT cabling from the Plant to the Energy Metering Cabinet.
- Clearly labelling all cables and earths as per design drawings.
- Cable management to the cabinets.

GPS Feed to Disturbance Recorder (Operational Metering)

A GPS feed to synchronise the Disturbance Recorder is required to be installed in Energy Metering cabinet within the Control building.
The GPS feed consists of several components: an antenna, an antenna mounting bracket, an arrestor, and a RF coaxial cable. The maximum distance from the antenna mounting bracket to the Disturbance Recorder is 25 m. The antenna mounting bracket is installed at an agreed location. The arrestor unit can be mounted on the wall above head height or underneath the false floor so long that its location is clearly identified above ground.
Cable protection / containment is required from the antenna to the Disturbance Recorder
A drawing shall be provided to the contractor.

The Contractor installs:

- Antenna, mounting bracket and arrestor,
- Earth cable from antenna mounting bracket to external earth, contained in steel conduit,
- RF cable from antenna to arrestor,

- RF cable from arrestor to the GPS Input on the Disturbance Recorder, located in the Energy Metering Cabinet.
- RF cable containment,
- 1 x 35mmsq earth from external earth grid to GPS antenna
- 1 x minimum 16mmsq earth from Telecoms Earth Bar to the GPS surge arrestor
- EirGrid Meter Operator shall free-issue the GPS Antenna, Antenna Bracket, GPS Arrestor and GPS Cable to the Contractor for installation.
- Standard Cabinet Dimensions:
    - Depth 600 mm x 800 width x 2200mm height.

Table 17 Energy Metering Device Requirements

Parameter	Requirements	
	Revenue	*Statistical*
Accuracy class	0.2S	0.5S
Power supply	Self-powered (VT input) with backup	
CT Inputs	3 (R, S, T)	
VT Inputs	3 (R-S-T-N)	
HMI Display	Text only (≥2 lines) with symbology	
Communications	Ethernet (fibre optic or RJ45) Local optical port for setup RS485/RS232 backup GSM/PSTN based on availability	
Load profiles	≥2	
Measurands (minimum)	P+/-, Q_{LAG}+/-, Q_{LEAD}+/-, cos-φ, THD	
Tariff management	By time-of-use or substation configuration (external signal)	
Integration period	15 minute	
Time synchronisation	(S)NTP – preferred, else Internal clock corrected with GPS 1pps	
Hardwired I/O	• 6x Pulse outputs OEM to specify voltage constraints	

5.2 QUALITY OF SUPPLY INSTRUMENTS

Instruments shall be installed for the monitoring of the power quality, to confirm compliance of the grid connection to the conditions set out in the licence and/or customer agreement, and for general performance monitoring during the production period. Devices shall be installed in accordance with EirGrid Grid Code requirements for PQ monitors. In case of conflict between this section and the Grid Code, requirements of Grid Code will take precedence. Instrument transformers supplying the devices shall be to the same class as revenue metering.

Each instrument shall continuously measure and record the set power quality parameters. Onboard storage shall be sufficient for up to 30 days of recorded data. An accompanying software package shall be installed on a workstation or substation computer, for the periodic extraction and archiving of recorded data. It shall be possible to retrieve archived data from remote locations. The necessary communication links shall be put in place to enable EirGrid to remotely interrogate these devices. Any required software to enable remote interrogation of these devices and analysis of data shall be provided to EirGrid.

Table 18 – QoS Instrument Requirements

Parameter	Requirements
Conformance standard	IEC 61000-4-30 Class A
Accuracy	Class 0.1 overall Class 0.2 for energy metering
Power supply	Substation DC system
CT Inputs	4 (R, S, T, N)
VT Inputs	3 (R-S-T-N)
Communications	Ethernet (fibre optic or RJ45) Local serial port for setup
Time synchronisation accuracy	Better than 1ms – general Better than 100µs – PMU applications (Via SNTP, PTP or GPS)
Hardwired I/O	IED Life / Watchdog contact Optional: • ≥2x Outputs • ≥2x Digital inputs OEM to specify voltage constraints
Measurands	Directly measured V, I Derived P, S, Q, cos-φ Harmonics to f(64) Interharmonic bandwidth 2-8kHz Small signal ≥50µs
Optional WAMS integration (Phasor Measurements Unit)	To IEEE C37.118 (2014) Frame rate ≥25/second

6 Indications, Monitoring and Alarms

6.1 By IEDs

IED binary inputs shall be used for the monitoring of the primary equipment (switchgear, transformers) and associated secondary systems. The equipment to be monitored shall provide potential-free contacts suitable for the application, for this purpose. Whereas circuit breakers are fast acting (~50ms trip, ~100ms close) and their contact timing is of lesser importance, the auxiliary contacts of slow acting (seconds) switches shall be suited to multiple applications (e.g., disconnector 89B should be early break for busbar protection and 89A late make for indication / runtime monitoring).

Care shall be taken in the wiring design to ensure independence of inputs, particularly where multiple parallel external contacts serve a common purpose (e.g., energise a trip circuit) and are required to signal the IED individually. If avalanche diodes are implemented for functional segregation, these shall be suitably robust for potentially high current applications (trip circuits). Where binary inputs or auxiliary relays are effectively wired in parallel with coil circuits, means of dissipating the energy of the negative EMF pulse associated with interruption of the coil current shall be provided (fly back).

Optionally, identified non-binary parameters may be monitored, typically by inclusion of transducers, connected to corresponding analogue inputs within the IEDs.

Switchgear status signals shall mostly be connected to BCUs, whilst protection-specific signals (e.g., transformer unit device alarm / trip) shall be connected to protection IEDs. Where signals monitored by a BCU are required for protection purposes (e.g., CB readiness status ahead of an auto-reclose cycle), these shall be shared as GOOSE messages.

Switchgear statuses shall be monitored in double bit format, with interpretation by the IED(s) based on both signals, per the following truth tables:

Table 19 – Switchgear Double Bit Status Interpretation

Circuit Breakers			Disconnectors / Earth Switches		
52A	*52B*	*Status*	*89A*	*89B*	*Status*
0	1	CB Open	0	1	Switch Open
0	0	Transition: alarm only if sustained	0	0	Transition; alarm after running timer expiry
1	0	CB Closed	1	0	Switch Closed
1	1	Invalid state; alarm	1	1	Invalid state; alarm

Programmed logic within the IEDs shall be applied to the various signals measured, in order to trigger various actions:

- Switchgear status display on HMI
- Trip and Close command execution
- Generation of alarms for internal logging and output to indication LEDs
- Activation of alarms to external, such as the General Alarm (hardwired) or SCADA (via S-LAN)

Each bay shall include a General Alarm function. This shall be implemented redundantly, via:

- Wiring of multiple alarm statuses to the designated IED, typically the BCU, and messaging thereof to the SCADA system digitally, and
- Logical OR of all alarms, together with the BCU watchdog, activates a GA auxiliary relay, which upon activation, signals the SCADA system (typically the General BCU) via a hardwired connection, and illuminates a bay-specific indication LED

Note that the GA supply is, by design, separate from the protection and control DC supplies, and is itself supervised. All substation bay GA contacts are connected to G-BCU binary inputs, or if wired in parallel, to a single input. The arrangement shown below is typical, many variations on the theme are possible.

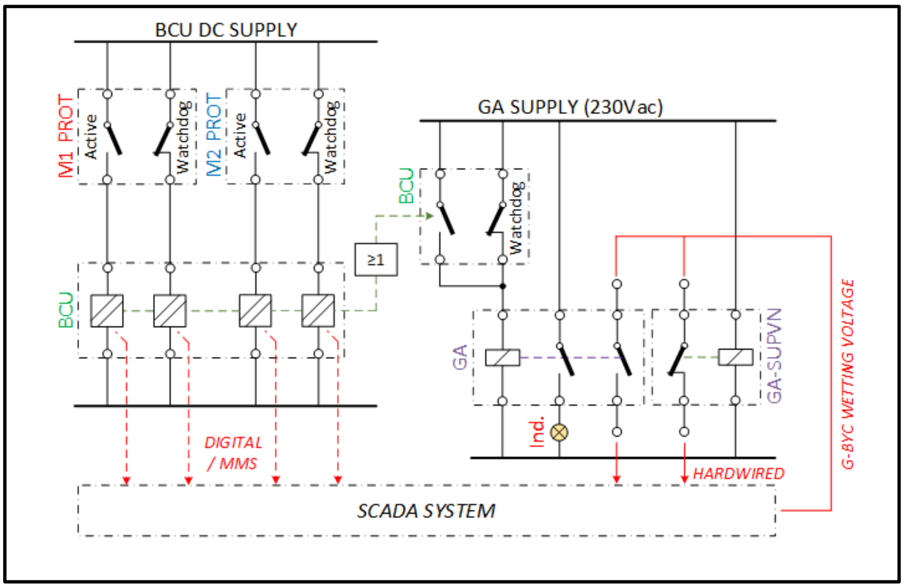

Figure 9 – General Alarm Schematic Arrangement

6.2 Plant and IED signals to SCADA

The IEC 61850 Manufacturer Messaging Specification (MMS) protocol shall be used for data exchange between protection and control IEDs and one or more designated gateways.

Within each IED, MMS report templates shall be established to capture and publish the analogue values (direct and derived), binary signals (raw or processed in logic), trip statuses, alarms and events required for the satisfactory monitoring and operation of the apparatus. Categorisation of content into buffered and unbuffered reports shall be application-appropriate.

Wherever possible, reports shall be compiled and published in the logical node, data object and data attribute structure defined in the standard, with the generic (GGIO) logical node class only used for those signals with a demonstrable absence of a specific LN/DO/DA.

The gateway(s) shall be functionally responsible for collating the reports emanating from the various IEDs in the installation, grouping statuses and alarms together where required, and mapping the substation data to IEC 60870-5-104 for transmission to superior control points. In case of compatibility issues, other communication protocols can be used only if accepted by EirGrid,

The per-bay and substation-wide signals lists shall be developed during the design phase.

IEDs shall provide log files, settings (read and write), disturbance records etc to the SCADA workstations with engineering access.

7 Communication Interfaces

7.1 Teleprotection

7.1.1 Export cable

The communications medium between the offshore and onshore substations shall be fibre optic links embedded in the export cable, managed by multiplexing equipment at each end. The protection IEDs shall interface with the multiplexers for the exchange of data.

For *differential* devices, the interfaces shall be fibre optic patch leads, type OM2 (850nm, 50/125µm), ruggedised, and run-in trunking or conduit.

For *distance* devices, since signal exchange consists only of a limited number of binaries, if a fibre optic interface (as above) is not available, a twisted pair serial connection (shielded EIA-422/485) or hardwired interface may be accepted, provided the multiplexing equipment includes the corresponding modules.

7.1.2 Grid Interface Feeder (Onshore)

Discrete Fibre optic interface devices required for use with distance protection. Use of PLC is not applicable, use of differential channels on differential devices are not acceptable.

Where a fibre optic network with multiplexers is present, IEDs shall be specified as for the export cable above. In the absence thereof, solutions may be explored from the following options.

Differential

IED-to-IED fibre optic:

- <500m – multimode, 850nm
- <2km – multimode, 1300nm
- >2km – single mode, 1310nm

Distance

- Discrete fibre optic interface devices (preferred and required where possible)
- Powerline carrier or similar Teleprotection interface
- Utilising the digital channels within the differential device

7.2 Automation System (SCADA / Telecontrol)

Each protection and control IED shall include two fibre optic ports for integration with the SCADA system. These shall be interfaced with the associated Ethernet switches via fibre optic patch leads, type OM2 (850nm, 50/125µm). Connectors shall preferably be SFP-LC or -SC. Where patch leads are routed entirely within a suite of protection and control cubicles, patch leads shall not need to be ruggedised. IED-to-switch communications shall support a minimum of 100Mbps bandwidth.

Although not the domain of this specification, it is envisaged that the Ethernet switches and switch-to-switch structure will result in a minimum 1Gbps substation LAN backbone.

The protocol within the SCS shall be IEC 61850 Edition 2, facilitating “horizontal” (IED-to-IED, bay-to-bay) GOOSE messaging and “vertical” (IED-to-gateway) MMS reporting.

The substation LAN shall also facilitate file transfer between IEDs and engineering workstations or OT servers, e.g., transfer of settings files, event records and oscillography. Security measures shall be implemented to prevent operating / switching from devices performing such administrative tasks.

It shall be advantageous if an IED offers a third port which may be used to create an OT / maintenance network separate from the automation networks. If offered, such port may be of wired / RJ45 architecture.

8 Cubicle Requirements

General requirements pertaining to cubicles are contained in OFS-SSS-402.

Whilst the above standards shall be followed as far as possible, the following requirements peculiar to *offshore substation* cubicles shall be noted.

Required cable entry point and configuration of cubicles shall be determined during the design phase. Penetrations shall be provided for cabling to locations external, such as GIS rooms or transformer bays.

In general, cable bottom entry into cubicles is preferred where practical. Top cable entries are allowed at OSP where cable entries are indoors. For outdoor equipment, bottom entry is required.

MCT (multi-cable transit) systems or cable termination glands shall be used for cable terminations.

It is envisaged that height available shall be limited, thus cubicles shall be specified based thereon. In any event, the maximum height for cubicles shall be 2,100mm (including a 100mm plinth), and the corresponding 19-inch rack capacity shall be ≤42U.

Cubicles should be placed in a manner geographically consistent with the primary equipment with which they are associated.

Protection and control rooms shall be provided with clean, cool, dry air during normal operating conditions. Where possible, protection and control rooms may be kept at positive pressure to prevent the ingress of ambient (marine) air. Cubicles shall be provided with thermostatically controlled anti-condensation heating.

The general arrangement of equipment to be installed on the swing frames shall be coordinated between cubicles to ensure uniform aesthetics and consistent location of device types.

Sufficient available floor space and space between cubicles / cabinets shall be provided for the placement of maintenance or test equipment and the safe passage of passers-by when cubicle doors / swing frames are fully opened. The space shall not be less than OEM recommended space and requirements of the international standards for operation and maintenance.

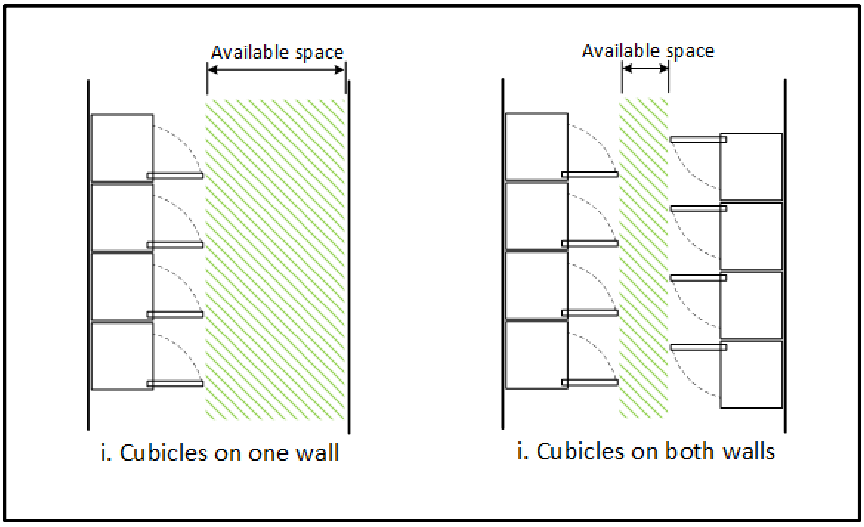

Figure 10 – Plan View of Cubicles

9 Quality Assurance

9.1 Document management

The *customer* shall establish and maintain a document management system per project. Each document, whether drawing or technical literature, shall be assigned a unique alpha-numeric identifier, textual title and revision. Documentation shall be in accordance with EirGrid's standard for documentation, coding and nomenclature document OFS-GEN-006

The language of all documentation shall be English. Metric units and ISO/IEC standard terminology shall be used throughout.

Symbols used in drawings shall be in accordance with IEC 60617 and associated ISO/IEC standards.

Drawings shall be issued in sets, delineated per bay or discrete system. Within each set, circuits performing various functions shall be grouped in sheets. Each drawing set shall include an index sheet detailing the contents and revision numbers of all subordinate sheets. A typical drawing set should incorporate the following elements:

- Equipment layout with legend
- Reference section – symbols, acronyms, explanatory notes
- Functional – block diagrams, programmed logic, trip matrix
- AC key diagrams – CT and VT circuits / IED inputs
- DC key diagrams – 110Vdc main 1, 2 trip, close, spring charge, disconnectors and earth switches, alarms and indication, control functions
- Auxiliary circuits – 230Vac diagram(s)
- Interfaces – terminal lists, bay cabling, communications
- Device reference – diagram(s) reflecting all significant devices included in the scheme, cross-referencing the appearance of each connection / element in the preceding sheets
- Manufacturing-specific – metalwork, label schedules

Drawings submitted to EirGrid or its appointed reviewers shall be provided in PDF format, accompanied by a Transmittal Form, detailing the sets and sheets under cover.

During the concept and detailed design phases, applicable device-specific documentation shall be provided to EirGrid, including:

- Equipment datasheet, IED technical datasheets
- Full sets of device installation, operation and maintenance manuals.

The technical package shall include:

- Operating manual based on the implemented functionality
- Maintenance procedures
- Settings guide / template
- IEC 61850 data model (as an extract from the broader capabilities)
- Decommissioning requirements

The technical materials shall be suitable for the day-to-day operation of the equipment, thus stored on site, in hardcopy format and on engineering workstation(s), as appropriate.

Documentation, drawing handover to EirGrid towards the end of the projects shall be as per EirGrid requirements (described in separate documents).

9.2 QUALITY DOSSIER CONCEPT

For each scheme procured and installed, a quality dossier shall be compiled, maintained and transferred to EirGrid upon handover of the plant. This shall provide a traceable record of each scheme, from procurement to commissioning. The dossier shall be archived by EirGrid since it is not intended to be of relevance for the day-to-day operation of the equipment. It is envisaged that the quality dossier shall contain:

- Original order information
- IED supply data – OEM build sheets, calibration certificates, dispatch documents, firmware
- Rationalised drawings – the applicable phase to be determined, typically As Delivered
- Vendor routine test results and punch lists
- FAT test results and punch lists
- (Site) Integration test reports
- As-built drawings, settings, logic diagrams
- Construction, pre-commissioning and commissioning checklists
- Handover certificate (“ready for voltage and current”)

9.3 CONFORMANCE TEST REQUIREMENTS

Compliance with key standards is a cornerstone of ensuring the offered devices are fit for purpose and will endure the envisaged service life, under onerous environmental conditions.

For each IED and significant device offered, the *customer* shall submit copies of type test and conformance to relevant standards certificates. The certificates shall have been issued by an independent accreditation authority, or where the issuer is an in-house laboratory, a supplementary certificate attesting to that facility’s impartiality shall accompany.

Testing shall have been conducted on a device materially equivalent to the offered products, with only minor variations in input / output configuration permitted. Latest firmware shall be used with similar version firmware for similar devices.

Where certificates are not available, the *customer* shall be responsible for securing same, at their expense.

Table 20 – Conformance and Type Test Requirements

<table>
<tr><th>Ref</th><th>Part</th><th>Description</th><th>Requirements</th></tr>
<tr><td>IEC 61850</td><td>6 – Configuration language
7-x – Basic communication structure
8-1 – Mapping to MMS
9-2 – SMV (future only)
80-1 – IEC 60870-5-10x data exchange (if applicable)</td><td>Multiple mandatory conformance blocks</td><td>Certificate required
Vendor to submit PICS, MICS, PIXIT, TICS</td></tr>
<tr><td>IEC 60529</td><td>-</td><td>Ingress protection</td><td>IP41 (case)
IP30 (with terminals)</td></tr>
<tr><td rowspan="2">IEC 60255</td><td rowspan="2">1 – Common requirements</td><td>Temperature, operation</td><td>-10 to +55°C</td></tr>
<tr><td>Temperature, storage</td><td>-25 to +55°C</td></tr>
</table>

Ref	Part	Description	Requirements
		Temperature, transport	-25 to +70°C
		Relative humidity	5 to 95% (non-condensing)
		Climate class	Vendor to state
		Pollution class	Vendor to state
	21 – Vibration, shock and seismic testing	Shock and bump withstand	Class 1
		Seismic response	Class 2
	26 – EMC	General classification	Class A
	27 – Product safety	Dielectric strength (All values 50Hz, 1 minute)	2kV – analogue inputs, relay outputs, binary inputs 3kV – power supply input 2kV – IRIG-B port 1kV Ethernet ports
		Impulse withstand – common mode	+/-1kV – Ethernet ports +/-2kV – IRIG-B port +/-5kV – Other ports
		Impulse withstand – differential mode	kV – analogue and binary inputs +/-5kV – Relay outputs
		Insulation resistance	100MΩ @ 500V
EN 55011	Interference – group 1	Conducted, 0.15 – 30Mhz	Class A
		Radiated, 30 – 1,000MHz	Class A
IEC 61000	4-2 – Electrostatic discharge	Class III	8kV – Contact 15kV – Air
	4-3 – Radiated RF immunity	20V/m	Sweep 80Mhz to 1GHz
		10V/m	Sweep 1.4 to 2.7GHz
	4-4 – Fast transient burst	Zone A	+/-2kV – comms ports +/-4kV – other ports
	4-5 – Surge immunity	Zone A	+/-2kV – L-L +/-4kV – L-E
	4-8 – Magnetic field immunity	Level 5	100A/m – >60s 1000A/m – 1s
	4-11 – Voltage dips, interruptions and variations 4-14 – Mains voltage fluctuations	Step voltage variations, 230Vac	+/-15% - continuous -20% - 50ms -50% - 20ms
		Wavelike voltage fluctuations, 230Vac	V_{NOM} +/-12%, T = 5s, t = 2s
		Frequency variation	f_{NOM} +/-15% - 1s

Ref	Part	Description	Requirements
	4-17 – DC power ports supplied by rectifier systems 4-29 – DC voltage dips	DC supply variations	V_{NOM} +10% / -20% - continuous
		Ripple content	<12%
		Inrush current	Class 1
		Polarity reversal	No damage
		Positive or negative to earth	No damage

9.4 SCHEME TESTING

The *customer* or their appointed manufacturer / sub-contractor shall develop test plans as part of the supply agreement, for various phases of the project. These shall reflect the progression of the equipment / systems from as-manufactured to ready for commissioning / energisation.

A key component for test plans shall be the compilation of automated test routines for use with commercial injection test sets. These routines shall permit the tester to insert the in-service settings, from which the various injection values are derived, with hold points where required. The routines shall be formatted for printing for record keeping purposes.

9.4.1 WORKS TESTING – MANUFACTURER

Following assembly and wiring of the schemes, the manufacturer shall perform works testing of a routine nature, in preparation for client-witnessed factory acceptance testing (FAT). The activities to be performed shall include:

- Visual inspection and mechanical orderliness test (terminal and mounting bolt tightness)
- Wiring integrity – ringing out
- Insulation integrity
- Power-up and soak test
- Functional testing of various elements – IEDs and auxiliary items
- Application of logic intended to meet the functional requirements
- Application of typical settings to protection elements and injection testing thereof
- Application of temporary LED labels to IEDs
- Functional integration with associated systems – busbar protection, external BCU, SCADA interface

Each scheme shall be provided with a punch list for the recording of defects and solutions applied. These punch lists shall be filed and provided to EirGrid on request.

Upon completion, the Customer shall notify EirGrid that the schemes are ready for FAT. The arrangements regarding the date, notice required, and the right to waive witnessing shall be agreed by the parties.

9.4.2 FAT (FACTORY ACCEPTANCE TESTS)

FAT shall serve as assurance that the schemes built meet the functional and other requirements specified, where after they may be dispatched to site or the OSP assembly yard. Sufficient time shall be allocated for the FAT in order to verify the functionality of all elements.

FAT test procedures and ITP (inspection and test plans) shall be submitted for review to EirGrid prior to FAT and shall include visual, mechanical, electrical and all relevant functional tests, including interfaces with external systems (like SCADA).

EirGrid reserves the right to appoint external parties to witness the FAT on its behalf, or to waive witnessing entirely.

Punch lists shall be provided for the recording of defects or issues. Following conclusion of the FAT tasks, the parties shall meet to discuss the contents of the punch lists, action items (with due dates) and the need, if any, for repeated tests or inspections.

Following the FAT, the manufacturer shall rectify all defects noted in the punch lists, modify drawings as required (revision “As FAT”), apply the permanent HMI labels, and prepare the schemes for delivery.

9.4.3 SAT / SIT

Site Acceptance / Integration Testing shall be conducted by Customer. In the case of equipment destined for sea, SAT / SIT shall take place principally at the OSP assembly yard, and finally with the OSP installed at sea. For OCC equipment, this refers specifically to the service site.

SAT / SIT (including at fabrication yard) test procedures and ITP (inspection and test plans) shall be submitted for review to EirGrid prior to SAT / SIT and shall include visual, mechanical, electrical and all relevant functional tests, including interfaces with external systems. Full integration tests with SCADA and other possible external systems will be required.

The tests will be witnessed by EirGrid and/or their representatives.

SAT / SIT shall have the aim of rigorously preparing the equipment, with full integration with associated systems, for live service. As such, actual settings, logic and SCADA programming for service shall be applied and tested.

Significant testing at sea shall be avoided. Only tasks directly associated with energization and taking of load should be performed:

- Functions dependent on the offshore-onshore communications link
- Checking phasing of potentially asynchronous systems prior to switching
- Onload measurements – ensuring IEDs read and display the correct values
- Verification of derived quantities – power calculations, bias and differential quantities

9.5 IN-SERVICE MAINTENANCE AND TESTING

The general reliability of protection and control devices and the adoption of comprehensive self-diagnostics and monitoring preclude the requirement for regular maintenance of schemes. As such, in-service maintenance shall be confined to:

- Routine injection and functional testing
- A comprehensive test program (audit) at the approximate mid-life interval, circa 12 years
- *Ad hoc* testing following suspected maloperations or anomalies

Given the likelihood that maintenance would need to be conducted with the equipment in service / on load, schemes shall be designed to facilitate testing under live conditions. Such design measures shall include:

- Per-main three-position Test Switches with In-service, Trip Off and Test positions
- Application of test terminal modules / test blocks which…

  - Automatically isolate and short-circuit CT circuits
  - Automatically isolate VT circuits
  - Optionally – provide a means of testing the response of the devices
- Provision of terminals for the testing of device responses (if not incorporated into the test blocks)
- The use of IEC 61850 test bits to prevent propagation of signals generated during testing to other devices / systems in the installation

10 Technical Support

10.1 Device support and/or spares

The *customer*, together with the OEM(s), shall include in their bid written proposals for the technical support to be offered in respect of the delivered systems and devices. The following elements shall be covered, as a minimum:

- The warranty period and conditions
- The expected period, following the warranty period, during which equipment remains commercially available and supported
- The period beyond the commercial availability period, during which support is rendered on a “best effort” basis
- Channels of communication between OEM(s) and EirGrid, for technical and commercial matters
- The recommended spares to be purchased and held by EirGrid – complete devices and individual cards / modules, as necessary
- The process, including time frames, for the repair of equipment submitted to the OEM(s)

The proposals shall be subjected to review by EirGrid.

10.1.1 Obsolescence

No product with a planned phase-out date scheduled within five years shall be offered for projects. For products phased out after this period, the OEM shall continue to offer spares and support for existing devices in accordance with the proposed support provisions.

During the “best effort” support period, should devices and/or modules not be available for purchase, the OEM shall assist with the identification of current products of materially equivalent functionality which may be substituted. Further, the OEM shall be obliged to assist with matters of an engineering matter, such as the installation of devices in existing schemes and the mapping of terminal connections from old to new.

It is noted that all reputable OEMs submit periodic lists of products soon to be discontinued, or for which replacement components / modules will no longer be manufactured, to their customers. The OEM shall add EirGrid to the database of contacts, in this regard. In turn, EirGrid undertakes to regularly update OEM(s) in the event of changes of technology custodians or commercial contacts.

10.2 Training

The Customer shall submit a training plan which shall describe in detail how the Customer proposes to train EirGrid staff for operation of future EirGrid assets.
Training requirements will be detailed further in OFS-GEN-009 - Operation and Maintenance General Specification.

APPENDIX A – P&C FUNCTIONALITY SUMMARISED

The following table summarises the minimum functions required per bay type:

Table 21 – Recommended Protection Functions – OSP

Bay Type	Main 1 IED	Main 2 IED	Other IED/s	Remarks
EHV Export Cable	Line differential with Distance Backup: • Dir O/C E/F • Voltage </> • Frequency </>/ROC	Distance (comms-aided)[1] Backup: • Dir O/C E/F • Voltage </> • Frequency </>/ROC	Bay Control in LCC Control Interlocking V, I, P, Q, cos-ϕ measurements	Comms medium for IEDs to be determined
EHV-HV Export Transformer EHV side	Impedance (distance) – EHV Binary inputs for alarms / trips Backup: • O/C E/F • Negative sequence	Biased differential Inrush restraint Restricted E/F (EHV) Over fluxing Binary inputs for alarms / trips	Bay Control in LCC Control Interlocking V, I, P, Q, cos-ϕ measurements	Intertripping to/from HV side Master Trip (lockout) to be implemented in IED(s) or as a discrete relay
HV Side	Impedance (distance) – HV Binary inputs for alarms / trips Backup: • Dir O/C E/F • Negative sequ. • Voltage </> • Frequency </>/ROC •	-	Bay Control in LCC (Customer) Control Interlocking Synch check V, I, P, Q, cos-ϕ measurements AVR / tap change controller	Intertripping to/from EHV side
EHV Busbar Protection (If busbars used)	Low-impedance biased differential With combined 2-Stage CB Fail[2, 3]	-	-	May be centralised or distributed[4]
HV-LV Aux Transformer	HV O/C E/F LV O/C E/F LV REF Binary inputs for alarms / trips	Biased differential Binary inputs for alarms / trips	Bay Control in LCC (Customer) Control Interlocking V, I, P, Q, cos-ϕ measurements	LV to be equipped with MCCB at input to 400Vac Distribution Board

Notes:

1. The distance scheme shall be considered as a whole – bespoke IEDs, communications medium and interfaces. It is envisaged that bespoke Teleprotection modules shall be included in the multiplexing equipment for the distance scheme signals. Various communications-aided logic shall be possible – POTT, PUTT, blocking, etc.
2. Circuit Breaker Fail – each protection function issuing a command to trip a designated circuit breaker shall simultaneously issue a “Trip / CB Fail Start” signal to the busbar protection scheme. The busbar scheme shall perform a two-stage CB Fail algorithm, comprising (i) retrip attempt to own CB, timer 1,

and (ii) upon expiry of the CBF Trip timer 2, issue back-trip commands to all bays connected to the same zone as the failed circuit breaker. In the case of cable / line CB Fail, the back-trip shall also include an intertrips to the remote end.

3. In the event of no EHV busbar scheme being applied, i.e. where the export cable and EHV side of the main transformer share a circuit breaker, CB Fail evaluation shall be done at bay level, with (i) intertrip transmission to the remote end, and (ii) local intertrip to the transformer HV circuit breaker.
4. Centralised vs distributed busbar protection – in a centralised scheme, all bays' currents, binary signals (disconnector status, CB Fail start, CB status if applicable) and outputs (trip contacts) are wired to a single IED (or three IEDs if the scheme is designed in an "IED-per-phase" manner). In a distributed scheme, each bay's signals are wired to a discrete BBP bay unit, which relays the data to a central unit over a dedicated communications channel. The central unit performs differential and CB Fail back-trip evaluation for the complete busbar, issuing the alarms / trips back to each bay unit for execution.
5. For distance protections of main EHV export cable and transformer, note that 3 forward, 2 reverse and a zone extension required at minimum. Separate distance relays are required for the export cable and transformer.
6. Protections for EHV/HV OSP transformer assume that neutral points will be grounded.

Further, it is observed that modern protection IEDs include numerous backup and complementary functions in addition to their core function. The fact that a device is specified to include a particular function does not necessarily mandate the use thereof in the eventual scheme.

The simplified P&C functionality is summarised in Figure 8. ANSI codes are used as a convenient shorthand to denote the principal protections.

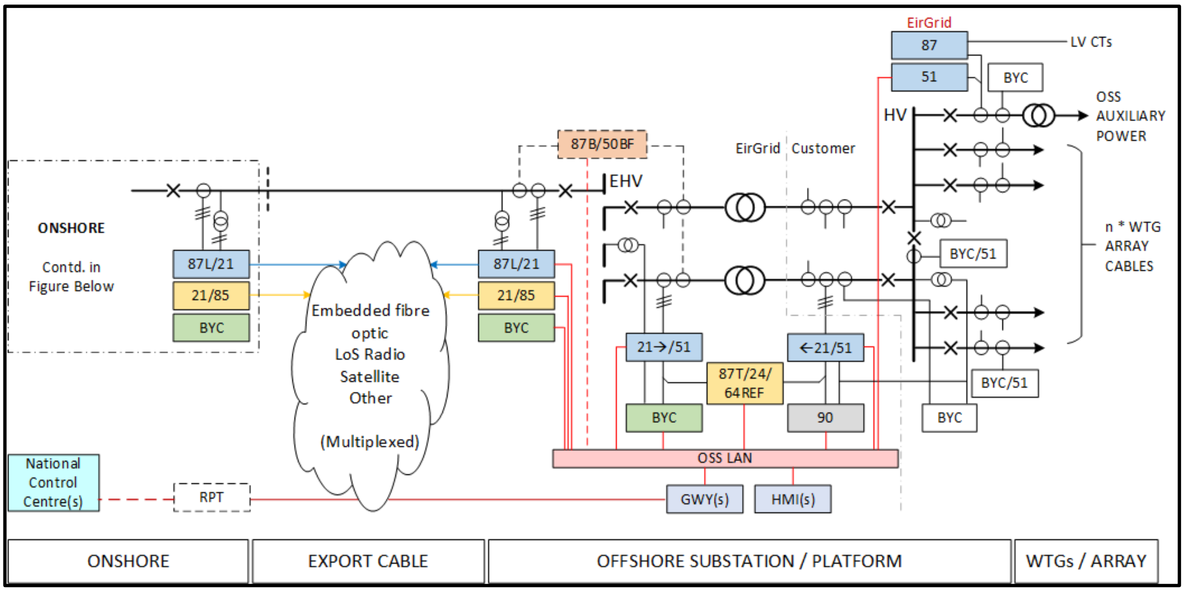

Figure 8 – OSP Protection Functions Summarised

The Shore Substation (Onshore Compensation Compound) serves as the point at which the main export cable is terminated upon making landfall, where cable reactive compensation and voltage regulation is done, and from which a connection to the envisaged transmission network (ESBN) is made.

Table 22 – Recommended Protection Functions – OCC

Bay Type	Main 1 IED	Main 2 IED	Other IED/s	Remarks
EHV Export Cable	*To match IEDs listed in Table above* Ancillary functions: • Transmit intertrips to OSP for reactor fault		Bay Control Control Interlocking V, I, P, Q, cos-ϕ measurements	-
EHV Shunt Reactor	Biased differential Inrush restraint Restricted E/F Binary inputs for alarms / trips	O/C E/F	Control of disconnector by associated feeder BYC IED	Intertripping to feeder CB and remote end
Statcom Equipment	*Protection to be provided by the Statcom vendor, with trip signals integrated with bay CB trip circuitry*		Bay Control Control Interlocking V, I, P, Q, cos-ϕ measurements	-
Harmonic Filter	*As recommended by the filter vendor* To be considered for inclusion in a dual main scheme: • Unbalance • Voltage differential • Overcurrent and earth fault • Overvoltage		Bay Control Control Interlocking V, I, P, Q, cos-ϕ measurements	-
ESBN Feeder (OHL)	Line differential 1&3-pole tripping Auto reclose Backup: O/C E/F	Distance 1&3-pole tripping Auto reclose Backup: O/C, Dir. Comparison E/F	Bay Control Control Interlocking V, I, P, Q, cos-ϕ measurements	Comms media for distance / diff to be determined
	Concurrence with protection to be applied by ESBN			
EHV Busbar Protection	Low-impedance biased differential With combined 2-stage CB Fail protection		-	Centralised vs Distributed
Station Aux Transformer	O/C E/F Binary inputs for alarms / trips	Biased differential Binary inputs for alarms / trips	Bay Control Control Interlocking V, I, P, Q, cos-ϕ measurements	LV to be equipped with MCCB at input to 400Vac Distribution Board

Note to Tables 9 and 10: EHV export cable , reactor, harmonic filter and possibly other 220kV CBs may require point on wave switching. The requirement will be checked and verified during electrical system studies and shall be implemented accordingly.

The simplified P&C functionality is summarised in Figure 9.

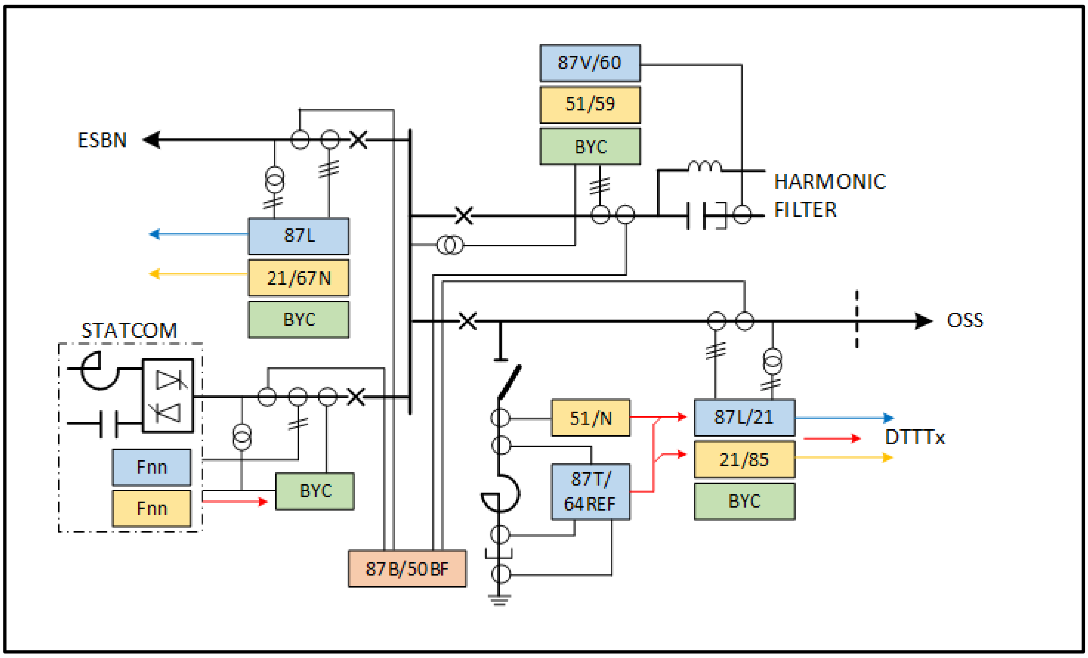

Figure 9 – OCC Protection Functions Summarised

The ANSI device codes used throughout this specification and the tables above are summarised in the following table.

Table 23 Selected ANSI codes pertinent to this specification

Code	Function
21	Distance
24	Over fluxing (volts-per-hertz)
25	Synchroniser or synchronism check
27	Undervoltage
32	Power
49	Thermal
50	Instantaneous overcurrent
50BF	Circuit breaker fail
51	Time-delayed overcurrent
52	(A/B) Circuit breaker auxiliary contacts
59	Overvoltage
60	Unbalance
63	(Over) Pressure
64REF	Restricted earth fault
67	Directional
68	Power swing detection / blocking
71	Liquid level detection
79	Auto reclose
80	Liquid or gas flow
81	Frequency (over, under, rate-of-change)
85	Teleprotection (permissive or direct intertrips)
86	Lockout / Master Trip
87x	Differential (suffix denotes type, e.g. line, transformer, busbar)
89	(A/B) Disconnector / Earth Switch auxiliary contacts
90	(Voltage) Regulator
-N	Suffix denoting fourth wire / earth fault, for 50, 51, 67