1. SCOPE

This specification details SP Energy Networks' requirement for protection and control equipment to meet the requirements defined in SP Energy Networks' policy for application of protection systems to the 33kV network.

2. ISSUE RECORD

This is a Reference document. The current version is held on the EN Document Library.

It is your responsibility to ensure you work to the current version.

Issue Date	Issue No.	Author	Amendment Details
Aug 2009	8	Graham Stirling	Aligned with SWG-03-020; CTs 8, 9 & 10 added.
Nov 2011	9	Darren Griffin	Updated in line with EE10 Solutions
Apr 2014	10	Darren Griffin	Minor editorial changes associated with INS.
May 2019	11	Darren Griffin	Minor editorial changes.

3. ISSUE AUTHORITY

Author	Owner	Issue Authority
Name: Darren Griffin Title: Lead Engineer Engineering Design & Standards	Name: Fraser Shaw Title: Substations Manager Engineering Design & Standards	Name: Fraser Ainslie Title: Head of Engineering Design & Standards F. Ainslie Digitally signed by Fraser Ainslie Date: 2019.07.29 11:50:30 +01'00'

4. REVIEW

This is a Reference document which has a 5-year retention period after which a reminder will be issued to review and extend retention or archive.

5. DISTRIBUTION

This document is not part of a Manual maintained by Document Control but has a maintained distribution list.

6. CONTENTS

7. REFERENCE DOCUMENTS

It is important that users of all standards, specifications and other listed documents ensure that they are applying the most recent editions together with any amendments. This specification makes reference to, or implies reference to, the following documents in addition to those listed within ENA TS 41-36.

Health and Safety at Work Act 1974
Electricity at Work Regulations 1989

BS 6701	-	Telecommunication Equipment and Telecommunications Cabling Specification for Installation, Operation and Maintenance
BS EN 41003	-	Particular Safety Requirements for Equipment to be connected to Telecommunication Networks
BS EN 60947-3	-	Low-voltage Switchgear and Controlgear. Switches, Disconnectors, Switch-Disconnectors and Fuse Combination Units
ENA ALP 1/*	-	ENA Protection Approved Equipment Register (*denotes latest revision)
ENA ER G99	-	Requirements for the connection of generation equipment in parallel with public distribution networks on or after 27th April 2019
ENA ER S15	-	Standard Schematic Diagrams
ENA TS 41-36	-	Switchgear for Service up to 36kV (Cable and Overhead Conductor Connected
ENA TS 48-3	-	Instantaneous High Impedance Differential Protection
ENA TS 48-4	-	DC Relays Associated With a Tripping Function in Protection Systems
ENA TS 48-5	-	Environmental Test Requirements for Protection Relays and Systems
ENA TS 48-6-7	-	Communication Services for Teleprotection Systems
ENA TS 50-18	-	Design and Application of Ancillary Electrical Equipment
ENA TS 50-19	-	Specification for Standard Numbering for Small Wiring for Switchgear and Transformers, Plus Associated Relay and Control Panels
ESDD-01-001	-	Design Philosophy & Principles
IEC 61850	-	Communication networks and systems in substations
IEC 61869 Part 2	-	Current Transformers
IEC 61869 Part 3	-	Inductive Voltage Transformers
IEC 60255-13	-	Biased (percentage) Differential Relays
IEC 60255-151	-	Functional Requirements for Over/Under Current Protection
IEC 62271-100	-	High-Voltage Switchgear and Control Gear – Part 100: High-Voltage Alternating Current Circuit Breakers
INS 50.42.06	-	Metal Enclosed Switchgear up to 52kV
PROT-01-006	-	33kV Protection and Control Application Policy
PROT-01-007	-	132kV Protection and Control Application Policy
PROT-03-015	-	Automatic Voltage Control Systems
PROT-16-001	-	Technical Specification Distance Protection
PROT-16-002	-	Technical Specification Feeder Unit Protection
PROT-16-006	-	Technical Specification Overcurrent & Earth Fault Protection
PROT-16-009	-	Technical Specification Command Based Teleprotection
PROT-16-010	-	Technical Specification Fault Recording Equipment
PROT-16-020	-	Technical Specification Operational Intertripping
PROT-16-026	-	Distribution Bay Control Unit IED
SWG-03-036	-	Specification for Double Busbar 36kV Indoor Metal Enclosed Switchgear

8. INTRODUCTION

This specification details the requirements for protection and control equipment to be applied to the 33kV network within the SP Distribution and SP Manweb licence areas. Sections 10 to 16 of this document details the performance and functional requirements for the equipment. The schedules in section 17 detail the individual requirements for the most commonly used circuit configurations.

This document should be read in conjunction with the 33kV Protection and Control Policy document PROT-01-006, which provides further detail on protection scheme logic and CT/VT allocation and the 33kV Indoor Switchgear Specification, INS 50.42.06 for single busbar and SWG-03-036 for double busbar equipment. Where relevant, SP Energy Networks specification documents PROT-03-020, INS 50.42.06 and SWG-03-036 shall be cross-referenced to ensure the overall applicability of a scheme.

9. DEFINITIONS

For the purpose of this specification, the following definitions shall apply:

SP Energy Networks (SPEN)	The brand name for the division of the ScottishPower group of companies that encompasses SP Distribution plc, SP Transmission plc, SP Manweb plc, SP Power Systems Ltd and Scottish Power Energy Networks Holdings Ltd.
The Engineer	SP Energy Networks' nominated representative having authority over technical matters contained within this specification.
Approved	Equipment approved in accordance with SP Energy Networks' Equipment Approvals Procedure and which is considered suitable for use and/or installation on SPEN's networks. Approval shall be given in writing by the Engineer.
The Tenderer	Manufacturer or distributor invited to tender in accordance with this specification.
The Supplier	The successful Tenderer (one or more).

10. PERFORMANCE REQUIREMENTS

The equipment design shall meet the following requirements.

10.1 Reliability

Where practicable, failure of any component shall not result in an undetected loss of system functions. The Supplier shall protect against multiple and cascading component failures. The mean time between failures (MTBF) of any sub-system component shall be not less than 25,000 hours.

10.2 Availability

The Supplier shall include supervisory checks required to optimise system availability. Alarms shall be initiated whenever a failure has been detected. The overall protection system availability shall be not less than 99.997%.

10.3 Maintainability

The Supplier shall incorporate all test points, isolation facilities and labelling required to enhance the maintainability of the system.

Recommended maintenance intervals for all supplied equipment shall be stated in the technical schedules at the time of tender.

11. GENERAL

11.1 Equipment Practice

The equipment supplied shall meet the requirements of ENA TS 48-5, “Environmental Test Requirements for Protection Relays and Systems” and ENA TS 50-18, “Design and Application of Ancillary Electrical Equipment”.

Enclosures shall be of metal construction or other approved material and the thickness of material shall ensure that relays or other equipment do not maloperate due to impact or vibration. The construction shall minimise the spread of fire from any enclosure to a neighbouring enclosure.

Where necessary, all enclosures shall be fitted with suitable switched illumination circuits with supply requirements in line with ENA TS 50-18 to provide safe working conditions.

All apparatus and terminals shall be easily accessible without the need to disturb other apparatus or wiring.

Each enclosure shall be fitted with a circuit identification label on its front surface. Where rear access is possible, the rear of the enclosure shall also be labelled. If it is possible to remove the enclosure doors, each door shall be individually labelled. All equipment on the exterior of the enclosure shall be labelled to identify its function and, where deemed appropriate by the Engineer, shall be fitted with a warning notice. Labels and inscriptions shall not degrade under the prevailing ambient conditions. The wording and location of all equipment labelling shall be to the satisfaction of the Engineer. The method of attachment and materials used to prevent corrosion shall be to the satisfaction of the Engineer.

Enclosures shall be prepared, primed and painted to the satisfaction of the Engineer.

Indoor and outdoor enclosures shall be fitted with anti-vermin protection to the satisfaction of the Engineer.

The Tenderer shall include details of crimps, crimping systems, wires, terminals and terminations, which they propose to use. Wire colours shall be to the satisfaction of the Engineer.

Earth wires shall be green or green/yellow and equipment shall be connected in a radial fashion. The removal of any component shall not affect the integrity of the earthing system.

In existing substations, wires are numbered in accordance with ENA TS 50-19. Where existing substations are to be modified, all new wiring shall also be in accordance with this standard. For new substations, the Tenderer shall provide details of the numbering system he proposes to use.

Protection devices, including hardware and software versions, shall be selected from the current issue of the Energy Networks Association Approval List - ALP 1/*.

In order to comply with IEC 62271-100 for circuit breakers, the cumulative protection and trip relay operating times shall not be less than 10 milliseconds.

The total fault clearance time, including circuit breaker operation, shall not exceed 200ms under normal system operating conditions.

The arrangement of equipment on panels shall be subject to approval by the Engineer.

The output contacts of protection relays shall be rated to make and break the loads connected without deterioration. The Supplier shall be responsible for providing all auxiliary and tripping relays required in order to meet the specification. Trip relays, where required, shall comply with ENA TS 48-4, defined as high or low burden, as required.

Protection and ancillary functions may be combined into one or more protective devices to give the most cost-effective arrangement. This arrangement shall be subject to the approval of the Engineer.

Time delayed protection shall provide a volt free output contact at an external connection to indicate pick-up of the starting element. Overcurrent and earth fault elements, where no clear indication of the operated element is apparent, shall have separate contacts.

In accordance with ENA TS 41-36, clause 2.5.8 the operation of the protection shall be so designed that if the closing and opening releases remain energised simultaneously, the circuit breaker shall not open and close continuously.

All protection scheme and circuit breaker operation counters shall be visible when standing in front of the switchgear or associated enclosure. When incorporated into protection relays, they shall be easily accessed by simple navigation of a menu system.

Protection Group setting selector switches shall be provided adjacent to the protection equipment, or alternatively this functionality may be provided via relay pushbuttons with suitable indication of status, to enable the protection to be switched from the normal service protection setting to an alternative setting group. (Note: If this facility is required, then it will be specified at the time of ordering).

The Supplier shall make economic and effective use of the communication medium and minimise physical wiring between relays, switchgear and any SCADA outstation.

Test facilities shall be provided for each protection system to allow independent injection testing of CTs and associated protection relay(s) for each HV circuit breaker. The facilities shall be clearly visible to an operator standing in front of the switchgear. Intertripping and unit protection systems shall be provided with facilities to allow communication and pilot cable isolation for end-to-end testing. The configuration of the test facilities shall be subject to the approval of the Engineer.

AC & DC power supply circuits may be protected using miniature circuit breakers in accordance with clause 6.4 and 6.5 of ENA TS 50-18. The circuit-breakers shall be suitable for providing a Point of Isolation in accordance with BS EN 60947-3. A lockable cover plate or enclosure shall be provided to prevent circuit-breakers from being closed after they have been opened and padlocked. Isolation links may be of the MC (multi-contact) type.

11.2 Accommodation

Any apparatus, which may require access for testing, maintenance or operational reasons in-situ, shall be accessible from ground level. Protection equipment that can be interrogated using either a front panel display or communications interface shall be positioned at a minimum distance of 450mm to the centre of the equipment from floor.

Equipment to which access is required for test or adjustment, shall not be mounted more than 1.8 metres above any permanent access way. Relays associated with protection and tripping functions shall be visible from the front of the equipment and again be mounted no higher than 1.8 metres above any permanent access way.

All indications associated with protection and control equipment shall be visible from the front of the cubicle.

All protection and control equipment related to an individual feeder circuit shall, where practicable, be accommodated within the associated circuit breaker auxiliary & control equipment enclosure. Where practicable, this shall include the intertripping relay for that circuit, plus associated intertripping equipment if required.

All protection and control equipment related to a transformer incomer circuit shall, where practicable, be accommodated within the associated circuit breaker auxiliary & control equipment enclosure. However, it is common practice for the transformer overall protection and intertripping equipment to be considered as part of the transformer HV protection and, as such, may be mounted on a separate, remote panel.

Automatic voltage control equipment for up to two transformers shall be mounted on a single common panel or wall mounted enclosure as required.

12. FUNCTIONAL REQUIREMENTS

All protection schemes shall be designed in accordance with the SP Energy Networks 33kV Protection and Control application policy PROT-01-006 in conjunction with the 132kV Protection and Control application policy PROT-01-007 for grid incomer circuits.

12.1 Instantaneous Earth Fault

High impedance definite time (instantaneous) earth fault protections, including any associated stabilising or shunt setting resistors plus Metrosil, shall comply with the requirements of ENA TS 48-3. The operating time shall not be greater than 100 milliseconds at three times the relay setting.

12.2 Instantaneous High Set Overcurrent

Three-phase definite time (instantaneous) high set overcurrent (HSOC) protection shall be provided with a minimum setting range of 100% to 400%. The relay shall have a transient overreach of not greater than 5% for system X/R ratios up to 30 across all settings, with a pick up/drop off ratio of not less than 80%.

The operating time of the HSOC relay shall not be greater than 100 milliseconds at 3 times setting. The resetting time of the relay from 2 times current setting value to zero current shall not be greater than 40 milliseconds. The assigned error of the relay shall not be greater than 5%.

12.3 IDMT Overcurrent and Earth Fault

This protection shall be in accordance with PROT-16-006 and generally as follows.

A three-phase and earth fault IDMT/DTL protection shall be provided with a minimum setting range of 25% to 200% for the overcurrent elements and 10% to 100% for the earth fault elements. The time-delayed protection shall have a range of SI, VI, EI and DTL characteristics in accordance with IEC 60255-151. The time multiplier range shall, as a minimum, be 0.1 to 1.5 in steps of 0.025. The assigned error of the relay shall not be greater than 5%, with a maximum overshoot of 80 milliseconds.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure and shall be capable of remote communication. It shall provide comprehensive fault and event recording facilities.

12.4 Directional Overcurrent

This protection shall be in accordance with PROT-16-006 and generally as follows.

A three-phase IDMT/DTL protection shall be provided with a minimum setting range of 25% to 200%. The time-delayed protection shall have a range of SI, VI, EI and DTL characteristics in accordance with IEC 60255-151. The time multiplier range shall, as a minimum, be 0.1 to 1.5 in steps of 0.025. The assigned error of the relay shall not be greater than 5%, with a maximum overshoot of 80 milliseconds. The relay shall have integral voltage transformer supervision with a user selectable option of alarm only or protection blocking and alarm.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure and shall be capable of remote communication. It shall provide comprehensive fault and event recording facilities.

12.5 Interlocked Overcurrent

A three-phase IDMT/DTL protection shall be provided with a minimum setting range of 25% to 200%. The time-delayed protection shall have a range of SI, VI, EI and DTL characteristics in accordance with IEC 60255-151. The time multiplier range shall, as a minimum, be 0.1 to 1.5 in steps of 0.025. The assigned error of the relay shall not be greater than 5%, with a maximum overshoot of 80 milliseconds. Operation of the protective element is inhibited and is only released upon the operation of a busbar protection tripping relay.

12.6 Two Stage Overcurrent

This protection shall be in accordance with PROT-16-006 and generally as follows.

Two stage HV three-phase overcurrent IDMT/DTL protection shall be provided with a minimum setting range of 25% to 200%. The time-delayed protection shall have a range of SI, VI, EI and DTL characteristics in accordance with IEC 60255-151. The time multiplier range shall, as a minimum, be 0.1 to 1.5 in steps of 0.025. The assigned error of the relay shall not be greater than 5%, with a maximum overshoot of 80 milliseconds. The relay shall include an integral timer with a setting range of 0.05 to 1 second in 50 millisecond steps.

Stage 1 operation shall initiate a trip output and start the timer. If stage 1 does not reset, then a separate trip output command shall be initiated following operation of the time delay element.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure and shall be capable of remote communication. It shall provide comprehensive fault and event recording facilities.

12.7 Grid Transformer Protection

This shall consist of an overall unit protection scheme to provide protection against phase to phase and phase to earth faults on the transformer and its associated connections. Note: This protection scheme will generally be mounted on a remote panel and will be treated as part of the transformer HV protection.

The protection scheme shall consist of overall biased differential protection to IEC 60255-13, together with HV and LV restricted earth fault protection. The protection shall be capable of accommodating change in transformer ratios of between +/- 20% of nominal and restrain for magnetising inrush conditions and shall provide internal compensation for vector group and HV/LV current transformer mismatch.

Where required, a separate standalone LV REF relay shall, where practicable, be accommodated within the associated circuit breaker auxiliary & control equipment enclosure.

The maximum protection operating time shall be 100 milliseconds and the reset time not exceeding 50 milliseconds.

The relay(s) shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure and shall be capable of remote communication. It shall provide comprehensive fault and event recording facilities.

12.8 Transformer Auxiliary Tripping

The following external protection systems shall trip into the transformer protection system:

- Main Buchholz
- Auxiliary Buchholz
- Tapchanger Buchholz
- Winding/oil temperature

- Pressure relief

LED indications and relay output contacts or hand reset current operated flag relays shall be used to provide local and remote indication of the above operations.

12.9 Transformer Auxiliary Alarms

The following external protection alarms shall provide local and remote indications:

- Main Buchholz gas
- Auxiliary Buchholz gas
- Winding/oil temperature
- Cooler Fail

12.10 Restricted Earth Fault

High impedance definite time (instantaneous) earth fault protections, including any associated stabilising or shunt setting resistors plus Metrosil, shall comply with the requirements of ENA TS 48-3. The operating time shall not be greater than 100 milliseconds at three times the relay setting.

12.11 Standby Earth Fault

This protection shall be in accordance with PROT-16-006 and generally as follows.

Two-stage standby earth fault protection operated from a current transformer located in the 33kV neutral earth connection. The relay shall have a range of SI, VI, LTI and DTL characteristics in accordance with IEC 60255-151, with a setting range of between 10 and 100%.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure and shall be capable of remote communication. It shall provide comprehensive fault and event recording facilities. Stage 2 of this protection scheme, where required, may be included within either the same relay or achieved using a separate relay.

12.12 Unit Protection

This protection shall be generally in accordance with PROT-16-002 and shall include the following specific requirements.

The maximum operating time of the protection shall be not greater than 100 milliseconds; the maximum reset time shall be 50 milliseconds.

Where practicable, and subject to the approval of the Engineer, the scheme shall include integral intertripping to initiate tripping of the remote end for an operation of the local end equipment, or from external initiating devices such as trip relays. The maximum operating time, defined as the time between initiation of a signal into the local equipment and receipt of the signal output by the remote equipment, shall be less than 100 milliseconds, including the channel propagation delay time.

The relay shall be suitable for use in configurations with single shot repetitive three pole auto reclosing schemes as detailed in section 12.18. It is acceptable that the auto reclosing function is incorporated within either the main or backup protection relay.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure. It shall provide comprehensive fault and event recording facilities.

The equipment shall be capable of communicating over any of the communication channels specified in the contract specific schedules. Reference shall be made to ENA TS 48-6-7 to ensure the performance of the communication medium is adequate for the specific protection in question.

12.13 Distance Protection

The equipment shall be generally in accordance with PROT-16-001 and shall include the following specific requirements.

The maximum zone 1 operating time of the protection shall be not greater than 100 milliseconds; the maximum reset time shall be 50 milliseconds.

A full scheme distance relay is required with independent measuring elements per zone and per fault loop, operating on a continuous measuring basis. It shall be equipped with a minimum of three forward zones and one reverse zone. The relay shall provide Mho and quadrilateral characteristics as selectable options, with the ability to either shape the characteristic in both axes or provide load blinders as required. The relay shall be capable of operating as a plain scheme with direct remote tripping where required.

Where specified, a permissive overreach transfer trip (POTT) distance scheme will be required for use within interconnected networks. This scheme will be equipped with directional earth fault elements capable of detecting and clearing up to 100 ohm earth faults within 200ms. This scheme will also include weak infeed logic to enable fast clearance of all in-zone faults in instances where the network is being run in an abnormal condition, e.g. with open points on interconnected feeders.

The scheme shall include integral intertripping to initiate tripping of the remote end for an operation of the local end equipment or from external initiating devices such as trip relays. The maximum operating time, defined, as the time between initiation of a signal into the local equipment and receipt of the signal output by the remote equipment, shall be 100 milliseconds, including the channel propagation delay time.

The equipment shall incorporate single-shot repetitive delayed automatic reclosing facilities in accordance with section 12.18.

The relay shall have self-monitoring circuits with a watchdog arranged to give an alarm on failure. It shall provide comprehensive fault and event recording facilities.

The equipment shall be capable of communicating over any of the communication channels specified in the contract specific schedules. Reference shall be made to ENA TS 48-6-7 to ensure the performance of the communication medium is adequate for the specific protection in question.

12.14 Busbar Protection

The Busbar protection system shall comprise of differentially connected current transformers on all circuit breakers in each zone, with individual phase relays for the detection of both phase and earth faults. Where busbar earthing is provided within the switchgear design the current transformer allocation for the busbar protection system shall ensure correct discrimination for operations which may result in an earth being applied to the live busbar. In the case where the bus section circuit breaker is used to apply the primary earth then the earthing device shall preferably be included within both zones of protection. Where it is not possible to include the earthing device within the protection zones, interlocking shall be applied to prevent operation of such devices unless all points of infeed are removed. In addition to the main discriminating system, a check system is also required and this may be provided in a number of different ways.

For SP Energy Networks (North) area, where the incoming supply neutral is available, a neutral check system may be fitted in each zone for the detection of earth faults. Where no incoming supply neutral is available, duplicate phase relays may be fitted to provide the check feature. Alternatively numeric based biased differential protection utilizing a check zone algorithm may be used. For small boards, e.g. windfarm connections, or three or four-panel boards, it may be permissible to utilise only one high-impedance relay or to include the busbar within feeder unit protected zones. For double busbar stations, a scheme consisting of separate Class X CT’s for the high impedance discriminating and check systems may be employed with the discriminating zone being switched via suitable auxiliary switch contacts. Alternatively a numeric based scheme using a centralised architecture using discriminating and check fault detection systems may be used.

For SP Energy Networks (South) area, a scheme comprising of a single Class X CT and two high-impedance relays connected in parallel shall be employed. Alternatively numeric based biased differential protection utilizing a check zone algorithm may be used. Where RMU replacement equipment is being installed, it is permissible to utilise only one high-impedance relay or to include the busbar within feeder unit protected zones.

High impedance differential protection shall be set in accordance with ENA TS 48-3.

Current transformer supervision (including connections) shall be provided to detect open circuit winding or connections. For electro-mechanical relays, the supervision relay shall be arranged to short circuit the bus wiring and provide a local and remote alarm. For modern IEDs, the supervision relay shall be arranged to block the protection element and provide a local and remote alarm. The supervision relay shall be set to 10% of the main detecting relay.

The connections from the current transformers shall pass through shorting/disconnection links before connection to the busbar protection system. In one position, the link shall provide a normal connection to the system, whilst in the other it shall short out the current transformer and isolate it from the busbar protection system. It shall be possible to short out the CT before moving the link to the isolated position. The test links shall normally be located at the front of the switchgear.

12.15 Connections Protection

A current differential protection shall be provided at the interface between SP Energy Networks and any third parties connection. The protection shall meet the requirements of ENA TS 48-3 using a differential algorithm based on current inputs from each end of the protected plant.

The protection shall be capable of detecting all phase to earth faults and phase-to-phase faults. Current transformer supervision (including connections) shall be provided to detect open circuit winding or connections.

12.16 Intertripping

Where required, an individual intertrip system shall be provided for each feeder. It is acceptable for the intertripping function to be an integral part of the main or backup protection system. Should an operational intertrip also be required then this shall be independent of the intertrip system used for protection purposes and shall be in accordance with PROT-16-020.

The maximum operating time, defined as the time between initiation of a signal into the local equipment and receipt of the signal output by the remote equipment, shall be 100 milliseconds, including the channel propagation delay time.

Intertrip supply supervision shall be provided. Upon loss of supply, an internal and external alarm shall be generated. The supply supervision may be integral to the intertripping equipment.

The intertripping scheme shall be in accordance with PROT-16-009, with the following options.

12.16.1 Metallic Pilot Wire Intertripping

For metallic pilot wire intertripping, the scheme shall include pilot wire supervision together with loss of supervision supply, which should preferably operate via an injection voltage of 110V AC. Use of other voltages shall be subject to the approval of the Engineer. If the pilot connection is via underground cable, then 5kV insulation shall be provided; if it is via overhead cable, then 15kV insulation with appropriate isolation transformers shall be provided. The scheme shall utilise a maximum of 4 cores within the pilot cable.

For transformer feeders, surgeproof intertripping over metallic pilot cable, complete with intertrip supply supervision and pilot wire supervision shall be provided. If the pilot connection is via underground cable, then 5kV insulation shall be provided; if it is via overhead cable, then 15kV insulation shall be provided. The scheme shall utilise a maximum of 4 cores within the pilot cable.

12.16.2 Voice Frequency Intertripping

The equipment shall be capable of operating over a voice frequency channel presented as a four-wire circuit with a nominal characteristic impedance of 600 ohms (balanced).

Note: VF Intertripping should be considered only when all other avenues of communication medium have been explored.

12.16.3 Digital Intertripping

The equipment shall be capable of operating over the following types of communications channels:

- n x 64 kbps optical fibre interface with multiplexer to C37.94.
- 64 kbits/s four wire co-directional duplex transmission to ITU-T G703.
- n x 64 kbits/s digital services to ITU-T X21.
- Direct fibre connection – the Supplier shall offer fibre terminations to match site conditions, including connectors, together with the maximum distance for the communication circuit.

12.16.4 Direct Intertripping (i.e. hard-wired)

Hard-wired intertripping may be employed where the local and remote ends of the circuit are situated within the same physically secure environment and where a full intertripping scheme is not considered necessary. e.g. Where a primary substation is located on the same site as the grid supply point. (Note: although no intertripping relays are required, the use of an intertrip receive/follower relay functionality may be required).

12.16.5 No Intertripping

Historically, transfer tripping was, in many cases, provided via fault thrower isolators installed within outdoor compounds of primary substations. As per ESDD-01-001 the intent is to remove such devices from the system. Where such devices are the only viable and economic solution, agreement to retain/install shall be sought from Network Planning and Regulation (NP&R).

12.17 Trip Relays

Trip relays, where required, shall comply with ENA TS 48-4, defined as high/low burden as required. Where electrically reset relays are employed, a means shall be provided to prevent the energisation of the reset coil whilst the trip initiation is still standing.

Trip relays and trip relay resetting facilities shall be provided in accordance with the following:

12.17.1 Busbar Protection

Trip relays shall be latched and electrically reset (hand-reset flag). These trip relays shall only be reset locally, by means of a common push-button located on the busbar protection panel.

12.17.2 Transformer Protection

Trip relays shall be self-resetting (hand-reset flag) with economy cut off.

12.18 Delayed Auto Reclosing (DAR)

The DAR function shall consist of a single shot repetitive scheme. DAR equipment shall be provided for post fault reclosing of a circuit breaker connected to a single busbar. The DAR shall be initiated by a valid protection relay operation whilst the associated circuit breaker is closed and in service. If any line reference voltage available does not go dead within 2 seconds, then the DAR sequence shall reset. Once a DAR sequence has commenced, the equipment shall provide an “Automatic Switching in Progress” indication and remote indication.

12.18.1 Dead Line Charge

Once the initiation has reset, the DAR sequence shall proceed to close the associated circuit breaker on expiry of the programmed dead time. The dead time setting shall be user selectable in the range of 1 to 120 seconds. After the reclose initiation, the DAR sequence shall enter the programmed reclaim period (user selectable in the range of 1 to 60 seconds). Upon timeout, the scheme shall reset then initiate an “Automatic Switching Complete” indication for a period of two seconds and provide a remote indication. (Note that for interconnector circuits between busbar stations the same operating principle shall apply, with a minimum of 2 seconds between the dead times of both equipments).

12.18.2 Transformer Feeder (low voltage end)

Once the initiation has reset, the relay shall remain in the “In Progress” condition until the voltage check input is active (i.e. HV volts have been restored). Following this, the relay shall enter the programmed dead time, after which it shall issue a close command to the associated circuit breaker. After the reclose initiation, the DAR sequence shall enter the programmed reclaim period and upon timeout, the scheme shall reset, initiate an “Automatic Switching Complete” indication for a period of 2 seconds and provide a remote indication.

12.18.3 Interconnector / Unit Protected Feeder

For SP Energy Networks (North), where DAR is to be applied to an interconnector or unit protected feeder, a voltage check facility is required at the remote end of the feeder to confirm that system volts have been successfully restored, prior to that remote end entering its DAR sequence. This shall normally be derived from a 33kV voltage transformer. Once confirmation that system voltage is present has been received, the remote end relay shall enter its programmed dead time and operate as detailed in section 12.18.2. Under certain conditions, it may be permissible for the DAR sequences to be initiated by settable timing delays, rather than using voltage sensing.

For SP Energy Networks (South), where DAR is to be applied to an interconnector or unit protected feeder DAR sequences are to be initiated by settable timing delays.

To enable a DAR sequence to be aborted, a facility shall be provided via a status input to lock out the DAR up to a point immediately prior to issuing the CB close command. A DAR lockout condition shall have a delayed drop off of 2 seconds.

To enable the DAR sequence to be paused until specific conditions are met, a DAR inhibit status input shall be provided. The sequence shall be suspended until the inhibit condition has been removed.

The equipment shall be capable of being switched IN/OUT of service, by energisation of status inputs. These shall be capable of accepting pulsed inputs of minimum 2 second duration. The service state shall be indicated locally and remotely by use of external relay contacts. When the DAR is switched IN/OUT of service, it shall move to the lockout condition for a period of 4 seconds.

Where such facilities exist, the equipment may be switched IN/OUT of service by function keys and SCADA commands via IEC 61850.

The equipment shall have an internal operation counter with the ability for the user to set maintenance pre-lockout and lockout values when used with oil circuit breakers. At the pre-maintenance value, local and remote indication shall be provided. At the maintenance lockout value, local and remote indications shall be provided and the equipment shall remain in the lockout condition until manually reset.

12.19 Trip Circuit Supervision

All circuit breakers shall be fitted with a trip circuit supervision scheme in accordance with ENA ER S15, type H7 functionality. Operation of the trip circuit supervision scheme shall inhibit closing of the circuit breaker and provide local indication and a remote alarm facility.

12.20 Protection Supply Supervision

The DC supply to each panel may be either fed radially from the distribution panel or by a ring system. Each separately fused circuit should include an individual protection supply supervision facility. Subject to the approval of the Engineer, the supply supervision may be included in the protection equipment connected to the supply in question. Operation of the Protection Supply Supervision element shall provide a local indication and a remote alarm facility.

12.21 Voltage Transformer Monitoring

VT monitoring shall be provided to detect the loss of any one or all phases. After a time delay, the relay shall block the operation of the associated distance or directional protection and provide a local indication and remote alarm facility. The time delay shall be user settable within the range 0 to 30 seconds in 0.5 seconds steps.

12.22 Under Frequency Load Shedding

All relays/IEDs used for Under Frequency Load Shedding shall be grid code compliant.

Under Frequency elements shall measure the frequency in all three phases and operate if the measured frequency in all three phases is outside of the applied setting. The relay shall include adjustable definite time settings and differential pick up/drop off operation.

Where grid code compliant functionality exits within bay control unit IEDs fitted to each bay, under frequency tripping may be performed via a single output on a bay by bay basis. It shall be possible to switch this function into/out of service locally via function keys and remotely via SCADA. Local and remote indication and remote operation alarm facilities shall be provided.

Where such facilities do not exist within each bay, then the under frequency tripping scheme shall operate on a 2 out of 2 basis. The main and check elements shall be supplied from different voltage transformers. Each panel shall have a self-reset follower trip relay, incorporating a 2 second delayed reset or alternatively may be included within the circuit protection equipment. No single stage will trip a circuit breaker without the check relay having operated. The main relay may utilise two separately adjusted output channels to give Stage 1 and Stage 2 detection from a single relay. The check feature shall be initiated from a separate relay set to operate at the Stage 1 level. Alarms to indicate under-frequency relay operation and trip shall be provided along with a load shedding “In service/Out of service” switch and an “Out of service” indication lamp.

The stage settings will be selected from standard set frequencies and those, along with feeder selection, will be the responsibility of SP Energy Networks.

12.23 Generator Interface Protection

The protection system shall where practicable include the following protection elements as a time-delayed backup to those within ENA ER G99:

12.23.1 Over/Under Voltage

This shall measure the phase to neutral voltages in all three phases and operate if the measured voltage in any single phase is outside of the applied setting. A 2-stage element shall be provided in each case with a setting range of between 10% to 110% (under voltage) and 60% to 150% (over voltage) of nominal voltage with a 1% step size. It shall be possible to apply a definite time delay to each element with a setting range of 0 to 20 seconds with a 0.5 second step size.

Pole dead logic shall be applied to each of the under voltage elements which uses under voltage and current detectors to determine if the circuit breaker has opened to isolate the voltage transformer. Operation of the pole dead logic shall block the under voltage element.

12.23.2 Over/Under Frequency

This shall measure the frequency in all three phases and operate if the measured frequency in all three phases is outside of the applied setting. A two-stage element shall be provided in each case with a setting range of between 40Hz to 55Hz (under frequency) and 45Hz to 60Hz (over frequency) of nominal frequency with a 0.01Hz step size. It shall be possible to apply a definite time delay to each element with a setting range of 0 to 100 seconds with a 0.5 second step size.

It shall be possible to apply a pole dead logic to under frequency elements, which uses under voltage and current detectors to determine if the circuit breaker has opened to isolate the voltage transformer. Operation of the pole dead logic shall block the under frequency element.

12.23.3 Rate of Change of Frequency (ROCOF)

This shall measure the frequency in all three phases and operate if the measured rate of change of frequency in all three phases is outside of the applied setting. A single stage element shall be provided with a setting range of between 0.1 to 10Hz/second with a 0.01Hz/s step size. It shall be possible to apply a definite time delay to the ROCOF element with a setting range of 0 to 100 seconds with a 0.5 second step size. During any applied time delay, the element shall continue to measure the ROCOF to determine if the applied setting is exceeded.

It shall be possible to apply a pole dead logic to ROCOF elements, which uses under voltage and current detectors to determine if the circuit breaker has opened to isolate the voltage transformer. Operation of the pole dead logic shall block the ROCOF element.

12.23.4 Voltage Vector Shift

This shall measure the change in voltage angle over successive power system half cycles, as well as the time taken between zero crossings on the voltage waveforms. Multiple samples shall be taken per cycle and operation shall occur within two cycles, should the average normalised values be above the setting threshold.

12.23.5 Neutral Voltage Displacement

This shall be used to detect earth faults in impedance, solidly earthed or un-earthed systems and shall incorporate rejection of third harmonic components. Voltage detection range 5 – 36V 50Hz in 1V steps, with a definite time delay range of 0.1 – 9.9 seconds.

12.24 Automatic Voltage Control

In order that the voltage at a common busbar is maintained within the required limits, an automatic voltage control system in accordance with SP Energy Networks specification PROT-03-015 shall be provided.

12.25 Substation Control and Data Acquisition (SCADA)

Control of all circuit breakers shall be possible from the following locations:

Local	-	Operation at circuit breaker by mechanical means i.e. pushbuttons mechanically linked to the circuit breaker operating mechanism. Close pushbutton operation should be restricted by use of a bolt and the open used for removal of earth only.
Standby	-	Electrical operation of the circuit breaker via bay IED or local control switch. When in Standby all remote controls which can result in plant movement shall be disabled.
Main	-	Electrical operation of the circuit breaker remote from site via SCADA system. When in Main all local control operations which can result in plant movement shall be disabled.

Where required, all new protection and control equipment offered shall be capable of interfacing with an existing RTU using conventional cabling to a common cable termination cubicle (CTC).

For new 33kV substations, SCADA facilities shall preferably be provided via an approved RTU utilising an electronic communications medium between protection devices compliant with PROT-16-026 and the outstation equipment making use of a recognised industry standard protocol. Common substation alarms may be marshalled to a common location and collected by use of an IED capable of communicating with the same industry standard protocol. The loss of any one communication connection shall not cause communication loss to multiple devices. Where a ring topology is utilised, it shall be possible to detect the loss of any single communication channel, even if a single communication channel loss does not result in loss of communication between any devices. The RTU, where required, shall also be capable of interfacing with existing hard-wired substation equipment(s).

The following circuit analogues shall be provided both locally (IED display) and remotely (SCADA). The local analogues may be displayed on a protection relay.

- Per transformer (SP Distribution plc): MW
MVAr
Volts
Amps
- Per feeder: Amps
(if VT present) MW
(if VT present) MVAr
- Per busbar (if VT present): Ph-Ph Volts

SCADA analogues will typically be obtained via an electronic link from the protection equipment direct to the SCADA system.

12.26 Statistical Metering (SP Manweb plc)

The following values shall be displayed locally per transformer:

- MW
- MVAr
- MVA
- kV

The following remote analogue values shall be made available to SCADA per transformer:

- MW
- MVAr
- Volts
- Amps
- %Vnps
- %Inps

12.27 11kV SBEF/EF Alarm (SP Manweb plc)

This protection shall be in accordance with SP Energy Networks specification PROT-16-006 and generally as follows.

A single stage standby earth fault protection operated from a current transformer located in the 11kV neutral earth connection. The relay shall have a range of SI, VI, LTI and DTL characteristics in accordance with IEC 60255-151, with a setting range between 10% and 100%.

A two stage earth fault alarm element operated from a current transformer located in the 11kV neutral earth connection. The relay shall have a DTL characteristic in accordance with IEC 60255-151 with a setting range between 5% and 100%.

The above relay(s) shall have self-monitoring circuits, with a watchdog arranged to give an alarm on failure and may be capable of remote communication. Relays used shall provide comprehensive fault and event recording facilities.

13. TELECOMMUNICATIONS EQUIPMENT

All telecommunications equipment shall comply with the standards of the International Telecommunications Union, the British Standards Institute and, where appropriate, carry BABT approval for connection to the Public Telecommunications Operators services. The equipment shall comply with the safety requirements of BS EN 41003 and be installed in accordance with BS 6701. Communications systems for use by Teleprotection shall comply with ENA TS 48-6-7.

14. CURRENT TRANSFORMERS

Current transformers shall comply with IEC 61869-2.

CT connection convention shall be as follows:

1. Each piece of apparatus in which CTs are mounted shall be regarded independently.
2. In circuit breakers all P1 markings shall be electrically nearer to the circuit breaker than the corresponding P2 markings.
3. In transformers, reactors or generators, the P1 markings shall be electrically nearer to the windings than the corresponding P2 markings.
4. For separately mounted CTs, if they are associated with the circuit breakers, they shall be considered as though they were an integral part of the circuit breaker. If separately mounted CTs are not associated with the circuit breakers, the P1 markings shall be electrically nearer to the junction of the primary connections or busbars than the P2 markings.

CT Star Point Connections:

1. For a three-phase 4-wire secondary system, the secondary star point shall generally be made by interconnecting the secondary terminals having the same instantaneous polarity as the primary terminals which are electrically nearest to the primary circuit being protected or metered.
2. The star point of the protection CTs shall be earthed through a bolted link at one point only. The bolted link shall be provided at the relaying point. For tariff metering circuits the CT earth link shall be located at the switchgear.
3. All CT connections shall be brought out to accessible positions so that the CT connections or star point can be easily changed.

Minimum CT characteristics are defined in tables 2, 3 & 4. The Supplier shall confirm that all CTs comply with the requirements contained therein and are suitable for use. Should the minimum CT specification prove insufficient for the intended duty, this shall be notified to SP Energy Networks and CTs with appropriate characteristics shall be provided.

Current transformers of the same type intended for use in similar schemes shall have characteristics that vary by no more than 1% e.g. Grid 1 CTs shall have characteristics and parameters within 1% of the corresponding values of similar CTs used on Grid 2.

Where reasonably practicable, CTs shall be mounted in the switchgear in the order detailed in Table 1. CTs are numbered from the busbar outwards, with number 1 nearest to the busbar, number 2 next to number 1, etc. For the bus section circuit breaker, the busbar protection CTs shall preferably be positioned outermost, with the zones configured as overlapping.

Where it is not possible to accommodate the CTs in the preferred position, an interlocking chain shall be provided between the busbar earthing devices and individual associated circuit breakers wired to prevent operation of the earthing device unless all associated circuit isolators are in an off or earthed state. Interlocked Overcurrent protection, as described in section 12.5, shall also be applied.

Table 1 – Preferred order of CT mounting within switchgear

CT Number	Transformer Incomer	Outgoing Feeder with 3 sets of CTs	Customer (Generation) Metering CB	Customer (Demand) Metering CB	Bus Section/Bus Coupler
1	Transformer main protection	Feeder main protection	Feeder main Protection	Feeder main protection	LHS busbar zone
2	Backup protection / instruments	Backup protection / instruments	Backup protection / instruments	Backup protection / instruments	LHS overcurrent
3	Metering / LDC		Metering	Metering	RHS busbar zone
4	Busbar zone	Busbar zone	Busbar zone / Connections protection	Busbar zone	
5	Busbar Check (Double Busbar only)		Busbar Check (Double Busbar only)		

CT number 2 and 3 on customer and transformer circuits may be interchanged if necessary.

Table 2 – Current Transformers – Protection

Reference Protection	Function	Rated Cont' Thermal Current A	Rated 2ndry Current A	Turns Ratio	Current Ratio	Minimum Knee Point Voltage / Class VA	Maximum 2ndry Winding Resistance	Maximum 2ndry Excitation Current at Vk
		Icth	Isn			Vk	Rct (Ohms)	Ie (A)
CT 2.11	Distance, unit & BEF	Note 1	1	1:400:800	800:400:1	50Rct+400 (800/1) 50Rct+200 (400/1)	4.0 2.0	0.04 0.08
CT 2.12	OC, EF & HSOC	Note 1	1	1: 800	800: 1	5P20, 5VA	-	-
CT 2.13	Unit/ Transformer Differential, REF	Note 1	1	1:800:1600	1600:800:1	18Rct+360 (1600/1) 18Rct+180 (800/1)	3.5 1.75	0.03 0.06
CT 2.14	DOC, OC & ILOC	Note 1	1	1:800:1600	1600:800:1	5P20, 30VA (1600/1) 5P10, 30VA (800/1)	-	-
CT 2.15	Bus zone & Connections Protection	Note 1	1	1:1000	1000:1	300	5.0	0.03
CT 2.16	BZ neutral check	Note 1	1	1:1000	1000:1	300	5.0	0.03
CT 2.17	SBEF	Note 1	1	1:800:1600	1600:800:1	5P20, 30VA (1600/1) 5P10, 30VA (800/1)	-	-
CT 2.18	Transformer Differential, REF	Note 1	1	1:2400	2400:1	18Rct+540	5.0	0.03
CT 2.19	DOC, OC & ILOC	Note 1	1	1:2400	2400:1	5P20, 30VA	-	-
CT 2.20	SBEF	Note 1	1	1:2400	2400:1	5P20, 30VA	-	-
Note 1	The rated continuous thermal current is defined as the rated current of the associated switchgear.							
Note 2	The rated short time thermal current withstand rating of all protection CT's is defined as the rated short time withstand current of the associated switchgear.							

Table 3 – Current Transformers – Control

Reference Control	Function	Rated Cont' Thermal Current A	Rated 2ndry Current A	Turns Ratio	Current Ratio	Rating VA	Class	Extended Primary Rating
		Icth	Isn					
CT 2.22	Line drop compensation & voltage control	Note 1	1	Note 3	Note 3	15	1	150%
Note 1	The rated continuous thermal current is defined as the rated current of the associated switchgear.							
Note 2	The rated short time thermal current withstand rating of all protection CT's is defined as the rated short time withstand current of the associated switchgear.							
Note 3	Turns ratio selected to correlate with Transformer rating.							

Table 4 – Current Transformers – Metering

	Function	Rated Continuous Thermal Current A	Rated Secondary Current A	Turns Ratio	Current Ratio	Accuracy Class to IEC 60044 Part 1	Rating VA
CT 2.21	Metering (M1)	Note 1	1 or 5	Note 3	Note 3	0.2s	20
Note 1	The rated continuous thermal current is defined as the rated current of the associated switchgear.						
Note 2	The rated short time thermal current withstand rating of all protection CT's is defined as the rated short time withstand current of the associated switchgear.						
Note 3	The turns & current ratios should be specified to ensure compliance with the relevant code of practice for the rating of the connection.						

15. VOLTAGE TRANSFORMERS

Voltage transformers shall comply with IEC 61869-3. For individually enclosed single-phase VTs, both secondary connections shall be brought out to an external connection point. For three-phase VTs, or single-phase VTs in a single enclosure, the 3 phase and neutral secondary connections shall be brought out to an external connection point. Where a tertiary winding is specified, the open delta connection shall be brought out to an external connection point.

15.1 Voltage Transformers VT3

(i) Ratio L-L 33000/110V.
(ii) Ratio L-E 19052/63.5V.
(iii) Output – 25VA Metering / 25VA Protection, based on the use of modern electronic relays.
(iv) Accuracy Class – 0.2 Metering / 3P Protection.
(v) Voltage Factor – 1.9pu, 30s.

For metering, two VTs with a single secondary winding, or one VT with two secondary windings shall be provided. Where specified, an open delta winding for protection shall also be provided, rated at accuracy class 6P, output 25VA.

16. SWITCHES AND SELECTORS

All switches may, with the Engineer's approval, be included within appropriate protection devices. All switches accommodated in this manner shall have clear indications as to the state. Any controls which cause movement of plant shall utilise select before operate checks against inadvertent operation.

Circuit Breaker Type	Circuit Breaker Control	Control Selector Switch	Protection Setting Group 2	U/F In/Out	Busbar Protection IN/OUT	DAR IN/OUT	Trip Relay Reset
Switch / Selector Type	1	2	3	4	5	6	7
33kV bus section	✓	✓	Only where specified	✓			
33kV transformer incomer	✓	✓		Where U/F is within Bay IED		✓	
33kV transformer feeder	✓	✓				✓	
33kV unit protected feeder	✓	✓				✓	
33kV distance protected feeder	✓	✓				✓	
33kV customer feeder	✓	✓					
33kV busbar zone panel					✓		✓

For conventional separate protection panels, switches and selectors may be as follows:

Switch 1 3 position labelled **“Circuit** Breaker Control”
Biased OFF in central position
Padlockable in the biased OFF position
Pistol grip handle
Interlocked to prevent inadvertent operation

Position 1 **“Trip”**
Position 2 **“Neutral”**
Position 3 “**Close**”

Switch 2 2 position labelled **“Control Selector Switch”**
Padlockable in both positions
Lozenge type handle

Position 1 **“Standby”**
Position 2 **“Main”**

Switch 3 2 position labelled **“Protection Setting Group 2”**
Padlockable in both positions
Lozenge type handle

Position 1 **“Normal Service Setting”**
Position 2 **“Group 2 Selected”**

Switch 4 2 position labelled **“Underfrequency Load Shedding”**
Lozenge type handle
Interlocked to prevent inadvertent operation

Position 1 **“In Service”**
Position 2 **“Neutral”**
Position 3 **“Out of Service”**

Switch 5 Labelled **“Busbar Protection”**
Padlockable in both positions
Lozenge type handle
Interlocked to prevent inadvertent operation

Position 1 **“In Service”**
Position 2 **“Out of Service”**

Switch 6 Labelled **“DAR”**
Lozenge type handle
Interlocked to prevent inadvertent operation

Position 1 **“In Service”**
Position 2 **“Neutral”**
Position 3 **“Out of Service”**

Switch 7 Pushbutton labelled “**Busbar Protection Trip Relay Reset”**

17. SCHEDULE OF EQUIPMENT CONFIGURATIONS

SCHEDULE NO. 1	**33KV SUBSTATION CIRCUIT TYPES**
GT.2	Grid transformer control
GT.3	Grid transformer control – Double busbar substations
GP.1	Bus section
GP.2	Transformer feeder with intertripping and auto reclose
GP.3	Feeder/interconnector with unit protection and auto reclose
GP.4	Feeder/interconnector with distance protection and auto reclose
GP.5	Customer (generation/demand) metering circuit breaker
GP.7	Local 33/11kV transformer
GP.8	Bus section reactor
GP.9	Busbar protection
GP.10	Bus coupler – Double busbar substations
GP.11	Customer (generation) metering circuit breaker – Double busbar substations
SCHEDULE NO. 2	**REMOTE INTERTRIPPING TYPES**
IT.1	Metallic pilot
IT.2	VF intertripping (where no other solution)
IT.3	Digital intertripping
IT.4	Direct intertripping (hard-wired)
IT.5	No intertripping (by agreement with NP&R)
SCHEDULE NO. 3	**UNIT PROTECTION TYPES**
UP.1	Pilot wire unit current differential protection
UP.2	Current differential protection over voice frequency channels
UP.3	Numeric current differential protection

17.1 GT.2: Grid Transformer Control

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main protection: biased differential and restricted earth fault protection to Specification CT 2.13, Table 2.	4
1.2	Backup protection (33kV): overcurrent, directional overcurrent, interlocked overcurrent (where applicable) and instrumentation, to Specification CT 2.14, Table 2.	3
1.3	Standby earth fault to Specification CT 2.17, Table 2.	1
1.4	Metering to Specification CT 2.21, Table 4.	2
1.5	Line drop compensation to Specification CT 2.22, Table 3.	1
1.6	Busbar protection to Specification CT 2.15, Table 2.	3
1.7	Neutral current check to specification CT 2.16, Table 2. (SP North only)	1
2	**Control Selectors** (Included within protection devices where practicable)	
2.1	Three-position control switch labelled “Circuit Breaker Control Switch”. Section 16, Type 1.	1
2.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
2.3	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
3	**Auxiliary Functions**	
3.1	Trip circuit supervision. Section 12.19.	1
3.2	CB control. Section 16 & 12.25.	1
3.3	Automatic voltage control (where specified). Section 12.24.	1
3.4	Statistical metering. Section 12.26.	1
4	**Voltage Transformer (VT3)**	As per section 15

17.2 GT.3: Grid Transformer Control – Double Busbar Substations

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main protection: biased differential and restricted earth fault protection to Specification CT 2.13, Table 2.	4
1.2	Backup protection (33kV): overcurrent, directional overcurrent, interlocked overcurrent (where applicable) and instrumentation, to Specification CT 2.14, Table 2.	3
1.3	Standby earth fault to Specification CT 2.17, Table 2.	1
1.4	Metering to Specification CT 2.21, Table 4.	2
1.5	Line drop compensation to Specification CT 2.22, Table 3.	1
1.6	Busbar protection to Specification CT 2.15, Table 2.	6
2	**Control Selectors** (Included within protection devices where practicable)	
2.1	Three-position control switch labelled “Circuit Breaker Control Switch”. Section 16, Type 1.	1
2.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
2.3	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
3	**Auxiliary Functions**	
3.1	Trip circuit supervision. Section 12.19.	1
3.2	CB control. Section 16 & 12.25.	1
3.3	Automatic voltage control (where specified). Section 12.24.	1
3.4	Statistical metering. Section 12.26.	1
4	**Voltage Transformer (VT3)**	As per section 15

17.3 GP.1: Bus Section

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Busbar protection, L/H side, to Specification CT 2.15, Table 2.	3
1.2	Backup protection: overcurrent & instrumentation, L/H side, to Specification CT 2.14 or CT 2.19, Table 2.	3
1.3	Busbar protection, R/H side, to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Back up protection: overcurrent. Section 12.3	1
2.2	Under frequency protection (where specified). Section 12.22.	1
2.3	Interlocked overcurrent (where specified). Section 12.5	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
3.3	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1

17.4 GP.2: Transformer Feeder with intertripping and auto reclose

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main protection: instantaneous earth fault & HSOC to Specification CT 2.11, Table 2.	3
1.2	Backup protection: overcurrent, earth fault & instrumentation to Specification CT 2.12, Table 2.	3
1.3	Busbar protection to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Main protection: instantaneous earth fault & HSOC. Sections 12.1 & 12.2.	1
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1
2.3	Intertripping. Section 12.16.	1
2.4	DAR. Section 12.18	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
3.3	Two-position selector switch labelled “Protection Setting Group 2” (where specified). Section 16, Type 3.	1
3.4	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1

17.5 GP.3: Feeder/Interconnector with unit protection and auto reclose

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main protection: unit protection, to Specification CT 2.11, Table 2.	3
1.2	Backup protection: overcurrent, earth fault & instrumentation to Specification CT 2.12, Table 2.	3
1.3	Busbar protection to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Main protection: unit (may require transformer inrush protection). Section 12.12.	1
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1
2.3	DAR. Section 12.18	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
3.3	Two-position selector switch labelled “Protection Setting Group 2” (where specified). Section 16, Type 3.	1
3.4	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1

17.6 GP.4: Feeder/Interconnector with distance protection and auto reclose

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main protection: distance protection, to Specification CT 2.11, Table 2.	3
1.2	Backup protection: overcurrent, earth fault & instrumentation to Specification CT 2.12, Table 2.	3
1.3	Busbar protection to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Main protection: distance protection. Section 12.13.	1
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1
2.3	Intertripping. Section 12.16.	1
2.4	DAR. Section 12.18	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
3.3	Two-position selector switch labelled “Protection Setting Group 2” (where specified). Section 16, Type 3.	1
3.4	Two-position selector switch labelled "DAR". Section 16, Type 6.	1
3.5	Two-position selector switch labelled “Underfrequency Load Shedding” (where specified). Section 16, Type 4.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1
4.4	VT monitoring. Section 12.21.	1
5	**Voltage Transformer (VT3)**	As per section 15

17.7 GP.5: Customer (generation/demand) metering circuit breaker

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main/unit protection: to Specification CT 2.11, Table 2.	3
1.2	Backup protection: overcurrent, earth fault & instrumentation to Specification CT 2.12, Table 2.	3
1.3	Metering, to Specification CT 2.21, Table 4.	2
1.4	Busbar (or customer connections) protection to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Main protection: unit. Section 12.12.	1
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1
2.3	Intertripping. Section 12.16.	1
2.4	Under/over voltage & frequency. Section 12.23.1 and 12.23.2. Rate of change of frequency (where specified). Section 12.23.3. Voltage vector shift (where specified). Section 12.23.4 Neutral voltage displacement. Section 12.23.5.	1
2.5	Busbar (or customer connections) protection. Sections 12.14 or 12.15.	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1
4.4	VT monitoring. Section 12.21.	1
4.5	Connections protection CT supervision. Section 12.15.	
5	**Voltage Transformer (VT3)**	As per section 15

17.8 GP.7: Local 33/11kV Transformer

Item No	Description	Number Required
1	**Current Transformers** [1]	
1.1	Main protection: HSOC & instantaneous earth fault, to Specification CT 2.11, Table 2.	3
1.2	Backup protection: Overcurrent, to Specification CT 2.12, Table 2.	3
1.3	Busbar protection, to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Main protection (33kV): HSOC and instantaneous earth fault. [1] Sections 12.1 and 12.2.	1
2.2	Backup protection (33kV): Overcurrent, Section 12.3.	1
2.3	Main protection (11kV): directional overcurrent and restricted earth fault. Sections 12.4 and 12.10.	1
2.4	Standby earth fault. Section 12.11.	1
2.5	Intertripping. [2] Section 12.16.	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled "Circuit Breaker Control" [1]. Section 16, Type 1.	1
3.2	Two-position selector switch labelled "Control Selector" [1]. Section 16, Type 2.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. [1] Section 12.19.	1
4.2	VT monitoring. Section 12.21.	1
4.3	CB control. [1] Section 16 and 12.25.	1
4.4	Transformer auxiliary tripping functions. Section 12.8.	1
4.5	Transformer auxiliary alarm functions. Sections 12.9.	1
4.6	Protection supply supervision. Section 12.20.	1
4.7	Automatic voltage control. Section 12.24.	1
4.8	Statistical metering. Section 12.26.	1
4.9	Fault recording facilities (PQR), as per SP Energy Networks Technical Specification PROT-16-010.	1

Notes

1. No 33kV protection is required at the transformer end of a transformer feeder. May require the use of multi-ended unit protection (Section 12.12) for some SP Energy Networks (North) applications.
2. If transformer end of transformer feeder, intertripping is required.

17.9 GP.8: Bus section reactor

Item No	Description	Number Required	
		CB A	CB B
1	**Current Transformers**		
1.1	Main protection: current differential protection to Specification CT 2.11, Table 2.	3	3
1.2	Backup protection: overcurrent, earth fault & instrumentation, to Specification CT 2.12, Table 2.	3	3
1.3	Busbar protection, to Specification CT 2.15, Table 2.	3	3
2	**Protection**		
2.1	Main protection: high impedance current differential protection. Section 12.15	1	-
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1	-
3	**Control Selectors** (Included within protection devices where practicable)		
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1	1
4	**Auxiliary Functions**		
4.1	Trip circuit supervision. Section 12.19.	1	1
4.2	CB control. Section 16 and 12.25.	1	1
4.3	Protection supply supervision. Section 12.20.	1	-
4.4	Reactor auxiliary tripping functions. Generally in line with section 12.8.	1	-
4.5	Reactor auxiliary alarm functions. Generally in line with section 12.9.	1	-
Note: CB A shall be the normally closed end. CB B shall be the open standby end where required.			

17.10 GP.9: Busbar protection panel

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Busbar protection, to Specification CT 2.15, Table 2.	Included per circuit
1.2	Neutral current check (where specified), to Specification CT 2.16, Table 2.	1 per GTx
2	**Protection**	
2.1	High impedance busbar protection. Section 12.14.	1 or 2
2.2	Neutral current check relay (where specified). Section 12.14.	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Two-position selector switch labelled “Busbar Zone Protection”. Section 16, Type 5.	2
3.2	Push button labelled “Busbar Trip Relay Reset”. Section 16, Type 7.	1
4	**Auxiliary Functions**	
4.1	Busbar zone CT supervision. Section 12.14.	2
4.2	Protection supply supervision. Section 12.20.	2
4.3	Indication lamps (In/Out of service).	2

17.11 GP.10: Bus Coupler – Double Busbar Substations

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Busbar protection, L/H side, to Specification CT 2.15, Table 2.	3
1.2	Backup protection: overcurrent & instrumentation, L/H side, to Specification CT 2.14 or CT 2.19, Table 2.	3
1.3	Busbar protection, R/H side, to Specification CT 2.15, Table 2.	3
2	**Protection**	
2.1	Back up protection: overcurrent. Section 12.3	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1

17.12 GP.11: Customer (generation/demand) metering circuit breaker – Double Busbar Substations

Item No	Description	Number Required
1	**Current Transformers**	
1.1	Main/unit protection: to Specification CT 2.13, Table 2.	3
1.2	Backup protection: overcurrent, earth fault & instrumentation to Specification CT 2.14, Table 2.	3
1.3	Metering, to Specification CT 2.21, Table 4.	2
1.4	Busbar protection to Specification CT 2.15, Table 2.	6
2	**Protection**	
2.1	Main protection: unit. Section 12.12.	1
2.2	Backup protection: overcurrent and earth fault. Section 12.3.	1
2.3	Intertripping. Section 12.16.	1
2.4	Under/over voltage & frequency. Section 12.23.1 and 12.23.2. Rate of change of frequency (where specified). Section 12.23.3. Voltage vector shift (where specified). Section 12.23.4 Neutral voltage displacement. Section 12.23.5.	1
3	**Control Selectors** (Included within protection devices where practicable)	
3.1	Three-position control switch labelled “Circuit Breaker Control”. Section 16, Type 1.	1
3.2	Two-position selector switch labelled “Control Selector”. Section 16, Type 2.	1
4	**Auxiliary Functions**	
4.1	Trip circuit supervision. Section 12.19.	1
4.2	CB control. Section 16 & 12.25.	1
4.3	Protection supply supervision. Section 12.20.	1
4.4	VT monitoring. Section 12.21.	1
5	**Voltage Transformer (VT3)**	As per section 15