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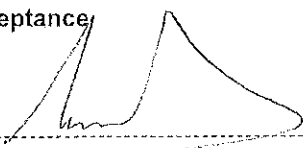
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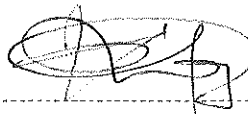


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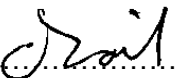
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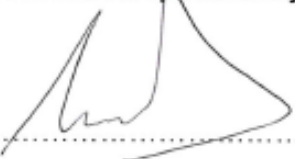
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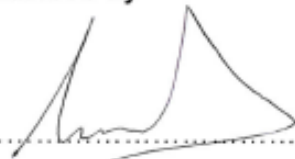
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1 INTRODUCTION

This standard serves to fulfil Eskom's obligation under Section 8.2 (4) of the South African Distribution Code: Network Code (SADCNC) which is applicable to all users of the distribution system and states the following:

“The Distributor shall develop the protection requirement guide for connecting Embedded Generators to the Distribution System to ensure safe and reliable operation of the Distribution System”.

This standard sets out the minimum technical and regulatory requirements for the connection of Embedded Generators (EG) to Eskom's EHV, HV and MV electrical networks. This standard therefore is inclusive of Eskom Distribution's protection requirement guide.

Users must adhere to the Grid Connection Code for Renewable Power Plants (RPPs) in South Africa (GCCRPPSA), the South African Grid Code (SAGC) and the South African Distribution Code (SADC) requirements where relevant. The table inserted below briefly explains where the listed codes above are technically relevant.

For information on pricing and contractual requirements with regard to the connection and operation of Embedded Generators, the user is referred to Eskom Policy 34-193 *Purchasing of energy from embedded distribution generators* or to Eskom Policy 240-68105435 *Purchasing of Energy from Embedded Generation Policy*.

In this document, references to 'Eskom' shall mean Eskom Holdings SOC Limited. In many instances, the terms 'Network Service Provider' or 'Distributor' have been used in place of 'Eskom' in anticipation of the standard's broader application in the electricity distribution industry in South Africa (NRS 097). In this context, 'Network Service Provider' includes Eskom Transmission, Eskom Distribution and any Municipal entity that might adopt this standard.

Table 1-1: South African Codes Technical Areas of Relevance

Code/ Standard	Relevance	Requirements/Capabilities Include	Omits	Refer To
GCCRPPSA	All RPPs (the GCCRPPSA code takes precedence)	System Operating Conditions & Response, FRT, Reactive, QOS, Protection, Anti-islanding, Power Constraints, Control Functions, SCADA, Forecasting, Data Communications, Testing & Compliance, Modelling (including the Process)	Protection Details, Anti-islanding Details Metering	This Standard Metering: Use of System Agreement
SAGCNC Section 3.1	All EGs, All Thermal, All Hydro	Protection, Excitation, Reactive, Multiple Unit Tripping, System Operating Conditions & Response, Governors (>50MVA), FRT, Equipment Design Standards, Earthing, QOS, System Protection, Planning, Performance, Forecasting, Integration	SCADA Details Metering	This Standard SAGC Metering Code
SADCNC	All EGs (except EHV connected)	Connection Process, Responsibilities, Protection, QOS, Earthing, Equipment Requirements, Planning, Investment Criteria, Metering, Connection Point, Telemetry, Power Station Supplies	SCADA Details Metering Details	This Standard SADCMC Metering: Use of System Agreement & 34-1024

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2 SUPPORTING CLAUSES

2.1 SCOPE

2.1.1 Purpose

This standard sets out the minimum technical and regulatory requirements for the connection of Embedded Generators to Eskom's Medium Voltage (MV), High Voltage (HV) and Extra High Voltage (EHV) electrical networks. As such and according to the categories as stipulated in the Grid Connection Code for Renewable Power Plants in South Africa (GCCRPPSA), this standard is also applicable to Category B and C Renewable Power Plants (RPP) but not Category A RPPs since this category only applies to Low Voltage (LV) connected RPPs¹.

2.1.2 Applicability

This standard applies to systems where the generating plant may be paralleled with the Eskom MV, HV or EHV network either permanently, periodically or temporarily. This standard does not apply to generating plant that does not operate in parallel with the Eskom Grid (e.g., own use customer generators or stand-by generators). Additionally this standard does not apply to Eskom owned generating plant that is not categorised as renewable power plant. Eskom's requirements for stand-by generators are detailed in ESKAGAAG2 (operation with alternative connection to the Eskom system), and the use of portable generators is addressed in NRS 098. All requirements of ESKAGAAG2 pertaining to generators that are operated in parallel with the Eskom network are superseded by the requirements of this standard.

The intention is that this interconnection standard, or one of broadly similar requirements, shall also apply to Embedded Generators connecting to Municipal electricity networks which, in turn, are supplied by Eskom. In this way, technical requirements for the point of connection between the Supply Authority and the Embedded Generator need not be replicated between Eskom and the Supply Authority.

The standard provides for generic interconnection requirements and shall be applicable to all types of generators, prime movers etcetera.

The standard applies to all Embedded Generation new builds.

¹ For LV connected Embedded Generators please refer to the NRS097-2 series.

2.2 NORMATIVE/INFORMATIVE REFERENCES

2.2.1 Normative

Parties using this standard shall apply the most recent edition of the documents listed below:

South African Legislation:

Electricity Regulation Act 4 of 2006, as amended.

Occupational Health and Safety Act No 85 of 1993.

South African Distribution Code (all parts).

South African Grid Code (all parts).

Grid Connection Code for Renewable Power Plants Connected to the Electricity Transmission System or the Distribution System in South Africa (also called the 'Grid Connection Code for RPPs in South Africa').

International and National Standards:

IEC 60870-5-101: Telecontrol equipment and systems – Transmission protocols – Companion standard for basic Telecontrol tasks.

IEEE 1815-2012: IEEE Standard for Electric Power Systems Communications—Distributed Network Protocol (DNP3).

IEC 62116: Test Procedure of Islanding Prevention Measures for Utility-Interconnected Photovoltaic Inverters.

IEC 62271-100: High-Voltage Alternating-Current Circuit-Breakers.

IEEE 1547: IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

IEEE 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

NRS 029, Current transformers for rated A.C. voltages from 3,6kV up to and including 420kV.

NRS 030, Electricity distribution – Inductive voltage transformers for rated A.C. voltages from 3,6kV up to and including 145kV for indoor and outdoor applications.

NRS 031, Alternating current disconnectors and earthing switches (above 1000V).

NRS 037-1, Telecontrol Protocol for stand-alone remote terminal units.

NRS 048-2, Electricity Supply – Quality of Supply Part 2: Voltage characteristics, compatibility levels, limits and assessment methods.

NRS 048-4, Electricity Supply – Quality of Supply Part 4: Application guidelines for utilities.

NRS 054, Rationalized User Specification – Power Transformers.

NRS 098, Guidelines for the installation and safe use of portable generators on utilities' networks.

SANS 211 (CISPR11), Industrial, scientific and medical equipment - Radio-frequency disturbance characteristics - Limits and methods of measurement.

SANS 222 (CISPR 22), Information technology equipment - Radio disturbance characteristics - Limits and methods of measurement.

SANS 474 (NRS 057), Code of practice for electricity metering.

SANS 1019, Standard voltages, currents and insulation levels for electricity supply.

SANS 10200, Neutral earthing in medium voltage industrial power systems.

SANS/IEC 50065-1, Signalling on low-voltage electrical installations in the frequency range 3 kHz to 148,5 kHz Part 1: General requirements, frequency bands and electromagnetic disturbances.

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International and National Standards (Protective Relays):

IEC 60068-2-1, Environmental testing — Part 1 Cold.

IEC 60068-2-2, Environmental testing — Part 2 Dry Heat.

IEC 60068-2-30, Environmental testing — Part 30 Damp heat, cyclic (12h + 12h cycle).

IEC 60255-6, Electrical relays Part 6: Measuring relays and protection equipment.

IEC 60255-21, Electrical relays Part 21 Vibration, shock, bump and seismic tests on measuring relays and protection equipment (All sections).

IEC 60255-22, Electrical relays Part 22 Electrical disturbance tests for measuring relays and protection equipment (All sections).

IEC 60255-30, Electrical relays Part 3: Single input energizing quantity measuring relays with dependent and independent time.

SANS IEC 60529, Degrees of protection provided by enclosures (IP Code).

SANS IEC 61000-4, Electromagnetic compatibility (EMC): Test and measurement techniques (All sections).

Eskom Standards²:

DGL 34-1944, Network Planning Guideline for Embedded Generation (Steady State Studies).

DST_34-1985, MV and LV Reticulation Earthing.

DST_34-906, Medium Voltage Earthing Practice.

DSP_34-392, Specification for digital transducer based measurement system for electrical quantities.

DST_34-462, Standard design for Distribution protection schemes.

DST_34-540, Distribution Standard for the application of Sensitive Earth Fault protection.

DST_34-542, Distribution voltage regulation and apportionment limits.

DPL 34-680, Policy on access to meters, metering circuits and metering data.

DST_34-1024, Standard minimum requirements for the metering of electrical energy and demand.

ESKAGAAG2, Minimum requirements for the connection of non-Eskom generating plant to the Eskom electrical networks (32-272).

ESKASAAW2, *Generator excitation system standard for power stations (under review – Nico Jacobs)*.

GGs 36-1054, Eskom generator protection philosophy for gas turbine power stations with generator circuit-breaker (240-56356543).

TST_32-1101: IEC 60870-5-101 Master Station implementation standard.

240-59089329 DNP3 Implementation Standard.

TST_240-46264031: Fibre optic Design Standard – part 2 substations.

TST_240-42623618: Labelling of Fibre Optic Cables.

240-65692753, Standard for Apportionment of Quality of Supply Parameters for All Customers.

Eskom Test and Maintenance Procedures:

DPC_34-759, Maintenance of L/M/H range nickel cadmium batteries.

DPC_34-1033, Voltage transformer test procedure.

DPC_34-1034, Isolator test procedure.

² Note: in cases where documents are still to be re-published using the revised document numbering system, the future document classification and number is indicated in brackets following the existing reference code.

DPC_34-1035, Current transformer test procedure.

DPC_34-1036, Procedure for testing of Circuit-Breakers.

DPC_34-1039, Procedure for the maintenance of D.C. supply equipment.

DPC_34-1043, Maintenance of vantage nickel cadmium cells.

DPC_34-1395, Over current and Earth fault relay test procedure.

Eskom Documentation:

DCUOSA, Distribution Connection and Use-of-System Agreement with Generators.

CUOSA, Connection and Use-of-System Agreement with Generators (Transmission).

2.2.2 Informative

BDEW Technical Guideline, Generating Plants Connected to the Medium-Voltage Network, June 2008.

Fieldstone report for NERSA. Development of Regulatory guidelines and qualifying principles for co-generation projects. November 2006.

DST_32-326, Terminology relating to the direction of power flow.

DST_32-327, Functional measurement requirements for network management.

Electrical Safety Authority, Distributor Safety bulletin, DSB-07/11.

ESB Networks, Conditions Governing Connection to the Distribution System, Doc Ref: DTIS-250701-BDW, March 2006. N. Jenkins, R. Allan, P. Crossley, D Kirschen, G Strbac. *Embedded Generation*.

IEC/SANS 61400, Wind Turbines.

IEEE 1547.2: 2008, Application Guide for IEEE Standard 1547.

IEEE Power and Energy series 31. 2000.

ISO 9001 Quality Management Systems.

Kinetrics Inc. Report no: K-418086-RA-001-R00, Technical review of Hydro One's anti-islanding criteria for microfit PV generators, November 2011.

Network Protection & Automation Guide, Alstom, July 2002.

NRS 097-2, Small Scale Embedded Generation.

Protection Relays Application Guide, Third edition 1990. GEC Alsthom Protection & Control Ltd.

2.3 DEFINITIONS

Automatic generation control (AGC): The automatic centralised closed-loop control of units by means of the computerised EMS of the System Operator. Unit output is controlled by changing the setpoint on the governor. [SAGC]

Co-generator: A source of electrical power that complies with types I, II or III below:

- **Type I:** Projects utilizing process energy which would otherwise be underutilised or wasted (e.g. waste heat recovery).
- **Type II:** Primary fuel based generation projects which produce, as part of their core design, other usable energy in addition to electricity (e.g. Combined Heat and Power projects).
- **Type III:** Renewable fuel based projects where the renewable fuel source is both the primary source of energy, and is a co-product of an industrial process (e.g. use of bagasse and/or forestry waste from the sugar and paper industries).

Distributor: A legal entity that owns or operates/distributes electricity through a *distribution system*. [SAGC]

Distribution System: An electricity network consisting of assets operated at a nominal voltage of 132 kV or less. [SAGC]

DNP3 protocol: DNP3 is the preferred protocol used for the Telecontrol of the South African distribution systems as per NRS 037-1.

Embedded Generator's authorised person: The person appointed by the *Embedded Generator* in terms of the appropriate act to sanction the return to service of plant after major maintenance or repair.

Embedded Generator's responsible person: The person appointed by the *Embedded Generator* in terms of the appropriate act to receive communications and take necessary action in accordance with instructions from the system controller.

Embedded Generator: A legal entity that operates or desires to operate any generating plant that is or will be connected to the Grid at MV or HV levels and *renewable power plant* connected at EHV levels. This definition includes all types of connected generation, including co-generators and renewables. Alternatively, the item of generating plant that is or will be connected to the Grid at MV or HV levels and *renewable power plant* connected at EHV levels.³

Extra High Voltage: The set of nominal voltage levels greater than 220 000 V and up to and including 400 000 V. [SANS 1019].

High Voltage: The set of nominal voltage levels greater than 44 000 V and up to and including 220 000 V. [SANS 1019].

Island: The opening of a circuit breaker or circuit breakers resulting in the severance of the synchronous connection between the *Network Service Provider's* network and the *Embedded Generator*, or between the *Network Service Provider's* network and another section of the *Network Service Provider's* network containing a Synchronised generator.

Loss-of-grid protection: Relay protection designed to detect the loss of connection to the utility network and trip the *Embedded Generator* to prevent it from energising an island.

Low Voltage: Nominal voltage levels up to and including 1 000 V. [SANS 1019].

Medium Voltage: The set of nominal voltage levels greater than 1 000 V and up to and including 44 000 V. [SANS 1019]

Network Service Provider (NSP): A legal entity that is licensed to provide network services through the ownership and maintenance of an electricity network⁴. [SAGC]

³ A request for review has been lodged with the Grid Connection Code document Secretariat concerning this revised definition for Embedded Generation.

⁴ For the purpose of this standard, the term 'NSP' refers to a Distributor and/or a Transmission Network Service Provider whichever is relevant within the context used.

Point of Common Coupling (PCC): The electrical node, typically a busbar, on the *Network Service Provider's* network, electrically nearest to the *Embedded Generator* facility, at which more than one customer is or may be connected or metered. The *PCC* is used in the context of Quality of Supply emission requirements.

Point(s) of Connection (POC)⁵: The electrical node(s) on the *Network Service Provider's* network where the *Embedded Generator's* electrical equipment is physically connected to the *Network Service Provider's* electrical equipment.

Point of Utility Coupling (PUC): The *PUC* may be located near the *Point of Connection* or may be some other point(s) within the *Embedded Generator's* facility between the *PGC* and *Point of Connection*.

Point of Generator Connection (PGC): The circuit-breaker and associated ancillary equipment (instrument transformers, protection, isolators) that connects a generator to any electrical network. Where more than one such circuit-breaker exists, the *PGC* shall be the circuit-breaker electrically closest to the generator.

Point of Secure Supply (PSS): That point on the Network Service Provider's network at which a single upstream contingency will not result in the islanding of an Embedded Generator with a portion of the supply network.

Point(s) of Supply (POS): The point(s) on the Network Service Provider's network from where electricity is supplied to the *Embedded Generator* by the Network Service Provider, or from where the *Embedded Generator* supplies electricity to the Network Service Provider.

Renewable Power Plant (RPP): A unit or a system of generating units producing electricity based on a primary renewable energy source e.g. wind, sun, water, biomass, etc. A *RPP* can use different kinds of primary energy sources. If a *RPP* consists of a homogenous type of generating units it can be named as follows [RSA Grid Code Requirements for Renewable Power Plants]:

- **PV Power Plant (PVPP):** A single photovoltaic panel or a group of several photovoltaic panels with associated equipment operating as a power plant.
- **Concentrated Solar Power Plant (CSPP):** A group of aggregates to concentrate the solar radiation and convert the concentrated power to drive a turbine or a group of several turbines with associated equipment operating as a power plant.
- **Small Hydro Power Plant (SHPP):** A single hydraulic driven turbine or a group of several hydraulic driven turbines with associated equipment operating as a power plant.
- **Landfill Gas Power Plant (LGPP):** A single turbine or a group of several turbines driven by landfill gas with associated equipment operating as a power plant.
- **Biomass Power Plant (BMPP):** A single turbine or a group of several turbines driven by biomass as fuel with associated equipment operating as a power plant.
- **Biogas Power Plant (BGPP):** A single turbine or a group of several turbines driven by biogas as fuel with associated equipment operating as a power plant.
- **Wind Power Plant (WPP):** A single turbine or a group of several turbines driven by wind as fuel with associated equipment operating as a power plant. This is also referred to as a wind energy facility (WEF).

⁵ A request for review has been lodged with the Grid Connection Code for Renewable Power Plants in South Africa document Secretariat concerning the following statement within the code, 'A RPP has only one POC' and the effect it would have on parallel feeds. In the intervening time, this standard ignores the statement.

Renewable Power Plant (RPP) Categories: Renewable power plants are grouped into the following three categories [RSA Grid Code Requirements for Renewable Power Plants]:

- **Category A:** 0 – 1 MVA (only LV connected *RPPs*). Typically called ‘small-’ or ‘micro turbines’. This category shall further be divided into 3 sub-categories:
 - (i) Category A1: $0 \text{ kVA} \leq x \leq 13.8 \text{ kVA}$
 - (ii) Category A2: $13.8 \text{ kVA} < x < 100 \text{ kVA}$
 - (iii) Category A3: $100 \text{ kVA} \leq x < 1 \text{ MVA}$

Note: RPPs with a rated power greater than 4.6 kVA must be balanced three-phase.
- **Category B:** $1 \text{ MVA} \leq x < 20 \text{ MVA}$ and RPPs less than 1MVA connected to the MV network.
- **Category C:** $20 \text{ MVA} \leq x$.

Stand-by generator: A legal entity that operates or desires to operate a generating plant so as to provide a stand-by supply in the event of a loss of the grid electricity supply. The stand-by generator’s plant will only be connected to the *Network Service Provider’s* network for maintenance load testing, and only if the requirements of this standard have been fulfilled.

Synch-check: (Synchro-check) relay/function that electrically determines if the difference in voltage magnitude, frequency and phase angle falls within allowable limits. Synch check allows the closing conditions of a circuit breaker to be checked by inhibiting the closing circuit until approach of the correct synchronising conditions [Protection Relay Application Guide: 1987].

Synchronising: The process of manually (synchroscope etc.) or automatically (synchronising unit) controlling generation equipment to attain the conditions where the voltage magnitudes, frequency and phase angle differences, of two independent electrical systems, fall within allowable limits so as to initiate an interconnection between the two electrical systems.

System Operator: The legal entity licensed to be responsible for short-term reliability of the Interconnected Power System, which is in charge of controlling and operating the *Transmission System* and dispatching generation (or balancing the supply and demand) in real time. [SAGC]

Thermal Generating Unit: A generating unit that uses heat (for instance the burning of fossil fuels) to generate electricity (either through steam or internal combustion processes). This shall include coal, concentrated solar power, nuclear and gas turbine units [SA Grid Code: The Scheduling and Dispatch Rules].

Transmission System (TS): The *TS* consists of all lines and substation equipment where the nominal voltage is above 132kV. All other equipment operating at lower voltages are either part of the *Distribution System* or classified as transmission transformation equipment. [SAGC]

Transmission Network Service Provider (TNSP): A legal entity that is licensed to own and maintain a network on the *Transmission System*. [SAGC]

2.3.1 Disclosure Classification

Controlled disclosure: controlled disclosure to external parties (either enforced by law, or discretionary).

2.4 ABBREVIATIONS

Abbreviation	Description
A.C. or ac	Alternating Current
AGC	Automatic Generator Control
ARC	Auto-reclose
ASDU	Application Service Data Unit
CB	Circuit Breaker
CT	Current Transformer
CUOSA	Connection and Use-of-System Agreement with Generators (Transmission)
D.C. or dc	Direct Current
DCUOSA	Distribution Connection and Use-of-System Agreement with Generators
DMS	Distribution Management System
DTT	Direct Transfer Trip
EG	Embedded Generator ⁶ (includes Co-Generator)
EMC	Electromagnetic Compatibility
EMS	Energy Management System
FRT	Fault Ride Through
FTP	File Transfer Protocol
GCCRPPSA	The Grid Connection Code for Renewable Power Plants in South Africa
HV	High Voltage
ICASA	Independent Communications Authority of South Africa
IED	Intelligent Electronic Device (e.g., Protection Relay)
IPP	Independent Power Producer
I/O	Input/output Protection or Telecontrol Signals
JB	Junction Box
LV	Low Voltage
MCOV	Maximum Continuous Operating Voltage
MUT	Multiple Unit Tripping
MV	Medium Voltage
NEC/R	Neutral Earthing Compensator with Resistor
NOD	Network Optimisation Department
NPD	Network Planning Department
NSP	Network Service Provider
PCC	Point of Common Coupling

⁶ The term is also used for Dispersed Generator or Distributed Generation (DG).

Abbreviation	Description
PF	Power Factor
PGC	Point of Generator Connection
pu	per unit
POC	Point of Connection
POS	Point of Supply
POP	Point of Presence
PSS	Point of Secure Supply
PUC	Point of Utility Connection
PVPP	Photovoltaic Power Plant
QOS	Quality of Supply
ROCOF	Rate of Change of Frequency (protection)
RPP	Renewable Power Plant
RTU	Remote Terminal Unit
RVC	Rapid Voltage Changes
SADC	The South African Distribution Code
SADCMC	The South African Distribution Code: Metering Code
SADCNC	The South African Distribution Code: Network Code
SAGC	The South African Grid Code
SAGCMC	The South African Grid Code: Metering Code
SAGCNC	The South African Grid Code: Network Code
SAGCSOC	The South African Grid Code: System Operation Code
SCADA	Supervisory Control and Data Acquisition (aka. Telecontrol)
SCOT	Steering Committee for Operational Technology
SEF	Sensitive Earth Fault
SO	System Operator
SOD	System Operator Department
TNSP	Transmission Network Service Provider
TOV	Temporary Over-voltage
TS	Transmission System
VRT	Voltage Ride Through ⁷
VT	Voltage Transformer

⁷ Often called LVRT (low voltage ride through) or Withstand Capability.

2.5 ROLES, RESPONSIBILITIES, MONITORING AND DOCUMENTATION

2.5.1 Roles and Responsibilities

The SCOT IPP Operations Care-Group are responsible for the implementation of this standard within Eskom (inserting it within the Eskom processes) whilst the various Control Plant sections in the Project Engineering Departments are responsible for the application of the standard. The standard DGL 34-1944 states that it is mandatory for Distribution Planners to familiarise themselves with this standard. Substation Design national team members should also familiarise themselves with this standard as it impacts on the various primary plant designs.

The SCOT Protection and Automation Study Committee together with the Telecontrol/SCADA Study Committee, Measurements Study Committee and DC Study Committee are responsible for the accuracy of this standard.

The EGs must adhere to the minimum requirements of this standard as partial fulfilment in order to connect to the Network Service Provider's network.

2.5.2 Process for Monitoring

Any revision of the Grid Codes referenced within this standard shall initiate a review of the relevancy and accuracy of this standard. The SCOT IPP Operations Care-Group shall be responsible for the initiation of the review.

2.5.3 Related/Supporting Documents

The following documents or parts of documents are superseded by this standard:

- a) Revision 0 of the Eskom standard 34-1765.
- b) Requirements of ESKAGAAG2 pertaining to generators that are operated in parallel with the Eskom network are superseded by the requirements of this document .

The most recent revision of this standard shall be inserted in the Appendices of the Agreements, DCUOSA and CUOSA.

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3 REQUIREMENTS

3.1 GENERAL REQUIREMENTS

By way of introduction to the detailed technical requirements of subsequent sections, this section serves to outline the broad principles on which the standard is based.

3.1.1 Open Access to Networks for Safe Operation

An Embedded Generator (EG) may connect to the Network Service Provider's network at any time provided safety can be assured.

EGs are required to operate within regulated power quality limits. Eskom and the Municipalities are held liable for deviations from regulated power quality limits that their customers may experience. Therefore no EG shall continue to energise any portion of the network that has been unintentionally islanded on a section of the Network Service Provider's network. Disconnection shall occur at the PUC upon detection of an unintentional island. The primary concern is for human safety, plant protection and power quality, in that order.

The National Transmission System Operator or Regional Network Optimisation Departments reserve the sole right to permit the operation of intentional islands within the Eskom network. EGs permitted to operate intentional islands shall adhere to the procedures and operating requirements as stipulated by the applicable System Operator.

The EG shall be responsible for protecting its own assets. Notwithstanding this, unnecessary tripping of EGs presents quality of supply and network stability problems and should be avoided where possible. The design philosophy, equipment used and settings applied to anti-islanding protection equipment will impact on the number of unnecessary trips obtained over the life of the EG (nuisance tripping).

Safe operation of the power system, its stability and security of supply are paramount and require that the Network Service Provider be responsible for specifying predetermined minimum Protection, Measurements and SCADA requirements to the EG.

As per the South African Distribution Code requirement, a circuit breaker and visible isolation shall be installed at the connection point to provide the means of electrically isolating the distribution system from the generating facility. The requirement stated above shall also apply to the transmission system.

It is the responsibility of the EG to establish synchronism between the EG's network and the Network Service Provider's Grid supply prior to paralleling the two networks. Detailed technical and regulatory requirements for synchronising onto the power network are stipulated in Section 3.4.2.

The neutral earthing philosophy to be applied shall be in accordance with Section 3.5.3.

Where it is necessary for Eskom to provide any electrical lines, or other electrical plant, or for any other works to be carried out to enable the connection of embedded generation to its networks, Eskom may require payments in respect of any expenditure incurred in carrying out this work.

The EG will be accountable for the cost to establish a communications infrastructure to the nearest Eskom Telecoms Point of Presence and if differential and/or intertripping circuits are required, to the associated Eskom substation.

3.1.2 Redundancy

The failure of any single component or system will not result in unsafe operation. Thus:

- a) No generator shall be connected to a Network Service Provider's network via a single circuit-breaker.
- b) Primary system protection provided at the PUC shall be duplicated elsewhere within the EG's facility. The protection requirements are dealt with in Section 3.6.2.1.
- c) Loss-of-grid protection as detailed in Section 3.6.2 shall be provided at the PUC by the EG or if the NSP owns the PUC circuit breaker(s), then loss-of-grid protection must be applied on the first circuit breaker(s) owned by the EG that can become an islanding point. Note that this protection shall be either the main or back-up loss-of-grid protection dependant on the governing criteria (refer to Section 3.6.2. for detailed requirements). Loss-of-grid protection and system integrity checks shall

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be provided elsewhere in the Network Service Provider's network (e.g., DTT, live-line close blocking etc.).

- d) The DC supplies at the Point of Utility Connection (PUC) and Point of Generator Connection (PGC) shall be independent of one another and shall be subject to continual monitoring, both locally and remotely by the owner of the equipment.
- e) EHV connected RPP's shall include dual redundancy on protection, control, D.C. supplies (double banks) and teleprotection circuits.

3.1.3 Ownership and Plant Clauses

The POC represents the point of demarcation between the Network Service Provider and the EG, examples of which are given in Annexure B. This standard does not stipulate the specific ownership of plant used at the PUC. The only exceptions are the Eskom metering equipment and communications infrastructure. These will be Eskom owned, operated and maintained. Specifics regarding the ownership of other plant, including the instrument transformers, must be agreed between the participants. It is preferred that Eskom owns the instrumentation transformers that supply the Eskom metering circuits.

The following ownership regimes are possible:

Regime 1

The EG owns, operates and maintains the PUC circuit-breaker(s) and there is no Distributor circuit breaker(s) between the PUC circuit breaker(s) and the Distributor busbars. Specifically, the EG shall own the circuit-breaker(s) and associated instrument transformers and protection and the isolator(s) to be installed between the PUC circuit-breaker(s) and the Distributor's network. The Distributor's network would consist of a busbar isolator and instrument transformers for metering. The specific point of demarcation between the Distributor and the EG shall be the Distributor-side terminals of the isolator(s) (POC). The clamps or cable terminations made at this point shall be the responsibility of the Distributor.

There were a number of installations accepted in Bid Round 1 where the Distributor did not own or control a circuit breaker (i.e., the EG connected directly to the Distributor busbars as above via their own PUC circuit breaker). Subsequently, a decision was made by the Eskom Substation Working Group in September 2012 that Eskom shall always have control and ownership of at least one circuit breaker per feeder (i.e., at a minimum this circuit breaker would be the circuit breaker closest to the Eskom busbars). Thus this standard does not currently support an EG owned PUC circuit breaker directly connected to the Eskom busbars.

OR

Regime 2

The EG owns, operates and maintains the PUC circuit-breaker(s). Specifically, the EG shall own the circuit-breaker(s) and associated instrument transformers and protection and the isolator(s) to be installed between the PUC circuit-breaker(s) and the Network Service Provider's network. The specific point of demarcation between the Network Service Provider and the EG shall be the Network Service Provider-side terminals of the isolator(s) (POC). The clamps or cable terminations made at this point shall be the responsibility of the Network Service Provider.

The Network Service Provider will control and own at least one circuit breaker per feeder (i.e. at a minimum this circuit breaker would be the circuit breaker closest to the Network Service Provider busbars). In circumstances where the Network Service Provider owns the powerline which terminates at the POC, the Network Service Provider shall have its own isolator for safety unless a double-lock mechanism is fitted on the POC isolator.

In certain network layouts, the Network Service Provider may require external protection trip inputs into the EG owned PUC protection and control circuits.

OR

Regime 3

The Network Service Provider owns, operates and maintains the PUC equipment. Specifically, the Network Service Provider shall own the circuit-breaker(s) and associated instrument transformers and protection and the isolator to be installed between the PUC circuit-breaker(s) and the EG's facility. The specific point of demarcation between the Network Service Provider

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and the EG shall be the EG-side terminals of the isolator(s) (POC). The clamps or cable terminations made at this point shall be the responsibility of the EG. The EG shall have its own isolator for safety.

The Network Service Provider will never own the PUC on a shared feeder (i.e., a feeder that has both customers and EG connected).

The EG will require external protection trip inputs into the Network Service Provider owned PUC protection and control circuits to meet the stipulated EG related PUC protection requirements as discussed in section 3.6.2.

Regime 1 ownership is not supported within this standard.

Regime 2 ownership is the preferred case.

It is preferred that the Network Service Provider owns the feeder power lines.

It is preferred that the EG builds the infrastructure and hands over the Network Service Provider's assets upon completion.

Each party shall be responsible for the commissioning, operation and maintenance of plant installed on their side of the POC.

The Eskom-owned metering and QOS instrumentation, Remote Terminal Units (RTU) and communications infrastructure will be commissioned, operated and maintained by Eskom irrespective of its specific location.

All equipment at the PGC(s) shall be owned, operated and maintained by the EG.

For EHV, HV and MV connections, the PUC and PGC breakers shall be separate.

For EG's connected at 220 kV or greater, only dedicated feeders shall be allowed.

It is preferred that EG's connected at all voltage levels, but especially at HV levels, are connected using dedicated feeders. Loop in/out substations must not cause any degradation of the system integrity (i.e., the protection of the network with regard to security, reliability and stability shall not be compromised when the EG is connected).

Zero sequence currents on the Network Service Provider's network and EG plant shall be decoupled from one another.

3.1.4 Autonomy

Each party is to design, protect and maintain their own assets to industry best practice. The POC represents the point of connection and is also the demarcation between the Network Service Provider and the EG. The PUC represents a point of common interest. The standard provides minimum technical requirements for the equipment and functionality to be provided at the PUC. The PGC provides back-up to the protection functions of the PUC, and is also subject to minimum technical requirements imposed by the Network Service Provider and the Grid Codes.

All of the required PUC functionality shall be provided at the PUC or in exceptional circumstances at an alternate location agreed to by both parties. All of the required functionality shall be provided at the same location. Any changes to the PUC or PGC will be agreed between the parties prior to implementation.

3.1.5 Interfaces

Where the Network Service Provider and EG substations are adjacent to each other, the following clauses are relevant:

- a) The earth mats shall be bonded together.
- b) A Customer Interface Junction Box (JB) shall be provided and furnished with all the required I/O and/or interface relays and connections for the Protection circuits, CT circuits, VT circuits and shared buszone wiring (if applicable). If the JB is situated in a yard, it should preferably be mounted on its own support structure and shall be connected to the earth mat as per the relevant NSP standard for earthing. For easy access to the shared JB, both by Network Service Provider and EG personnel, it is recommended that if the JB is situated in a yard then the JB should be placed at the fence line in a separate enclosure, with a gate to the EG yard and a gate to the NSP yard. This enclosure may also serve as a controlled access point between the two yards during

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commissioning and maintenance. The gates shall have a mechanism that provides the option for two locks⁸.

Refer to SCADA Chapter 4 for preferred Telecontrol and remote indication interface options.

- c) Where Fibre Optical cables are used they should not be connected through this Interface JB as it would constitute another point of potential failure.
- d) Where copper Solkor is used it should be wired through the Interface JB (with suitable insulation applied) as it would also be a point of test during fault-finding.

In the case where the Network Service Provider substation is not adjacent or the earth mats are not bonded together, all connections between the two yards shall be fibre optical for the I/O.

3.1.6 Audits

Owing to the strong interdependence between the EG and the Network Service Provider, and so as to avoid a requirement for duplication of equipment as far as possible, either party is entitled to perform technical audits of the other's equipment relevant to the interconnection. This specifically includes the PUC and PGC equipment and the metering equipment. Audits shall be performed with a minimum notice of 24 hours.

⁸ The double lock mechanism would be used during commissioning/maintenance when one party worked on circuits within the JB and required limiting the access due to safety concerns.

3.2 LEGAL AND REGULATORY REQUIREMENTS

The Electricity Regulation Act 4 of 2006 details the legislative requirements with regard to the generation, transmission, distribution and trading of electricity. In this regard, the Operator of a Grid-connected generator is required to hold a licence from the Regulator (Section 8). Operators of non-grid connected generators are not required to hold a license provided that the plant is designated only for own-use and is not used commercially (Schedule II).

Section 47 (1) of the Act makes provision for the Regulator to, following consultation with licensees and other participants, set guidelines and publish codes of conduct and practice. The South African Grid Code, Grid Code Requirements for Renewable Power Plants and Distribution Code are examples of such codes of practice.

The South African Distribution Code includes a section of specific requirements for the connection of EG's. The Distribution Network Code (Section 8.4.1.1 (1)) requires that all EG's of nominal capacity greater than 10 MVA shall in addition to the other requirements of the Distribution Code, also comply with the protection requirements of Section 3.1 of the South African Grid Code: Network Code.

Under Section 8.2 (4) of the South African Distribution Code: Network Code, each South African Distributor is required to develop a protection requirement guide for the connection of EG's. This standard serves to fulfil Eskom's obligation in this regard.

Each EG installation must be designed to comply with the Grid Code, Distribution Code, Grid Code Requirements for Renewable Power Plants and the Eskom NSP requirements detailed in this standard.

The South African Grid Code Requirements for Renewable Power Plants takes precedence whenever there is a conflict between it and the other Codes.

3.3 OPERATIONAL SAFETY

3.3.1 Operational and Safety Aspects

The EG must obtain from the relevant Network Service Provider a written agreement to operate generating equipment in parallel with the Network Service Provider's network once NERSA has licenced the entity. A plant diagram and schedule giving details of ownership, operation, maintenance and control of substation and generation plant shall be prepared, as agreed between the parties. The schedule shall include:

- a) Names and contact details of responsible persons from both parties.
- b) A description of any operating limitations with regard to the plant and/or the interconnection.

The EG shall ensure that all operating personnel are competent in that they have adequate knowledge and sound judgment to take the correct action when dealing with an emergency. Failure to take correct action may jeopardize the EG's and/or the Network Service Provider's systems.

EGs shall ensure that;

- a) Except in the case of agreed unmanned facilities, a responsible person is available at all times to receive communications from Eskom's Control Centre so that emergencies requiring urgent action by the EG can be dealt with adequately. Where required by Eskom, it will also be a duty of the EG's staff to advise Eskom's Control Centre immediately of any abnormalities that occur on the Embedded Generating plant which have caused, or might cause, disturbance to the Network Service Provider's network;
- b) In the case of unmanned facilities, the Network Service Provider will have remote control facilities to trip and isolate the facility at the EG Feeder circuit breaker or if not available, at the PUC.⁹ The Network Service Provider shall not control the PGC circuit breaker directly.
- c) Where it is necessary for their employees to operate Eskom equipment (where provided), they have been designated in writing by Eskom as an 'authorised person' for this purpose. All operations on the Eskom equipment must be carried out to the specific instructions of the Eskom Control Centre. In an emergency, a switch can be opened by anybody, without prior agreement in order to avoid danger. The operation must be reported to the Eskom Control Centre immediately afterwards.

3.3.2 Means of Isolation

Every installation or network which includes an Embedded Generating plant must include a means of isolation, suitably labelled, capable of disconnecting the whole of the Embedded Generating plant in-feed from the Network Service Provider's network.

The means of visible-break isolation must be lockable, in the open position only, by a padlock. Rackable indoor metal clad switchgear is deemed acceptable for this function, provided that it is lockable.

The EG must grant the Network Service Provider rights of access to the means of isolation without undue delay. The Network Service Provider shall have the right to reasonably isolate the EG's network connection at any time as network conditions dictate. The means of isolation will normally be installed at the EG feeder circuit breaker, alternatively at the PUC or at both points with the Network Service Provider's written agreement.

⁹ Note that in the case of RPPs, under the heading 'Control Signals' the GCCRPPSA states that it shall be possible for the Distributor to send a trip signal to the circuit breaker at the HV side of the POC.

3.4 GENERATOR CAPABILITIES AND OPERATION

The various codes, standards and sources that govern the requirements and settings for excitation control, governors, normal and abnormal voltage and frequency ranges, reactive capabilities and Voltage Ride Through (VRT)/Fault Ride Through (FRT) response of RPPs/EGs are summarised in the following table:

Table 3-1: Generator Capabilities and Operation

Plant	Requirement	Governing Source	Overriding Criteria
RPPs: \geq 0 MVA on MV/HV/EHV	Excitation control, V & f ranges, frequency response, VRT, reactive power capabilities, power constraint functions.	Detailed capabilities, ranges and settings in GCCRPPSA.	<ul style="list-style-type: none"> • U_n for normal conditions initially determined by NPD, dynamically by SOD/NOD in consultation with RPP. • SOD/NOD decides frequency control droop & power-frequency response frequency defaults. • Category B/C: Control Mode & Operating point initially determined by NPD, dynamically by SOD/NOD. • Category B/C: Power constraint initiated by SOD/NOD dynamically.
RPPs: All Thermal & Hydro on MV/HV/EHV	Excitation control, V & f ranges, frequency response, reactive power capabilities, power constraint functions, power system stabilisers, MUT risks, VRT.	Detailed capabilities, ranges and settings in GCCRPPSA and capabilities, synchronous power system stabilisers in SAGCNC/ SAGCSOC.	<ul style="list-style-type: none"> • As above. • GCCRPPSA takes precedence. • RPP to categorise MUT risk only if rated MW > 920 MW, no MUT1 trip, MUT2 trip 1/10year period – SOD to determine risk. • VRT: GCCRPPSA takes precedence over SAGCNC.
RPPs: All Thermal & Hydro > 50 MVA on MV/HV/EHV	Governor capabilities.	Turbo-alternators and hydro-alternators detailed in SAGCNC & SAGCSOC.	<ul style="list-style-type: none"> • GCCRPPSA takes precedence. • SOD requirement for Governor capabilities may override the > 50 MVA minimum level clause (i.e., stipulate a lower level).
EGs: \geq 0 MVA on MV/HV excluding RPPs.	Excitation control, reactive capabilities, power system stabilisers, MUT risks, VRT capabilities.	Detailed capabilities in SAGCNC and limits in SAGCSOC, detailed ranges and settings for VRT criteria in SAGCNC, synchronous power system stabilisers in SAGC.	<ul style="list-style-type: none"> • Excitation settings initially determined by NPD in consultation with EG, dynamically by SOD/NOD in consultation with EG. Normal operating range detailed in SAGCSOC, defined voltage initially determined by NPD and supplied in Connection & Use-of-System Agreement, dynamically by SOD/NOD in consultation with EG. • Connection & Use-of-System Agreement gives PF range at rated Power (MW) determined by NPD in consultation with SOD/NOD (default synchronous: 0.85lag < PF < 0.95 lead). Reactive Power to be variable between these limits. • EG to categorise MUT risk only if rated MW > 920 MW, no MUT1 trip, MUT2 trip 1/10 year period – SOD to determine risk. • VRT: Required for all EG. Requirement may be overridden or decreased by SOD decision.
EGs: > 50 MVA on MV/HV excluding RPPs	Governor capabilities.	Turbo-alternators and hydro-alternators detailed in SAGCNC & SAGCSOC.	<ul style="list-style-type: none"> • SOD requirement for Governor capabilities may override the > 50MVA minimum level clause (i.e., stipulate a lower level).

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3.4.1 Excitation Control and Governor Requirements

The EG shall consult the Network Service Provider's standards and shall familiarise themselves with the local operating conditions. The EG's normal operation shall not cause conditions on the network which are outside the accepted power quality standard limits. The generator's excitation control mode must best suit the local environmental conditions.

The South African Grid Code Requirements for Renewable Power Plants states that all thermo¹⁰ and hydro units shall comply with the design requirements specified in the South African Grid Code (specifically section 3.1 of the Network code). Section 3.1 of the South African Grid Code Network Code details, amongst other items, the excitation system requirements, the reactive capabilities, the governor controls (governor controls mandatory for units > 50 MVA), mandatory power system stabilisers, the external supply disturbance withstand capability and testing and compliance monitoring. The South African Grid Code Network Code, Section 3.1 also has relevance concerning Embedded Generation which is not deemed to be renewable.

All EG units that are not designated as RPP's and are of nominal capacity larger than 50 MVA shall conform to the continuous and short-duration frequency operating limits outlined in the Section 3.1.6 (Governing) of the South African Grid Code: Network Code. The same section of the code also stipulates the frequency vs. guaranteed operating time capability, as well as the requirements for governor control using a droop characteristic, required by turbo-alternators.

With regard to voltage, frequency, reactive power, VRT control and response, RPPs shall comply with sections 5 – 7 of the South African Grid Code Requirements for Renewable Power Plants.

3.4.2 Synchronisation

All Embedded Generating plant other than mains excited asynchronous machines must be synchronised with the Eskom supply prior to making the parallel connection. For mains excited asynchronous machines the responsibility rests with the EG to prove that the EG cannot self-excite prior to being connected, alternatively a dead EG bar voltage check interlock on the PUC breaker must be installed.

Where the mode of operation of generating equipment is such that frequent synchronising of a machine or machines will occur, the EG will ensure compliance with the rapid voltage change requirements stipulated within NRS 048-4 (refer to Section 3.5.2.).

Automatic synchronising equipment shall be the preferred method of synchronising. However, manual synchronisation of the EG units is permissible on condition that synchronising check relays (three phase comparators) are used by the EG in conjunction with the manual synchronising, and that the EG's responsible person is authorised in writing to do so. Synchronising shall occur using all three phases on both sides of the circuit breaker and shall only occur either at the PUC circuit breaker if owned by the EG or within the EG plant (i.e. it is not a requirement to apply synchronising facilities on the Network Service Provider network past the POC)¹¹. If synchronising occurs within the EG plant and not at the PUC, then synch check or a dead EG bar voltage check interlock on the PUC breaker must be installed.

The SADCNC states that it is the responsibility of the EG to provide synchronising facilities and to synchronise within agreed limits. Section 5.1.1 of the South African Grid Code Requirements for Renewable Power Plants states governing times for connection and voltage and frequency ranges at the Network Service Provider's POC for connection or synchronising (EG plant other than RPPs shall also adhere to these requirements). The voltage between the unit and the system prior to synchronising shall not differ by more than the values specified in Table 3-2 below:

¹⁰ Please note that the SA Grid Code: The Scheduling and Dispatch Rules define 'thermal' as including coal, concentrated solar power, nuclear and gas turbine units. The author believes that in the context used here (i.e., by GCCRPPSA), it was meant for thermally driven rotating units.

¹¹ The statement does not preclude the Network Service Provider or EG from applying 'synch-check' or dead-line checks elsewhere.

Table 3-2: Typical synchronising parameter limits (IEEE 1547 p.12)

Aggregate rating of EG (kVA)	Maximum Frequency Difference Δf (Hz)	Maximum Voltage Difference ΔV (%)	Maximum Phase Angle Difference $\Delta \phi$ (Degrees)
$S < 500$	0.3	10	20
$500 \leq S < 1500$	0.2	5	15
$S \geq 1500$	0.1	3	10

3.4.3 Islanded Operation

Intentional islanding of a generator with part of the Eskom network is not permitted unless specifically agreed to with Eskom. Refer to the Eskom policy for neutral earthing of electrical networks (DPL 34-2149) for the permitted earthing arrangements under islanded conditions.

For unintentional islanding, where a generator is synchronised with the Eskom network at the time that an upstream Eskom circuit breaker opens, severing the connection between the generator supply and the grid supply, the Eskom Connection and Use-of-System Agreement and the South African Grid Code for Renewable Power Plants for Category B and C, requires detection by the EG and shutting down of generation within 2 seconds¹². If at any stage it is found that the EG is in breach of the above condition or could be in breach of the above condition and the EG is not linked to the PSS via a dedicated feeder, it shall be mandatory to retrofit direct transfer trips that operate the PUC circuit breaker from all of Eskom's circuit breakers up to the PSS at the cost to the EG.¹³

3.4.4 Voltage Ride Through Capabilities

The voltage ride through capabilities that the EG shall comply with are specified in Section 5.2.1 of the South African Grid Code Requirements for Renewable Power Plants and in Section 3.1.9 of the South African Grid Code Network Code for EG that is not deemed renewable (non-renewable EG).

Maximum disconnection times for various under- and over voltage levels for non-renewable EG are stipulated in Section 3.6.2.4 of this standard.

¹² Internationally values ranging from a Class 3 DTT to 2 s are found.

¹³ Operate time of ≤ 100 ms which includes the communication end to end time and the circuit breaker switching time. Internationally, times obtained range from Class 3 to 100 ms.

3.5 REQUIREMENTS FOR THE UTILITY NETWORK INTERFACE

3.5.1 Fault Infeed

When it is proposed to install Embedded Generating plant, consideration must be given to the contribution that the plant will make to the fault levels on the Network Service Provider's network. The design and safe operation of the EG's and the Network Service Provider's installations depend upon accurate assessment of the fault contributions made by all plant operating in parallel at the instant of the fault. The EG shall discuss this with the relevant Network Service Provider at the earliest possible stage. The EG shall provide all relevant information for the Network Service Provider to be able to model the generator and its contribution to fault current over time. The fault current in-feed over time must be confirmed in writing to NPD by the EG using the format presented in the Standard IEEE 1547, Table 6: Generator short-circuit current and reactance versus time.

Should the EG result in the increase of fault levels to such an extent that the Network Service Provider's or Customer's plant at the PCC is placed at risk, the EG shall apply fault current limiting measures to ensure that the fault levels are maintained at acceptable levels. The fault limiting solution applied shall be presented to the Network Service Provider for acceptance prior to implementation.

3.5.2 Quality of Supply

Power quality and voltage regulation impact shall be monitored at the POC and shall include an assessment by the Network Service Provider of the impact on power quality from the EG concerning the following disturbances at the POC:

- a) voltage fluctuations:
 - (i) rapid voltage changes (RVC)
 - (ii) flicker
- b) high-frequency currents and voltages:
 - (i) harmonics
 - (ii) inter-harmonics
 - (iii) disturbances greater than 2 kHz.
- c) unbalanced currents and voltages:
 - (i) deviation in magnitude between three phases
 - (ii) deviation in angle separation from 120° between three phases.

Note that the EG will generally follow the supply network frequency; any attempt by the EG to change the supply frequency may result in severe distortion of the voltage at the POC, PCC and other points in the network.

Voltage and current quality distortion levels emitted by the EG at the POC shall not exceed the apportioned limits as determined by the Network Service Provider. The calculation of these emission levels shall be undertaken according to the standard 240-65692753 in line with NRS 048-4. The EG shall ensure that the EG is designed, configured and implemented in such a way that the specified emission limit values are not exceeded.

Voltage changes shall be limited according to minimum values provided in Table 3-3 below. These limits apply at the full range of fault levels and network impedance angles at the POC of the EG, regardless of contingencies that may exist on the network.

Table 3-3: Maximum V change at different V levels as a function of the freq. of these V changes.

Number of changes per hour <i>(r)</i>	Percentage Change in the Voltage	
	nominal voltage at PCC ≤ 44 kV	nominal voltage at PCC > 44 kV
$r < 1$	4	3
$1 < r \leq 10$	3	2,5
$10 < r \leq 100$	2	1,5
$100 < r < 1000$	1,25	1

The EG can assume that the network harmonic impedance at the POC will be less than 3 times the base harmonic impedance for the range of reference fault levels at the POC. That is the network harmonic impedance shall not exceed a harmonic impedance of:

$$|Z(h)| = \frac{V}{S} \cdot i$$

where h is the harmonic number, V is the nominal phase-to-phase voltage in kV, and S is the fault level in MVA. The angle of the network harmonic impedance may range from fully inductive to fully capacitive.

In order to assist with the maximum resonance of 3 times, no EG may connect equipment (e.g., shunt capacitor banks) that will cause a resonance of more than three times at the POC at any frequency.

There shall be main and check QOS instruments if the main and check metering instruments are not used.

3.5.3 Electromagnetic Compatibility¹⁴

Electromagnetic Compatibility (EMC) entails the coordination of all electromagnetic disturbances emitted by a device or an installation as well as the susceptibility of devices to electromagnetic disturbances. Electromagnetic disturbances may be radiated or conducted.

In the event of susceptibility to both radiated and conducted electromagnetic interference, the EG shall be fail-safe (i.e., any deviation from intended performance must comply with all relevant specifications), both in terms of safety (i.e., disconnection) and impact on the network.

Radiated interference shall be tested according to relevant clauses of SANS 211 (CISPR11) or SANS 222 (CISPR 22) and test certificates provided. Whilst these tests will typically be for units of the EG, reasonable assurance of compliance at the EG boundaries will be required.

Conducted interference shall be tested according to SANS/IEC 50065-1 in the frequency range 3 kHz to 148.5 kHz and with SANS 211 (CISPR11) above 148.5 kHz, using limits for Class B group 1 equipment.¹⁵

Exceedance of emission limits of SANS 211 and SANS/IEC 50065-1 may be temporarily allowed, provided that no interference exists to existing PLC, smart grid or other communication protocols implemented by the Network Service Provider. Should interference occur in future, the temporary exemption will be retracted and the EG will have to reduce intentional and unintentional emissions to levels acceptable to the Network Service Provider.

¹⁴ The IEC is presently dealing with a specification for EMC requirements with regard to EG. Once the IEC specification is issued, this standard shall be updated.

¹⁵ The start frequency given in SANS 211 is 150 kHz; however, to avoid the existing gap, limits applying at 150 kHz will be extrapolated down to 148.5 kHz.

3.5.4 Neutral Earthing

The neutral earthing philosophy to be applied on EG networks that are galvanically connected to the Eskom supply network shall comply with the Eskom Standard DPL_34-2149 for neutral earthing of electrical networks. Adequate earthing of networks at other voltage levels within the EG plant is the responsibility of the EG and is not stipulated herein.

The Network Service Provider's networks may use effective, resistive or reactive earthing methods depending on the voltage level and local requirements. The magnitude of the possible earth fault current will depend on which of these methods is used. The EG's earthing arrangement must therefore be designed as follows:

- a) In consultation with the Network Service Provider such that the EG's system is compatible with the Network Service Provider's network.
- b) Such that the EG's plant safety is not compromised due to the above requirement.

The actual earthing arrangements will also be dependent on the number of machines in use and the EG's system configuration and method of operation. Earthing within the EG plant could be achieved by the use of a busbar earthing transformer (e.g., NEC/R), the use of the star point of the generator, or by earthing the star point of the generator transformer.

Care should be taken with multiple generator installations to avoid excessive circulating third harmonic currents. It may therefore be necessary to restrict the earthing to the star point of a single machine and provide automatic transfer facilities of the generator star point earth to another machine in the event of the selected machine being tripped. The use of suitable generator transformers with delta windings may provide a means of avoiding excessive circulating harmonic currents.

The winding configuration of the EG transformer(s) (e.g., delta-star, star-delta etc.) closest to the POC shall be such that zero sequence currents on the Network Service Provider's network and EG systems are decoupled from one another. Due to the above decoupled mandatory clause, the use of autotransformers is not permitted at the PUC.

Under conditions of separation between the Network Service Provider's network and the EG system, care must be taken to not run any part of any of the systems unearthed. In such circumstances, it will be necessary to provide automatic switched facilities of the EG's Network Service Provider-side neutral earth (star point) as stated within DPL_34-2149. If at any stage it is found that the EG is in breach of the condition (re., energising an unearthed system or having the ability to energise an unearthed system¹⁶), it shall be mandatory to retrofit direct transfer trips that operate the PUC circuit breaker from all of Eskom's circuit breakers up to the PSS at the cost to the EG¹⁷.

3.5.4.1 MV networks

Eskom's MV networks are generally resistively earthed at the source substation. Standard DPL_34-2149 states that in new installations, the NEC or NECR for each point of MV neutral earthing shall be specified so as to limit earth fault currents contribution per neutral earthing point to the typical ranges: less than 360A (Rural networks) and less than 960 A (urban networks). SABS 0200-1985 recommends 300 A per earthing device.

The preferred neutral earthing philosophy for MV-connected generators is that the MV neutral point directly connecting onto the Network Service Provider's network (at the POC) be left un-earthed. This will serve to avoid issues of earth fault relay de-sensitisation, as well as avoiding 'circulating' zero sequence or triplen (i.e., 3rd, 6th, 9th etc.) harmonic currents between the distant earth connections. Alternatively, as stated in the Eskom Standard DPL_34-2149, when a separate earth mat is provided (i.e., a separate earth mat to the network's neutral earth connection), the EG may provide a permanent point of neutral earthing as long as

¹⁶ GCCRPPSA states the maximum time to be 2 s for Category B and C. EGs that do not fall under the aegis of GCCRPPSA have a maximum operate time of 2 s according to the DCUOSA agreement. Internationally values ranging from a Class 3 DTT to 2 s are found.

¹⁷ Operate time of $\leq 100\text{ms}$ which includes the communication end to end time and the circuit breaker switching time. Internationally, times obtained range from Class 3 to 100 ms.

the total earth fault current contribution from this neutral point is less than or equal to 10% of the total earth fault current contribution from the Eskom source, but no more than 72 Amperes¹⁸.

No MV connected generators will be allowed to connect directly to the Eskom system. This means that an isolating transformer(s) is required at the POC. An auto-transformer is not acceptable as it does not provide isolation.

With the EG not earthing the Eskom MV network, and in the case of the source tripping as a result of a line earth fault, the healthy line voltages may momentarily be raised to full phase-to-phase values. In addition, there is a possibility of resonant over-voltages or capacitive driven over-voltages. Possible damage to surge arresters may be avoided by specifying arrester Maximum Continuous Operating Voltage (MCOV) values at the full phase-to-phase voltage and grading the over-voltage protection functions with regard to the surge arrester Temporary Over-voltage (TOV) curves.

In the case of an agreed intentional island, the conditions of which are stipulated in Section 3.4.3, the MV star-point shall be earthed. The EG shall ensure that the star-point is resistively earthed the instant prior to intentional islanded operation, as per Eskom standard DPL 34-2149. As stated within the Standard DPL_34-2149, the earth shall be disconnected an instant after the reconnection to the Grid for resumption of parallel operation.

3.5.4.2 HV and EHV networks

HV and EHV networks are required to be effectively earthed at source substations. The high voltage side of the transformer winding shall therefore cater for solid earthing of the neutral using a star-connected winding at the side of the transformer connecting to the Network Service Provider's network. The generator side of the transformer winding shall use a delta-connected winding. The HV or EHV neutral point will have the least effect on the Network Service Provider's protective relays if it is not included in a feeder protective primary system zone.¹⁹

3.5.5 Prevention of Out of Synchronism Closure

The Network Service Provider shall provide synchronism check (synch check) and/or live-line close blocking functionality on all circuit-breakers and/or pole-mounted switchgear²⁰ between the PUC and the PSS. This shall serve as additional security against possible out-of-phase closure onto an islanded EG. Synchronising (auto or manual) shall remain the sole responsibility of the EG and this shall be done at the PUC or PGC, and/or elsewhere within the EG's plant. It is important to note that unintentional islanding events can occur in the event of equipment failure or under power system circumstances that fall within the non-detection zones of inverter protection (i.e., it can never be guaranteed as stated in the Kinetics Inc. report K-418086-RA-001-R10)²¹.

3.5.6 Requirements for Directional and/or Unit/DTT Protection

Where the EG is adjacent to the Network Service Provider substation, shares the same earth-mat and it is deemed prudent by the Network Service Provider to employ an extended buszone sectionalised by bus-sections, that part of the protection functionality requirements listed below pertaining to the dedicated EG feeder(s) may be ignored (i.e., the protection functionality requirements for the feeder from the PCC to the POC).

The protection functionality requirements for the network/connected feeders have been split into the three relevant voltage levels and are listed below:

¹⁸ This Standard requires the total earth fault current from the Eskom source to be the 'total minimum earth fault current contribution from the Eskom source'. Eskom's Regional Operating Unit Manager/Grid Business Management is required to give written approval for this connection.

¹⁹ That is, within a feeder unit protection zone or impedance reach zone 1 or zone 2 without communication assisted tripping.

²⁰ Currently the auto reclosers on Eskom's contract have the ability for live-line close blocking. It may possibly require masking of the function.

²¹ An anti-islanding failure of an inverter is reported in the Electrical Safety Authority bulletin DSB-07/11.

3.5.6.1 MV networks

For MV networks with a dedicated EG feeder²² or dedicated EG feeders, feeder bays with unit protection are required on the EG feeder(s) if the incoming feeder(s) from the Network Service Provider source to the PCC has unit protection. Serious consideration should be given to the type of unit protection functionality applied as the 'differential' type is generally more immune than the 'distance' type to EG related installations. The back-up protective relays shall be directional.

For MV networks, with an added EG source, feeder bays or reclosers are required to protect fault in-feeds at the local and remote point.

In some cases, the fault current in-feed from the EG to network faults will be a small fraction of the grid-supplied fault current. The fault current in-feed from the generator may also decay rapidly with time. As a result, it is unlikely in these circumstances that the traditional non-directional IDMT overcurrent, earth fault and SEF protection applied to radial MV networks will be rendered unsuitable by the presence of an EG. The fault current in-feed over time must, however, be confirmed in writing by the EG using the format presented in the Standard IEEE 1547, Table 6: Generator short-circuit current and reactance versus time, and checked by NPD in collaboration with the Network Service Provider Co-ordination and Settings Department during the early design phase of each project (NPD are to obtain the confirmation and tabulated results). Where no confirmation is obtained and/or studies indicate otherwise, directional protective relays shall be used.

It is important to note that for substantial fault in-feed over time from the EG, the protective devices applied to the radial MV Network Service Provider network will have reduced sensitivity. In these cases, differential type protection may be required.

To maintain safety and to minimise equipment damage of the network and nuisance tripping of the EGs connected to non-dedicated feeders in MV networks and where the maximum rated aggregated EG output (aggregated only if more than one EG of a different energy source is connected on the feeder) is greater than one third of the connected minimum aggregated Customer load (i.e., it is not beyond doubt that the EG will disconnect within the stipulated 2 second period – this information is to be obtained by NPD) or where there is a proven safety concern, it is recommended to employ a DTT from the relevant Network Service Provider circuit breakers for anti-islanding purposes²³.

For MV networks, implementation of a DTT from the relevant Network Service Provider circuit-breakers shall be mandatory with regards to EG Inverters connected to the Network Service Provider at any point other than the PSS except where EGs are certified to pass the non-islanding tests as stipulated in IEEE 1547.1 or if preferred, stipulated in IEC 62116 (IEC 62116 is relevant to photovoltaic inverters only). Note that the above test requirement is also stipulated in the pre-commissioning tests in Table 5-1. Certificated proof of the non-islanding test pass is to be obtained from the EG in the early stages of the design by the relevant Eskom Grid Access Unit as design and installation of DTTs in most MV networks will impact on the cost and complexity of the project.

As certificated proof of the non-islanding capability is required in the early design stages as stipulated above, in this instance, the requirement for this test to be conducted on-site as stipulated in Section 5.1 is waived. However, this does not in any way cancel the requirement for the unintentional islanding test of Section 5.1 for the test to be conducted on-site at the time of commissioning.

²² The term 'dedicated feeder' used in this context, means that no customer/s or alternative NSP feed shares the same feeder or the supply from that feeder.

²³ Maximum rated generation versus minimum aggregated loading criteria found internationally ranges from 1/3 to 1/2. The maximum rated generation may be taken as an aggregated value when more than one EG is connected on the same feeder.

3.5.6.2 HV networks

The terminology used in this sub-section is explained in the generic layout diagram of Figure 3-1 inserted below:

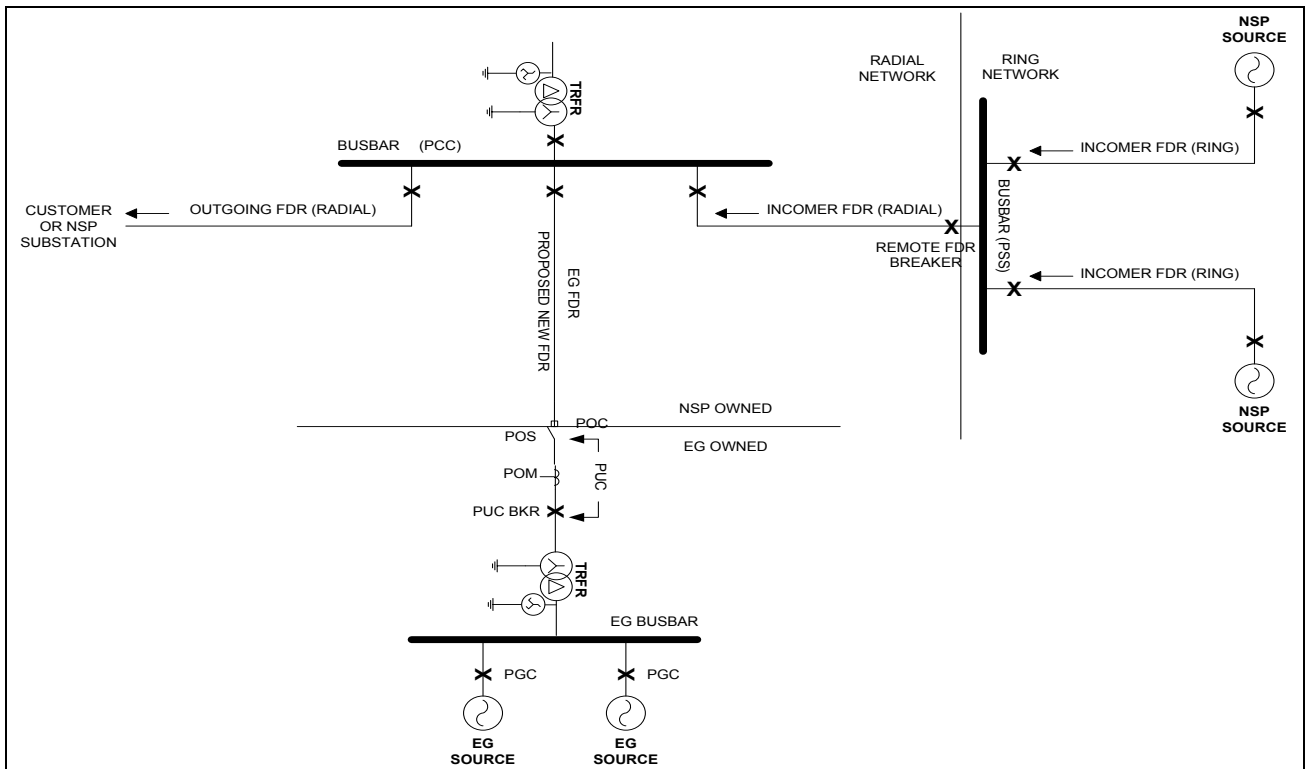


Figure 3-1: Layout of HV Network Indicating the Terminology used

For HV networks with a dedicated EG feeder or dedicated EG feeders, full feeder bays with unit protection are required on the EG feeder(s).

For HV networks, full feeder bays with unit protection are required on the Network Service Provider incomer (*ring*) feeders at a ring-supplied in-out substation (PSS). The back-up protective relays shall be directional.

For HV radial networks, full feeder bays with unit protection are required on the Network Service Provider incomer (*radial*) feeder (from the PCC up to the PSS) for the following conditions²⁴:

- Where DTT to the PUC breaker or dedicated EG feeder from the PCC is required from any remote Network Service Provider breaker up to the PSS. This DTT clause shall be mandatory where Customers are connected to the PCC busbar or are connected downline (in essence the Network Service Provider incomer in this case is a non-dedicated feeder).²⁵
The mandatory DTT clause may be ignored if the maximum rated aggregated EG output (aggregated only if more than one EG of a different energy source is connected on the feeder) is greater than one third of the connected minimum aggregated Customer load (the information is to be obtained by NPD) and, in the case of EG Inverters, where EGs are certified to pass the non-islanding tests as stipulated in IEEE 1547.1 or if preferred, stipulated in IEC 62116 (IEC 62116 is relevant to photovoltaic inverters only).

²⁴ An in-out substation with no feeder bay on the incomer radial source is, with reference to the application of protective relays and the problems encountered, still regarded as a tapped station.

²⁵ Internationally, this has been instituted by a number of utilities and is strongly recommended even in those cases where it is not mandatory.

- b) Where limited nuisance tripping of the EG is important as the main anti-islanding protection will employ a DTT²⁶.
- c) Where the Network Service Provider's incomer remote feeder (*remote feeder breaker*) zone E/F under-reach due to the EG transformer being in service is $\geq 10\%$.
- d) Where the installed maximum capacity of EG generation, the source impedances and network layout causes a Network Service Provider incomer remote feeder (*remote feeder breaker*) zone phase underreach $\geq 10\%$.
- e) Where the risk of cross-country trips is increased.
- f) Where a tapped connection causes sequential tripping of the protective devices.
- g) Where an out-feed at the tapped terminal desensitises a multi-terminal differential protective scheme by $\geq 10\%$ or causes a feeder zone overreach $\geq 10\%$.
- h) Where single-pole tripping and ARC are employed.
- i) Where the QOS of the PSS is important as unit protection will decrease the dip duration to < 150 ms for all faults between the two line ends.
- j) Where there is increased risk of an ARC block due to the generation being temporary islanded.
- k) Where it is considered important to retain the same ARC dead-time as was previously applied on the feeder (e.g. QOS impact - retain instantaneous ARC or the standard 3 second dead-time).
- l) Where the Network Service Provider incomer originates from an Eskom Transmission substation.

The 'unit protection' clause stated above for radial networks on the Network Service Provider incomer may be ignored if item a, (the feeder is a dedicated EG feeder), h, i and l are not applicable and the EG indicates in writing that their plant will adequately feed into a fault over time on the Network Service Provider incomer (so it is not considered a weak in-feed point).

For HV radial networks, the Customer/Network Service Provider outgoing (*radial*) feeders at the PCC busbar, other than the EG feeder, shall include either full feeder bays with unit protection or zone II accelerated trip functionality (dependant on the Network Service Provider's network layout).

3.5.6.3 EHV networks

For EHV networks, full feeder bays with main1 and main2 unit protection per bay are required. The main1 and main2 unit protection shall include both distance and differential functionality except where the EG is adjacent to the EHV substation, shares the same earth-mat and it is deemed prudent by the Transmission Network Service Provider to employ an extended buszone together with bus-sections. Note that only dedicated feeders are allowed for EHV networks.

3.5.7 Auto-reclose Dead-time Settings on Networks with Embedded Generation

Auto-reclose dead-time settings on all circuit-breakers between the PUC and the PSS shall be increased from the standard 3 seconds to at least 5 seconds so as to provide additional margin for the detection and isolation of possible power islands except in cases where QOS and/or power system criteria override this clause. In this case, Section 3.5.5 shall prevent any out-of-synch closures.

It must be noted that the fault current supplied by inverter based EGs is not unbalanced and therefore single-pole ARC may not be possible in certain network layouts (where it would be difficult to detect the correct faulted phase).

3.5.8 Tapchanger Requirements at the PUC for Connected EG

When EG is connected to the MV busbar of a HV/MV Distributor substation where the MV busbar voltage is controlled by means of an automatic tapchanger, the possibility exists that the EG may cause the tapchanger to lose control of the busbar voltage. It is recommended that the automatic tapchanger control

²⁶ It is well documented internationally that it is difficult to obtain both security and reliability using localised anti-islanding protection.

scheme utilised at these stations be remotely controllable to allow the NSP's Control Centre to remotely switch the tapchanger operation to manually tapped to prevent unwanted lockouts. Additionally, according to the Eskom Standards DGL_34-1944 and DST_34-542, NPD or a department within Network Services are to conduct load flow simulations with regard to the application of EG. Recommendations from the above simulations may include reverse power flow tapchanger block or in some cases the application of bi-directional tapchanger schemes.

For HV and EHV networks it is recommended that the automatic tapchanger control schemes utilised at the interface stations be remotely controllable to allow the NSP's Control Centre to remotely control the tapchanger operation.

3.6 REQUIREMENTS AT THE PUC AND PGC

This section details the requirements for the primary plant and control plant equipment to be installed at the PUC and PGC.

3.6.1 Primary equipment

3.6.1.1 Current Transformers

Current transformers shall be specified in accordance with NRS 029. Protection CTs shall be in compliance with the protection relay manufacturer's requirements with regard to accuracy class. Metering circuits shall use Class 0.2 CTs as a minimum, with Class 0.2s CTs being preferred²⁷. Refer to Section 3.7 for further requirements with respect to metering CT cores for Eskom use. Measurement circuits shall use Class 0.2 CTs or protection class CTs. Protection class CTs will typically only be used for Telecontrol measurements where the measurement data is derived from a protection relay instead of a stand-alone transducer.

3.6.1.2 Voltage Transformers

Voltage transformers shall be specified in accordance with NRS 030. Metering and measurement circuits shall use VTs of accuracy class 0.2. Protection VTs shall be of accuracy Class 3P. The VTs shall not be overburdened so as to ensure accuracy within class definitions.

3.6.1.3 Isolator/Disconnecter

The isolator fulfilling the requirements of Section 3.3.2 shall be specified in accordance with NRS 031.

The isolator shall include at least one normally-open and one normally-closed auxiliary status contact for use by Eskom for remote indication purposes. The contacts shall operate in the fully-opened and fully-closed positions of the primary contacts respectively. These contacts may not be provided by a separate relay or device not forming an integral part of the isolator.

The isolator shall be lockable using a standard Eskom padlock:

- a) Case: 35–38 mm high, 28–40 mm wide, 18–20 mm thick; and
- b) Shackle: 6 mm diameter, 30–34 mm length (in the locked position), 20 mm width (minimum).

(Dimensions from Eskom Specification DSP_34-1488 Specification for Master Locks and Master Keys for Electrical and Related Equipment)

3.6.1.4 Circuit-Breakers

The circuit-breakers shall comply with the requirements of IEC 62271-100 and shall be suitably rated to interrupt the maximum prospective fault current at the PUC or PGC as appropriate.

To allow for network growth, the fault interruption capability of circuit-breakers shall be chosen to be at least 30% higher than the maximum fault levels calculated in the initial integration study for the EG plant.

The maximum circuit-breaker trip operating times shall be as follows:

- a) EHV network: < 40ms
- b) HV network: < 60 ms
- c) MV network: < 100 ms

The circuit-breakers shall have a 'maximum over-voltage' factor for switching conditions of IEC 62271-100 of 2.5 pu or higher.

The circuit-breakers shall include at least one normally-open and one normally-closed auxiliary status contact for use by Eskom for remote indication purposes. These contacts may not be provided by a separate relay or device not forming an integral part of the circuit-breaker.

²⁷ Class 0.2s CTs are more accurate over a wider range when compared with Class 0.2 CTs. Large load/supply variances are expected for EG's.

3.6.2 Protection

3.6.2.1 Protection overview

This section details the protection functionality that shall be installed at the PUC, irrespective of whether the same functionality is installed elsewhere within the EG's plant. Protection requirements are also stipulated for the PGC, providing back-up to the PUC protection. The protection systems shall provide adequate protection of the parts of the Network Service Provider's network that could be supplied by the EG, either in parallel operation or under conditions of the EG supplying an intentionally islanded portion of the Network Service Provider's network.

Further, the protection systems shall:

- a) Inhibit connection of the generating equipment to the Network Service Provider's network unless all phases of the Network Service Provider's network are energised and operating within the agreed limits;
- b) Disconnect the generator from the system when a system abnormality occurs that results in an unacceptable deviation of the voltage or frequency at the point of connection; and
- c) Prevent un-intentional islanding of the EG with a portion of the Network Service Provider's network.

Table 3-4 includes a summary of specific protection functions that shall be provided at the PUC²⁸.

Table 3-4: PUC minimum protection requirements per voltage level

Protection Type	Section	EHV/HV	MV
Overcurrent, Earth Fault	3.6.2.3	Yes	Yes
Sensitive Earth Fault (SEF)	3.6.2.3	No	Note 1
Phase Under/Over Voltage *	3.6.2.4	Yes	Yes
Residual over-voltage *	3.6.2.5	No	Note 1
Under/Over Frequency *	3.6.2.6	Yes	Yes
Loss-of-Grid *	3.6.2.7	Yes	Yes
Check Synchronising / interlocking (Block dead line charge)	3.6.2.8	Yes	Yes
Reverse Power *	3.6.2.9	Note 2	Note 2
DC Failure Monitoring	3.6.2.10	Yes	Yes
Double Trip Coils with Trip Circuit Supervision and Breaker Failure	3.6.2.12	Yes	Yes
<p>Note 1: Depends on neutral earthing philosophy adopted. Neutral voltage displacement protection will be applied on networks where the EG or generator transformer does not provide an earth connection to the Eskom network. Earth Fault and Sensitive Earth Fault protection will be required in the event that an earth connection is provided</p> <p>Note 2: Reverse power protection shall be applied in the event that the EG does not plan to, or is not permitted to export power to the Grid, but which will be synchronised with the Grid.</p> <p>* These functions are to be applied by the EG. As such, if the Network Service Provider owns the PUC circuit breaker(s) then they must be applied on the first circuit breaker(s) owned by the EG that can become an islanding point. The Network Service Provider may also provide these functions but only as a back-up to the EG applied functions.</p>			

²⁸ The requirements of this section indicate the Network Service Provider's minimum requirements at the PUC and PGC so as to safeguard the network in the event of faults within the EG's facility, or faults within the network with a fault current contribution from the EG. In keeping with the requirements of the SADCNC, the SAGCNC and the GCCRPPSA, the EG may require additional protection (e.g., biased differential, restricted earth-fault, pole slipping protection, negative phase sequence overcurrent etc.) to safeguard his/her assets against damage due to abnormal events or faults on the power system.

Notwithstanding the requirements of Table 3-4 for the PUC, Table 3-5 below lists the minimum protection functionality to be installed at the PGC:

Table 3-5: PGC Protection requirements

Protection Type	Section
Phase Under/Over Voltage	3.6.2.4
Under/Over Frequency	3.6.2.6
Synchronising	3.4.2
Reverse Power	3.6.2.9
DC Failure Monitoring	3.6.2.10
Negative Phase Sequence overcurrent	3.6.2.11
Double Trip Coils with Trip Circuit Supervision and Breaker Failure	3.6.2.12

The South African Grid Code Requirements for Renewable Power Plants states that all thermo and hydro units shall comply with the design requirements specified in the South African Grid Code (specifically section 3.1 of the Network Code). The Distribution Code: Network Code requires all EGs of nominal capacity greater than 10 MVA, in addition to the South African Distribution Code, to comply with the protection requirements of Section 3.1 of the South African Grid Code: Network Code. The latter requires generators to be provided with back-up impedance (for EGs ≥ 20 MVA) and circuit-breaker fail protection, in addition to the requirements of Table 3-4 and Table 3-5 above. Reverse power is required on rotating plant that is capable of motoring. EGs of capacity larger than 20 MVA require loss-of-field and pole slipping protection where applicable.

3.6.2.2 General protection requirements

- All protection relays used at the PUC, PGC and other intermediate points if installed, shall comply with the type test requirements of Annex C.
- Protection relay accuracy requirements of the following sections shall be defined as per IEC 60255-3 and -6.
- The PUC and PGC protection shall be totally independent of each other.
- Protection clearance times and coordination shall comply with the requirements specified as a result of the EG integration fault studies. EG fault levels over time shall be supplied to the Network Service Provider prior to acceptance of the EG protective design.
- If automatic resetting of the protective equipment is used (e.g., for an unmanned EG facility), the time delays must be applied in consultation with the regional auto-reclose philosophy. The automatic reset must be inhibited for faults within the EG installation.
- To prevent nuisance tripping and to assist with grading, it is mandatory that the EG shall have overlapping unit protection whenever the Network Service Provider applies unit protection at the PCC.
- Buszone protection shall be applied at the PCC or an equivalent unit protection dependant on the relevant Distributor standard. It is mandatory to apply buszone protection on the generating busbar when this is connected directly to a Eskom Transmission substation.
- Circuit breaker fail protection shall always be implemented at the PUC, PGC and other intermediate points, together with trip circuit supervision of both trip circuits (breaker fail retrip and/or crosstrip to energise the second trip coil, timed breaker failure to energise back-up circuit breakers and/or zone).
- It is mandatory for EHV connected EGs to have main 1 and main 2 protection functionality.
- Each protection relay system shall include a sequence of event recording function that logs any settings change; settings group change, protection pick-up or trip operation, or change in circuit-breaker and/or input and output status.

CONTROLLED DISCLOSURE

- k) The relay system installed at the PUC, PGC and other interconnected points if installed, shall incorporate an oscillographic waveform recording function capable of storing at least five recordings, with a settable recording window to record any protection start until trip output (this may also be achieved with a settable pre-fault duration followed by the fault duration). A sampling rate of sixteen samples per cycle or higher is required. The recording shall have retrigger capability to capture an event subsequent to the initial trigger with a complete recording of the second event. The waveform recording shall contain the three phase voltage, three phase current and neutral current signals from the PUC as well as all significant digital signals (i.e., protection tripping elements, circuit-breaker status, input and output contact status etc.). A recording shall be triggered upon any protection operation.
- l) The event and waveform recordings shall be stored in non-volatile memory and shall be time stamped with a resolution of 1 millisecond real time. It shall be possible for the recordings to be made available in COMTRADE format.
- m) Protection settings for all functions identified in Table 3-4 and Table 3-5 to be applied at the PUC, PGC and other intermediate points if installed, will be to the Network Service Provider's written approval. No changes to the settings shall be made without written consent from the Network Service Provider. The EG shall keep written record of all protection settings, and provide a signed electronic copy of the same to the Network Service Provider.

3.6.2.3 Overcurrent, Earth Fault and Sensitive Earth Fault protection

Overcurrent and earth fault protection shall provide Inverse Definite Minimum Time (IDMT) time-current characteristics. IDMT curves shall be in accordance with the requirements of IEC 60255-3: Type A, B and C curves (i.e., IEC Normal Inverse, Very Inverse and Extremely Inverse). Directional protection is recommended.

Overcurrent protection will be provided in all cases. Voltage-controlled overcurrent protection shall be considered in applications where the fault current contribution of EG decays with time.

Appropriate earth-fault protection will be applied in all cases. Current-based detection is not appropriate in MV networks where the generator or generator transformer does not include a point of neutral earthing.

Sensitive earth-fault (SEF) protection will be applied on MV networks where the generator or generator transformer provides a point of neutral earthing to the Distributor network. SEF protection will be set in compliance with Eskom Standard *DST_34-540*.

Sensitive earth-fault protection will use a definite time characteristic.

The overcurrent, earth-fault and SEF protection shall be set to co-ordinate with the Network Service Provider's network protection as dictated by the integration fault studies.

3.6.2.4 Under- and Over-Voltage protection

Under- and over-voltage protection shall be provided. The voltage protection functions shall detect the effective (i.e., root mean square) or the fundamental component of each phase-to-phase voltage. The under-voltage condition shall be supervised using fuse failure check and fuse MCB trip (i.e., blocked for any failed circuit to prevent a maloperation).

RPPs shall comply with the voltage requirements as set out in Section 5.2.1 of the Grid Code for Renewables. Non-renewable EG shall comply with the maximum operating times for the voltage protection as indicated in Table 3-6 below as stipulated in IEEE 1547.

Table 3-6: Maximum operating times for voltage protection

Voltage range (% of nominal)	Maximum Operate Time (s)
$V < 50\%$	0.2 s
$50\% \leq V < 90\%$	2 s
$110\% < V < 120\%$	1 s
$V \geq 120\%$	0.2 s

CONTROLLED DISCLOSURE

In cases where the EG facility may import or export power from the network, the voltage protection may be supervised so as only to operate in the event of real and/or reactive power export by the facility to the network. Care should be taken to still meet the GCCRPPSA requirements for reactive power support.

3.6.2.5 Residual over-voltage / neutral voltage displacement protection

Residual over-voltage (also known as neutral voltage displacement) protection shall be applied on MV networks where the generator or generator transformer MV neutral is unearthed. The voltage signal must be derived from a VT configuration that is capable of transforming zero-sequence voltage: three single phase VTs or three phase 5-limb VTs, with primary neutral earth connection. The residual voltage may be derived from a broken-delta configuration of the VTs, or may be calculated by the relay based on the measured phase-to-neutral voltages.

The pick-up and time delay of the residual over-voltage protection shall be chosen so as to grade with the current-based earth-fault protection that is applied to the Network Service Provider's network. It is preferred that the residual over-voltage protection uses an inverse voltage-time characteristic rather than a definite time characteristic. The residual over-voltage protection will be less sensitive and slower than the Network Service Provider network protection. Refer to Annex E for a worked grading example.

3.6.2.6 Under and Over Frequency protection

Under- and over frequency protection shall be provided. The under- and over frequency protection relay shall be accurate to within 10 millihertz of the setting. Where an averaging 'window' is used for the frequency measurement, this shall be limited to a maximum length of 6 cycles.

The frequency protection shall be set so as to allow generator operation within the frequency ranges referenced in Section 3.4.1. Operation above the over frequency ranges shall cause the EG to sever the connection with the Network Service Provider's network within 4.1s. Operation below the under frequency ranges for greater than 200ms for RPPs and turbo-alternators and greater than 1.0s for hydro-alternators, allows EGs to sever the connection with the Network Service Provider's network.

In cases where the EG facility may import or export power from the Network Service Provider network, the frequency protection may be supervised so as only to operate in the event of real power export by the facility to the Grid.

3.6.2.7 Loss-of-Grid protection

Operation of an EG in an unintentional islanded mode with part of the Network Service Provider network constitutes a serious safety hazard to both equipment and personnel, and shall be avoided.

The philosophy to be applied is that the detection of an islanding condition shall take precedence over the continuity of the EGs Grid connection (via the PUC). The EG must be disconnected from the Network Service Provider network upon reasonable suspicion of islanded operation. EGs of capacity greater than 50 MVA must also include more definitive islanding detection methods (e.g., communication-assisted intertripping schemes); so as to further avoid nuisance tripping for non-islanding events. If communication-assisted intertripping is used, it is mandatory that dedicated loss-of-grid protection be installed as back-up protection.

Dedicated loss-of-grid protection will be applied at the PUC in all applications. An EG may be exempted from this requirement in the event that it is prohibited from exporting real power to the Network Service Provider network by a suitable reverse power relay (see Section 3.6.2.9). An exemption could be given for applications where it is physically impossible to island and the EG has obtained independent certificated proof of this. Care should be taken by the SOD/NOD when considering an exemption on this basis and it must be noted that obtaining a certificate for the required tests as given in Section 3.5.6. does not preclude the necessity for loss-of-grid protection (i.e., even the best designed and tested protection systems may experience component failure as stated in the Kinectrics Inc. Report).

Loss-of-grid protection may take the form of Rate-of-Change of Frequency (ROCOF) with typical settings as suggested in Table 3-7 below. Voltage Vector Shift protection has been discontinued due to nuisance tripping in the German Association of Energy and Water Industries which includes the associations BGW, VDEW, VRE, and VDN [BDEW] and discussed in the IEEE 1547 Working Group. As such Voltage Vector Shift should be used with caution.

Table 3-7: Typical settings for loss-of-grid protection

ROCOF	Δf	0.2–1.0 Hz/s (0.4 Hz/s typical)
	Δt	40 ms – 2000 ms
	Time delay	200 ms – 500 ms
Voltage Vector Shift	ΔV	6° – 12° (6° typical. 12° on weak networks).

Where ROCOF is not deemed suitable, a communication-based direct transfer trip scheme (DTT) must be applied such as to disconnect the EG in the event of an island developing. The onus rests on the EG to prove that the Loss-of-grid protection is suitable and the Network Service Provider takes no liability for the frequency of nuisance tripping.

It must be noted that use of a communication-assisted intertripping scheme, regardless of MW size, allows for minimum nuisance tripping that could be caused by passive loss-of-grid protection schemes such as ROCOF and voltage vector shift.

3.6.2.8 Check Synchronising / Block dead line charge

The circuit-breaker at the PUC shall be blocked from closing onto a de-energised Network Service Provider network (block dead line charge). Charging of the EG network shall be permitted subject to synchronism check having been performed.

Synchronising shall be done at the PGC, in accordance with the requirements of Section 3.4.2. Where synchronising occurs at the PUC, for situations where the EG would island onto his/her own internal network, the PUC shall also adhere to the requirements in Section 3.4.2.

3.6.2.9 Reverse Power protection

There are two principal applications of reverse power protection:

a) Prevention of generator motoring:

This shall be applied as standard at the PGC on all rotating generators.

The recommended setting for a reverse power relay is 10–20% of the maximum allowable motoring power. The operating time is typically 10–30 s. The time delay is required to prevent a maloperation during power swings or when synchronising the generator to the network [Jenkins p.177].

b) Prevention of power export to the Grid:

A reverse power protection relay may be installed at the PUC of an EG whose entire output will be consumed by the plant in which it is embedded. The reverse power protection relay will prevent unintended export of power to the Network Service Provider's network, and may obviate the need for dedicated loss-of-grid protection (see Section 3.6.2.7). When serving as loss-of-grid protection, the reverse power protection relay shall be graded with time overcurrent protection in order to ensure ride-through during fault conditions. The clearance times shall comply with the requirements determined by the EG integration fault studies.

3.6.2.10 DC Failure Monitoring

DC failure within the EG facility is deemed a serious safety risk. The DC supplies provided for the PUC and PGC circuit-breakers and associated protection systems shall be subject to continuous monitoring. Two separate DC alarms shall be provided per DC system:

a) Non-urgent DC alarm:

An alarm activated when the battery voltage is lower than normal, or for any fault appearing on the AC supply to the battery charger.

b) Urgent DC alarm:

An alarm activated when the battery voltage is such that the available capacity is less than 20% of the rated Ampere-hour capacity, and when the DC voltage is less than 90% of the nominal DC voltage.

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The EG shall initiate disconnection from the Network Service Provider network immediately upon receipt of an Urgent DC alarm.

3.6.2.11 Negative Phase Sequence Overcurrent

Negative phase sequence overcurrent protection shall be applied as a generator protection function, and shall serve to protect the generator against damage due to unbalanced loading, broken conductors or other asymmetrical operating conditions.

Negative sequence current components can be extremely harmful to the EG. System faults, by their nature, are a large contributor to negative sequence currents. The EG should be aware that negative phase sequence overcurrent protection must be effectively applied.

3.6.2.12 Circuit Breaker Fail/Double Trip Coils/ Trip Circuit Supervision

Circuit breaker fail protection shall be applied firstly as a breaker fail re-trip/cross-trip of the second trip coil and then secondly as a breaker fail trip to a back-up circuit breaker or zone (bus strip). Both trip circuits within each circuit breaker shall have trip circuit supervision functionality.

Note that where a circuit breaker is installed at a node where there is the possibility of a source on both sides of the node (e.g., NSP source and EG source), both source in-feeds must be tripped for a breaker fail trip operation.

There shall be a 'breaker fail' bus strip time and a retrip time. The timers shall only start when there is a protection initiation and an overcurrent condition (selectable). The 'breaker fail' bus strip and retrip timers shall start simultaneously when the initiating conditions become true and reset instantaneously when either the protection initiation and or the overcurrent condition terminates.

A 'breaker fail' bus strip output shall be produced once its set time has expired. A retrip shall be issued before expiry of the set 'breaker fail' bus strip time. If the retrip function is not offered then this function shall be replaced by a selectable time delayed trip contact from the main protective relay operating the back-up trip coils for single-pole protection operations. For three-pole protection operations (in a single-pole scheme) an instantaneous 'retrip' shall be issued to the back-up trip coils. A three-pole scheme shall issue a retrip (settable time) via the retrip timer. Supervisory indications of both the retrip and bus strip outputs shall be provided.

The 'breaker fail' retrip output contact (normally open) shall be located in the back-up D.C. circuit and shall issue trip commands to the back-up trip coil when the TNS switch is selected to the 'NORMAL' position only.

Three bus strip output contacts (normally open) should be provided as a minimum. One bus strip output contact should be located in the main D.C. circuit and shall initiate a direct transfer trip send command (where relevant) when the TNS switch is selected to the "NORMAL" position only. The second bus strip contact shall issue trip commands to the buszone panel or back-up circuit breaker when the TNS switch is selected to the 'NORMAL' position only. The third bus strip contact shall be located in the back-up D.C. circuit and shall issue trip commands to the back-up trip coil when the TNS switch is selected to the 'NORMAL' position only (this output may be shared with the 'retrip' output).

All initiating contacts shall be located in the main D.C. circuit and as a minimum the following conditions where relevant should be arranged to initiate the 'breaker fail' function:

- a) external trip input to the scheme.
- b) buszone trip input to the scheme (where applicable).
- c) main protection trips and intertrip receive (where applicable).
- d) back-up protection trips.
- e) direct transfer trip receive (where applicable).
- f) pole disagreement trip (single-pole tripping schemes only).

3.6.3 DC Systems and Auxiliary Supplies

The circuit-breakers and associated protection systems at the PUC and PGC shall operate from independent DC supplies.

The DC supplies to the PUC and PGC shall be subject to continual monitoring as per Section 3.6.2.10. The EG shall cease to energise the Network Service Provider's network upon critical failure of either the DC system at the PUC or at the PGC or both.

The DC systems at the PUC and PGC shall be maintained in accordance with the applicable Eskom standard or an alternative written policy acceptable to Eskom. Eskom reserves the right to perform audits on the DC systems.

In the scenario of a switching substation where there is no Eskom auxiliary supply point available, the *Distribution standard Provision of Auxiliary Supplies at Switching Substations* (DST_34-2095) discusses the following options:

- a) Single phase power VTs
- b) Power from a nearby reticulation line
- c) Power from the customer's auxiliary transformers

If thyristor controlled rectifiers or larger battery charger A.C. currents are required to meet the Distributor design for its DC system and the Power VT's cannot meet the current AC requirements then the following options are to be made available to the Distributor:

- a) At initiation stage the EG is required to apply to Eskom for a minimum of 50 kVA three phase rural AC supply. This supply will be used during the construction phase. Eskom will then use this as the alternative mains AC supply, to the Eskom control room.
- b) The cabling from the NEC/R/T/Aux on the EG side is to be fitted with LV surge arrestors, fitted into the NEC/R/T/Aux (DEHNBlock Maxi fitted to the 3 phases).
- c) The EG shall supply Eskom's control room from their NEC/R/T/Aux transformer(s) with a minimum of 63 Amps three phase AC supply. This supply will be fed via the EG standby generator (if available), with a chop-over on the EG side.

For each new substation, the regional or national DC Specialist should consider and compare all the available options against the substation load requirements, and decide on the best possible solution for each application.

3.7 METERING

The metering arrangement adopted per EG application will depend on the specific conditions of the power purchase agreement. The following metering philosophy shall, however, apply to all EG interconnections:

- a) Tariff metering, which shall be maintained and owned by the Network Service Provider, shall be installed through a main and check meter arrangement normally at the PUC which will be used to bill the EG for their auxiliary load. The Network Service Provider's metering shall comply to NRS057 as well as the relevant Eskom standards where applicable.
- b) It is recommended that this same tariff metering infrastructure be used by the Network Service Provider for billing purposes on behalf of the EG. The EG may, as a safeguard, install a back-up meter on the Network Service Provider check circuit for verification purposes and audit the installations as per Section 3.1.5.
- c) Where the EG does not want to use the Network Service Provider's infrastructure, the EG will be responsible for the installation, maintenance and operation of its own metering system including the optional verification billing. The EG shall comply with the NRS057 requirements as a minimum.
- d) Tariff meters for the sale of electrical energy to the Network Service Provider will be located such that they measure the net energy exported by the EG, excluding the power consumed by its auxiliaries. In certain circumstances, the Network Service Provider may allow the power consumed by the auxiliaries to be a fixed unmetered amount but this decision rests with the Network Service Provider.
- e) All Eskom-owned meters shall include facilities for automated remote downloading by Eskom. The meters shall be energised via their auxiliary input, preferably by a 110V DC supply, alternatively by a 240V AC supply. Class 0.5 meters, which do not have the auxiliary input facility, may be energised through the normal 110V VT supply. The selected (chop-over) VT supply should be used where more than one VT exists.
- f) In limited cases where the Network Service Provider metering system is installed within a customer- or EG-owned substation or industrial plant, the Network Service Provider metering equipment shall be limited to the metering panel and the associated equipment. The EG shall provide suitable instrument transformers, which will be owned by the EG. In this case, sharing of instrument transformer circuits shall be in accordance to DPL_34-680.
- g) All access to data shall be in accordance with DPL_34-680.

4 SUPERVISORY CONTROL AND DATA ACQUISITION

This section details the requirements, standards and procedures to ensure that adequate and reliable SCADA facilities exist between the NSP and the EG to enable trouble-free operation of the Grid.

The SCADA system utilised for this purpose must be designed; operated and maintained in such a manner that does not compromise the stability of the NSP's network.

For the Transmission and/or Distribution NSP to monitor the EG plant, the NSP's Control Centre must connect to the SCADA system installed at the EG station. The NSP is also required to control the EG plant under certain circumstances as per the connection agreement.

Sections 13.1.1 to 13.1.5 of the GCCRPPSA point to the need for "...SO or NSP designated communication gateway equipment located at the RPP site:"

Section 13.6.1 of the GCCRPPSA states that "The RPP shall have external communication gateway equipment that can communicate with a minimum of three simultaneous SCADA Masters, independently from what is done inside the RPP."

Section 3.6.3 of the GCCRPPSA states that "The necessary communications links, communications protocol and the requirement for analogue or digital signals shall be specified by the SO..."

4.1 GATEWAY EQUIPMENT

As required by the GCCRPPSA, the SO designates that the communication gateway equipment located at the EG site shall be an RTU or Gateway currently approved on Eskom's Gateway/RTU Contract.

This Eskom Approved Gateway shall be the gateway through which the EG interfaces to the relevant Eskom Control Centre. The EG shall not interface to Eskom Control Centres directly or via the SCADA system in the Eskom substation.

The Approved Gateway shall be located in the EG control room. The Approved Gateway shall be owned and operated by the EG.

The Approved Gateway will essentially serve as a protocol and communications interface device that will greatly simplify the interfacing of many different EGs to Eskom's Control Centres via Eskom's various communications channel types. With this approach; there will be no need for the EG to conduct protocol implementation conformance testing to ensure interoperability with the Eskom Control Centres. Protocol implementation and interoperability with the Eskom Control Centres will already have been tested and approved by Eskom.

In order to ensure the above mentioned interoperability between the Approved Gateway and the Eskom Control Centres, the protocol firmware used on the Approved Gateway shall be the latest Eskom approved version. Eskom will inform the EG if and when a new approved firmware version is available. The EG must implement the latest firmware version within 90 days of being notified by Eskom.

The Codes stipulate that this Gateway shall have at least three communication ports available exclusively for Eskom master station communications. This is to cater for cases where the EG is connected to the Eskom Transmission Network and hence is required to communicate with the Main and Standby Transmission Control Centres and the delegated Distribution Control Centre. For Distribution connected EGs it should be noted that two of these communication ports may not be required.

The EG must determine from Eskom the details of the currently approved Gateway/RTUs and source it directly from the Eskom approved Vendor. Ordering information for the Eskom Approved Gateway/RTUs as at the publish date of this standard is provided in Annex F.

4.2 PROTOCOLS FOR INFORMATION EXCHANGE

Only the IEC 60870-5-101 and DNP3 protocols shall be used for SCADA information exchange between the EG and the Eskom Control Centres.

The EG SCADA system shall be capable of reliably exchanging system status and data with the Eskom Control Centres.

The EG shall cater for the communication infrastructure to connect the required number of Approved Gateway ports to the Eskom telecommunications infrastructure in the Eskom substation.

4.2.1 SCADA Protocol between the EG and the Approved Gateway

The IEC 60870-5-101 protocol shall be implemented between the EG system and the Approved Gateway when the EG connects to the Eskom Transmission System.

The DNP3 protocol shall be implemented between the EG system and the Approved Gateway when the EG connects to the Eskom Distribution System.

It shall be the responsibility of the EG to ensure correct implementation of the applicable protocol on their device for communication with the Approved Gateway. It shall also be the responsibility of the EG to ensure the interoperability between the EG systems and the Approved Gateway.

Eskom shall however reserve the right to witness and endorse the correctness of the interface prior to commissioning. The EG shall demonstrate to Eskom that each Application Service Data Unit (ASDU) that was implemented is behaving as expected.

The EG shall supply Eskom with the Acceptance Test Procedure to be followed for conducting the conformance test. Eskom shall be given the opportunity to influence the Test Procedure prior to its finalisation.

Eskom shall supply the EG with the applicable Protocol Implementation Document upon request.

4.2.2 SCADA Protocol between the Approved Gateway and Eskom Control Centre

The IEC 60870-5-101 protocol shall be implemented between the Approved Gateway and the Eskom Control Centre when the EG connects directly to the Eskom Transmission System.

The DNP3 protocol shall be implemented between the Approved Gateway and the Eskom Control Centre when the EG connects to the Eskom Distribution System.

4.2.3 SCADA Protocols within the EG system

The EG may use any protocol of their choice for communication between the EG field devices and the EG RTU.

The protocol used should however be capable of time stamping of all digital inputs at the IED level.

The EG shall be responsible for correct implementation of the communication protocol between the EG RTU and the field IEDs.

If the IEDs in the EG substation support the applicable Eskom Approved protocols (IEC 60870-5-101 or DNP3), the EG may interface the IEDs directly to the Approved Gateway. The serial port capacity limitations of the Approved Gateway must be ascertained from the Supplier and must not be exceeded.

Where a Distribution connected EG is using the approved Eskom RTU as their SCADA Gateway/RTU it can double-up as the Eskom Approved Gateway provided that the applicable Eskom firmware is used.

Where a Transmission connected EG is using the approved Eskom RTU or approved Eskom Gateway (currently GE D400) as their SCADA Gateway/RTU it can double-up as the Eskom Approved Gateway provided that the applicable Eskom firmware is used.

4.3 TELECOMMUNICATION INTERFACE REQUIREMENTS

Large capacity EGs have the potential of pushing the system voltage to the trip level, which is an undesirable situation. It is therefore imperative for larger EGs to have a very reliable communication link between the EG and the Eskom Control Centres. The type of communication interface shall therefore be dictated by the generating capacity of the EG and the voltage level that the EG connects to the Grid.

The available telecommunication interface to the Eskom Control Centres may vary from substation to substation.

There are three acceptable communication interface options as follows;

- a) Option 1: X.21 channel (very high availability full-duplex channel suitable for polled comms).
- b) Option 2: UHF radio channel (high availability half-duplex channel not suitable for polled comms).
- c) Option 3: Satellite channel (high availability option for where Eskom has no comms infrastructure)

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The EG should obtain verification at the inquiry stage from Eskom as to which interface option will be used in order to adequately cater for this.

Eskom shall be responsible for the running cost and maintenance of the communication equipment between the Eskom substation and the Eskom Control Centre, once commissioned.

In all cases, The EG shall supply and install at least a 24-core 9/125 µm single-mode fibre optic cable between the EG substation and the Eskom substation.

4.3.1 Option1: X.21 communication interface

Due to the impact that a category C generator can have on the Grid, it shall use the X.21 interface for communication with the Eskom Control Centres wherever feasible. If the Eskom connecting substation does not have X.21 communications, it should be upgraded to have this facility wherever feasible.

Regardless of its size, all EGs connecting at EHV levels shall use the X.21 option.

For the Self-Builds, where the EGs are building a new substation for Eskom, the new Eskom substation shall be equipped with the X.21 communication facility. The EG shall make timely provision for the communication equipment to be installed at the new substation.

The fibre optic cable will facilitate the communication interface between the Eskom Approved Gateway at the EG substation and the X.21 communication equipment installed at the Eskom substation.

A fibre optic to RS422/RS485(4-wire) media converter shall be used to interface with the X.21 communication equipment. This requirement is to enable the connection of the Approved Gateway and Eskom substation RTU to the same X.21 interface on the Eskom telecommunications equipment. The standard media converter used for this purpose shall be sourced from the Substation Control System Eskom National Contract (ENC).

The Approved Gateway at the EG substation shall also have a fibre to RS232 communication interface for each master station communication channel to facilitate interfacing with the fibre to RS422/RS485 media converter at the Eskom substation.

4.3.1.1 Responsibilities and Ownership

- a) The EG shall supply, install and commission at least a 24-core 9/125 µm single-mode fibre optic cable between the fibre patch panels in the EG and Eskom substations. OPGW is recommended.
- b) When installed on a power line, the fibre shall be owned and maintained by the owner of the line otherwise the fibre shall be owned and maintained by the EG. The extent of this responsibility is to the fibre patch panels in the substations at each end.
- c) The EG shall supply and install the fibre patch panel at the EG substation.
- d) Eskom shall provide and install the fibre patch panel at the Eskom site
- e) It shall be Eskom's responsibility to terminate from the fibre patch panel to the communications equipment located at the Eskom substation.
- f) Eskom shall also supply all ancillary equipment and cabling requirements for the connection from the fibre patch panel located at the Eskom substation to the Eskom communications equipment.

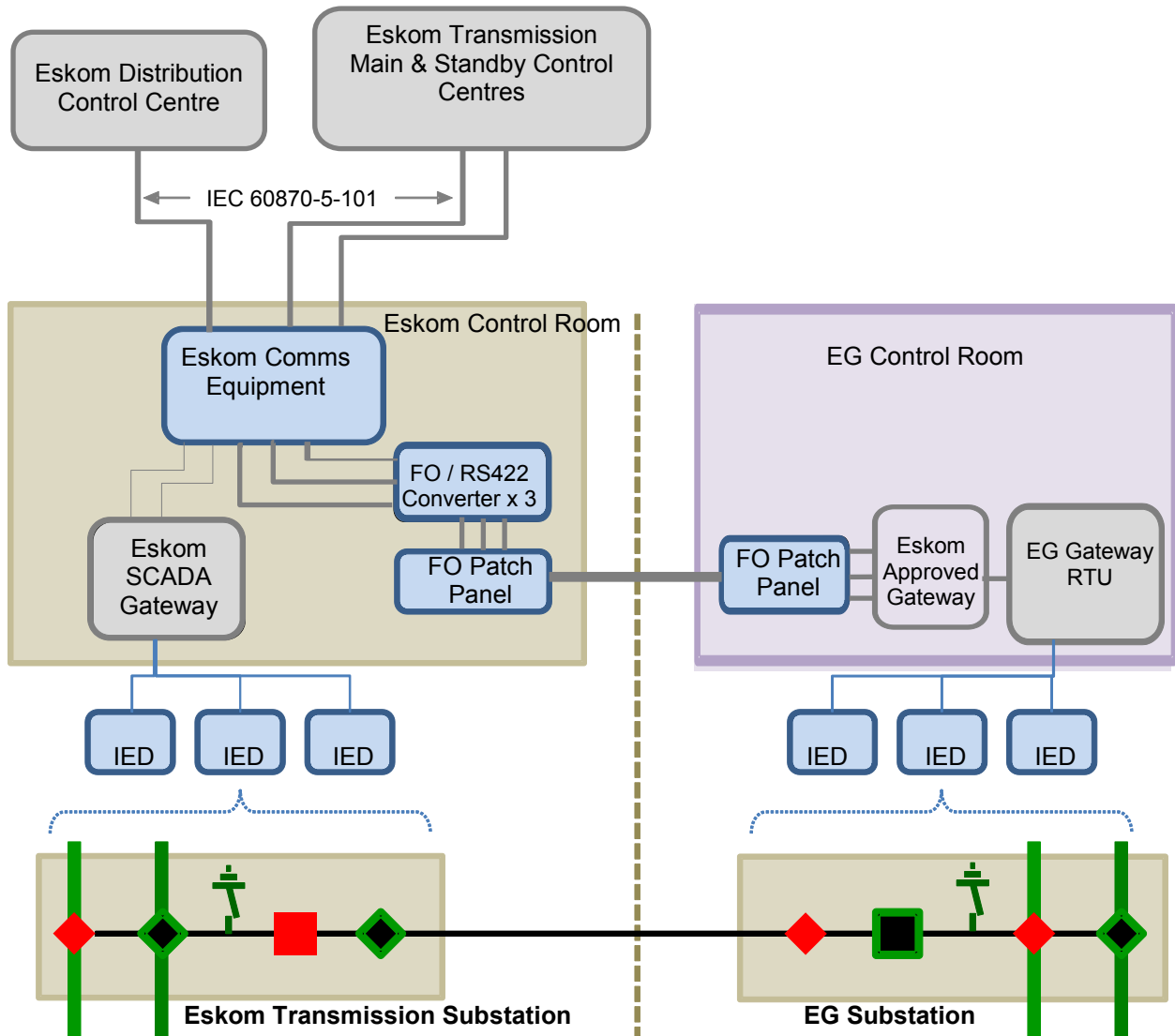


Figure 4-1: X.21 communication interface (Transmission)

Figure 4-1 above illustrates the communication links, interfaces and protocols for the case of a Transmission connected EG.

CONTROLLED DISCLOSURE

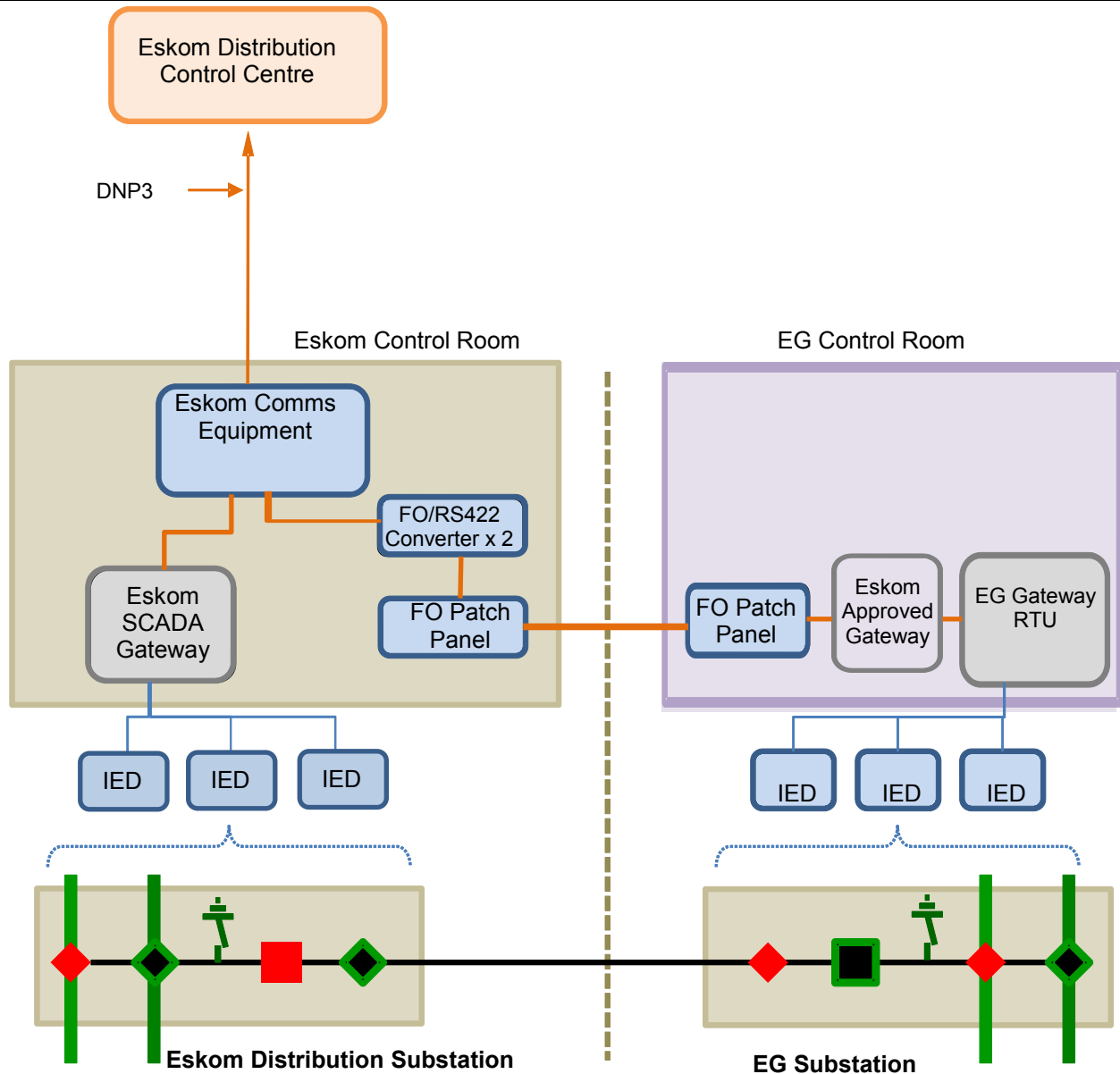


Figure 4-2: X.21 communication interface (Distribution)

Figure 4-2 above illustrates the communication links, interfaces and protocols for the case of a Distribution connected EG interfacing via an Eskom X.21 link.

4.3.2 Option2: UHF radio communication interface.

For category B generators, the UHF area radio option may be used. This however does not preclude the EG from employing X.21 communication where feasible as this is the more reliable form of communication interface. It should be noted that the Eskom UHF Radio channel is shared by up to 40 substations which results in non-deterministic latency.

The availability of this option depends on the availability of a UHF radio repeater within range.

The Approved Gateway will ensure that the EG SCADA system is adequately capable of successful communication over this interface.

This option is not allowed for Transmission connected generators.

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4.3.2.1 Responsibilities and ownership

- The EG shall supply, install and commission at least a 24-core 9/125 μm single-mode fibre optic cable between the fibre patch panels in the EG and Eskom substations, OPGW is recommended.
- When installed on a power line, the fibre shall be owned and maintained by the owner of the line otherwise the fibre shall be owned and maintained by the EG. The extent of this responsibility is to the fibre patch panels in the substations at each end.
- The EG shall supply and install a fibre patch panel at the EG substation.
- Eskom shall supply and install the fibre patch panel at the Eskom site.
- It shall be Eskom's responsibility to terminate from the fibre patch panel to the communications equipment located at the Eskom substation.
- Eskom shall also supply all ancillary equipment and cabling requirements for this connection from the fibre patch panel located at the Eskom substation to the Eskom communications equipment.
- Eskom shall be responsible for the UHF radio equipment hardware and installation thereof. Eskom shall be responsible for application of the radio operating frequency license from the Independent Communications Authority of South Africa (ICASA).

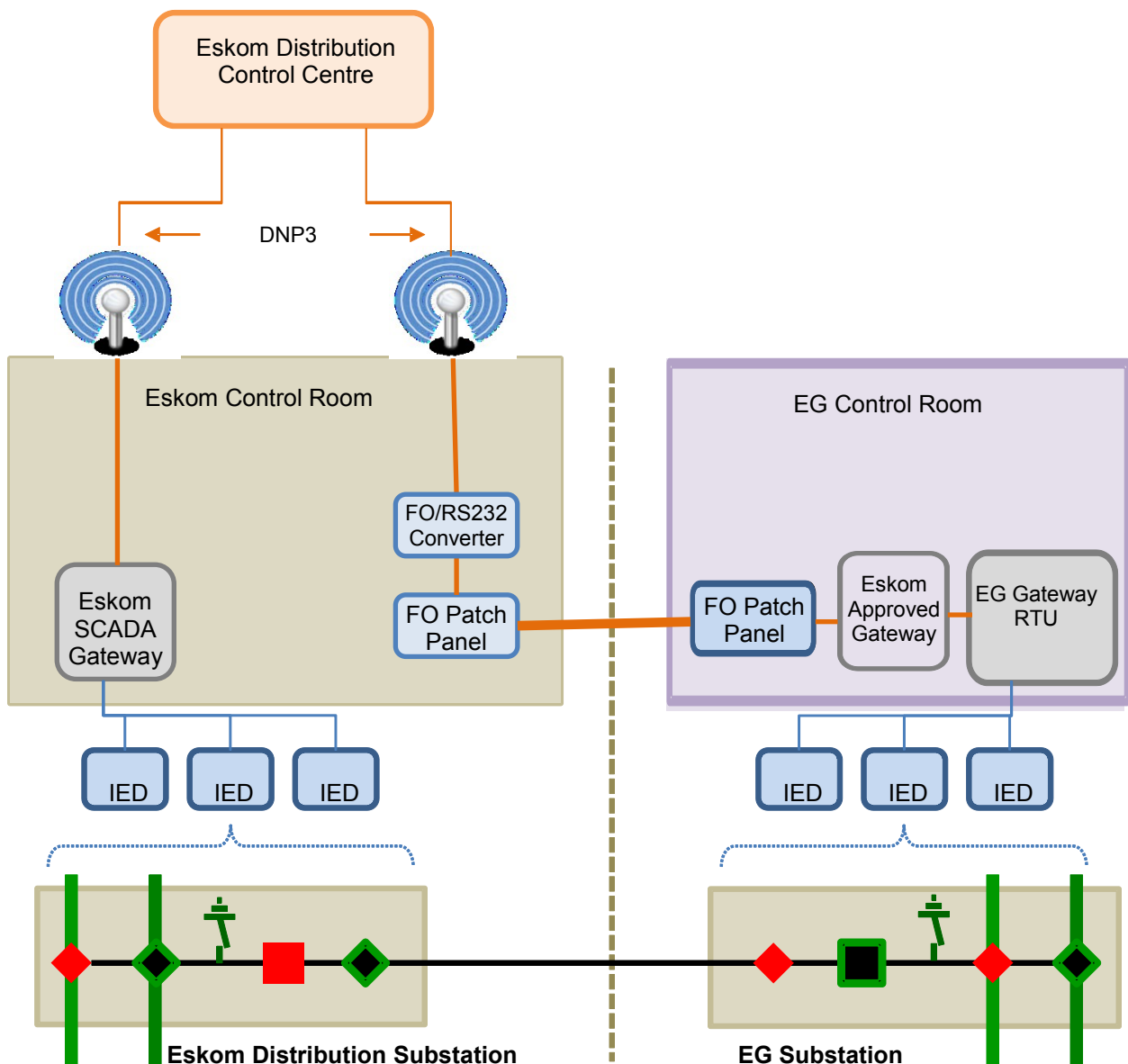


Figure 4-3: UHF radio communication interface

CONTROLLED DISCLOSURE

4.3.3 Option3: Satellite communication interface.

This communication interface may only be considered if options 1 and 2 are not possible or allowed. This will probably only be needed in deep rural areas where the installation of terrestrial communication is impractical or too costly.

4.3.3.1 Responsibilities and ownership

- a) The EG shall supply, install and commission at least a 24-core 9/125 µm single-mode fibre optic cable between the fibre patch panels in the EG and Eskom substations, OPGW is recommended.
- b) When installed on a power line, the fibre shall be owned and maintained by the owner of the line otherwise the fibre shall be owned and maintained by the EG. The extent of this responsibility is to the fibre patch panels in the substations at each end.
- c) The EG shall supply and install a fibre patch panel at the EG substation.
- d) Eskom shall supply and install the fibre patch panel at the Eskom site.
- e) It shall be Eskom's responsibility to terminate from the fibre patch panel to the communications equipment located at the Eskom substation.
- f) Eskom shall also supply all ancillary equipment and cabling requirements for the connection from the fibre patch panel located at the Eskom substation to the Eskom communications equipment.
- g) Eskom shall be responsible for the satellite equipment connectivity and licensing arrangements. The satellite receiver equipment shall be located at the Eskom substation.

CONTROLLED DISCLOSURE

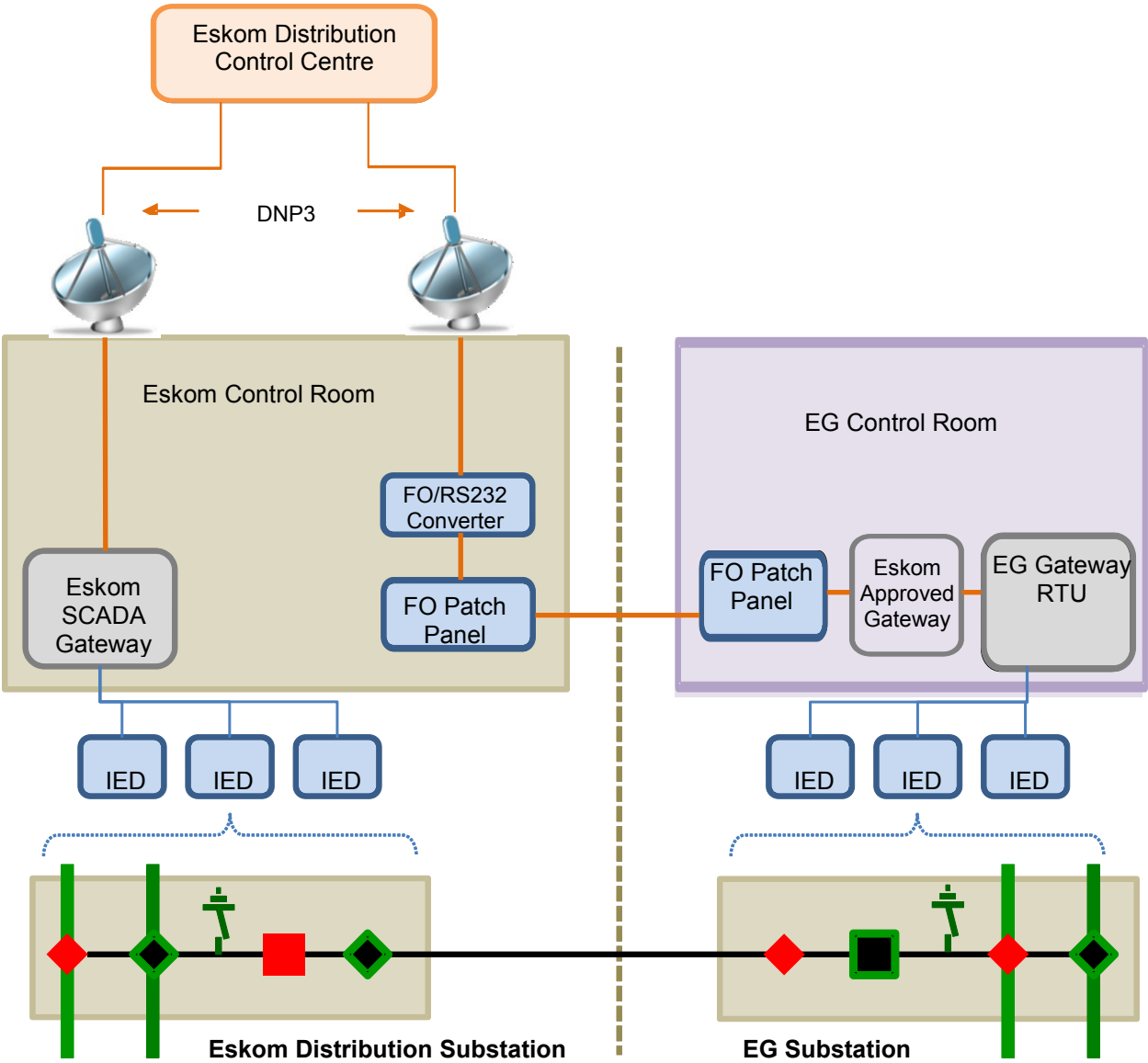


Figure 4-4: Satellite communication interface.

4.4 MINIMUM DATA EXCHANGE REQUIREMENTS

The data exchange requirements of the System Operators related to the Eskom owned Substation and Lines is covered in Eskom's internal design standards and will not be dealt with specifically in this standard.

The data exchange between the EG SCADA systems and Eskom Control Centres shall conform to the Codes and this standard as laid out in section 0 above.

In the GCCRPPSA the data exchange requirements for the EG are grouped according to the EG category.

Currently the category definitions in the GCCRPPSA indicate that only LV connected Embedded Generators fall into category A. As illustrated in the table below, MV connected EGs with rated power less than 1 MVA fall into category B.

Table 4-1: Embedded Generation categories

RATED POWER	LV Connected	MV, HV or EHV connected
less than 1 MVA	Category A	Category B
1 MVA but less than 20 MVA	Category B	Category B
20 MVA and higher	Category C	Category C

Therefore the requirements for the exchange of signals between the NSP and category A Embedded Generators are outside the scope of this standard and will be covered by NRS 097-2.

Requirements for the exchange of signals between the NSP and EGs of category B and C are described in subsequent sections. A detailed signal list is provided in Annex G.

The signals indicated below are the minimum requirement that the EG must provide; additional site-specific signals may also be accommodated in agreement with the relevant SO.

Section 13.2 of the GCCRPPSA stipulates periodic update requirements for Analogue and Digital signals but due to the nature of Eskom's SCADA implementations these requirements are impractical. The times stipulated in the GCCRPPSA will instead be interpreted as maximum delays between the initiation of a change and the arrival of the related signal at the Approved Gateway as explained below²⁹.

All digital input changes shall be reported to the Approved Gateway within 1 second of any change and shall be timestamped to an accuracy of +/-10 milliseconds (UTC +2:00).

Timestamps on analogue changes are not required.

All analogue input changes shall be reported to the Approved Gateway within 2 seconds of any change greater than or equal to the applicable jitter-values as follows;

- Frequency shall be updated when the value changes by 0.01 Hz or more.
- Power factor values shall be updated when the value changes by 0.01 or more.
- Active power values shall be updated when the value changes by 1% or more of rated power. If rated power is 50 MW or more then values shall be updated when the value changes by 0.5 MW or more.
- Actual Ramp Rate shall be updated when the value changes by 1 MW/min or more.
- All other analogues shall be updated when the value changes by 1% or more of the full-scale or nominal value.

To protect the communications bandwidth especially on Area Radio channels the jitter values used by the Approved Gateway to report analogue changes to the NSP Control Centre may be set higher than the values listed above.

Support for both direct operate and select-before-operate Commands shall be provided between the Eskom Approved Gateway and the EG Gateway/RTU.

²⁹ A request for review has been lodged with the GCCRPPSA document Secretariat concerning this change

4.4.1 Generator Availability and Forecast Production values

It should be noted that the delivery of the Availability and Forecast Production Values to the Control Centres are no longer required via SCADA but rather required via an FTP push service from the EG to the Eskom FTP site³⁰.

The content of each forecast will be structured using XML tags. An example is provided in the table below. The format is subject to change.

Table 4-2 - XML definition for 6 hour forecast data

```
<?xml version="1.0" encoding="UTF-8"?>
<esk:OfferFile xmlns:esk="http://www.eskom.co.za/offers"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.eskom.co.za/offers offers.xsd">
  <FileHeader Filename="H6_forecast.xml" Timestamp="2013/10/17 06:02:41 AM">
    <Station StationId="4101">
      <Unit UnitId="Unit ID">
        <OfferDay Date="2013-09-12">
          <OfferIncrement Increment="0">
            <MW>0</MW>
            <Price>0.0</Price>
          </OfferIncrement>
          <OfferHour Hour="22">
            <Availability>100</Availability>
            <Flexible>false</Flexible>
            <Run>true</Run>
            <Forecast>30 </Forecast>
            <MVARLowLimit>10</MVARLowLimit>
            <MVARHighLimit>40</MVARHighLimit>
          </OfferHour>

          <OfferHour Hour="23">
            <Availability>100</Availability>
            <Flexible>false</Flexible>
            <Run>true</Run>
            <Forecast>31 </Forecast>
            <MVARLowLimit>10</MVARLowLimit>
            <MVARHighLimit>40</MVARHighLimit>
          </OfferHour>
        </OfferDay>

        <OfferDay Date="2013-09-13">
          <OfferIncrement Increment="0">
            <MW>0</MW>
            <Price>0.0</Price>
          </OfferIncrement>
          <OfferHour Hour="0">
            <Availability>100</Availability>
            <Flexible>false</Flexible>
            <Run>true</Run>
            <Forecast>31 </Forecast>
            <MVARLowLimit>10</MVARLowLimit>
            <MVARHighLimit>40</MVARHighLimit>
          </OfferHour>
        </OfferDay>
      </Unit>
    </Station>
  </FileHeader>
</OfferFile>
```

³⁰ A request for review has been lodged with the GCCRPPSA document Secretariat concerning this change.


```
</OfferHour>

<OfferHour Hour="1">
  <Availability>100</Availability>
  <Flexible>false</Flexible>
  <Run>true</Run>
  <Forecast>30 </Forecast>
  <MVARLowLimit>10</MVARLowLimit>
  <MVARHighLimit>40</MVARHighLimit>
</OfferHour>

<OfferHour Hour="2">
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  <Flexible>false</Flexible>
  <Run>true</Run>
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  <MVARLowLimit>10</MVARLowLimit>
  <MVARHighLimit>40</MVARHighLimit>
</OfferHour>

<OfferHour Hour="3">
  <Availability>100</Availability>
  <Flexible>false</Flexible>
  <Run>true</Run>
  <Forecast>30 </Forecast>
  <MVARLowLimit>10</MVARLowLimit>
  <MVARHighLimit>40</MVARHighLimit>
</OfferHour>

</OfferDay>
</Unit>
</Station>
</FileHeader>
</esk:OfferFile>
```

4.4.2 The concept of a Bay

Figure 4-5 is an example of a typical Eskom Transmission connected EG electrical interface diagram.

In this figure the Breakers are shown as squares and the line isolators and busbar isolators are shown as diamonds. In this case a solid red symbol indicates that the device is closed and a hollow green symbol indicates that the device is open or tripped.

The breaker, line isolators, earth switches and busbar isolators are all grouped together into a logical unit called a Bay. The Bay is the group of electrical devices that provide the electrical connection to the busbars.

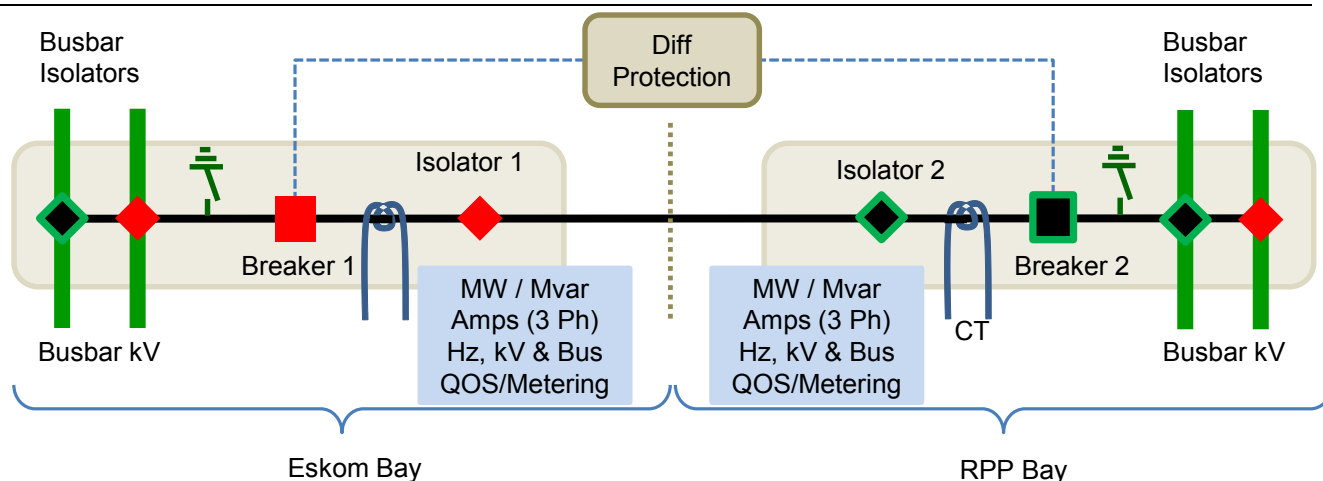


Figure 4-5: Simplistic view of an Eskom—EG Electrical interface

The indications shown in Table 4-4 below refer to the Bay as a unit and the alarms associated with it.

In all cases, each bay shall have a Supervisory Isolator Switch associated with it, which when switched off, effectively prevents any and all supervisory controls from reaching the physical plant. All operating on the Bay under these conditions shall be performed locally from the panel by the substation personnel.

It should be noted that the EG Breaker will not normally be tripped directly by the Eskom Control Centres. In practice Eskom Control Centres will use the 'Stop' command to reduce the plant output to zero.

4.4.3 Double-bit Indications

Breakers, isolators, earth switches and any other power system switch such as links etc. shall be indicated by means of two sensors/contacts, one bit that indicates all poles fully opened and another bit that indicates all poles fully closed.

When the IEC-101 protocol is used between the EG and the Approved Gateway, these two bits shall be reported via the double-bit ASDU.. When the DNP3 protocol is used between the EG and the Approved Gateway, two consecutive single bits should be used rather than the DNP3 double-bit ASDU.

Double-bit indications being sent to the Eskom Control Centres are required to adhere to the convention described in the table below.

Table 4-3: Double-bit indications

Bit values per index number n+1 n	Meaning for Breaker and Isolator states	Meaning for Supervisory Switch states	Meaning for Start/Stop function states
0 0	In transit	In transit	In transit
0 1	Opened	On (active)	Stopped
1 0	Closed	Off (inactive)	Started
1 1	Invalid	Invalid	Invalid

It should be noted that all other signals stipulated in the GCCRPPSA as double-bit indications have been changed by Eskom to single-bit indications³¹.

³¹ A request for review has been lodged with the GCCRPPSA document Secretariat concerning this change.

4.4.4 Digital Input Signals From the EG

The bay-wide digital indications for each bay as required by the Grid Code and NSP are as follows:

Table 4-4: Bay-wide binary indications

Bay binary Indications	State	Type	Report	Explanation
Supervisory Switch	In transit-00 On-01 Off-10 Invalid-11	Double-bit	1 second On change	When Off this switch prevents supervisory controls from being transferred from the gateway device to the bay devices.

4.4.4.1 Breaker State and Isolator State Indications

It is a System Operator requirement that all Breakers and Isolators between the HV side of the EG transformer and the PSS are telemetered.

The breaker and isolator state indications for each POC are listed as shown in Table 4-5

Table 4-5: Switch state indications

Device State	State	Type	Report	Explanation
Breaker State	Opened-01 Closed-10 In transit-00 Invalid-11	Double-bit	1 second On change	Circuit Breaker State
Isolator State	Opened-01 Closed-10 In transit-00 Invalid-11	Double-bit	1 second On change	Isolator State (if needed)

4.4.5 Analogue Input Signals

The analogue indications for each bay are listed in the Grid Code and comprise the following.

Table 4-6: Bay Analogues from the EG site

Analogue indications	Type	Report	Explanation
Active power sent out	Analogue	2 seconds(On change)	Measured summated three phase active power sent-out at the POC Export/Produce(+)
Reactive power sent out	Analogue	2 seconds(On change)	Measured summated three phase Reactive Power sent out at the POC Export/Produce(+) Import/Absorb(-)
Current sent out	Analogue	2 seconds(On change)	Red, White and Blue phase amps
Actual ramp rate	Analogue	2 seconds(On change)	Active Power Ramp rate of the entire facility. (+)Up, (-)Down
Power Factor	Analogue	2 seconds(On change)	Power Factor of the EG
Voltage sent out	Analogue	2 seconds(On change)	Voltage at the POC
Frequency	Analogue	2 seconds(On change)	Frequency of the generated energy (only required where Islanding is allowed)

CONTROLLED DISCLOSURE

The digital indications for each bay as required by the Grid Code and comprise the following:

It should be noted that all of the following single-bit signal will use at '1' state when active and '0' value when non active.

Table 4-7: Bay Binary Indications

Bay digital indications	State	Type	Report	Explanation
Plant Islanded	Yes-1 No-0	Single-bit	1 second (On change)	This indication must go high when the EG detects that it is islanded. This indication must stay high as long as the EG is in an islanded state. Typically this could be a result of the frequency dropping below the sustainability point of the plant which will ultimately result in the plant disconnecting from the Grid
Plant Shutdown	Yes-1 No-0	Single-bit	1 second (On change)	High when the EG initiates a shutdown. Stays high as long as the EG is shutdown. Not set when a stop or trip command is issued from the NSP

4.4.6 Weather and Environmental Data

As per the Grid Code the environmental measurements required from the EG are listed in the table below.

Table 4-8: EG environmental inputs

Environmental data	Type	Report	Explanation
Wind Speed	Analogue	1 minute	Within 75% of the hub height) – measured signal in meters/second (for WPP only)
Wind Direction	Analogue	1 minute	Within 75% of the hub height) – measured signal in degrees from true north(0-359) (for WPP only)
Air temperature	Analogue	1 minute	Measured signal in degrees centigrade (-20.0 to 50.0);
Air pressure	Analogue	1 minute	Measured signal in millibar (800 to 1400).
Air density	Analogue	1 minute	Measured signal in kg/m ³ (for WPP only)
Solar Irradiation	Analogue	1 minute	Measured signal in watts/m ²
Humidity	Analogue	1 minute	Measured signal in Percentage

4.4.7 Command Function Requirements

The table below differs from Table 3 in the GCCRPPSA due to changes requested by the SO. The purpose of the various command functions is to ensure overall control and monitoring of the EG's generation.

The Control Centre shall be able to dispatch the command signals listed in this document to each EG.

There are typically two types of controls:

1. Normal device state change – Trip/Close or On/Off or Stop/Start etc.
2. Setpoint controls – Analogue Output commands or Digital Raise/Lower commands

The Grid Codes stipulated Raise/Lower commands for all Setpoint controls however Analogue Output commands have many advantages and therefore the System Operator has requested that setpoint commands be performed via Analogue Outputs rather than Raise/Lower Digital Outputs³². Where AGC is

³² A request for review has been lodged with the GCCRPPSA document Secretariat concerning this change.

fitted, this document makes provision for both options. EGs should confirm the choice of AGC setpoint control with the SO.

Table 4-9: Command functions

Command function	Category B	Category C
Absolute production constraint	X	X
Power factor control	X	X
Q control	X	X
Voltage control *	X	X
Power gradient constraint	X	X
Frequency control *	-	X
Delta production constraint	-	X

* The EG must not perform any frequency or voltage control functions without having entered into a specific agreement to this effect with the Network Service Provider.

The Control Centre shall be able to send a trip signal to the Breaker that fulfils 13.3.2 of the GCCRPPSA using the following control:

Table 4-10: Breaker Command Signal

Command	Action	Reason
Breaker Trip	Trip (no Close)	Isolate the EG from the Grid

4.4.7.1 Frequency Response System Settings

Primary frequency control services are only provided if the EG has entered into an ancillary services agreement with the SO.

The EG shall make the following primary frequency control signals available via the Approved Gateway:

Table 4-11: Primary frequency response command

Command	Action	Reason
Frequency Control	On/Off	Activate or deactivate Frequency Control Mode as requested by the applicable Control Centre

Table 4-12: Primary frequency response indications

Digital indications	State	Type	Report	Explanation
Frequency Control Mode Status	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Frequency Control not ready	Yes-1 No-0	Single-bit	1 second (On change)	Will report high if frequency control cannot be done

4.4.7.2 Automatic Generation Control System Settings

Automatic Generation Control (AGC), also called Secondary frequency control, is only required if the EG has entered into an ancillary services agreement with the SO. This function is currently only applicable to category C EGs connected to the Transmission system (excluding PVPPs). The AGC functional requirements are specified in the Transmission AGC functional description, Unique identifier: 32-1211.

The AGC governor setting can be adjusted by a setpoint command.

CONTROLLED DISCLOSURE

Table 4-13: AGC commands

Command	Action	Reason
AGC Mode	On/Off	Activate or deactivate Automatic Generation Control
AGC setpoint	Setpoint command	Setpoint command to change the AGC setpoint when the EG is on AGC

Table 4-14: AGC indications

Binary indications	State	Type	Report	Explanation
AGC mode status	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Raise block	Yes-1 No-0	Single-bit	1 second (On change)	Will report high if the controller opts to not take any more Raise commands. The raise block signal is set high when the AGC setpoint value is equal to or higher than the AGC high regulating limit.
Lower block	Yes-1 No-0	Single-bit	1 second (On change)	Will report high if the controller opts to not take any more Lower commands. The lower block signal is set high when the AGC setpoint value is equal to or lower than the AGC low regulating limit.

Table 4-15: AGC analogues

Analogue indications	Type	Report	Explanation
AGC Setpoint feedback	Analogue	2 seconds(On change and jitter)	EG echo response to a setpoint command or a bit string command
AGC High regulating limit	Analogue	2 seconds(On change and jitter)	Higher limit of the active power provided for AGC. This limit shall also be updated when in Delta mode.
AGC Low regulating limit	Analogue	2 seconds(On change and jitter)	Lower limit of the active power provided for AGC. This limit shall also be updated when in Delta mode.

If secondary frequency control is not possible, then the 'frequency control not ready' indication shall be set high.

4.4.7.3 Active Power Constraint / Curtailment

The following discussion pertains to the following constraint areas:

- Absolute Production Constraint (Curtailment)
- Delta Production Constraint (P-delta)
- Power Gradient Constraint (Power Gradient)

In the event of excessive voltage or frequency conditions, the only way to bring the power system back within the defined operating limits is to reduce generator output.

CONTROLLED DISCLOSURE

The System Operator has decided that the Absolute Production Constraint (Curtailment) and Delta Production Constraints will be mutually exclusive.

4.4.7.4 Absolute Production constraint

Curtailment to a set Power

The Control Centre will set the desired Power output by sending a 'setpoint' command.

The Control Centre will send a 'Curtailment mode ON' command.

The EG installation will do nothing until the Curtailment Mode is activated.

When it is in the 'ON' state the EG installation will limit the total MW output to the value that is defined by the Curtailment setpoint.

When conditions in the power system improve, the Control Centre will reset the 'Curtailment mode' state to 'OFF'. When the EG installation detects the reset, it will then be able to resume its planned MW output.

It is essential that when Curtailment is initiated and cancelled that the time and the Curtailment setpoint value is captured and logged to ensure that disputes are minimised.

When the setpoint for Curtailment (Absolute Production Constraint) has to be changed, such change shall be commenced within contractual time frames and ramp rates.

Table 4-16: Curtailment commands

Command	Action	Reason
Curtailment mode	On/Off	Activate or deactivate production curtailment in the event of system constraints.(also called absolute production constraint)
Curtailment setpoint	Setpoint command	Setpoint command to change the active power setpoint of the EG

Table 4-17: Curtailment indications

Digital indications	State	Type	Report	Explanation
Curtailment mode status	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Curtailment in progress	Yes-1 No-0	Single-bit	1 second (On change)	Will be high while the facility is moving from the current value to the curtailed value. Once the facility reaches the curtailment value, this bit will be reset.
Curtailment Not Ready	Yes-1 No-0	Single-bit	1 second (On change)	Will be high in the event of conditions at the plant preventing the plant from being curtailed. In the case of any not ready indication being detected, it is up to the EG to correct the problem as soon as possible.

Table 4-18: Curtailment analogue

Analogue indications	Type	Report	Explanation
Curtailment Setpoint feedback	Analogue	2 seconds(On change)	EG echo response to a new Power setpoint issued by the Control Centre.

CONTROLLED DISCLOSURE

Curtailement to 0 MW

Under extreme system conditions and when the curtailment option will take too long, provision has been made to send a 'Stop' command to the EG to initiate a controlled shutdown of the installation at a rate faster than the normal operational ramp rate setting. The normal operating and startup ramp rate setting is called the Positive or Up Ramp Rate. The ramp rate applicable to a 'Stop' command is called the Negative or Down Ramp Rate as per Chap 12 of the GCCRPPSA.

When this 'Stop' command is received by the EG it should set the 'Curtailment Setpoint feedback' to zero, the 'Curtailment Mode' and 'Curtailment in Progress' indications to 'ON' and should ramp the installation to zero output at the negative ramp rate setting. Once generation has stopped, the 'Curtailment in Progress' indication should be set 'Off'.

It is not expected that this command action would open the EG Breaker but only reduce the output to zero. This will maintain supply to auxiliaries as required.

When the 'START' command is issued, the EG should set the 'Curtailment Mode' to 'Off' and ramp up generation to the scheduled generation output but no faster than the positive ramp rate setting.

Table 4-19: Generation Stop/Start command

Command	Action	Reason
Generation Start/Stop	Start/Stop	By sending a START command, the Control Centre should be able to start generation of the EG and by sending a STOP command, the Control Centre should be able to bring the EG to a non-generating mode, but do not open the Breaker.

Table 4-20: Generation Stop/Start indication

Digital indications	State	Type	Report	Explanation
Generation State	Started-10 Stopped-01	Double-bit	1 second (On change)	Will report a '10' state on receipt of a START command and '01' state for STOP command

4.4.7.5 Delta Production Constraint

This function is only applicable to Category C (exception of PVPP).

To activate this function the Control Centre will send the 'ON' command to the 'P-Delta Mode' address.

Before activating P-delta mode the Control Centre shall set the P-delta setpoint (percentage) as a 'setpoint' command. The EG shall decrease the output by P-delta providing reserves for frequency control. The Control Centre shall reset the 'Delta Production Mode' to 'OFF' if the reserve functionality is not required any further.

The 'P-delta Constraint mode not ready' shall be set high whenever the Delta Production Constraint facility is not available.

When the P-delta Constraint is changed, such change shall be commenced within contracted time frames.

Table 4-21: Delta production commands

Command	Action	Reason
P-delta constraint mode	On/Off	Activate or deactivate delta production constraint. The EG shall decrease its output by the set percentage of available active power to provide reserve for frequency control
P-delta Setpoint	Setpoint command	Setpoint command to change the P-delta setpoint (expressed in percentage).

Table 4-22: Delta production binary indications

Digital indications	Start	Type	Report	Explanation
P-delta constraint mode	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
P-delta mode Not Ready	Yes-1 No-0	Single-bit	1 second (On change)	Will be high in the event of conditions at the plant preventing the plant from going into Delta Production Mode.

Table 4-23: Delta production analogues

Analogue indications	Type	Report	Explanation
P-delta setpoint feedback	Analogue	2 seconds(On change and jitter)	EG echo response to a new P-delta setpoint(percentage) issued by the applicable Control Centre

4.4.7.6 Power Gradient Constraint

A Power Gradient Constraint is used to limit the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply of the EG.

A Power Gradient Constraint is typically used for reasons of system operation to prevent rapid changes in active power from impacting the stability of the Grid.

For example when a conventional generator is shutting down with ramp rates less than a wind farm, the ramp rates of the wind farm (which has increased to compensate for the loss of generation) can be set by the Control Centre in order to keep the power balance.

The Control Centre will send 'setpoint commands' to change ramp rate setpoints of the EG to new values within the limits specified by the EG.

The EG will echo the updated values within 2 seconds of the change and will proceed to respond to the updated ramp rates within 30 seconds.

To implement the Power Gradient Constraint, the Control Centre will send an 'ON' command to the 'Power gradient constraint mode' address.

The 'Power gradient mode not ready' mode shall be set to high by the EG whenever ramp rate modifications cannot be done.

Apart from the echo values being updated, no additional activation is implemented.

CONTROLLED DISCLOSURE

Table 4-24: Power gradient commands

Command	Action	Reason
Power gradient constraint mode	On/Off	Activate or deactivate power gradient constraint in the event of system constraints.
Up Ramp Rate Setpoint	Setpoint command	Setpoint command to change the up ramp rate of the EG
Down Ramp Rate Setpoint	Setpoint command	Setpoint command to change the down ramp rate of the EG

Table 4-25: Power gradient indications

Binary indications	State	Type	Report	Explanation
Power gradient constraint mode	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Power gradient mode not ready	Yes-1 No-0	Single-bit	1 second (On change)	Will report a '1' state when 'not ready' and '0' state when 'ready'

Table 4-26: Power gradient analogues

Analogue indications	Type	Report	Explanation
Up Ramp Rate setpoint feedback	Analogue	2 seconds (On change)	EG echo response to a new 'up' ramp rate setpoint issued by the applicable Control Centre
Up ramp rate high limit	Analogue	2 seconds (On change)	When the plant is in power gradient constraint mode, the EG shall give the NSP an indication of what the high limit is for up ramp rate.
Up ramp rate low limit	Analogue	2 seconds (On change)	When the plant is in power gradient constraint mode, the EG shall give the NSP an indication of what the low limit is for up ramp rate.
Down Ramp Rate setpoint feedback	Analogue	2 seconds (On change)	EG echo response to a new 'down' ramp rate setpoint issued by the applicable Control Centre
Down Ramp rate high limit	Analogue	2 seconds (On change)	When the plant is in power gradient constraint mode, the EG shall give the NSP an indication of what the high limit is for down ramp rate.
Down ramp rate low limit	Analogue	2 seconds (On change)	When the plant is in power gradient constraint mode, the EG shall give the NSP an indication of what the low limit is for down ramp rate.

4.4.7.7 Reactive Power and Voltage Control Functions

The EG shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the EG at the POC as well as a voltage control function capable of controlling the voltage at the POC via commands using setpoints and gradients.

The required reactive power ranges for Category B and C are shown in the table below.

CONTROLLED DISCLOSURE

Table 4-27: Reactive Power Output ranges

Category	Power Factor
B	0.975 lagging and 0.975 leading available from 20% of rated power measured at the <i>POC</i> .
C	0.95 lagging and 0.95 leading available from 20% of rated power measured at the <i>POC</i>

The reactive power and voltage control functions are mutually exclusive, which means that only one of the three functions mentioned below can be active at a time. At least one of these functions must be active.

- Reactive Power Control (Q control)
- Power Factor control (PF Control)
- Voltage control (V Control)

The control function and applied parameter settings for reactive power and voltage control functions shall be determined by the NSP in collaboration with the SO, and implemented by the EG.

The agreed voltage control functions shall be documented in the operating agreement.

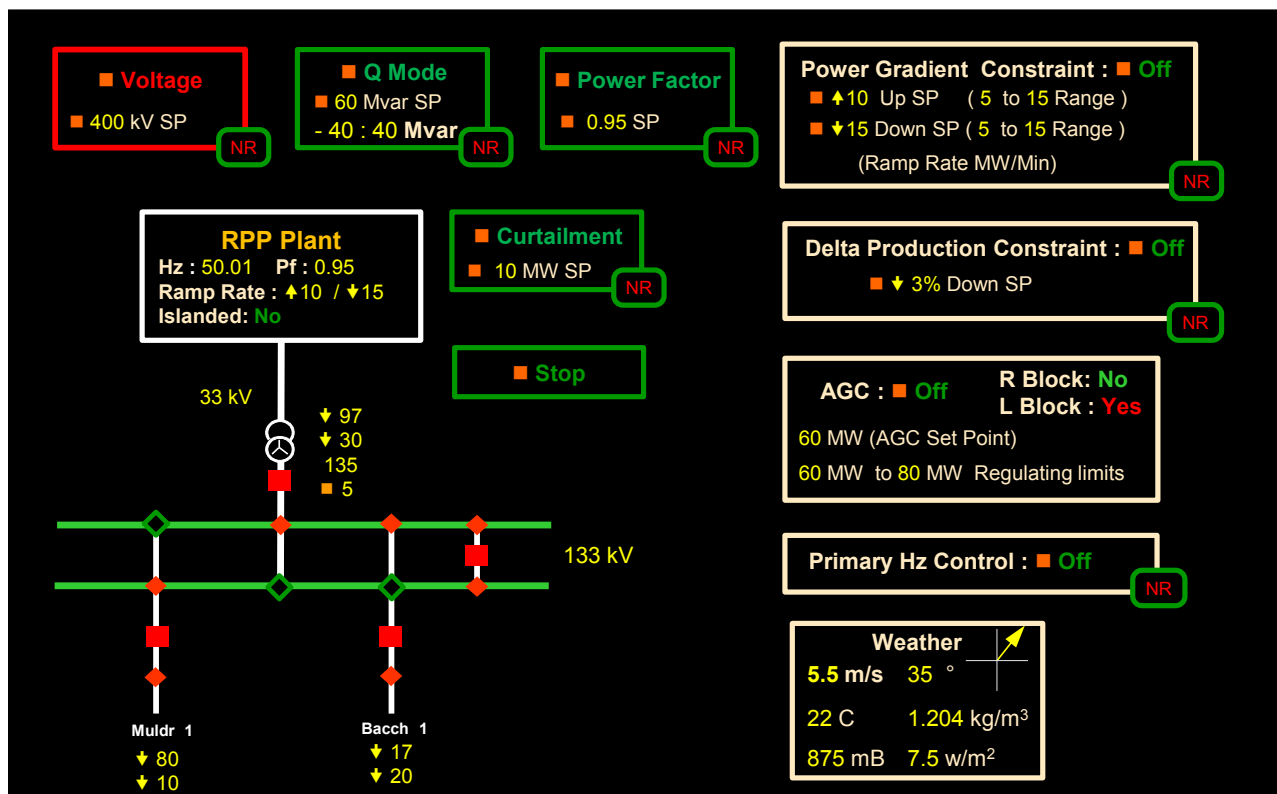


Figure 4-6: Mode Change HMI interface example

Figure 4-6 shows an example screen of the mode change functions and the stop(start) command button.

4.4.7.8 Reactive Power Control Mode

The Control Centre will firstly change the analogue setpoint of the Q-Control value to the desired output.

On receipt of the Q-mode activation request, the EG shall update its Q-mode echo analogue value in response to the new value within two seconds.

The Control Centre will then send a supervisory command to the EG to move the plant to Q control mode which will set the associated digital indication to 'active'.

CONTROLLED DISCLOSURE

At the same time the EG control system shall deactivate both the Power Factor Control mode and the Voltage Control mode.

The EG shall respond to the new setpoint within 30 seconds after receipt of an order to change to the new setpoint.

Table 4-28: Q mode commands

Command	Action	Reason
Q control mode	On (no OFF)	Activate Reactive Power Control Mode as requested by the Control Centre
Q control setpoint	Setpoint command	Command to change the kvar or Mvar setpoint of the EG

Table 4-29: Q mode binary indications

Digital indications	State	Type	Report	Explanation
Q control mode status	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Q control mode Not Ready	Yes-1 No-0	Single-bit	1 second (On change)	Will be high in the event of conditions at the plant preventing the plant from going into Q mode.

Table 4-30: Q mode analogues

Analogue indications	Type	Report	Explanation
Q Lower Limit	Analogue	2 seconds (On change and jitter)	This value is an indication of the low Reactive Power operating limit. This value can change depending upon environmental or plant conditions.
Q Upper Limit	Analogue	2 seconds (On change and jitter)	This value is an indication of the high Reactive Power operating limit. This value can change depending upon environmental or plant conditions.
Q Setpoint feedback	Analogue	2 seconds (On change and jitter)	This value is an indication of the Reactive Power setpoint issued by the Control Centre

4.4.7.9 Power Factor Control Mode

This function is covered in section 8.2 of the GCCRPPSA.

It is preferred that a single bit is used to indicate the state of this mode to the Control Centre. If the EG can only provide a double bit indication, this can be changed in the Approved Gateway.

Table 4-31: Power factor commands

Command	Action	Reason
PF control mode	On (no OFF)	Activate Power Factor Mode as requested by the applicable Control Centre
PF control setpoint	Setpoint command	Setpoint command to change the power factor of the EG. Producing vars (-), Absorbing vars (+)

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Table 4-32: Power factor binary indications

Digital indications	State	Type	Report	Explanation
PF control mode	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
PF control mode Not Ready	Yes-1 No-0	Single-bit	1 second (On change)	Will be high in the event of conditions at the plant preventing the plant from going into this mode.

Table 4-33: Power factor analogue

Analogue indications	Type	Report	Explanation
PF setpoint feedback	Analogue	2 seconds (On change)	Echo response to a new Power Factor setpoint issued by the applicable Control Centre. Producing vars (-), Absorbing vars (+)

4.4.7.10 Voltage Control mode

The Control Centre will firstly change the analogue setpoint of the Voltage Control value to the desired output. On receipt of the Voltage Control setpoint command, the EG shall update its Voltage control mode echo analogue setpoint value to the new value within two seconds.

The Control Centre will then send a supervisory command to the EG to move the plant to Voltage Control mode.

At the same time the EG control system shall set both the Q-Control mode and the PF Control mode as deactivated and update these states.

On receipt of the Voltage Control-mode activation request, the EG shall respond to the new setpoint within 30 seconds after receipt of an order to change to the new mode.

Table 4-34: Voltage mode commands

Command	Action	Reason
Voltage control mode	On (no Off)	Activate Voltage control Mode as requested by the applicable Control Centre
Voltage control setpoint	Setpoint command	Setpoint command to change the voltage

Table 4-35: Voltage mode binary indications

Digital indications	State	Type	Report	Explanation
Voltage control Mode	On-1 Off-0	Single-bit	1 second (On change)	Will report a '1' state when active and '0' state when not active
Voltage mode Not Ready	Yes-1 No-0	Single-bit	1 second (On change)	Will be high in the event of conditions at the plant preventing the plant from going into the Voltage mode.

Table 4-36: Voltage mode analogue

Analogue indications	Type	Report	Explanation
Voltage setpoint feedback	Analogue	2 seconds(On change and jitter)	EG echo response to a new voltage setpoint issued by the Control Centre

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4.4.8 Data Communications Specifications

Active Power Curtailment or Voltage Regulation facilities at the EG may be tested at minimum once a month. It is essential that facilities exist to allow the testing of the functionality without tripping the EG.

Test procedures will involve a setpoint being sent then activated (which monitors the response) and then returning to normal.

Where signals or indications required to be provided by the EG become unavailable or do not comply with applicable standards due to failure of the EG equipment or any other reason under the control of the EG, the EG shall restore or correct the signals and/or indications within 24 hours.

4.4.9 IEC 60870-5-101 Address Ranges

When an EG is connected to the National Control Centre the SCADA signals need to conform to the Standard 32-1101, TEMSE IEC 60870-5-101 Implementation Standard.

A summary of address numerical ranges found in Appendix C of the above mentioned standard is shown in the table below.

Table 4-37: Eskom ASDU Information Object Address Range

IEC 60870-5-101 ASDU	Information Object Address Range
Single point information	1 to 10 000
Double point information	10 001 to 15 000
Step position information	15 001 to 20 000
Measured value	20 001 to 25 000
Integrated totals	25 001 to 30 000
Single command	30 001 to 35 000
Double command	35 001 to 40 000
Bit string of 32 bit command (lamp drive outputs)	40 001 to 43 000 (not used)
Bit string of 32 bit command (AGC outputs)	43 001 to 45 000 (not used)
Setpoint command (meter drive outputs)	(not used)
Setpoint command (setpoint outputs)	45 001 to 65 355

Notes:

1. If no meter drives are present then setpoint commands start at address 45 001.

4.4.10 Provision of the Signal Data and Substation Layout Information to Eskom

When the EG is ready to commence with commissioning of their plant, the following data should be provided to Eskom commissioning personnel at least 8 weeks prior to the planned commissioning date.

- An Excel spread sheet containing the following signal sets – each in its own work sheet.
 - o Digital inputs - including cross links to the associated commands
 - o Analogue inputs – including scaling information e.g. Low Engineering Value, Low Transmitted Value, High Engineering Value, High transmitted value, associated Setpoint command if any etc.

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- o Digital commands – including cross links to the associated digital inputs.
 - o Setpoint commands – including scaling information e.g. Low Engineering Value, Low Transmitted Value, High Engineering Value, High transmitted value, associated analogue input etc.
 - o Revision History
 - o Each row on the spread sheet should list the point address, description in full, a 32 character SCADA database Tag name for database identification, and space to record the commissioning tests.
- Station Electric diagram showing all bays; CT ratios, VT Ratios etc.

An example spreadsheet is available from the System Operator on request.

5 TESTS

Full tests on the equipment needed to meet the requirements of this document must be carried out to the satisfaction of the Network Service Provider. These tests are the responsibility of the equipment owner. Tests carried out on equipment installed at the PUC and PGC, as well as loss-of-grid and synchronising tests must be witnessed by a technical representative of Eskom.

The test on primary equipment must be carried out on site with the equipment installed in its final position. Results from tests performed before delivery and installation are not acceptable.

The EG must keep a written record of all Protection and Control drawings, protection settings and of test results. A copy of this record should be available for inspection at the PUC or as required by the Network Service Provider.

Measurement and injection test equipment used in testing shall have a traceable calibration record, and shall be of suitable accuracy for the tests to be undertaken.

5.1 PRE-COMMISSIONING AND COMMISSIONING TESTS

Tests to be conducted at the PUC and PGC are divided into two categories:

- a) Pre-commissioning tests include all tests to be performed prior to the EG synchronising with the Network Service Provider's network for the first time.
- b) Commissioning tests: those tests that can only be completed during the first synchronisation of the EG with the Network Service Provider's network, or thereafter. Commissioning tests shall be conducted upon written agreement of the Network Service Provider after acceptance of the pre-commissioning test results.

Pre-commissioning and commissioning tests for equipment installed at the PUC and PGC shall be as per the requirements of Table 5-1 and Table 5-2 below. Table 5-1 and Table 5-2 also indicate the applicable synchronising tests to be conducted at every point at which auto-synchronising functionality is provided.

The applicable pre-commissioning and commissioning tests shall be repeated in the event of any firmware or software change on the control plant equipment, or any hardware component has been replaced, repaired or modified.

Table 5-1: Pre-commissioning Tests at the PUC and PGC

Equipment	Applicable Eskom Test Procedure	Test requirements
Primary Plant Equipment		
Current Transformers	DPC_34-1035	Insulation Resistance test. Ratio test. Magnetising test. Secondary resistance and burden test. Polarity test. Primary injection test. Visual inspection and application checks.
Voltage Transformers	DPC_34-1033	Insulation Resistance test. Ratio test. Lead and burden resistance test. Polarity test. Visual inspection and application checks.
Isolators	DPC_34-1034	Insulation Resistance test. Contact Resistance test. Contact Timing test. Visual inspection and application checks.

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Equipment	Applicable Eskom Test Procedure	Test requirements
Circuit-breakers	DPC_34-1036	Insulation Resistance test. Contact Resistance test. Timing Test. SF6 Gas/Oil tests. Miscellaneous and General Checks.
Control Plant Equipment		
Over Current, Earth Fault & SEF Protection	DPC_34-1395	Insulation resistance test of CT, VT and DC circuits. Pick-up/Drop Off tests. Timing Characteristic Test. Directional limit tests (where applicable). Visual Inspection.
Voltage Protection	-	As per IEEE 1547.1 Section 5.2.
Frequency Protection	-	As per IEEE 1547.1 Section 5.3. See Note 1.
Loss-of-grid protection (Unintentional Islanding)	-	As per IEEE 1547.1 Section 5.7 using appropriate frequency ramps.
Inverter Anti-islanding	-	As per IEEE 1547.1 Section 5.7 or if preferred, stipulated in IEC 62116 (relevant to photovoltaic inverters only)
Synchronisation	-	As per IEEE 1547.1 Section 5.4.1.
Reverse Power	-	As per IEEE 1547.1 Section 5.8.
DC Failure	-	Non-urgent and urgent DC failure alarms to be issued as per the requirements of Section 3.6.2.10.
Note 1. For Frequency relays employing an averaging technique, timing tests may be more appropriately done using ramp frequency changes in the range from ± 50 mHz/s to ± 1 Hz/s rather than a step frequency change as per IEEE 1547.1.		

Table 5-2: Commissioning Tests

Equipment	Applicable Eskom Test Procedure	Test requirements
Control Plant Equipment		
Unintentional islanding	-	As per IEEE 1547.1 Section 7.4
Synchronisation (all points of synchronisation)	-	As per IEEE 1547.1 Sections 5.4.2, 5.4.3 or 5.4.4 as appropriate.
Interlocking circuits	-	All interlock circuits to be tested as per Design.
DTT	-	All transfer trip circuits to be tested dynamically.
Differential functionality	-	All differential functionality to be tested dynamically with GPS timed injection methodology.
Distance unit functionality	-	All distance functionality to be tested dynamically with GPS timed injection methodology

5.2 MAINTENANCE TESTS

Maintenance of the primary and control plant and metering equipment shall be conducted according to the recommendations of NRS-089.

The control plant equipment at the point of connection shall be subject to routine inspection on a three year cycle, witnessed by a technical representative of Eskom. Major maintenance including secondary injection of all protection relays and testing of primary equipment (e.g., CTs, VTs, circuit-breakers etc.) shall be conducted at intervals of 6 years. Major maintenance shall include repeating the unintentional islanding test conducted during commissioning.

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6 AUTHORISATION

This document has been seen and accepted by:	
Name	Designation
Adam Bartylak	Corporate Specialist
Prince Kara	Chief Engineer
Reginald Brooks	SCOT Metering & Measurements SC Chair
Riaan Smit	Convenor RIPP Care Group
Teresa Smit	Corporate Specialist
Thomas Jacobs	SCOT DC SC Chair
Prudence Madiba	Snr Manager, Electrical and C&I Engineering (Gx)

This standard shall apply throughout Eskom Holdings its divisions, subsidiaries and entities wherein Eskom has a controlling interest.

7 REVISIONS

This revision cancels and replaces revision number 0 of document number **DST_34-1765**.

Date	Rev.	Compiled By	Clause	Remarks
Oct 2013	1	A Craib		Document published
Oct 2013	0.3	K Brown	various	Removed category A signals Separated Primary and Secondary Frequency Control functions into 2 sections. All Mode statuses changed to single bit indications. Added RPP Code references to the signal list. All double-bit indications which are not real switches changed to single bits. Setpoint commands changed from Raise/Lower digital commands to Analogue Output setpoint commands. Removed the signals pertaining to the NSP substation and feeder. Removed 32-bit AGC Control
Oct 2013	0.2	A Craib	All Clauses	Document revised extensively.
Aug 2013	0.1	J Ranyane	4	Added the contents of the draft document, <i>Standard for interfacing EG SCADA systems and Eskom Control Centres</i> .
Aug 2013	0.1			Doc number changed to 240_61268576
July 2013	1	L Kleyn	Bibliography	Updated document references

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Date	Rev.	Compiled By	Clause	Remarks
			0	<p>Corrected Electricity Supply Act number from Act 6 of 2006 to Act 4 of 2006; added 'as amended'</p> <p>Added reference to the Renewable Grid Code</p> <p>SCSASAAL9 superseded by DST_34-1985</p> <p>SCSASACB6 superseded by DST_34-906</p> <p>SCSPVAAS9 superseded by DPC_34-1039</p> <p>DISPVAEB6 superseded by DPC_34-1033</p> <p>DISPVAEC6 superseded by DPC_34-1035</p> <p>DISPVAED1 superseded by DPC_34-1395</p> <p>DISPVAEF9 superseded by DPC_34-1043</p> <p>DISPVAEG1 superseded by DPC_34-759</p> <p>DISPVAEQ6 superseded by DPC_34-1036</p> <p>Added reference to DST_34-1024</p>
			0	<p>Updated definition for 'Island' to be the same as in the Distribution Connection and Use of System Agreement</p> <p>Updated definition for 'Point of Common Coupling (PCC)' to be the same as in the Distribution Connection and Use of System Agreement</p> <p>Added 'Point of Connection (POC)' definition</p> <p>Updated definition for 'Point of Utility Connection (PUC)' to be the same as in the Distribution Connection and Use of System Agreement</p> <p>Updated Secure Supply Point (SSP) to Point of Secure Supply (PSS) as per the Distribution Connection and Use of System Agreement</p> <p>Added 'Renewable Power Plant (RPP)' definition as well as a list of and definitions for the different types of renewable power plants according to the renewable energy sources – as defined in the Grid Code for Renewable Power Plants.</p> <p>Added RPP Categories</p>
			0	Removed Secure Supply Point (SSP)
			0	<p>Corrected Electricity Supply Act number from Act 6 of 2006 to Act 4 of 2006; added 'as amended'</p> <p>Added reference to Grid Code Requirements for Renewable Power Plants</p>
			3.4.1	<p>Added reference to Grid Code Requirements for Renewable Power Plants</p> <p>Removed power factor requirements – specified in Grid Code already</p> <p>Moved neutral earthing requirements to 3.5.3</p>
			3.4.2	<p>Corrected table auto-numbering and references</p> <p>Added reference to NRS 048-4</p>
			3.4.3	Added reference to DPL 34-2149 and SA Grid Code requirements for RPPs
			3.4.4	Changed 'fault ride through' to 'voltage ride through' to align with the SAGC for RPPs; referenced ride through requirement in SAGC for RPPs
			3.5.3	<p>Re-wrote section to comply with DPL 34-2149</p> <p>Clarified MV earthing requirements</p>

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Date	Rev.	Compiled By	Clause	Remarks
			3.5.5	Changed SSP to PSS
			4.5.5	Added reference to IDMT overcurrent protection
			3.5.7	Changed SSP to PSS
			4.5.7	Added section
			3.6.1.3	DISSCAAM8 superseded by DSP_34-1488
			3.6.2.1	Corrected table auto-numbering and references Added recommendation for EG to use unit-protection at POC
			3.6.2.2 (m)	Corrected table references Added requirement for fault level submission Added unit protection recommendation Added CB fail requirement
			3.6.2.4	Corrected table auto-numbering and references Added reference to SAGC for RPPs
			3.6.2.7	Corrected table auto-numbering and references Re-worked section
			0	Added reference to DST_34-2095 for auxiliary supply at switching stations
			3.7	Rewrote Metering section to refer to and comply with relevant Eskom Metering standards and policies.
			5	Added requirement for Eskom representative to be a technical representative Added requirement to keep signed copy of protection & control drawings
			5.1	Corrected table, table auto-numbering and table references DISPVAEB6 superseded by DPC_34-1033 DISPVAEC6 superseded by DPC_34-1035 DISPVAED1 superseded by DPC_34-1395 DISPVAEQ6 superseded by DPC_34-1036
			5.2	Added requirement for Eskom representative to be a technical representative
March 2008	0	SJ van Zyl		Document published Incorporated changes agreed upon by work-group and KEC Rewrote Section 4.5.3 (Metering). Document issued for TESCO comments Revised Section 4.5.4.2 (SCADA Controls) to indicate possible requirement of Eskom remote control of interconnection circuit-breaker. Rewrote Section 4.6.2 (Quality of Supply). Extensive revision to incorporate work-group feedback. Original issue for work-group comments

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8 DEVELOPMENT TEAM

The original revision 0 document was based upon Eskom Guideline ESKAGAAG2 “Minimum requirements for the connection of non-Eskom generating plant to the Eskom electrical networks” that was compiled in 1995 by a working group led by Graeme Topham. ESKAGAAG2 in turn was based upon Engineering Recommendation G.59 “Recommendations for the connection of private generating plant to the Electricity Boards’ Distribution Systems” issued by the Electricity Council, and prepared for use in relation to the United Kingdom’s system.

The present document constitutes an update of the original revision, with contributions made by the following individuals:

Andrew Craib	PTM&C, Power Delivery, Engineering
Lize-Mari Kleyn	ex-Eskom, EDNS Technology, Eastern Cape Operating Unit
<u>D.C. Requirements:</u>	
Richard Vlantis	Design Base & Operating Unit Support, Power Delivery, Engineering
<u>EMC Requirements:</u>	
Hendri Geldenhuys	Technology, Power Delivery, Engineering
<u>Metering Requirements:</u>	
Mohammed Omar	PTM&C, Power Delivery, Engineering
Reginald Brooks	Maintenance and Operations, WCOU, Distribution
<u>Primary Plant and IPP Workgroup Interface:</u>	
Riaan Smit	Planning, Power Delivery, Engineering
<u>QOS Requirements:</u>	
Gerhard Botha	PD&U, Research Testing & Development, Sustainability
<u>SCADA Requirements:</u>	
Ian Naicker	Control & Automation, PTM&C, Power Delivery, Engineering
James Ranyane	Control & Automation, PTM&C, Power Delivery, Engineering
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9 ACKNOWLEDGEMENTS

The compiler would like to acknowledge the work completed on the DST_34-1765 revision 0 document by Stuart van Zyl and on the subsequent revision by Lize-Mari Kleyn. The compiler would also like to thank both Stuart van Zyl and Lize-Mari Kleyn for their subsequent support to this document.

James Ranyane and Kenneth Brown added the in-depth SCADA requirements to the present document.

Kenneth Brown proofread the entire document, debated, raised and solved numerous issues and re-worked the SCADA requirements. The compiler would therefore like to thank the co-author Kenneth Brown for his considerable input to this document.

Riaan Smit supplied in-depth feedback, sometimes at short notice and was of great help throughout the process.

Teresa Smit provided a co-ordination role which included links to the various committees and debate on certain issues.

Adam Bartylak, who at short notice checked the System Operations requirements within the document.

Richard Vlantis provided the updated D.C. and Auxiliary Supplies requirements.

Gerhard Botha provided the updated QOS requirements.

Mohammed Omar provided detailed comments concerning the metering section.

Graeme Topham who compiled the original document, made it available.

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Annex A – Impact Assessment (Normative)

Impact assessment form to be completed for all documents.

1 Guidelines

- o All comments must be completed.
- o Motivate why items are N/A (not applicable)
- o Indicate actions to be taken, persons or organisations responsible for actions and deadline for action.
- o Change control committees to discuss the impact assessment, and if necessary give feedback to the compiler of any omissions or errors.

2 Critical points

2.1 Importance of this document. e.g. is implementation required due to safety deficiencies, statutory requirements, technology changes, document revisions, improved service quality, improved service performance, optimised costs.

The document serves to establish the technical standard for the interconnection of Embedded Generation to Eskom's EHV, HV and MV networks. The standard sets out some key safety aspects relating to the interconnection of Embedded Generation and is central to the National Co-generation project.

2.2 If the document to be released impacts on statutory or legal compliance - this need to be very clearly stated and so highlighted.

The standard serves to fulfil the requirements of the South African Distribution Code: Network Code in so far as a Protection, Measurement and Telecontrol interconnection standard for Embedded Generation is required.

2.3 Impact on stock holding and depletion of existing stock prior to switch over.

Not applicable

2.4 When will new stock be available?

Not applicable

2.5 Has the interchangeability of the product or item been verified - i.e. when it fails is a straight swap possible with a competitor's product?

Not applicable

2.6 Identify and provide details of other critical (items required for the successful implementation of this document) points to be considered in the implementation of this document.

A generic Power Purchase Agreement (PPA) and Connection Agreement for EG's has been developed separately to this document. A planning guideline for the integration of Embedded Generation has been developed and describes in detail the types of impact assessment studies required.

2.7 Provide details of any comments made by the Regions regarding the implementation of this document - None.

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Annex A
(continued)

3 Implementation timeframe

3.1 Time period for implementation of requirements.

Dependant on IPP Caregroup decision.

3.2 Deadline for changeover to new item and personnel to be informed of DX wide change-over.

Dependant on IPP Caregroup decision.

4 Buyers Guide and Power Office

4.1 Does the Buyers Guide or Buyers List need updating?

No.

4.2 What Buyer's Guides or items have been created?

Not applicable.

4.3 List all assembly drawing changes that have been revised in conjunction with this document.

Not applicable.

4.4 If the implementation of this document requires assessment by CAP, provide details under 5

4.5 Which Power Office packages have been created, modified or removed?

Not applicable.

5 CAP / LAP Pre-Qualification Process related impacts

5.1 Is an ad-hoc re-evaluation of all currently accepted suppliers required as a result of implementation of this document?

Depends on IPP Caregroup decision.

5.2 If NO, provide motivation for issuing this specification before Acceptance Cycle Expiry date.

Changing technology.

5.3 Are ALL suppliers (currently accepted per LAP), aware of the nature of changes contained in this document?

No.

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Annex A
(continued)

Is implementation of the provisions of this document required during the current supplier qualification period?

To be decided by IPP Caregroup.

5.4 If Yes to 5.4, what date has been set for all currently accepted suppliers to comply fully?

Possibly not applicable.

5.5 If Yes to 5.4, have all currently accepted suppliers been sent a prior formal notification informing them of Eskom's expectations, including the implementation date deadline?

Not applicable.

5.6 Can the changes made, potentially impact upon the purchase price of the material/equipment?

Possibly not applicable.

5.7 Material group(s) affected by specification: (Refer to Pre-Qualification invitation schedule for list of material groups)

Not applicable.

6 Training or communication

6.1 State the level of training or communication required to implement this document. (e.g. none, communiqués, awareness training, practical / on job, module, etc.)

The document is to be issued by the IPP Workgroup to all relevant parties.

6.2 State designations of personnel that will require training.

Not applicable.

6.3 Is the training material available? Identify person responsible for the development of training material.

No training material is available at this stage.

6.4 If applicable, provide details of training that will take place. (E.G. sponsor, costs, trainer, schedule of training, course material availability, training in erection / use of new equipment, maintenance training, etc.).

To be announced.

6.5 Was Training & Development Section consulted w.r.t training requirements?

No.

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Annex A
(continued)

7 Special tools, equipment, software

7.1 What special tools, equipment, software, etc. will need to be purchased by the Region to effectively implement?

None.

7.2 Are there stock numbers available for the new equipment?

Not applicable.

7.3 What will be the costs of these special tools, equipment, software?

Not applicable.

8 Finances

8.1 What total costs would the Regions be required to incur in implementing this document? Identify all cost activities associated with implementation, e.g. labour, training, tooling, stock, obsolescence

Project costing will be evaluated on a per-project basis via the normal Investment Committees, guided by the pricing policies for Embedded Generation presently under development.

Impact assessment completed by:

Name: Stuart van Zyl

Designation: Chief Engineer, Protection Discipline Specialist

Updated by: Andrew Craib

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Annex B – Summary of generator connection types

(Informative)

This section provides typical examples of generator connection types to which this standard shall apply, indicating the likely locations of the PUC, PGC and PCC in each case. The application of the standard shall not be limited to only these plant connection types.

Generator connection to NSP busbar: The EG in this case is connected directly to a NSP busbar, via a generator transformer. In the case where the EG is within the same substation as the NSP (e.g., one earth-mat with two separately owned yards), and noting that the standard states that Eskom will own the circuit breaker closest to the Eskom busbar and that there shall be a minimum of two owned EG circuit breakers in series, the following figure is relevant:

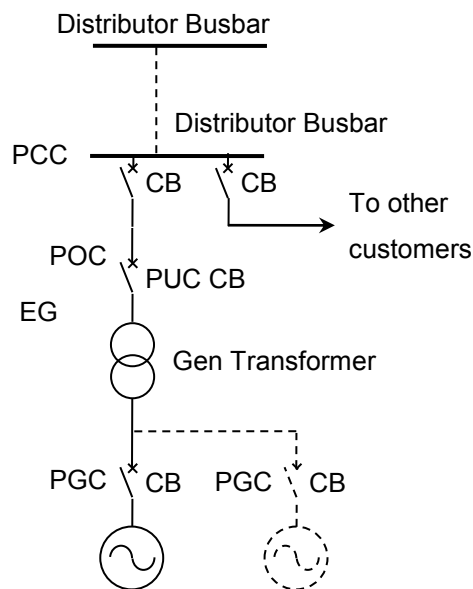


Figure B-1: Generic Layout with Shared Earth Mat

The unit protection of the generator transformer and the busbar protection shall overlap such that there is no unprotected zone between the two circuit breakers. The EG and NSP shall make a suitable CT core available to the other party to facilitate this zone overlapping.

Radial line tee-in generator connection: The EG is connected via a tee-in on a radial distribution line, via a transformer.

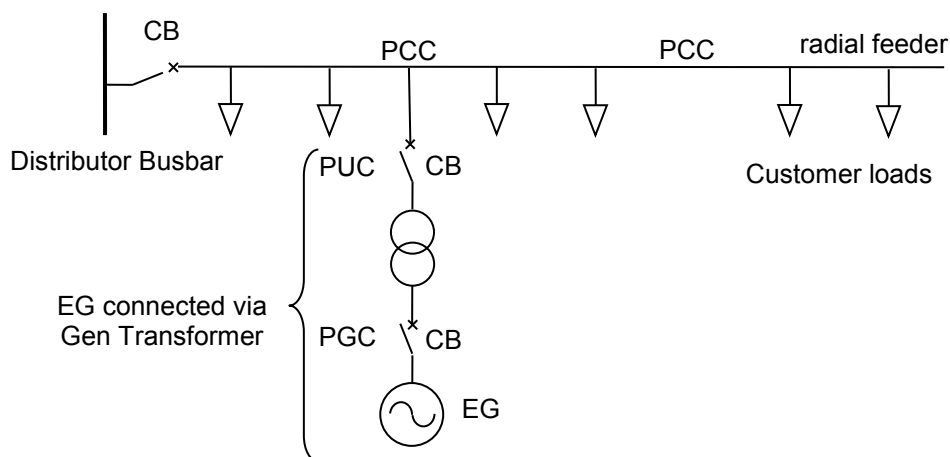


Figure B-2: Radial Connection

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Annex C – Summary of plant types

(Informative)

This section provides a summary of the typical plant types to which this standard shall apply. The application of the standard shall not be limited to only these plant types.

Synchronous generator: A type of rotating electrical generator which operates at a speed that is directly related to system frequency. The machine is designed to be capable of operation in isolation from other generating plants. The output voltage, frequency and power factor are determined by control equipment associated with the generator. Under certain conditions, the synchronous generator may be paralleled with a network containing other generation. On disconnection of the paralleled connection, the synchronous generator will continue to generate at a voltage and frequency determined by its control equipment.

Mains-excited asynchronous generator: A type of rotating electrical generator which operates at a speed not directly related to system frequency. The machine is designed to be operated in parallel with a network containing other generation. The machine is excited by reactive power drawn only from the network to which it is connected.

The output voltage and frequency are determined by those of the system to which it is connected. On disconnection of the parallel connection, the mains-excited asynchronous generator will cease generation.

Power factor corrected asynchronous generator: A derivative of the mains-excited asynchronous generator where the machine is excited partly by the network to which it is connected and partly by a device of fixed capacitance connected locally to the machine. On disconnection of the parallel connection, the power factor corrected asynchronous generator may continue to generate electrical power at a voltage and frequency determined by the machine and system characteristics.

Self-excited asynchronous generator: A derivative of the mains-excited asynchronous generator where the machine is excited purely by a device of variable capacitance connected locally to the machine. The machine is capable of operation in isolation from a network containing other generation and in this respect is similar to the synchronous generator. Under certain conditions, the self-excited asynchronous generator may be operated in parallel with other generation, and on failure of that connection, the machine will continue to generate at a voltage and frequency determined by its control equipment.

Self-commutated static inverter: An electronic device to convert direct current (D.C.) to alternating current (A.C.) in which the output value of A.C. frequency and voltage is determined by control equipment associated with the device. It is similar to the rotating synchronous generator in that, under certain conditions, it may be connected in parallel with a network containing other generators. On failure of that connection, the device will continue to provide power at a voltage and frequency determined by its control equipment.

Line-commutated static inverter: A derivative of the self-commutated static inverter where the output A.C. frequency and voltage are determined by the network containing other generation to which it must be connected. On disconnection of the parallel connection, the line-commutated static inverter will normally cease operation.

Annex D – Protective Relay Type Test requirements (Normative)

Protective relays installed at the Point of Connection shall comply with the following international type test requirements.

Table D-1: International standard type test requirements for protective relays

Item	Test	Standard	Test Level	Compliance Criteria
Auxiliary power supply				
1	Operating range		-	$V_{Nom} - 20\%$ to $V_{Nom} + 10\%$.
2	Interruption	IEC 60255-11	-	For supply interruptions lasting less than 10 ms, the device shall function as if no interruption had occurred.
3	A.C. ripple	IEC60255-11	-	Device shall function correctly with 12% 100 Hz A.C. signal superimposed on the D.C. supply.
Power frequency magnetic field				
4	Steady State	SANS 61000-4-8	Class 4	30 A/m continuous, 300 A/m short duration, 50Hz
Insulation resistance				
5	Dielectric withstand	IEC 60255-5	-	2 kV rms 50 Hz for 1 minute between all terminals to case earth. Transverse tests between contacts shall also be performed to the above specification.
6	Insulation resistance	IEC 60255-5	-	Insulation resistance greater than 20 MΩ when measured at 500 Vdc
Environmental tests				
7	Cold	IEC 60068-2-1	-10 °C or less	Operates within tolerance at -10 °C (LCD screen operative)
8	Dry Heat	IEC 60068-2-2	+55 °C or more	Operates within tolerance at +55 °C
9	Cyclic Temperature and Humidity	IEC 60068-2-30	Test Db	25 °C and 95% relative humidity/ 55 °C and 95% relative humidity, 12 + 12 hour cycle
10	Enclosure protection	SANS 60529	IP53	Protected against ingress of dust particles, spraying water
Mechanical tests				
11	Vibration	IEC 60255-21-1	Class 2 (response and endurance)	Response: 1 g, 10-150 Hz, 1 sweep energised. Contacts should not close for longer than 2 ms. Endurance: 2 g 10–150 Hz, 20 sweeps, unenergised contacts should not close for longer than 2 ms.
12	Shock	IEC 60255-21-2	Class 1 (response and withstand)	Response: 5 g, 11 ms, 3 pulses in each direction, energised Withstand: 15 g, 11 ms, 3 pulses in each direction, unenergised
13	Bump	IEC 60255-21-2	Class 1	10 g, 16 ms, 1000 pulses unenergised.
14	Seismic	IEC 60255-21-3	Class 1	Test method A (single axis sine sweep test) 1 – 35 Hz, 1 sweep.

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Annex D
(continued)

Table D-1. International standard type test requirements for protective relays (continued)

Item	Test	Standard	Test Level	Compliance Criteria
Impulse tests				
15	Electrical impulse (1.2/50 μ s)	IEC 60255-5	-	5 kV 1.2/50 μ s waveform, 0.5J
Electromagnetic compatibility				
16	1MHz Disturbance Burst	IEC60255-22-1 or SANS 61000-4-12	Class 3	2.5 kV common mode, 1 kV differential mode, 2 s total test duration, 6 – 10 bursts
17	Fast Transient	IEC 60255-22-4 or	Class A (IV)	4 kV, 2.5 kHz 2 kV, 5 kHz on Comms ports
		SANS 61000-4-4	Class 4	4 kV, 5 kHz (power port) 2 kV, 5 kHz (I/O signal, data and control ports)
18	Electrostatic Discharge	IEC 60255-22-2 or SANS 61000-4-2	Class 3	6 kV Contact Discharge, 8 kV Air Discharge
19	Surge immunity	IEC 60255-22-5 or SANS 61000-4-5	- Class 3	2 kV
20	Radiated Radio Frequency EM field immunity	IEC 60255-22-3 or SANS 61000-4-3	- Class 3	10 V/m, 80 MHz – 1 GHz
21	Conducted Radio Frequency EM field immunity	IEC 60255-22-6 or SANS 61000-4-6	- Class 3	10 Vrms, 150 kHz – 80 MHz

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Annex E – Residual over-voltage protection grading example (Informative)

Reference: Network Protection & Automation Guide, p309.

This section provides an example of the method to be used to grade the residual over-voltage protection at an MV point of connection with the current-based earth fault protection on the Distribution system.

The voltage pick-up must be set at a value corresponding to the current pick-up of the least sensitive earth fault relay on the network. The least sensitive current pick-up will typically occur on the source substation feeder circuit-breakers. For a relay that operates using the residual voltage, $3V_0$, the effective setting is given by Equation D.1.

$$V_S = \frac{I_S \times 3 \times Z_N}{VT \text{ Ratio}} \quad (D.1)$$

Where:

V_S = Voltage setting of the residual over-voltage protection

I_S = Highest current setting of the Distribution network earth fault protection

Z_N = Earthing impedance

The time delay of the residual over-voltage protection, either definite time or using an inverse-time characteristic, must be chosen such that it operates after the slowest earth fault protection relay on the feeder.

Application example:

Consider a 22 kV network that is supplied by two power transformers, each earthed via a 35.8Ω resistor to limit the earth fault current to 710 A. The highest earth fault current pick-up applied on the network is 40 A. The earth fault protection uses a normal inverse characteristic with a time multiplier of 0.2.

The voltage setting is calculated as follows:

$$V_S = \frac{I_S \times 3 \times Z_N}{VT \text{ Ratio}} = \frac{40 \text{ A} \times 3 \times \frac{35.8 \Omega}{2}}{200} = 10.8 \text{ V}$$

The earth fault protection will operate in 470 ms for a 710 A fault. Assuming that the residual overvoltage protection uses a time-current curve given by the equation:

$$\text{Trip Time, } t = \frac{K}{\frac{V_M}{V_S} - 1}$$

Where:

K = Time multiplier

V_M = Measured voltage during the fault

V_S = Voltage setting.

For the residual over-voltage protection to operate in 870 ms at 190 V requires a setting of $K = 14.5$.

Annex F – Eskom Approved Gateway ordering information

(Informative)

Intended Application	Isolated Voltage Output	Power Supply	Product Description	Product Part No	Budgetary Cost *	Protocol Support	Firmware Set Part No	Bootrom Version	Required Rack Space	Physical Dimensions
Transmission connected Embedded Generator	48VDC	20-60VDC	D20ME Single CPU Gateway (Non-VME) with IEC-101 drivers for power supplies in the range 20-60VDC	ISTE-800360	R 38,400	IEC101 DCA (For comms with IEC101 Slave) IEC101 DPA (For comms with IEC101 Master)	ISTE-000145-164	P-130-0 ver 2.07	3U	Width: 482.6mm Height: 133.35mm Depth: 215.9mm
		100-300VDC / 85-264VAC	D20ME Single CPU Gateway (Non-VME) with IEC-101 drivers for power supplies in the range 100-300VDC or 85-264VAC	ISTE-800370	R 38,400					
Distribution connected Embedded Generator	48VDC	20-60VDC	D20ME Single CPU Gateway (Non-VME) with DNP3 drivers for power supplies in the range 20-60VDC	ISTE-800340	R 38,400	DNP DCA (For comms with DNP Slave) DNP DPA (For comms with DNP Master)	ISTE-000037-164	P-130-0 ver 1.33	3U	Width: 482.6mm Height: 133.35mm Depth: 215.9mm
		100-300VDC / 85-264VAC	D20ME Single CPU Gateway (Non-VME) with DNP3 drivers for power supplies in the range 100-300VDC or 85-264VAC	ISTE-800350	R 38,400					
	NA	20-60VDC	iBox Serial Substation Controller with DNP3 drivers for power supplies in the range 20-60VDC	ISTE-800380	R 13,300	DNP3 DCA DNP3 DPA	SAX0001.06	P-155-0 ver 3.10	7U 5U + 1U above and 1U below	Width: 279.4mm Height: 190.5mm Depth: 43.9mm
		110-290VDC / 100-240VAC	Optional Power Supply for iBox to accept 110-290VDC/100-240VAC	ISTE-800390	R 1,100	NA	NA	NA	To be integrated with iBox	Width: 45mm Height: 75mm Depth: 91mm

* Prices exclude VAT, are based on a rate of exchange of 1USD = R10.25 Prices are provided as an indication only and are subject to change without notice.

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Annex G – Detailed Signal list required between the EG and the Approved Gateway (normative)

B	C	Point Name	State	RPP Grid Code Ref	Cross Reference	Signal Number	Assoc signal	DNP3 Index	DNP3 Class	DNP3 Data Type	IEC -101 ASDU (Address)	IEC 60870-5-101 ASDU Type	IEC -101 Class	Point Description	Note
DIGITAL INPUTS															
X	X	Generation status	Stopped-01 Started-10	13	Table 4-23	DI 0	DO 3	0,1	1	binary input event with time (2 bits)	10001	<31> Double-point info with time tag CP56Time2a	1	Unit operation status	
X	X	Supervisory switch	On-01 (Dx=0) Off-10 (Dx=1)		Table 4-4	DI 1		2,3	1	binary input event with time (2 bits)	10002	<31> Double-point info with time tag CP56Time2a	1	Supervisory isolator switch 'Off' means supervisory controls are disabled	A Control Centres that requires a single bit indication for this can use the most significant bit of the pair
X	X	Breaker State	Open-01 Closed-10 In Transit-00 Invalid-11	13.3.2	Table 4-5	DI 2	DO 1	4,5	1	binary input event with time (2 bits)	10003	<31> Double-point info with time tag CP56Time2a	1	State of the PUC Circuit Breaker	
X	X	Isolator State	Open-01 Closed-10 In Transit-00 Invalid-11		Table 4-5	DI 3		6,7	1	binary input event with time (2 bits)	10004	<31> Double-point info with time tag CP56Time2a	1	State of the PUC Isolator	
X	X	Plant shut down	Yes-1 No-0		Table 4-10	DI 4		8	1	binary input event with time	1	<30> Single-point info with time tag CP56Time2a	1	Plant Shutdown	EG has initiated the shutdown
X	X	Plant islanded	Yes-1 No-1		Table 4-10	DI 5		9	1	binary input event with time	2	<30> Single-point info with time tag CP56Time2a	1	Plant islanded	
X	X	Curtailement mode status	On-1 Off-0	13.1.3	Table 4-20	DI 6	DO 4	10	1	binary input event with time	3	<30> Single-point info with time tag CP56Time2a	1	Curtailement mode status	
X	X	Curtailement in progress	Yes-1 No-0	13.1.3	Table 4-20	DI 7		11	1	binary input event with time	4	<30> Single-point info with time tag CP56Time2a	1	Curtailement in progress	
X	X	Curtailement mode not ready	Yes-1 No-0	13.1.3	Table 4-20	DI 8		12	1	binary input event with time	5	<30> Single-point info with time tag CP56Time2a	1	Curtailement mode not ready	
X	X	Power gradient constraint mode status	On-1 Off-0	11.3	Table 4-28	DI 9	DO 5	13	1	binary input event with time	6	<30> Single-point info with time tag CP56Time2a	1	Power gradient constraint mode status	
X	X	Power gradient constraint mode not ready	Yes-1 No-0	11.3	Table 4-28	DI 10		14	1	binary input event with time	7	<30> Single-point info with time tag CP56Time2a	1	Power gradient constraint mode not ready	
X	X	PF control mode status	On-1 Off-0	8.2	Table 4-35	DI 11	DO 6	15	1	binary input event with time	8	<30> Single-point info with time tag CP56Time2a	1	Power factor control mode status	
X	X	PF control mode not ready	Yes-1 No-0		Table 4-35	DI 12		16	1	binary input event with time	9	<30> Single-point info with time tag CP56Time2a	1	Power factor control mode not ready	
X	X	V control mode status	On-1 Off-0	8.3	Table 4-38	DI 13	DO 7	17	1	binary input event with time	10	<30> Single-point info with time tag CP56Time2a	1	Voltage control mode status	
X	X	V control mode not ready	Yes-1 No-0		Table 4-38	DI 14		18	1	binary input event with time	11	<30> Single-point info with time tag CP56Time2a	1	Voltage control mode not ready	
X	X	Q control mode status	On-1 Off-0	8.1	Table 4-32	DI 15	DO 8	19	1	binary input event with time	12	<30> Single-point info with time tag CP56Time2a	1	Reactive power control mode status	

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B	C	Point Name	State	RPP Grid Code Ref	Cross Reference	Signal Number	Assoc signal	DNP3 Index	DNP3 Class	DNP3 Data Type	IEC -101 ASDU (Address)	IEC 60870-5-101 ASDU Type	IEC - 101 Class	Point Description	Note
DIGITAL INPUTS															
X	X	Q control mode not ready	Yes-1 No-0	8.1	Table 4-32	DI 16		20	1	binary input event with time	13	<30> Single-point info with time tag CP56Time2a	1	Reactive power control mode not ready	
	X	Frequency control mode status	On-1 Off-0	13.1.4	Table 4-15	DI 17	DO 9	21	1	binary input event with time	14	<30> Single-point info with time tag CP56Time2a	1	Primary frequency control mode status	As per agreement only
	X	Frequency control mode not ready	Yes-1 No-0		Table 4-15	DI 18		22	1	binary input event with time	15	<30> Single-point info with time tag CP56Time2a	1	Primary Frequency control not ready	Not needed?
	X	P-delta mode status	On-1 Off-0	11.2	Table 4-25	DI 19	DO 9	23	1	binary input event with time	16	<30> Single-point info with time tag CP56Time2a	1	Delta production constraint mode status	not PVPP
	X	P-delta mode not ready	On-1 Off-0	11.2	Table 4-25	DI 20		24	1	binary input event with time	17	<30> Single-point info with time tag CP56Time2a	1	Delta production constraint mode not ready	not PVPP
	X	AGC mode Status	On-1 Off-0		Table 4-17	DI 21	DO 11	25	1	binary input event with time	18	<30> Single-point info with time tag CP56Time2a	1	AGC mode state	Only required for Transmission connected IPP (not PVPP)
	X	AGC Raise block	Yes-1 No-0		Table 4-17	DI 22		26	1	binary input event with time	19	<30> Single-point info with time tag CP56Time2a	1	AGC Raise block	Only required for Transmission connected IPP (not PVPP)
	X	AGC Lower block	Yes-1 No-0		Table 4-17	DI 23		27	1	binary input event with time	20	<30> Single-point info with time tag CP56Time2a	1	AGC Lower block	Only required for Transmission connected IPP (not PVPP)

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DIGITAL COMMANDS															
X	X	RESERVED				DO 1		0			35001		1	Reserved for future use (broadcast)	
X	X	Breaker (Trip)	Trip-01 Close-NA	13.3.2	Table 4-13	DO 2	DI 3	1	-	Binary Command - CROB	35002	<46> Double Command	1	Remote disconnection (Trip the POC or PUC or PGC Circuit Breaker)	
X	X	Generation (Stop/Start)	On-10 Off-01	13	Table 4-22	DO 3	DI 0	2	-	Binary Command - CROB	35003	<46> Double Command	1	Stop/Start generation of the EG	
X	X	Curtailment mode (Deactivate/Activate)	On-10 Off-01	13.1.3	Table 4-19	DO 4	DI 6	3	-	Binary Command - CROB	35004	<46> Double Command	1	Curtailment mode (Deactivate/Activate)	mutually exclusive with P-delta constraint
X	X	Power gradient constraint mode (Deactivate/Activate)	On-10 Off-01	11.3	Table 4-27	DO 5	DI 9	4	-	Binary Command - CROB	35005	<46> Double Command	1	Power gradient constraint	
X	X	PF control mode (Activate)	On-10 Off-NA	8.2	Table 4-34	DO 6	DI 11	5	-	Binary Command - CROB	35006	<46> Double Command	1	Activate power factor control mode	deactivate V / Q
X	X	V control mode (Activate)	On-10 Off-NA	8.3	Table 4-37	DO 7	DI 13	6	-	Binary Command - CROB	35007	<46> Double Command	1	Activate voltage control mode	deactivate PF / Q
X	X	Q control mode (Activate)	On-10 Off-NA	8.1	Table 4-31	DO 8	DI 15	7	-	Binary Command - CROB	35008	<46> Double Command	1	Activate reactive power control mode	deactivate PF / V
	X	Frequency control mode (Deactivate/Activate)	On-10 Off-01	13.1.4	Table 4-14	DO 9	DI 17	8	-	Binary Command - CROB	35009	<46> Double Command	1	Primary frequency control deactivate/activate command	As per agreement only, If EG sends double bit, send only most significant bit
	X	P-delta mode (Deactivate/Activate)	On-10 Off-01	11.2	Table 4-24	DO 10	DI 20	9	-	Binary Command - CROB	35010	<46> Double Command	1	Activate/Deactivate Delta production constraint mode	Mutually exclusive with Curtailment
	X	AGC mode (Deactivate/Activate)	On-10 Off-01		Table 4-16	DO 11	DI 21	10	-	Binary Command - CROB	35011	<46> Double Command	1	AGC mode Deactivate/Activate command	Only required for Transmission connected IPP (not PVPP)

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ANALOGUES INPUTS															
X	X	Active Power sent out	Kw or MW	13.1.1	Table 4-9	AI 1		0	2	Analog Input Event 16-bit without time	20001	<9> Measured value, normalized value	2	Measured summated three phase active power sent-out (at the POC)	Actual summated three phase sent-out at the POC
X	X	Reactive Power sent out	kvar or Mvar	13.1.1	Table 4-9	AI 2		1	2	Analog Input Event 16-bit without time	20002	<9> Measured value, normalized value	2	Total summated three phase Reactive Power Import/Export (+/-Mvar) at the POC	Total summated three phase Reactive Power Import/Export (+/-Mvar) at the POC
X	X	Red Phase Amps	A		Table 4-9	AI 3		2	2	Analog Input Event 16-bit without time	20003	<9> Measured value, normalized value	2	Red phase current	
X	X	White Phase Amps	A		Table 4-9	AI 4		3	2	Analog Input Event 16-bit without time	20004	<9> Measured value, normalized value	2	White phase current	
X	X	Blue Phase Amps	A		Table 4-9	AI 5		4	2	Analog Input Event 16-bit without time	20005	<9> Measured value, normalized value	2	Blue phase current	
X	X	Power Factor	PF	13.1.1	Table 4-9	AI 6		5	2	Analog Input Event 16-bit without time	20006	<9> Measured value, normalized value	2	Power Factor at the POC	neg = Gen producing vars (lagging) pos = Gen absorbing vars (leading)
X	X	Voltage sent out	kV	13.1.1	Table 4-9	AI 7		6	2	Analog Input Event 16-bit without time	20007	<9> Measured value, normalized value	2	Voltage at the POC	
X	X	Curtailment setpoint feedback	kW or MW	13.1.3	Table 4-21	AI 8	AO 2	7	2	Analog Input Event 16-bit without time	20008	<9> Measured value, normalized value	2	Curtailment setpoint feedback	
X	X	PF setpoint feedback	PF	8.2	Table 4-34	AI 9	AO 5	8	2	Analog Input Event 16-bit without time	20009	<9> Measured value, normalized value	2	Power factor setpoint feedback	
X	X	Frequency	Hz		Table 4-9	AI 10		10	2	Analog Input Event 16-bit without time	20010	<9> Measured value, normalized value	2	Frequency	Only required where intentional islands are allowed
X	X	Actual ramp rate	MW/min	13.1.1	Table 4-9	AI 11		11	2	Analog Input Event 16-bit without time	20011	<9> Measured value, normalized value	2	Active Power Ramp rate of the entire facility	pos = ramp up, neg = ramp down
X	X	Q setpoint feedback	kvar or Mvar	8.1	Table 4-33	AI 12	AO 7	13	2	Analog Input Event 16-bit without time	20012	<9> Measured value, normalized value	2	Reactive power control setpoint feedback	
X	X	Q lower limit	kvar or Mvar	13.1.1	Table 4-33	AI 13		14	2	Analog Input Event 16-bit without time	20013	<9> Measured value, normalized value	2	Reactive Power Lower limit	
X	X	Q upper limit	kvar or Mvar	13.1.1	Table 4-33	AI 14		15	2	Analog Input Event 16-bit without time	20014	<9> Measured value, normalized value	2	Reactive Power Upper limit	

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ANALOGUES INPUTS															
X	X	V setpoint feedback	kV	8.3	Table 4-39	AI 15	AO 6	16	2	Analog Input Event 16-bit without time	20015	<9> Measured value, normalized value	2	Voltage setpoint feedback	
X	X	Up ramp rate setpoint feedback	MW/min	11.3	Table 4-29	AI 16	AO 3	17	2	Analog Input Event 16-bit without time	20016	<9> Measured value, normalized value	2	Up ramp rate setpoint feedback	applies to startup and normal operation
X	X	Down ramp rate setpoint feedback	MW/min	11.3	Table 4-29	AI 17	AO 4	18	2	Analog Input Event 16-bit without time	20017	<9> Measured value, normalized value	2	Down ramp rate setpoint feedback	applies to shutdown
X	X	Up ramp rate high limit	MW/min		Table 4-29	AI 18		19	2	Analog Input Event 16-bit without time	20018	<9> Measured value, normalized value	2	Up ramp rate high limit	
X	X	Up ramp rate low limit	MW/min		Table 4-29	AI 19		20	2	Analog Input Event 16-bit without time	20019	<9> Measured value, normalized value	2	Up ramp rate low limit	
X	X	Down ramp rate high limit	MW/min		Table 4-29	AI 20		21	2	Analog Input Event 16-bit without time	20020	<9> Measured value, normalized value	2	Down ramp rate high limit	
X	X	Down ramp rate low limit	MW/min		Table 4-29	AI 21		22	2	Analog Input Event 16-bit without time	20021	<9> Measured value, normalized value	2	Down ramp rate low limit	
X	X	Wind speed	m/s	13.1.5	Table 4-11	AI 22		23	2	Analog Input Event 16-bit without time	20022	<9> Measured value, normalized value	2	Wind speed	Within 75% of the hub height) - measured signal in metres/second (for WPP only)
X	X	Wind direction	Deg	13.1.5	Table 4-11	AI 23		24	2	Analog Input Event 16-bit without time	20023	<9> Measured value, normalized value	2	Wind direction	Within 75% of the hub height – measured signal in degrees from true north (0-359) (for WPP only)
X	X	Air temperature	°C	13.1.5	Table 4-11	AI 24		25	2	Analog Input Event 16-bit without time	20024	<9> Measured value, normalized value	2	Measured Air temperature	Signal in degrees centigrade (-20.0 to 50.0)
X	X	Air pressure	mbar	13.1.5	Table 4-11	AI 25		26	2	Analog Input Event 16-bit without time	20025	<9> Measured value, normalized value	2	Air pressure	Signal in millibar (800 to 1400).
X	X	Air density	kg/m ³	13.1.5	Table 4-11	AI 26		28	2	Analog Input Event 16-bit without time	20026	<9> Measured value, normalized value	2	Air density	WPP only
X	X	Solar Irradiation	W/m ²	13.1.5	Table 4-11	AI 27		27	2	Analog Input Event 16-bit without time	20027	<9> Measured value, normalized value	2	Solar radiation (for PVPP only)	PVPP only
X	X	Humidity	%		Table 4-11	AI 28		29	2	Analog Input Event 16-bit without time	20028	<9> Measured value, normalized value	2	Humidity	
	X	P-delta setpoint feedback	%	11.2	Table 4-26	AI 29	AO 8	30	2	Analog Input Event 16-bit without time	20029	<9> Measured value, normalized value	2	Pdelta setpoint feedback	

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B	C	Point Name	Unit	RPP Grid Code Ref	Cross Reference	Signal Number	Assoc Signal	DNP3 Index	DNP3 Class	DNP3 Data Type	IEC 60870-5-101 ASDU (Address)	IEC 60870-5-101 ASDU Type	IEC 60870-5-101 Class	Point Description	Note
ANALOGUES INPUTS															
	X	AGC setpoint feedback	MW		Table 4-18	AI 30	AO 9	31	2	Analog Input Event 16-bit without time	20030	<9> Measured value, normalized value	2	AGC setpoint feedback	Only required for Transmission connected EG
	X	AGC high regulating limit	MW		Table 4-18	AI 31		32	2	Analog Input Event 16-bit without time	20031	<9> Measured value, normalized value	2	AGC high regulating limit	Only required for Transmission connected EG
	X	AGC low regulating limit	MW		Table 4-18	AI 32		33	2	Analog Input Event 16-bit without time	20032	<9> Measured value, normalized value	2	AGC low regulating limit	Only required for Transmission connected EG

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B	C	Point Name	Unit	RPP Grid Code Ref	Cross Reference	Signal Number	Assoc Signal	DNP3 Index	DNP3 Class	DNP3 Data Type	IEC 60870-5-101 ASDU (Address)	IEC 60870-5-101 ASDU Type	IEC 60870-5-101 Class	Point Description	Note
ANALOGUE CONTROLS															
X	X	RESERVED				AO 1		0	-		45001	Setpoint Command		Reserved for future use (broadcast)	
X	X	Curtailment setpoint	kW or MW	13.1.3	Table 4-19	AO 2	AI 8	1	-	Analog Output 16-bit	45002	Setpoint Command		Absolute Production Constraint Setpoint (Active Power)	
X	X	Up ramp rate setpoint	MW/min	11.3	Table 4-27	AO 3	AI 16	2	-	Analog Output 16-bit	45003	Setpoint Command		Up ramp rate setpoint	applies to startup and normal operation
X	X	Down ramp rate setpoint	MW/min	11.3	Table 4-27	AO 4	AI 17	3	-	Analog Output 16-bit	45004	Setpoint Command		Down ramp rate setpoint	applies to shutdown
X	X	PF control setpoint	PF	8.2	Table 4-34	AO 5	AI 9	4	-	Analog Output 16-bit	45005	Setpoint Command		Power Factor control setpoint	neg = Gen producing vars (lagging) pos = Gen absorbing vars (leading)
X	X	V control setpoint	kV	8.3	Table 4-37	AO 6	AI 15	5	-	Analog Output 16-bit	45006	Setpoint Command		Voltage control setpoint	
X	X	Q control setpoint	kvar or Mvar	8.1	Table 4-31	AO 7	AI 12	6	-	Analog Output 16-bit	45007	Setpoint Command		Reactive Power control setpoint	
	X	P-delta setpoint	%	11.2	Table 4-24	AO 8	AI 29	7	-	Analog Output 16-bit	45008	Setpoint Command		Pdelta setpoint(percentage of available power)	
	X	AGC setpoint	MW		Table 4-16	AO 9	AI 30		-		45009	Setpoint Command		AGC setpoint	Only required for Transmission connected EG

CONTROLLED DISCLOSURE