Part of the Energy Queensland Group

Standard for Connection of Embedded Generating Systems to a Distributor's HV Network

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Abstract: This Standard sets out the requirements for connecting Embedded Generating systems (EG systems) to any High Voltage portion of a Distribution System owned and operated by either Energex or Ergon Energy (the Distributors), where the EG system is intended to operate in parallel with that Distribution System. This Standard has been prepared by the Distributors to provide Proponents of EG systems with information about the relevant connection requirements.

Keywords: embedded, generating, high voltage, IES, solar, photovoltaic, wind, rotating, connection, synchronous, HV, 1.5 MW, 5 MW, 30 MW

Standard for Connection of Embedded Generating Systems to a Distributor's HV Network

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Standard for Connection of Embedded Generating Systems to a Distributor's HV Network

1 Overview

1.1 Purpose

This Standard outlines a number of technical requirements that shall be met in order for a Proponent to connect an Embedded Generating system (EG system) to a High Voltage Distribution System owned and operated by either Energex or Ergon Energy (the Distributors), where that EG system is intended to operate in parallel with the Distribution System.

EG systems include both synchronous and asynchronous generating systems, and include generating equipment such as rotating machines and Inverter Energy Systems (IES).

This Standard is also intended to assist the relevant Registered Professional Engineer of Queensland (RPEQ) in designing and commissioning such EG systems so that they are able to connect to the relevant Distribution System.

1.2 Scope

This Standard applies to:

- All generating technology types including, but not limited to, IES and rotating machines; and
- EG systems that are interconnected with the Distributor's HV Distribution System,

where the aggregate installed nameplate capacity of all of the interconnected EG systems at the Proponent's Connection Point shall exceed 30 kW.

Where the relevant connection is to a single wire earth return (SWER) part of the Distribution System or an Isolated Distribution System, additional requirements may apply.

For each of the generating technology types and operating regimes, this Standard gives consideration to the following:

- The safety and security of the Distribution System;
- Protection of the interconnection between an EG system and the Distribution System;
- The management of thermal capacity limits of a Distribution System;
- Control of voltages and voltage fluctuation on the Distribution System;
- Contribution to fault levels by EG systems;
- Power factor and quality of supply of electricity generated;
- Stability of the Distribution System (steady-state and transient); and
- Ongoing operating and maintenance procedures and communications.

1.3 Terminology

In this Standard, the word *shall* indicate a mandatory requirement, the word *should* indicates a recommendation and the word *may* indicates a requirement that may be mandatorily imposed on the Proponent by the Distributor, depending upon the outcome of the Distributor's Technical Assessments.

Joint Standard Document between Energex and Ergon Energy
Energex Limited ABN 40 078 849 055 ■ Ergon Energy Corporation Limited ABN 50 087 646 062

2 References

2.1 Energex controlled documents

A copy of the latest version of this Energex Standard may be obtained by searching for **embedded standard** in the following website:

https://www.energex.com.au/

Document number	Document name	Document type
0768	Large Customer Connection Manual	Policy Document
Standard 01618	Standard for Connection of Embedded Generating Systems (>30 kW to 1,500 kW) to a Distributor's LV Network	Customer Standard

2.2 Ergon Energy controlled documents

A copy of the latest version of this Ergon Energy Standard may be obtained by searching for **embedded standard** in the following website:

https://www.ergon.com.au/

Document number	Document name	Document type
n/a	Major Customer Connection Manual	Policy Document
STNW1174	Standard for Connection of Embedded Generating Systems (>30 kW to 1,500 kW) to a Distributor's LV Network	Customer Standard

2.3 Other documents

2.3.1 Australian and Australian/New Zealand Standards

Document number	Document name	Document type
AS 2067	Substations and high voltage installations exceeding 1kV A.C.	Australian Standard
AS 60034.22	Rotating electrical machines Part 22	Australian Standard
AS 60038	Standard voltages	Australian Standard
AS/NZS 3000	Electrical installations (known as the Australian/New Zealand Wiring Rules)	Australian Standard
AS/NZS 4777.1	Grid connection of energy systems via inverters- Installation requirements	Australian Standard
AS/NZS 4777.2	Grid connection of energy systems via inverters- Inverter requirements	Australian Standard
AS/NZS 60044 series	Instrument transformers	Australian Standard

Document number	Document name	Document type
AS/NZS IEC 60947.6.1	Low-voltage switchgear and controlgear – Part 6.1 : Multiple function equipment – Transfer switching equipment	Australian Standard
AS/NZS 61000 series	Electromagnetic compatibility (EMC)	Australian Standard

2.3.2 International Standards

Document number	Document name	Document type
IEC 60255-1	Measuring relays and protection equipment – Part 1: Common requirements	International Standard
IEC 60255-12	Electrical relays – Part 12: Directional relays and power relays with two input energizing quantities	International Standard
IEC 60255-26	Electrical relays - Part 26: Electromagnetic compatibility requirements	International Standard
IEC 60255-27	Electrical relays - Part 27: Product safety requirements	International Standard
IEC 60255-127	Measuring relays and protection equipment - Part 127: Functional requirements for over/under voltage protection	International Standard
IEC 62116:2014 Ed.2	Utility-interconnected photovoltaic inverters – Test procedure of islanding prevention measures	International Standard
IEEE C37.20.2	Metal-clad switchgear	IEEE Standard

2.3.3 Relevant technical documents

Document number	Document name	Document type
n/a	System Strength Impact Assessment Guidelines	AEMO guideline
n/a	Power System Model Guidelines	AEMO guideline

3 Legislation, regulations, rules, and codes

This Standard refers to the following legislation:

Legislation, regulations, rules, and codes
Electricity Act 1994 (Qld) and Electricity Regulation 2006 (Qld)
Electrical Safety Act 2002 (Qld) and Electrical Safety Regulation 2013 (Qld)
National Electricity Rules being the rules in force in Queensland under the National Electricity (Queensland) Law under the Electricity – National Scheme (Queensland) Act 1997 (Qld)
Professional Engineers Act 2002 (Qld)

4 Definitions, acronyms, and abbreviations

4.1 Definitions

For the purposes of this Standard, the following definitions apply. Please note that certain abbreviations and acronyms are separately defined in the next section.

Term	Definition
Anti-islanding	Refers to the functionality of a protection system to detect islanded conditions and disconnect the EG system from the Distribution System.
Connection Agreement	The agreement for connecting an EG system to a Distribution System, as contemplated in Chapters 5 and 5A of the NER. This typically comprises a connection establishment part for new or altered connections and an ongoing connection part for the continued connection after the works have been done.
Connection Assets	Those components of the Distribution System which are used to provide connection services (that is, to a particular Connection Point).
Connection Point	The agreed point of supply established between the Distributor and a Proponent
Distribution Network	A Network in Queensland which is not a transmission network (as defined in rule 9.32.1(b) of the NER).
Distribution System	A Distribution Network, together with the Connection Assets associated with the Distribution Network.
Distributor	Either Energex (who owns and operates the Distribution System in South East Queensland) or Ergon Energy (who owns and operates the Distribution System in the remainder of Queensland).
EG system(s)	One or more electricity generating units and auxiliary equipment that are Interconnected with a Distribution System.
Embedded Generating unit or EG unit	A generating unit connected within a Distribution System and not having direct access to the transmission network.

Term	Definition
Energy Laws	Relevant laws relating to the subject matter of this Standard, including, without limitation and where applicable, the *Electricity Act 1994* (Qld), the *Electricity Regulation 2006* (Qld), the *Electrical Safety Act 2002* (Qld), the *Electrical Safety Regulation 2013* (Qld), the Electricity Distribution Network Code, the National Electricity (Queensland) Law, the National Electricity Rules, the National Energy Retail Law (Queensland) and the National Energy Retail Rules.
Export	Net power that is fed into the Distribution System through the Connection Point.
Generator	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a distribution system and who is registered by AEMO as a Generator.
High Voltage (HV)	A voltage exceeding 1,000 V AC and 1,500 V DC.
Interconnected	Refers to the synchronous parallel operation of an EG system with a Distribution System.
Inverter Energy System (IES)	A system comprising one or more inverters together with one or more energy sources (which may include batteries for energy storage), controls and one or more grid protection devices.
Isolation Device	A device designed to safely prevent the flow of current such as a circuit breaker or contactor.
Isolated Distribution System	Refers to the small remote electricity Distribution Systems operated by Ergon Energy that are not connected to the National Grid. These are typically supplied with electricity via a dedicated power station.
Lagging Power Factor	When the EG unit absorbs reactive power from the Distribution System; that is, when the EG unit acts as an inductive load from the perspective of the Distribution System.
Leading Power Factor	When the EG unit acts as a source of reactive power into the Distribution System; that is, when the EG unit acts as a capacitive load from the perspective of the Distribution System.
Low Voltage (LV)	A voltage not exceeding 1000 V AC or 1500 V DC.
MSCR Method	A screening method for the preliminary assessment of system strength based on 'available fault level' method described in Appendix A of System Strength Impact Assessment Guidelines from AEMO.
Multiple Earth Neutral (MEN)	A multiple earth neutral system of earthing is one in which the LV neutral conductor is permanently connected to earth.
National Grid	Has the meaning given to the term *national grid* in the NER.
NER	The National Electricity Rules under the National Electricity Law as in force in Queensland.

Term	Definition
Network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any Connection Assets. In relation to a Distributor, a Network owned, operated or controlled by that Distributor.
Proponent	The relevant owner, operator or controller of the EG system (or their agent).
PSCAD™/EMTDC™	Refers to a software package developed by the Manitoba-HVDC Research Centre that comprises a power systems computer-aided design package which includes an electromagnetic transients (including DC) simulation engine, and which is used to carry out electromagnetic transient type studies.
Registered Participant	A person who is a *Registered Participant* under the NER (broadly speaking, someone who is registered by AEMO).
Short Circuit Ratio	For the purposes of this Standard, is the synchronous three phase fault level in MVA of the Distribution System at the Connection Point divided by the rated output of the generating unit or system. Several other methods exist to calculate Short Circuit Ratio (SCR) and need to be used based depending on the conditions and configuration of the EG system. Further information of these methods is included in Annex A.
Technical Assessments	A study to evaluate the effects the proposed connection of the EG system shall have on the Distribution System under different loading conditions or in the event of particular faults.

4.2 Acronyms and abbreviations

The following abbreviations and acronyms appear in this Standard.

Abbreviation or acronym	Definition
AC	Alternating Current
ACR	Automatic Circuit Recloser
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AVR	Automatic Voltage Regulator
CB	Circuit Breaker
CBF	Circuit Breaker Fail
DC	Direct Current
EG	Embedded Generating
GPR	Grid Protection Relay

Abbreviation or acronym	Definition
GID	Grid Isolation Device
HV	High Voltage
IED	Intelligent Electronic Device
LV	Low Voltage
MSCR	Minimum Short Circuit Ratio
NER	National Electricity Rules
NVD	Neutral Voltage Displacement
PSS/E	Power System Simulator for Engineering
ROCOF	Rate of Change of Frequency
RPEQ	Registered Professional Engineer of Queensland
SCR	Short Circuit Ratio
VCO	Voltage Controlled Overcurrent

5 Connection arrangements

5.1 General

Under the Energy Laws, Proponents of EG systems shall obtain consent from a Distributor before connecting their EG system to the Distributor's Distribution System. This is done through the parties entering into an appropriate Connection Agreement. Detailed connection arrangement information for Ergon Energy and Energex can be found in connection manuals specified in Sections 2.1 and 2.2 of this Standard.

This Standard covers the installation of EG systems to premises having HV connections to the Distribution System. The EG systems may be connected to a dedicated or shared HV circuit.

The negotiation of a Connection Agreement with the Distributor involves the Distributor carrying out Technical Assessments of the proposed connection of the EG system to determine the impact of that connection on the Distribution System. These Technical Assessments are used to work out the technical requirements that the Proponent shall comply with.

Where there are multiple EG systems at a premises connected to a single Connection Point, the Distributor's Technical Assessments shall consider the aggregate of the existing and proposed EG systems.

5.2 Methods of operation and export capability

For the purpose of this Standard, Table 1 illustrates the operation types, nature of parallel operation and export capability for EG systems that may connect to the Distribution System.

Table 1 Types of EG systems

Operation Type	Parallel Operation		Export Capability
	Duration	Frequency	
Bumpless Transfer	up to 2 seconds	N/A	Non-export only
Standby (for testing only)	up to 6 hours	Every 3 months	Either export or non-export
Continuous Parallel	greater than 24 hours	In a year	Either export or non-export

5.2.1 Export EG systems

EG systems that export electricity into the Distribution System can be categorised as partial-export or full export. Partial-export EG systems shall be designed and operated to limit the amount of export into the Distribution System to an agreed export threshold set out in the Connection Agreement.

Full export EG systems do not need to be so limited, and are permitted to export into the Distribution System to the full nameplate capacity (full AC rating) of that EG system.

5.2.2 Non-export EG systems

EG systems that are not allowed to export electricity into the Distribution System shall be designed and operated to prevent this export of electricity and comply with the Connection Agreement.

5.2.3 Bumpless transfer EG systems

Bumpless transfer EG systems shall incorporate a make-before-break automatic transfer switch compliant with AS/NZS IEC 60947.6.1 or IEEE C37.20.2. Parallel operation with the Distribution System shall comply with the duration limits shown in Table 1. Bumpless transfer EG systems do not require Technical Assessment for the effect of increased thermal or fault ratings on the Distribution System, and are exempt from certain specific protection requirements detailed in Section 8.14.

5.3 Specific nature of connection

The Proponent shall be responsible for the energisation of the transformer and associated equipment, and ensuring that the operation is within the obligations of the Connection Agreement and any operating protocol agreed with the Distributor.

Unless otherwise agreed with the Distributor, an EG system shall only connect to the Distribution System via a single Connection Point. Connection and parallel operation with any part of the Distribution System is dependent upon compliance with the requirements outlined in this Standard and the Connection Agreement at each point where the EG system can parallel with the Distribution System.

EG systems that supply only part of the Proponent's installation shall have adequate mechanisms in place to prevent connection of the EG system to the Distribution System occurring without synchronisation and the operation of associated protection systems.

5.4 Connection categories

This Standard categorises EG system connections based on the capacity of the EG system and the strength of the Distribution System in the relevant area, as set out in Table 2 below. The three levels of requirements are outlined as Class A1, Class A2 and Class B in this Standard.

Table 2 Connection Categories

Generation Capacity[1]	Short Circuit Ratio	Connection Category	Default NER Process
<= 1.5 MW	All SCR	Class A1	Chapter 5A of the NER[2]
> 1.5 MW but < 5 MW	SCR > 5	Class A2[3]	Chapter 5A of the NER[2]
> 1.5 MW but < 5 MW	SCR <= 5	Class B[4]	Chapter 5A of the NER[2]
>= 5 MW	All SCR	Class B	Chapter 5 of the NER

Note 1: Generation capacity is the combined nameplate maximum continuous AC capacity of the EG system irrespective of any export control limitation.

Note 2: A Proponent can elect to use the Chapter 5 process in certain limited circumstances.

Note 3: Non-export rotating machine EG systems over 1.5 MW and under 5 MW may be categorised as Class A2 regardless of the SCR.

Note 4: Class B connections shall comply with the performance standards set out in Chapter 5 of the NER, even if exempt from registration.

5.5 Distributor Technical Assessments (general)

An overview of the connection application process is set out on each Distributor's website, as follows:

- Energex: https://www.energex.com.au/home/our-services/connections/establish-a-connection-using-embedded-generator-over-30kw
- Ergon Energy: https://www.ergon.com.au/network/connections/major-business-connections/major-connections

As part of this process, the Distributor shall carry out certain Technical Assessments to determine what impact the connection of the EG system shall have on the Distribution System. The specific detail of these Technical Assessments depends upon the category the particular EG system falls within.

In order to carry out these Technical Assessments, the Distributor requires certain information from the Proponent. Details of the information requirements are provided to the Proponent during the process, and the Proponent shall provide this information in order to progress through the process. In some circumstances the Proponent shall be requested to provide additional information to facilitate the Technical Assessments.

Note that fees apply to various stages in the process. The Proponent shall bear the cost for any modification required on the Distribution System to connect its EG system.

5.6 Distributor Technical Assessments – Class A1 and Class A2

The Distributor shall conduct a penetration or capacity check on the existing Distribution System. Depending on the outcome, the Distributor may conduct a number of additional tests during their initial Technical Assessment, being:

- Power quality checks (fluctuation/distortion/voltage rise) on the Distribution System;
- System strength testing;
- Distribution System voltage control;
- Operating power factor or voltage control mode;
- Distribution System infrastructure thermal capacity;
- Distribution System and interconnection protection; and
- Fault current contribution for rotating machines.

5.7 Technical Assessments – Class B

Class B Technical Assessments are carried out for those EG systems identified as Class B in Table 2. The following items shall be addressed for all connections of EG systems within the Distribution System:

- Distribution System safety and security;
- Distribution System and interconnection protection;
- Distribution System infrastructure thermal capacity;
- Distribution System voltage control;
- Fault level contribution;
- Operating power factor or voltage control mode;
- Quality of supply;
- System strength;
- Distribution System stability; and
- Operational capability (planned and unplanned).

Prior to the connection of an EG system to the Distribution System, the Distributor shall carry out a detailed Technical Assessment of the impact of that connection on the Distribution System. The detailed Technical Assessment and subsequent engineering report shall identify any Distribution System operating constraints, Distribution System reinforcement/augmentation requirements due to increases in fault levels, levels of reactive support and impact on system strength having regard to AEMO guidelines under rule 4.6.6 of the NER, Distribution System voltage compensation control, operating protocols and interface requirements between the EG system and the Distributor for the proposed connection.

Schedule 5.2 of the NER sets out various technical requirements applicable to EG systems. These are relevant to all of the Class B EG systems, regardless of size. EG systems that connect under Chapter 5 of the NER shall use the Minimum Short Circuit Ratio (MSCR) method to calculate and assess the system strength in accordance with the System Strength Impact Assessment Guidelines of AEMO.

These technical requirements are the "access standards" that shall be met by the EG system in order to connect. Access standards are divided into "automatic access standards" (the default position), "negotiated access standards" (a negotiated position) and "minimum access standards" (the minimum requirement for a negotiated access standard"). Further information on this is set out in Table 3.

Table 3 Access Standards Explanation

Access Standard	Explanation
Automatic	EG systems that meet the automatic access standard for a technical parameter shall not be denied access to the Distribution System based on that technical parameter. This is the default requirement for all EG systems.
Minimum	This access standard is the minimum technical level of performance that the Distributor shall consider for connection to the Distribution System. EG systems that do not meet the minimum access standard shall be denied access to the Distribution System.
Negotiated	Where an EG system is incapable of meeting the automatic access standard, the Proponent and the Distributor may agree on a lower access standard. This negotiated access standard shall be as close as possible to the automatic access standard, and cannot be any lower than the relevant minimum access standard. Note that some negotiated access standards shall be reviewed not only by the Distributor but also by AEMO and the transmission network service provider, Powerlink Queensland

6 General EG system requirements (all Classes)

6.1 General

The design of all EG systems shall take into account both the Distribution System performance requirements and the specific requirements for the EG system equipment and the installation.

6.2 Device approval and compliance

6.2.1 General

This section sets out device approval and compliance requirements for Class A1, Class A2 and Class B EG systems.

6.2.2 Protection equipment

Protection equipment shall have certified compliance with the relevant provisions of IEC 60255 and shall operate the relevant Isolation Device either directly or through interposing equipment that also complies with:

- IEC 60255-1 Common requirements;
- IEC 60255-26 EMC requirements;
- IEC 60255-27 Product safety requirements;
- IEC 60255-127 Functional requirements for over/under voltage protection; and

  For EG systems requiring power limiting protection as per Section 7.3.2
- IEC 60255-12 Directional relays and power relays with two input energizing quantities.

Marshalling of protection trips through control equipment shall be compliant with IEC 60255.

The instrument transformers used to interface the protection equipment with the Proponent's installation shall have certified compliance with:

- AS 60044.1 Current transformers;
- AS 60044.2 Inductive voltage transformers; and
- AS 60044.3 Combined transformers.

6.2.3 Rotating EG systems

All EG systems that contain a rotating machine EG unit shall have certified compliance with:

- AS 60034.1 Rotating electrical machines, Part 1: Rating and performance; and
- AS 60034.22 Rotating electrical machines, Part 22: AC generators for reciprocating internal combustion (RIC) engine driven EG sets

6.3 Distribution System equipment ratings

The ratings of equipment both within the Distribution System and the Proponent's side of the Connection Point shall not be exceeded when the EG system operates in parallel with the Distribution System.

6.4 Equipment selection

Equipment shall be selected and designed so that maintenance and testing of any equipment can be carried out without any adverse impacts on the performance of the overall EG system and Distribution System.

6.5 Fault levels and protection impacts

6.5.1 General

In designing the EG system, protection systems shall be used to manage faults and abnormalities:

- Within the EG system's generating unit(s);
- Within the Proponent's installation associated with the EG system;
- In the vicinity of the Connection Point; and
- In the wider Distribution System.

Fault levels shall not exceed the equipment rating of the EG system, associated switchgear and protection equipment. Where the EG system is able to contribute to fault levels, the Distributor may:

- Conduct fault studies inclusive of faults in the Proponent's installation and the Distribution System; and
- Provide the Proponent with the existing fault levels and protection equipment ratings to assess whether the design of the EG system exceeds relevant equipment ratings.

Where it is determined that the design of the EG system has the potential to raise the fault levels on the Distribution System beyond the capacity of the Distributor's protection device(s), the Proponent shall meet the cost to upgrade the protection device(s) and any impacted Distribution System assets. The Proponent shall ensure that its switchboard and equipment can withstand the total prospective fault currents.

6.5.2 Fault level considerations for rotating machines

Where a site has an EG system with multiple rotating machine generating units, the fault current contribution can be significant for both export and non-export systems. As such, the Distributor shall assess the impact of the fault current on their Distribution System assets for rotating machine systems.

Bumpless transfer EG systems shall have fault levels considered only at the secondary (lower voltage of the step-up transformer) Distribution System level.

Standby EG systems shall have a pro-rated factor applied to the prospective fault levels, where the factors is dependent on the number of EG systems connected to the relevant part of the Distribution System at the same time.

Continuous parallel EG systems shall have fault levels considered for both primary and secondary Distribution Systems.

6.6 Means of isolation

The Proponent shall provide a means of isolation that is capable of disconnecting the entire EG system from the Distribution System. Where the EG system is an aggregate of smaller distributed EG systems, multiple isolation points may exist. The means of isolation shall be able to be locked in the open position only.

Where the auxiliary supply to the EG is from a separate Distribution System connection rather than the main EG system Connection Point, this shall be clearly identified in the approved drawings as well as in the SCADA system. The separate connection for auxiliaries shall only be through a dedicated distribution substation LV connection and shall be implemented and charged as per standard LV connection practices.

6.7 Operating voltage and frequency

6.7.1 Standard power system voltage

Available voltage for connection is dependent on the location and EG system capacity. Ergon Energy and Energex HV Distribution Systems normally include systems operating at 132 kV, 110 kV, 66 kV, 33 kV, 22 kV and 11 kV.

EG systems shall comply with the voltage control requirements in AS/NZS 60038 and AS/NZS 61000.3.100.

6.7.2 Lightning insulation levels for surge arrestors

The Proponent shall (at a minimum) install surge arresters at the Connection Point. The minimum insulation levels and voltage ratings for the surge arresters are given in Table 4.

Table 4 Lightning impulse withstand voltages for surge arrestors

Distribution System voltage (kV)	Lightning impulse withstand voltage (kVp)	Nominal surge arrestor rating (kV)
11	95	12
22	150	24
33	200	36
66	325	60
110	550	96
132	650	120

6.7.3 Standard power system frequency

The performance standards for power frequency variations are governed by the NER and the Frequency Operating Standards published by the AEMC[1], as given in Table 5.

Table 5 Frequency Standard (Except islands)

Condition	Containment	Stabilisation	Recovery
Accumulated time error	15 seconds		
No contingency event or load event	49.75 to 50.25 Hz*, 49.85 to 50.15 Hz 99% of the time^	49.85 to 50.15 Hz within 5 minutes	
Generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Distribution Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Protected event / Multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

^ - This is known as the normal operating frequency band.
* - This is known as the normal operating frequency excursion band.

The frequency standards in Table 6 apply where a part of the National Grid becomes islanded. This table does not strictly apply to Isolated Distribution Systems.

[1] AS/NZS61000.2.2 details that the frequency range is typically plus or minus 1 Hz, but it is usually much less where synchronous interconnection is used on a continental scale. This requirement is overridden by the National Electricity Rules.

Table 6 Frequency Standard for National Grid - Island Conditions

Condition	Containment	Stabilisation	Recovery
No contingency event or load event	49.5 to 50.5 Hz		
Generation event, load event or Distribution Network event	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
The separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Protected event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 52 Hz (reasonable endeavours)	49.0 to 51.0 Hz within 2 minutes (reasonable endeavours)	49.5 to 50.5 Hz within 10 minutes (reasonable endeavours)

7 Class A1 and Class A2 EG system requirements

7.1 General

Section 7 covers the requirements for Class A1 and Class A2 EG systems as defined in Section 5.4. Protection requirements for Class A1 and Class A2 are found in Section 8.

7.2 Inverter systems

7.2.1 General

Guidance on voltages, power quality modes and settings for LV inverters is found in STNW1174 / STD 01618.

The inverters in Class A1 EG systems shall have certified compliance with AS/NZS 4777.2 and IEC62116 Edition 2. Class A2 system may require certified compliance with AS/NZS 4777.2 and IEC62116 Edition 2 to be determined in the Technical Assessment. Where the EG system is ≤ 200 kVA, they shall also comply with AS/NZS 4777.1.

7.2.2 Power limiting controls

Where the EG system is approved by the Distributor as a non-export or partial-export system, it shall be fitted with export power limiting control that limits the level of electricity exported at the Connection Point to the amount set out in the Connection Agreement. Where this control is implemented within the IES generating unit, it shall comply with section 3.4.8 of AS/NZS 4777.1 using a soft limit. Further details are set out in Table 7 below.

Table 7 Power limiting settings for IESs

	Non-export	Partial-export
Export power limit	0 kW[1]	*n* kW[1,2]

Note 1 – A measurement tolerance of +5 % of the rated size of the EG system for the set export power limit is allowable for compliance with this Standard. For example, a 100 kW non-export EG system can have measured export of up to 5 kW at the Connection Point for durations longer than 15 seconds and any export above 5 kW shall occur for no longer than 15 seconds.

Note 2 - *n* is equal to the approved partial-export power limit for the EG system. For example, where the approved partial-export value is 50 kW of a 100 kW IES, *n* = 50 kW.

Where export limiting is implemented within a relay not part of the generating unit, It shall comply with AS60255-12.

7.2.3 Multiple inverters

Where the EG system comprises multiple inverters:

- There shall be an overall protection scheme for the Connection Point in addition to protection for each inverter;
- There shall be balanced inverter output between phases at all times with respect to the Connection Point whilst connected to the Distribution System. There shall not be an unbalance of any more than 5 kVA between phases; and
- All inverters on all three phases of the EG system shall simultaneously disconnect from, or connect to, the Distribution System in response to the operation of the protection scheme due to a protection event.

7.2.4 Power control

EG systems shall be capable of injecting or absorbing reactive power. The Distributor shall specify the acceptable operating power factor setting or mode as part of the Technical Assessment, and this shall be recorded in the Connection Agreement.

IES EG systems shall operate between 0.95 leading and 0.9 lagging at the Connection Point with a preference for a volt-var response mode. The required mode shall be specified in the Connection Agreement following the Technical Assessment.

7.3 Rotating machine systems

7.3.1 Power control

EG systems shall be capable of injecting or absorbing reactive power. The Distributor shall specify the acceptable operating power factor setting or mode as part of the Technical Assessment, and this shall be recorded in the Connection Agreement.

An EG system comprising a rotating machine EG unit(s) shall be designed and operated to adequately control real and reactive power output to achieve a power factor at the Connection Point of greater than 0.8 lagging and not leading, unless otherwise agreed by the Distributor.

7.3.2 Power limiting control

Where the EG system has been approved by the Distributor as either a non-export or partial-export system, reverse power or power limit controls (respectively) shall be installed at the Connection Point. Any power limiting control settings shall be approved by the Distributor as part of the Technical Assessment.

7.4 Coordination of EG systems with Distribution System operation

The Distributors apply an automatic feeder re-closing scheme on the majority of their Distribution System. Automatic re-energisation of the feeder during this process opens the circuit breaker (with minimum delay) following a power system fault, and then attempts to automatically re-energise the feeder component after a predefined disconnected time (dead time). Automatic reclosing can happen multiple times depending on the Distribution Network location.

The EG system shall disconnect within this dead time upon a loss of mains power to ensure safe restoration. Failure of the EG system to so disconnect when there is a loss of supply from the Distribution System may result in damage to the EG system.

When the system voltage has been restored on the Distribution System side of the Connection Point, and the voltage and frequency have been maintained within protection limits for a period of greater than 60 seconds, the EG system may reconnect with the Distribution System.

The EG system shall incorporate either automatic or operator-controlled equipment that ensures that the frequency, voltages, and phase sequence of the EG system is identical with (synchronised to) those in the Distribution System before it connects to the Distribution System. The EG system shall not reconnect until it is synchronised with the Distribution System.

Disturbance ride-through capability may be required for Class A2 systems if determined by the Technical Assessment. Where disturbance ride-through capability is required for Class A2 systems it shall be based on the criteria for Class B systems.

A Grid Isolation Device (GID) shall be installed on the Distributor's assets for Class A2 EG systems and may be required for Class A1 EG systems if determined by the Distributor from its Technical Assessments.

The GID is to ensure a single point of isolation for Distribution System protection. It shall be either a HV Automatic Circuit Recloser (ACR) or a HV circuit breaker within a switchboard with associated protection and control mechanisms. The GID shall have protection and synchronising facilities that grade with the downstream devices. The GID protection settings shall look at the Distribution System protection as its primary function rather than being a backup protection device for the EG system. The GID shall be owned and operated by the Distributor and incorporate remote communications to it. In the instance of the use of a HV circuit breaker as a GID, the protection and control of the circuit breaker for Distribution System protection shall be owned and operated by the Distributor.

7.5 Power Quality Assessment

An allocation of both voltage fluctuation and harmonic (voltage and current) limits shall be provided as part of the Technical Assessment.

Voltage fluctuation shall ensure compliance with S5.1a.5 of the NER and assessment methodology in AS/NZS 61000.3.7:2001. The Proponent shall ensure compliance with the harmonics and inter-harmonics levels in the Connection Agreement, to meet compliance with S5.1.6 of the NER and AS/NZS 61000.3.6:2001.

Additional details on the compliance levels shall be given by the Distributor through the Technical Assessment and Connection Agreement.

A dedicated power quality meter may be required to be installed for Class A2 systems and will be determined at the Technical Assessment. Where a power quality meter is required the following shall apply:

- Measurement to be based at the Connection Point; and
- Installed, owned and managed by the Distributor; and
- The Proponent to bear the cost to establish the power quality meter.

8 Protection and operational requirements for Class A1 & Class A2

8.1 General protection requirements

The protection requirements outlined in this Section 8 are in relation to the protection of Distributor assets and personnel, and are not intended to replace or override any of the protection specifically required for the Proponent's installation and EG system. Testing and commissioning of the protection shall meet the requirements outlined in Section 14.1 of this Standard.

The protection schemes for Class A1 & A2 EG systems shall be designed with main and backup protection designed to detect all credible AC fault types.

In the event of a loss of supply from the Distribution System, EG systems shall not be able to operate connected to the Distribution System, unless this has been explicitly approved by the Distributor. To prevent the EG system operating connected to the Distribution System, a Distributor-approved protection scheme or schemes shall be installed.

In addition to the protection installed for the EG system, the Proponent shall install a protection system so that:

- The EG system cannot connect to the Distribution System unless all phases of the Distribution System are energised at the Connection Point. The connection shall ensure synchronisation before closure. If one or more phases of the Distribution System are lost, then the EG system shall disconnect from the Distribution System;
- It operates within the protection settings agreed with the Distributor;
- If a system abnormality occurs that results in an unacceptable deviation of voltage or frequency at the Connection Point, the EG system shall be disconnected from the Distribution System; and
- The EG system is to automatically disconnect from the Distribution System in the event of failure of any auxiliary supplies to the protection equipment that would inhibit its correct operation.

When any of these conditions are detected, the EG system shall be disconnected from the Distribution System at an agreed Isolation Device within the Proponent's facility that ensures complete disconnection.

Bumpless transfer EG systems do not require Technical Assessment for the effect of increased thermal or fault ratings on the Distribution System.

8.2 Remote or Transfer Trip (Inter-tripping)

The Proponent's design shall not require an inter-trip from the Distributor. The Distributor may send a backup control signal to the Proponent's control system for it to take immediate action through the SCADA system.

8.3 Grid Protection Relay

The protection system for the EG system shall contain a Grid Protection Relay (GPR) at the Connection Point that shall meet the following requirements:

- Be based on a measurement at the upstream of all generation sources;
- Provide under voltage, over voltage, under frequency, over frequency and ROCOF protection designed to meet the requirements of this Standard;
- Be integrated in such a way that it fails safe, and not allow generation whilst the protection is out of service; and
- Open the Isolation Device at either the Proponent's Connection Point or EG system.

The GPR shall be configured to meet the functions specified for inverter energy systems and rotating machines in Table 9.

8.4 IES EG protection arrangements

A typical protection arrangement for a Class A1 EG system is shown below.

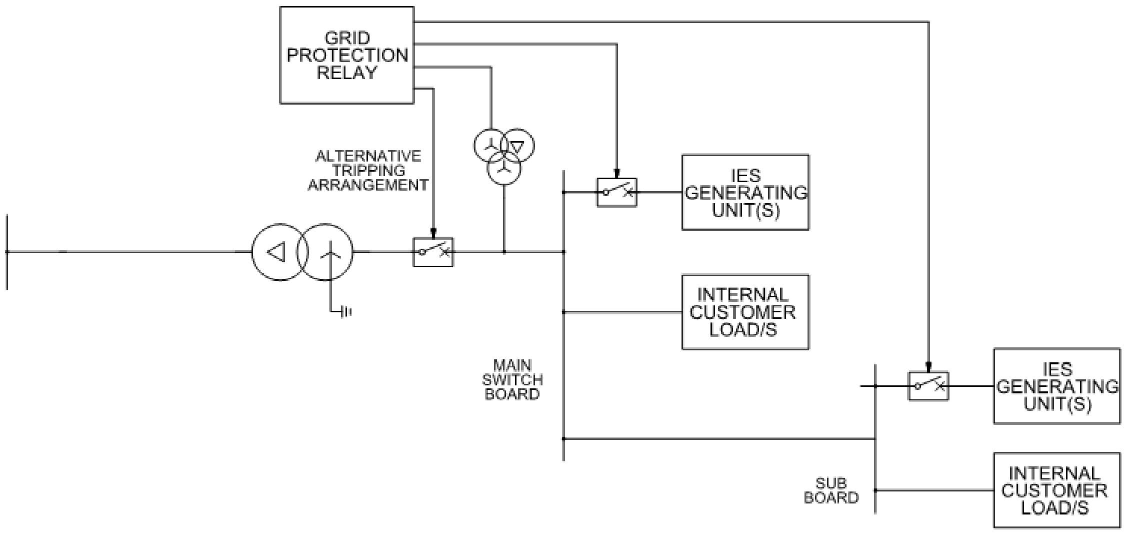

Figure 1 Typical protection arrangement for Class A1 IES EG systems

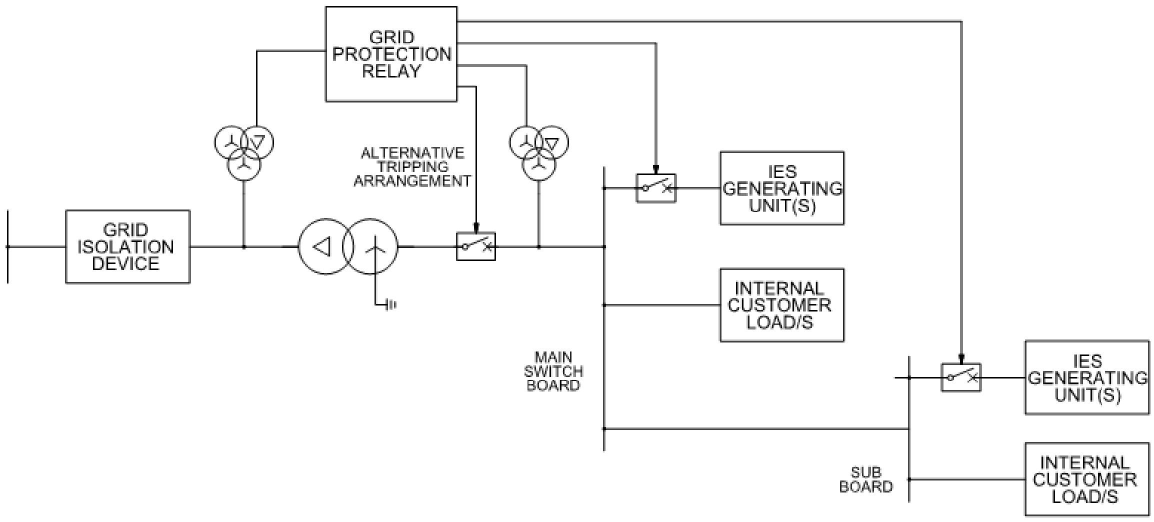

Figure 2 : Typical protection arrangement for Class A2 IES EG systems

8.5 Over current and earth fault protection

Overcurrent and earth fault protection shall also be provided at the EG system in accordance with AS/NZS 3000 for the LV components. This protection shall be set to detect faults within the Proponent's installation. This protection shall coordinate with the protection scheme of the Distribution System.

8.6 Isolation Device fail protection

Loss of mains and Anti-islanding protection scheme design shall make allowance for the failed operation of the Proponent's Isolation Device. The Proponent need not provide a backup Isolation Device for the GID.

The protection scheme shall not operate the same Isolation Device for both primary and backup protection. There may be multiple Isolation Devices for either primary or backup protection.

8.7 Loss of mains protection

The EG system shall be automatically disconnected from the Distribution System whenever there is a loss of supply from the Distribution System.

All EG systems shall have a GPR protection device for loss of mains protection.

Additionally, IES EG systems shall have:

- Passive and active Anti-islanding protection achieved through the installation of inverters accredited to AS/NZS 4777.2 and IEC 62116 Edition 2 for IES systems (only IEC 62116 required for Class A2 Inverter systems); and
- Neutral Voltage Protection (NVD) for Class A2 systems.

NVD protection is required to ensure that an EG system disconnects if there is a HV Distribution System earth fault. NVD protection requires either phase-neutral or an open delta voltage measurement of the HV Distribution System. The selection of the HV voltage transformer for NVD protection shall ensure compatibility with GPR functionality.

8.8 Voltage protection

The Proponent shall install under and over voltage protection to monitor all three phases at the Connection Point. This protection shall be set to detect if the voltage exceeds predetermined limits that shall be based on the proposed connection arrangement and operating requirements at this point. The voltage protection shall be based on the HV phase to phase voltage even if the measurement is on the LV.

8.9 Frequency protection

The Proponent shall install under and over frequency protection at either the Connection Point or the EG system. The frequency protection tripping shall be based on the proposed connection arrangement and operating requirements, as outlined in the Connection Agreement. The protection frequency settings shall be determined at the design stage, and are subject to the results of the Technical Assessment. Any backup protection should grade over the EG unit settings.

8.10 Unbalance protection

Negative sequence voltage and current protection may need to be installed and appropriate settings applied at the EG system to protect against voltage and current unbalance from the Distribution System and/or the Proponent's Network.

8.11 ROCOF protection

The Proponent shall ensure that:

- The EG system is fitted with a ROCOF relay to monitor frequency excursions and control the disconnection of the EG system from the Distribution System; and
- The ROCOF operates to prevent an island being formed when there is a loss of supply from the Distribution System.

Where the calculated value is greater than 3 Hz/s, the Proponent shall consult the Distributor.

8.12 Wireless transfer

Where an EG system's GPR and export monitoring device is remote from the EG system's Isolation Device or inverters, a wireless communication system may be used. A GPR and export monitoring device utilising a wireless communication system shall:

- Have a supervised wireless communications link;
- Consider in terms of reliability, availability and redundancy; and
- Disconnect the EG unit(s) from the Distribution System for any loss of communications longer than 5 seconds.

8.13 Rotating machine systems – additional protection requirements

All rotating EG systems shall have NVD protection for loss of mains protection. NVD protection requires equipment to be installed on the Distributor's assets.

For EG systems comprising rotating machines, the overcurrent and earth fault protection relays shall provide compensation for under voltage field weakening. Compensation for under voltage field weakening is not required where the Proponent can demonstrate that voltage depression at the EG system during fault events shall not adversely impact on the operation of the protection scheme. Unless this can be demonstrated, Voltage Controlled Overcurrent (VCO) functionality shall be incorporated to the GPR for rotating machine systems (refer to Table 9).

8.13.1 Rotating machine systems – protection arrangements

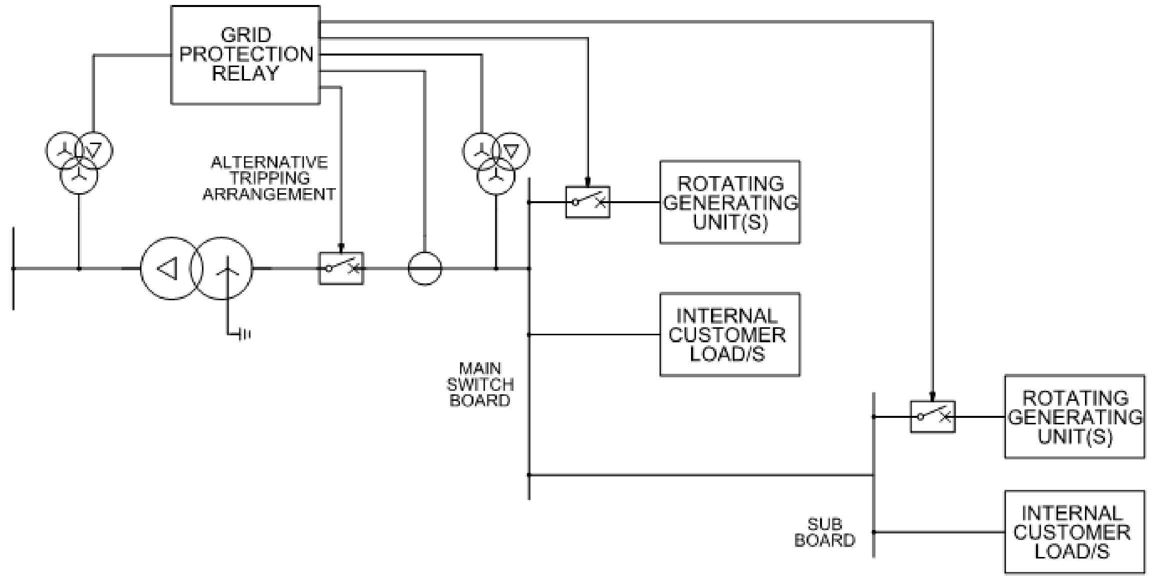

Figure 3: Typical protection arrangement for Class A1 rotating machine EG systems

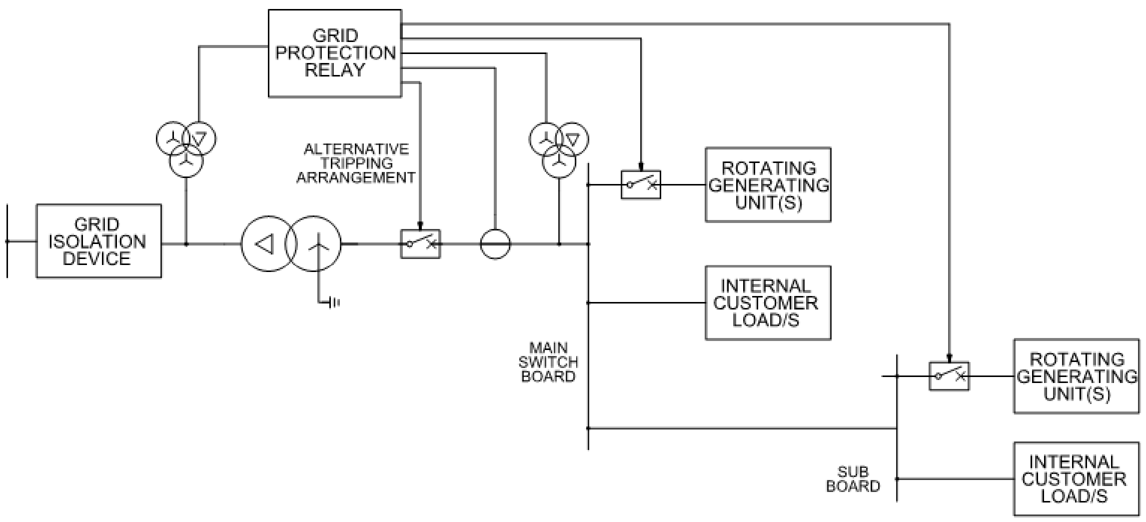

Figure 4 : Typical protection arrangement for Class A2 rotating machine EG systems

8.14 Exemptions

Due to the reduced risk associated with certain EG system configurations, the following configurations are exempt from particular protection requirements of this Standard, as set out below:

- Asynchronous (Induction) EG systems with ratings not exceeding 200 kW does not specifically require NVD protection;
- Rotating machine systems under 200 kW does not specifically require equipment installed on the Distributor's assets for NVD protection and can be installed at the Proponent's assets;
- EG systems with bumpless transfer operation are not required to have NVD protection, loss of mains protection or backup Anti-islanding protection; and
- EG systems with standby operation are not required to have NVD protection.

8.15 Grid Isolation Device setting

The HV ACR or the circuit breaker owned by the Distributor shall be configured to meet the requirements of Section 7.4 and have the following functions in Table 8.

Table 8 Distributor Grid Isolation Device Protection Functions

Protection functional description	ANSI/IEEE C37.2 Code	IEC 60617 Code
Overcurrent (OC)	51	I>
Earth Fault (EF)	51G	I0>
Under voltage (UV)	27P	U<
Over voltage (OV)	59P	U>
Neutral voltage displacement (NVD)	59N	U0>
Negative sequence current	46	I2>

8.16 GPR settings

The GPR shall be configured with the functions specified in Table 9. For requirements, refer to section 8.3. Refer to Ergon Energy / Energex – STNW1174 / STD 01618 - Standard for Connection of Embedded Generating Systems to a Distributor's LV Network for guidance of specific settings that may apply.

Table 9 EG Grid Protection Functions

Protection functional description	ANSI/IEEE C37.2 Code	IEC 60617 Code
Level 1 backup protection		
Under voltage (UV)	27P	U<
Over voltage (OV)	59P	U>
Under frequency (UF)	81U	f<
Over frequency (OF)	81O	f>
Rate of change of frequency (ROCOF)	81R	df/dt
Loss of mains protection – additional requirements		
Neutral voltage displacement (NVD)[1]	59N	U0>
Non-export rotating EG systems		
Directional power	32	P→
Other methods that may be required depending on the outcome of Technical Assessment of the Proponent's rotating machine EG system design		
Voltage Controlled Overcurrent (VCO)	51V	I(U)>

Note 1 : See NVD exemptions in Section 8.14.

9 EG system requirements for Class B

9.1 General

The default requirement is that EG systems having an aggregate nameplate rating of over 5 MW shall comply with the automatic access standard. Non-export EG systems over 5 MW could be exempted from some requirements relating to Class B, if the EG system obtains an exemption from AEMO from registering as a Generator.

The Proponent shall meet additional requirements to this Standard as required by the NER where:

- Registration is required as a Generator for the EG system (refer to AEMO guide for Generator Registration); or
- For systems over 30 MW or as deemed relevant from applicable NER rules at the time of connection.

9.2 Technical requirements overview

The following Table 10 highlights the NER references and the associated performance requirements.

Table 10 Technical requirements overview

Technical Requirement	NER reference	Compliance Standard Required / Additional Comments
Reactive power capability	S5.2.5.1	Automatic access Standard
Quality of supply	S5.2.5.2	Refer section 9.3
Response to frequency disturbance	S5.2.5.3	Refer section 9.4
Response to voltage disturbance	S5.2.5.4	Refer section 9.5
Response to disturbances following contingency events	S5.2.5.5	Refer section 9.6
Quality of electricity and continuous uninterrupted operation	S5.2.5.6	Refer section 9.3
Partial load rejection	S5.2.5.7	Automatic access standard
Protection of generating systems from power system disturbances	S5.2.5.8	Refer Section 9.7
Protection systems that impact on power system security	S5.2.5.9	
Protection to trip plant for unstable operation	S5.2.5.10	
Frequency control	S5.2.5.11	Refer Section 9.8
Impact on Network capability	S5.2.5.12	Refer Section 9.9

Technical Requirement	NER reference	Compliance Standard Required / Additional Comments
Voltage control	S5.2.5.13	Refer Section 9.10
Active power control	S5.2.5.14	Refer Section 9.11

9.3 Quality of supply

9.3.1 Power quality monitoring

Where the EG system is of asynchronous generating unit(s), the Proponent shall fund the installation of a power quality meter within the Distribution System.

9.3.2 Voltage fluctuations

Voltage fluctuation (flicker, rapid voltage change) shall be through the compliance of S5.1a.5 of the NER and assessment methodology in AS/NZS 61000.3.7:2001. Additional details on the compliance levels shall be given by the Distributor through the Technical Assessment and Connection Agreement.

9.3.3 Voltage harmonics

The Proponent shall ensure compliance with the harmonics and inter-harmonics levels in the Connection Agreement, which shall be designed to target compliance with S5.1.6 of the NER and AS/NZS 61000.3.6:2001.

9.3.4 Voltage unbalance

The Proponent shall ensure compliance with the requirements of S5.1.7 of the NER. For the purposes of that rule, the voltage unbalance limits determined in S5.1a.7 are set out in Table 11 below.

Table 11 Voltage unbalance limits

Nominal supply voltage (kV)	Maximum negative sequence voltage (% of nominal voltage)			
	no contingency event	credible contingency event or protected event	general	once per hour
	30 minute average	30 minute average	10 minute average	1 minute average
More than 100	0.5	0.7	1.0	2.0
More than 10 but not more than 100	1.3	1.3	2.0	2.5
10 or less	2.0	2.0	2.5	3.0

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Proponents need to comply with the automatic access standard in S5.2.5.6 of the NER, which requires the EG system to remain connected for the specified values of voltage fluctuation, harmonic voltage distortion and voltage unbalance at the Connection Point.

9.4 Response to frequency disturbances

Table 12 provides power frequency disturbance guidelines under S5.2.5.3 of NER for which the Distributor shall use to determine the level of access standard for the EG system.

Table 12 Frequency disturbance standard

Access standard	Requirement
Automatic	Continuous uninterrupted operation within the given ranges in accordance with Figure 5 Automatic Access
Minimum	Continuous uninterrupted operation within the given ranges with reduced timing and in accordance with Figure 5 Minimum Access.
Negotiated	Operation as close to the automatic access standard without impacting on quality of supply.

As noted previously, the default access standard is the automatic access standard, which requires the EG system (and its component units) to be capable of continuous uninterrupted operation within the relevant ranges set out below in Figure 5 below.

Where the EG system is demonstrated to be incapable of meeting the automatic access standard, a negotiated access standard may be agreed, which shall be as close as possible to the automatic access standard, and cannot be any less onerous than the minimum access standard.

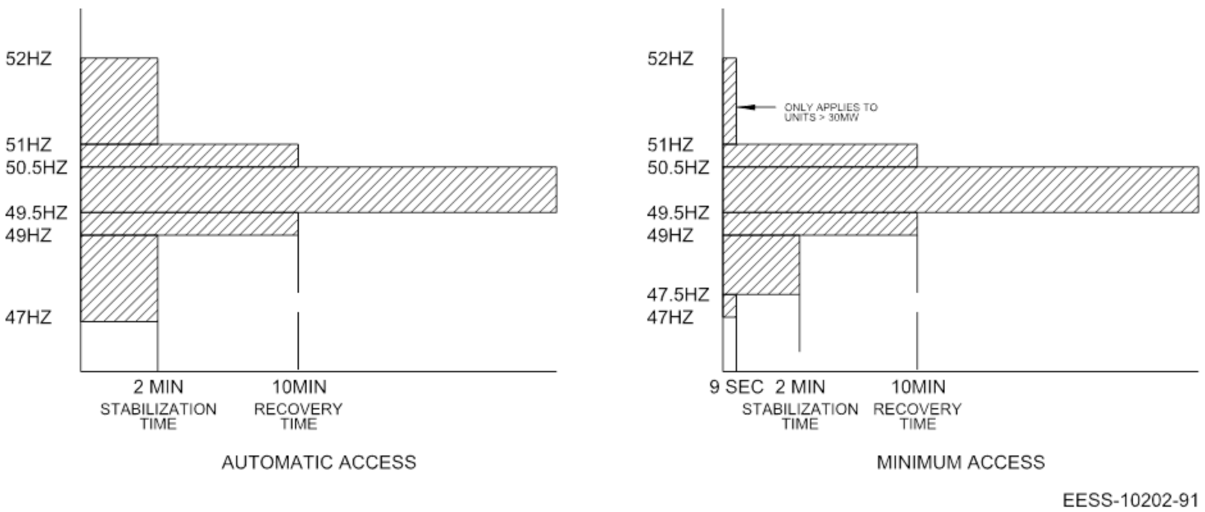

Figure 5 Frequency access levels

The Proponent shall provide details of the over and under frequency protection, steady state frequency range operating capability and maximum ROCOF operating capability of the EG system.

9.5 Response to voltage disturbances

The Proponent shall provide to the Distributor:

- Details of over and under voltage protection and their settings/limits;
- A curve (similar to Figure S5.1a.1 of the NER) which shows the range of voltages the EG system can ride through and remain connected for that range; and
- Details of the EG system's voltage operating capability.

Note the generator terminal voltage and the Connection Point voltage may not necessarily be the same. The Technical Assessment shall demonstrate that the Connection Point voltage requirements can be complied with for the settings applied at the EG system.

The Proponent shall have protection in place to trip the EG system where all three line to line voltages are below 0.85 p.u and the EG system is absorbing inductive reactive power. This is to prevent the EG system from impeding Distribution System voltage recovery after a fault. In addition, the EG system shall not cause nearby LV Networks to exceed the operating range.

The ranges of response detailed as part of the automatic access standard under S5.2.5.4 of the NER are shown below.

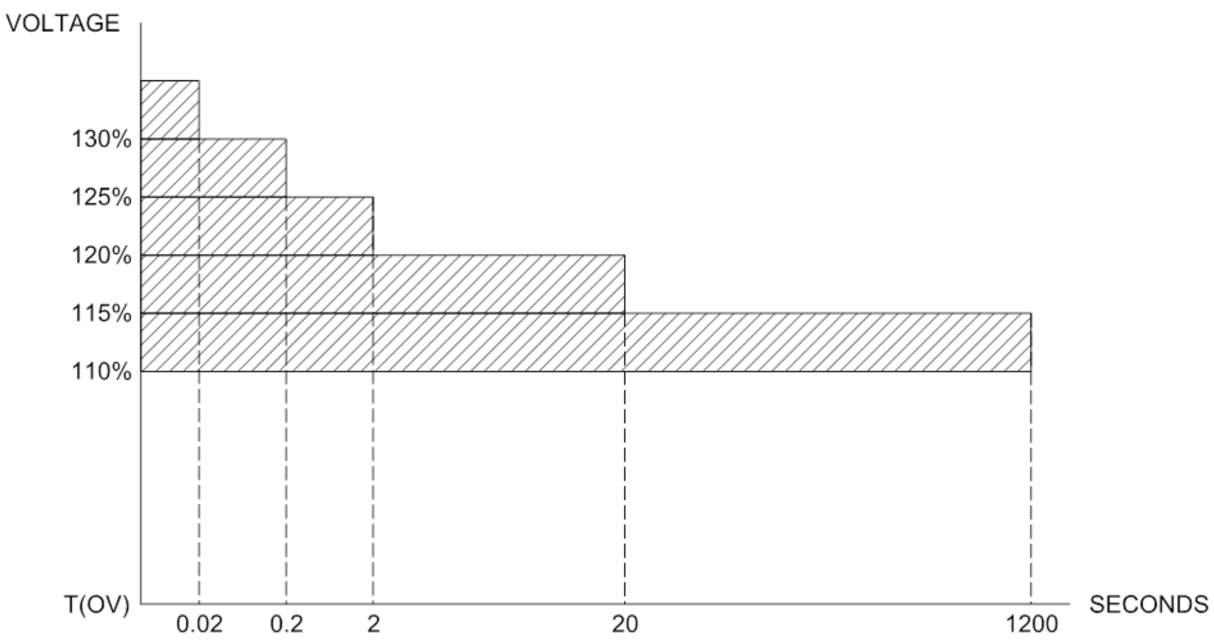

Figure 6 Response to a voltage disturbance over 110% (automatic access)

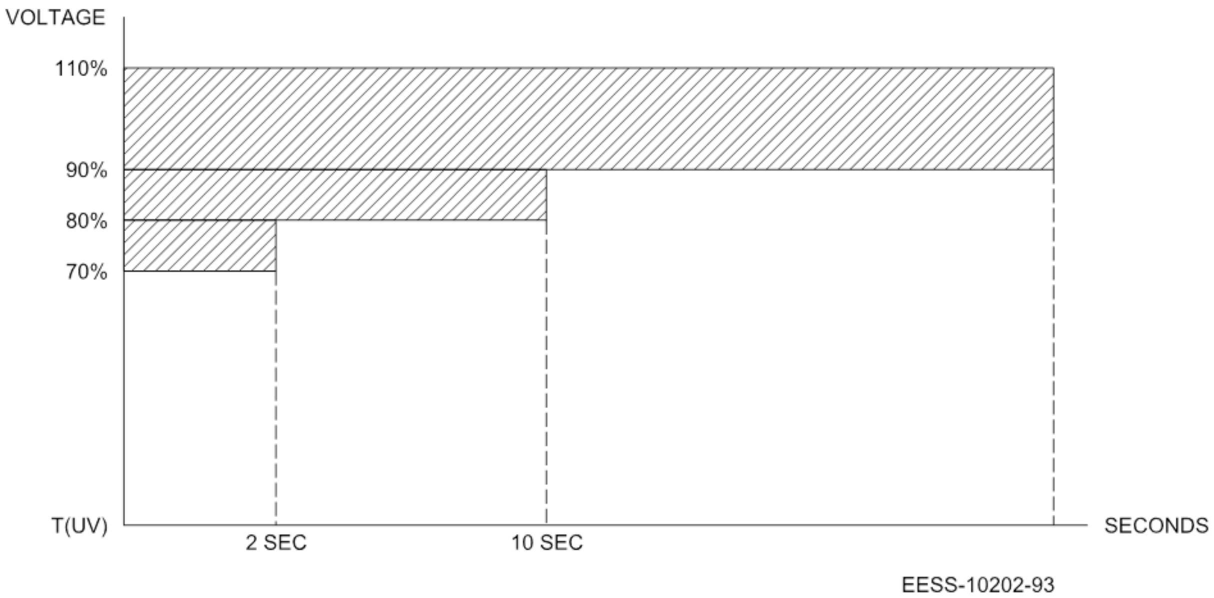

Figure 7 Response to a voltage disturbance under 90% (automatic access)

9.6 Response to disturbances following contingency events

Clause S5.2.5.5 of the NER requires the EG system to remain in continuous uninterrupted operation through credible contingency events and Distribution System faults.

The Proponent shall conduct time domain dynamic studies showing the EG system's capability to remain connected for the range of faults described in the automatic access standard for synchronous or asynchronous generating systems. The studies should cover a range of operating conditions such as, but not limited to, the following:

- Various power generation levels and a range of Distribution System conditions;
- Selected Distributor equipment or EG system out of service;
- Distribution System conditions resulting in reactive current limits being reached;
- Low and high impedance faults; and
- High and low level of interconnector transfer conditions.

Operational arrangements such as control settings for the EG system's terminal voltage or transformer tap changers shall meet the agreed level of performance.

9.7 Protection requirements

9.7.1 General protection requirements

Protection of the EG system and the Distribution System shall be in accordance with the NER and other relevant Energy Laws and standards and coordinated with the Distributor. Sufficient redundancy needs to exist in the protection system so that the protection scheme is able to operate with any single component out of service. This also applies to the DC systems, including batteries, chargers, and distribution boards that power the scheme. This requirement applies to the EG system as well as the other Distribution System connected equipment such as a utility substation (unless the Distributor specifically rules that this is unnecessary). The Proponent shall bear the cost to establish the protection system to the Standard.

Inverter systems with their fault ride through mode may need to simulate and demonstrate performance compliance with the anti-islanding mode on or off. The Distributor reserves the right to prescribe islanding protection requirements in the detailed design stage. The following is a minimum requirement for protection design which does not take into account site-specific constraints.

Where the connection between the EG system and the Distributor is a dedicated line terminating at the Distributor's zone substation busbar and the line is:

- Owned by the Distributor:
  - Full duplicate and diverse protection devices and related communications equipment owned and operated by the Distributor;
  - Duplicate DC supply to the protection relays and communications equipment; and
  - Dedicated CT and VT secondary winding; or
- Owned and operated by the Proponent:
  - Duplicate protection schemes that are compatible with the protection schemes employed by the Distributor at the supplying HV substation. The Proponent's protection scheme shall be coordinated with that of the Distributor.

Where the line between the EG system and the Distributor is not dedicated to connecting the EG system, the Distributor shall have a switching station with:

- One or more circuit breakers depending on the configuration and operational requirements of the Distributor;
- Full duplicate and diverse protection devices and related communications equipment;
- Duplicate DC supply to the protection relays, communications equipment and circuit breaker; and
- CT's and VT's with secondary winding available for protection and metering purposes.

9.7.2 Protection of EG systems from power system disturbances

S5.2.5.8 of the NER states that the EG system shall have sufficient operational protection systems that disconnect and prevent damage to the EG system or the Distribution System from a power system disturbance. Table 13 provides guidelines which the Distributor shall use to determine the level of access standard applicable for the EG system.

Table 13 Protection of generating systems from power system disturbances access

Access Standard	Requirement
Minimum	Plant protection and control system shall keep the EG system connected under abnormal conditions as required by the relevant provisions of the NER unless it is required to trip to: • disconnect any faulted element in its system (S5.2.5.9); or • prevent a condition that would lead to unstable operation (S5.2.5.10).

Anti-islanding protection may also be specified as an additional requirement by the Distributor. Conditions of trip and other performance conditions shall be specified in the Connection Agreement. The Distributor is not liable for loss or damage incurred by the EG system as a result of the fault on either the power system or the EG system's facility.

The minimum protection requirements are outlined in:

- Class A1/ A2 systems in this Standard; and
- If additional protection and SCADA schemes are required, the Distributor shall notify the Proponent after conducting the review of the Technical Assessment.

The Proponent shall provide the following:

- Protection single line diagram showing all the protection schemes including AC and DC circuits and circuit breaker tripping logic; and
- A report showing proper interface and coordination between the EG system and the Distribution System and confirmation that fault clearance times are as specified in Table S5.1a.2 of the NER.

9.7.3 Protection of EG systems from power system disturbances

S5.2.5.9 of the NER requires adequate levels of protection that prevent a fault in the EG system from compromising the Distributor's power system security. Table 14 provides protection system guidelines which the Distributor shall use to determine the level of access standard applicable for the EG system.

Table 14 Protection systems that impact on power system security access

Access Standard	Requirement
Automatic	EG system shall have redundant primary protection and breaker fail protection to disconnect the faulted element within the applicable fault clearance times given in the NER for any fault in the EG system and in protection zones that include the Connection Point.

Under the NER, the EG system shall provide primary, backup and breaker fail protection in accordance with the automatic access standard at the Connection Point. This is to ensure that the protection system is robust and reliable with as little impact on the rest of the power system as possible. The type of protection required is covered in Section 9.7.2.

9.7.4 Protection to trip EG system for unstable operation

S5.2.5.10 of the NER requires disconnection of the EG system for unstable conditions such as active power, reactive power or voltage instability at the Connection Point. Table 15 provides guidelines which the Distributor shall use to determine the level of access standard applicable for the EG system.

Table 15 Protection for unstable EG system operation access standard

Access Standard	Requirement
Automatic	The protection shall trip when active power, reactive power or voltage at the Connection Point becomes unstable as specified under rule 4.3.4(h) of the NER. For synchronous EG units, the protection system shall include disconnection under pole slipping conditions.

9.7.5 Fault current

S5.2.8 of the NER deals with fault current contribution to the Distribution System and the fault current withstand of the EG system and associated circuit breakers required to isolate it from the Distribution System. Table 16 provides fault current guidelines which the Distributor shall use to determine the level of access applicable.

Table 16 Fault Current access standard

Access Standard	Requirement
Automatic	The EG system does not produce fault currents in which the contribution exceeds the operational limits of the existing Distribution System lines and equipment. The EG system's connecting equipment shall be rated to the levels specified by the Distributor and could be the ultimate fault level of the Distribution System.

For EG systems with inverters, the sustained fault current contribution shall not exceed the rated current of the inverter(s). If this occurs then the use of short circuit current limiters shall be used in agreement with the Distributor.

9.8 Frequency control

Subject to the EG system output definition, in regards to scheduled, semi-scheduled or non-scheduled EG units, S5.2.5.11 of the NER reviews the power response of the EG system to an increase or decrease in Distribution System frequency.

The EG system shall not increase or decrease its power transfer for a rise or fall in the Distribution System frequency measured at the Connection Point respectively. The EG system shall be capable of operating in frequency response mode such that it can reduce or increase its power output in response to a rise or fall in system Distribution System frequency as measured at the Connection Point.

The EG system control system shall be adequately damped.

The Proponent shall provide the following:

- Details of the control system to be supplied, such as operating modes, topology, control system time constants, droop settings and operating dead bands; and
- Time domain dynamic studies showing the active power response to an increase or decrease in Distribution System frequency.

9.9 Impact on Distribution System capability

S5.2.5.12 discusses the impact on inter-regional and intra-regional power transfer as per Table 17.

Table 17 Impact on Distribution System capability access

Access Standard	Requirement
Automatic	No reduction in inter-regional and intra-regional transfer capability.

The impact on the Distribution System capability is ascertained by what happens to the local Distribution System when the EG system is connected. This is defined by EG system stability, Distribution System stability, Distribution System rating and inter-regional flow.

9.9.1 EG system stability

The Proponent shall carry out a time domain dynamic study on the EG system's response to a frequency or voltage disturbance on the Distribution System. The study shall include the response of the EG system to various Distribution System faults or conditions.

9.9.2 Distribution System stability

The study needs to show the dynamic response of the Distribution System to an EG system trip (or fault). For a prescribed trip (say instantaneous trip of the EG system), the Distribution System voltages shall not exceed voltage change limits and absolute limits. If they do then remediation measures need to be provided by the Proponent, as the EG system will cause the Distribution System to operate outside its prescribed boundaries. Otherwise, a limitation on generation operation may be applied.

9.9.3 Distribution System rating

The thermal response of the Distribution System feeders and equipment shall be included in the studies. Under worst case scenarios such as summer-high and summer-low the thermal loading of transformers, circuit breakers and feeders need to be shown with and without the connection of the EG system. This shall show if the EG system will have any impact on the Distribution System.

9.9.4 Inter-regional power flow

The inter-regional feeders can be assessed by comparing the transient stability power flow responses prior to the EG system connection and after the connection. For both cases the Distribution System has the same fault applied and the transient response waveforms are overlaid to show the impact. If they are identical, then this will indicate that there is no significant change/impact.

9.10 Voltage and reactive power control

S5.2.5.13 of the NER refers to the control of the voltage at the Connection Point. It considers the performance of the voltage control system and the ability of the EG system to increase or decrease its reactive power output due to a power system disturbance.

The NER has a number of detailed provisions surrounding the capability of the control system on the level of settling times, rise times and various other responses to control signals received or the control strategy employed. Whilst Proponents shall address these requirements, they have not been duplicated in this Standard.

9.10.1 Reasonable approaches for voltage and reactive power control

For EG system connections less than 100 kV and less than 30 MW, the following sections offer the basis for a reasonable approach to addressing some of the requirements of S5.2.5.13 of the NER. The Distributor does not guarantee that these sections are exhaustive, nor does the Distributor guarantee it shall accept this level for all locations in the Distribution System – they are provided as a guide only. Additional to the Distributor's requirements, any proposed negotiated access standard, including standards based off this template, requires input from AEMO.

9.10.2 Voltage control strategy

The Distributor may require that the design and operation of the control systems of an EG unit or EG system be coordinated with the existing voltage control systems of the Distributor and of other Distribution System users, in order to avoid or manage interactions that would adversely impact on the Distributor and other Distribution System users.

There will be cases were the Distributor will require the EG system to operate in voltage control mode or constant power factor mode, or a combination of both.

An EG system connected to the Distribution System shall have a voltage control system. This shall be in the form of constant power factor, constant reactive power or constant voltage (similar to an AVR). The Distributor generally considers the following voltage control strategies to be reasonable:

- Q = constant
- V = constant with droop
- Cos ϕ = constant
- Cos ϕ = f(P)
- Q = f(V)
- Cos ϕ = f(V)

The Technical Assessment shall show that the voltage control strategy from the Proponent does not hinder the Distributor from achieving the system standards in Schedule 5.1a of the NER.

Proponents should seek a control strategy with a dynamic response in accordance with the automatic access standard in the NER.

9.10.3 Control system

S5.2.5.13(b)(2)(i) and (ii) of the NER requires facilities for both monitoring of key variables and for testing its operational characteristics. Where appropriate, the main control system shall have duplicate power source (DC) similar to outlined in the protection requirements.

A fault recorder which logs events such as voltage disturbances, changes in set point, etc. to log and report on the control system's dynamic response to operational events is considered mandatory. The Distributor requires Proponents to provide details of how their testing and monitoring facilities shall prove its dynamic operating characteristics.

9.10.4 Control system damping

The EG system shall have a voltage control system that ensures any oscillations are adequately damped with no degradation of critical oscillatory modes and with no instabilities such as hunting.

9.10.5 Control system testing

The control system shall include a way, means or method to test its performance. Facilities for testing and their needs are to be agreed with the Distributor on the specified limits and requirements. One or more of the following methods may form the basis of a reasonable approach to control system testing:

- Simulating inputs with software;
- Test links; and
- Primary injection points.

The above list is not intended to be exhaustive; other methods may be proposed by the Proponent.

9.10.6 Power system stabiliser

The control system shall not detract from the performance of any power system stabiliser, and shall be coordinated and as agreed by the Distributor.

9.11 Active power control

S5.2.5.14 of the NER deals with the control of the output active power and the ability of the EG system to increase or decrease its active power transfer when required by AEMO. Table 18 provides active power control guidelines which the Distributor shall use to determine the level of access standard for the EG system.

Information supplied by the Proponent shall include details of the active power control system via drawings and a description detailing how the EG system shall respond to AEMO's dispatch targets.

Table 18 Active Power Control access standards

Access Standard	Requirement
Automatic	Pending their scheduling, the EG systems shall be able to manage their active power output as specified including complying with dispatch instructions.

The EG system active power output shall be reduced or disconnected in response to control request signals as agreed with the Distributor. This includes events where danger, overload, islanding, Distribution System stability, safety and management are critical. The active power output needs to be capable of being reduced in 10 % steps and the target output shall be realised within five minutes of receipt of the signal from the Distributor.

10 Power system modelling requirements

10.1 General

The Proponent shall:

- undertake steady-state, root mean square (RMS) modelling as required to confirm compliance to this Standard's requirements; and
- develop and supply an EMT model to the Distributor as required in Section 10.2.

The Proponent shall comply with the AEMO Power System Model Guidelines defined under S5.5.7(a)(3) of the NER and modelling guidance from the Distributor.

10.2 EMT modelling requirements

EMT modelling shall comply with the requirements in Table 19. The EMT modelling and analysis shall be through PSCAD™/EMTDC™ simulation.

All models and analysis shall be certified by an RPEQ with competence in the relevant area of practice.

Table 19 Modelling requirements[1]

Generation Capacity	Connection Type	Additional Modelling Requirement
Class A1 , <= 1.5 MW	Chapter 5A of the NER	EMT model generally not required[2]
Class A2 , > 1.5 MW < 5 MW	Chapter 5A of the NER	Site-specific EMT model[3,4]
Class B , > 1.5 MW < 5 MW	Chapter 5A of the NER	Site-specific tuned EMT model by the Proponent
Class B , >= 5 MW	Chapter 5 of the NER	Site-specific tuned EMT model by the Proponent

Note 1: Bumpless transfer and stand-by EG systems are exempt from EMT modelling.

Note 2: The Distributor reserves the right to request an EMT model from Class A1 systems based on Distribution System constraints.

Note 3: Synchronous rotating machines may be exempt from this requirement.

Note 4: The EMT Model shall be supplied with supporting documentation including site-specific settings.

Class B registered systems shall have the PSCAD model benchmarked against the PSS/E model. The PSS/E model shall be fine-tuned based on the benchmarking. Where the requirement is identified through a preliminary assessment, a full impact assessment shall be completed by the Distributor.

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Where EMT studies are required, the Proponent shall:

- Supply the model to the Distributor and AEMO (for registered Generators), within agreed timeframes, in the modelling package PSCAD™/EMTDC™ (version 4.6.0 or later), and compiled with Intel Fortran compiler (version 11 or later). The Proponent may elect to provide a black box encrypted model;
- Ensure that any model provided has been properly tested, certified and verified with the applicable OEM (with a copy of such provided to the Distributor) as representing the fully detailed inner control loops, phase locked loops, fault ride-through controllers, internal and external voltage controllers, system level controllers and all protection systems of the EG system, where possible embedding the actual hardware code. ;
- Provide modelling information to the Distributor and AEMO (for registered Generators), within agreed timeframes, which shall include an R1 data level accuracy pre-validated and current black box encrypted electromagnetic transient-type simulation model which includes all settings and the inverter and EG system control systems complete with the controller block diagrams (so as to explain the operation of the model without compromising the model veracity);
- Where R2 testing and model validation is required, update the model information to include the commissioned settings and provide evidence the model is as per actual performance. The model simulated performance shall be overlaid with actual performance, and shown to be within tolerable error bands of ±10% of simulated value; and
- Not undertake any on-site tuning of any EG system parameters that impact dynamic EG unit performance, or remotely adjust any EG system parameters, without prior written approval from the Distributor and AEMO (if applicable).

11 Communications

11.1 Class A1 and Class A2 requirements

The following EG systems does not specifically require a communications interface:

- Class A1 systems; and
- Class A2 non-export systems.

Class A2 partial-export and full export EG systems may require a communications interface for inter-tripping and SCADA indication and control. The Distributor shall determine the requirement for communications interface as part of the Technical Assessment. Where required the communications interface shall meet the requirements outlined in Section 11.2.

11.2 Class B requirements

S5.2.6.2 of the NER details the basic communications required between AEMO and the Distributor's control centres and the electrical supply requirements for the remote monitoring and control equipment. Table 20 provides the communication equipment guidelines the Distributor shall use to determine the level of access standard for the EG system.

Table 20 Communications equipment access standards

Access Standard	Requirements
Automatic	Two separate telephone facilities to be provided. Back-up power supply for remote communication and control facilities for three hours following on from a loss of supply.
Minimum	Provision of a telephone facility and one hour back up supply.
Negotiated	Agreed communication facilities between AEMO, the Distributor and the Proponent subject to the specified limits

Subject to availability, the use of fibre optic telecommunications cables between the EG system and the nominated SCADA interface point (typically the zone substation the EG system is connected to) and the nominated protection inter-tripping point is preferred. Where fibre optic telecommunication cables are not readily available the Distributor shall investigate the suitability of alternative radio options. The Proponent shall provide and install telephone line isolation equipment to comply with ACMA, the NER and telecommunications company requirement.

In the event of communications failure for the protection inter-tripping circuit, the Proponent shall be responsible for tripping the EG system protection equipment to disconnect the source of generation. The EG system protection equipment shall remain tripped until the protection inter-tripping communications circuit is operating.

Selected components of the Distributor's protection, SCADA, and communications systems shall be installed at the Proponent's facility to facilitate inter-tripping, SCADA and communications interface requirements. The Distributor shall provide the equipment in a panel. The Proponent shall provide space to house the Distributor's equipment.

12 SCADA (Remote Monitoring and Control)

12.1 General requirements

The requirements of this Section shall apply as per Table 21.

Table 21 SCADA requirements per connection category

Connection Class	SCADA Requirement
Class A1	No SCADA interface required
Class A2	May be required to be determined through the Distributor's Technical Assessment
Class B	Required as per Section 11 and the NER.

S5.2.6.1 of the NER deals with remote monitoring of EG systems by AEMO and the Distributor's control centres to monitor the performance of the EG system. Table 22 provides remote monitoring guidelines which the Distributor shall use to determine the level of access standard for the EG system.

Table 22 Remote monitoring and control access standards

Access Standard	Requirement
Automatic	Subject to scheduling and size, the EG system shall have remote monitoring equipment to transmit to AEMO the specified quantities required for AEMO to discharge its duties. Details of the specified quantities are provided in Annex D.
Minimum	Subject to scheduling and size, the EG system shall have remote monitoring equipment to provide AEMO with the information detailed in Section 12.2. IES EG systems shall also comply with Section 12.8.
Negotiated	As agreed with AEMO and documented in the agreed performance standard. The Proponent shall provide SCADA indication as detailed in Sections 12.3 to 12.7.

The supported SCADA communications protocols shall communicate in order of preference of:

1. DNP3 Level 1; Sequence Of Events (SOE) timestamping required.
2. Modbus (not available for EG system connections in South East Queensland).

Note: Any Distribution System event such as switching or protection operation shall be time stamped at the source, and the time-stamped event sent to the Distributor.

For time-stamped data, the Distributor can provide the time source over DNP3 or the Proponent can synchronise via their GPS clock.

Due to cyber security requirements, the current SCADA interface is serial, supporting either RS-232 or RS-485 utilising media converters as required. The Distributor has an ethernet inter-connection capability method under development which can be considered for use by Proponents upon application.

12.2 Plant status

The Proponent shall transmit all necessary EG system and EG unit status information required by the Distributor and third parties as required to operate the Distribution System. As a minimum, status information shall include:

- Power production: MW, Mvar, current, voltage, PF. Information shall indicate direction of power flow;
- Proponent's Connection Point circuit breaker status: Open /Closed /Tripped /Racked in or out;
- Auto/Manual start availability;
- IED status for critical components;
- EG system specific information relevant to the EG units such as number of wind turbines operating and available, battery state of charge; and
- For Proponents that can island their HV Network from the Distribution System, the Proponent shall provide information on the status of the Proponent's connection to the Distribution System.

12.3 Voltage control

Proponents controlling the HV bus voltage shall transmit the voltage control mode, control set point to the utility and the status of the voltage control; for example: constant power factor mode, volt/var mode. If Distribution System information is required for the operation of a voltage control mode it may be provided on negotiation.

12.4 Distribution System support mode

Proponents that provide Distribution System support shall transmit the necessary information to the Distributor, including whether the Proponent is in frequency creation or frequency reflection mode. If Distribution System information is required for the operation of a Distribution System support mode it may be provided on negotiation.

12.5 Constraints

For EG systems that require the capability to be constrained by the Distributor or AEMO, the Distributor shall transmit the information required for the Proponent to operate within constraints. If the Proponent operates outside the transmitted constraints, then the Distributor may disconnect the EG system from the Distribution System.

Constraints include but are not limited to line capacity, transformer capacity, fault contribution and thermal.

12.6 Controls

The Distributor may be required to issue controls to the Proponent, including on behalf of third parties. Controls may include advisory controls such as for constraints, or direct controls such as active power control to maintain the security and reliability of the Distribution System. All controls shall have appropriate feedback from the Proponent to ensure the function can be completed.

12.6.1 Ramp down

The Distributor shall send condition based ramped down signals based on active power control requirements as per the requirements in Section 9.11.

12.6.2 Remote start

EG systems capable of a remote start may enable this through the Distributor system. The Distributor may allow third party control for example an aggregator to start a peaking EG system for peak response market event.

12.7 Meteorological data

Where required, the Proponent shall transmit meteorological data, including wind speed and irradiance.

12.8 Inter-trip

The Distributor may require a backup anti-islanding protection scheme via the SCADA system if determined as required through the Technical Assessment.

13 Earthing

Depending on the location of the proposed connection, the Distribution System is operated as either a solidly- or impedance-earthed system. The Proponent shall provide satisfactory earthing for the EG system independent of the Distribution System in accordance with regulatory requirements and Energy Network Association earthing guidelines. This is required to prevent earth fault current flowing between the Distribution System and the EG system that can affect earth fault protection on the Distribution System. Any subsequent connection to the Distributor's earth grid shall be by mutual agreement in writing.

EG system and transformer earthing shall be reviewed and designed on a case by case basis by the Distributor and the Proponent. All metallic equipment housing and fixtures shall be connected to an earth point in accordance with AS/NZS 3000 and AS 2067.

13.1 Neutral Isolation

HV generating units directly connected to the Distribution System shall have their neutral effectively isolated from earth (i.e. isolated or earthed via high impedance). This is to limit any contribution to a Distribution System earth fault, and to inhibit the flow of harmonic currents through the neutral.

14 Operation

14.1 Commissioning and testing

Prior to the Interconnection of the EG system with the Distribution System, the Distributor is entitled to inspect the EG system and, where necessary, require the Proponent to arrange for testing of those parts of the EG system that have a direct effect on the Distribution System. This is to enable the Distributor to verify that the EG system is acceptable for Interconnection, and that it complies with this Standard and the Connection Agreement.

The Distributor shall test and commission the Distribution System assets connected to the Proponent's EG system where it does not affect the Proponent's EG system.

For EGs connecting under Chapter 5 of the NER, notice under clause 5.8.4(a) shall be given not less than 3 months prior to commencement of commissioning.

The Proponent shall arrange for a commissioning plan to test the EG system. The commissioning plan shall be followed to confirm that the EG system complies with the technical requirements specified in the relevant Connection Agreement.

In addition, commissioning shall verify that the EG system:

- Does not adversely affect the security of the Distribution System or the quality of supply of electricity through the Distribution System; and
- Minimises any possible threat of damage to the Distribution System, or any other equipment or installations of any other person that is connected to the Distribution System.

The commissioning plan and a report shall be carried out under engineering supervision by an RPEQ. The Proponent shall keep a written record of all protection settings and of test results. A copy of this record shall be made available to the Distributor on request. Engineering supervision by an RPEQ need not be required for the commissioning of an EG system with a bumpless transfer connection to the Distribution System.

14.2 Ongoing operation, monitoring and maintenance

The Proponent shall ensure that adequate operational, monitoring, maintenance procedures and programs are documented and undertaken to ensure compliance with the Connection Agreement.

The Proponent shall not change the installation or operation of the EG system in a manner that contravenes the Connection Agreement.

The Proponent shall notify the Distributor of any scheduled and unscheduled protection or communications outages or failures.

The Distributor may require access to the site of the EG system and isolation points for Distribution System maintenance and testing purposes.

Distribution System maintenance may cause interruptions to the operation of the EG system. Co-operative scheduling of these activities should be undertaken to reduce the outage period and minimise the associated impacts.

Annex A – Short Circuit Ratio calculation methods (normative)

A.1. Short Circuit Ratio (SCR)

Short Circuit Ratio is calculated with the following formula:

$$SCR = \frac{S_{CMVA}}{P_{max}}$$

Where

S_{CMVA} is the minimum sub-transient fault contribution in MVA of the studied bus prior to the proposed connecting EG system; and

P_{max} is the maximum inverter capacity of the proposed asynchronous (power electronic converter based) EG system.

A.2. Aggregated Short Circuit Ratio (WSCR)

Aggregated Short Circuit Ratio means consideration for combined generation in a shared Distribution Network which could be based on Weighted Short Circuit Ratio (WSCR), or other methods.

In this Standard, the Short Circuit Ratio also means the aggregated Short Circuit Ratio depending on the presence of nearby existing or committed EG systems. WSCR is used in this Standard for assessment when nearby asynchronous EG systems are present.

A WSCR calculation should be performed as per the following formula:

$$WSCR = \frac{\sum_i^N S_{SCMVAi} * P_{RMWi}}{(\sum_i^N P_{RMWi})^2}$$

Where S_{SCMVAi} is the minimum fault contribution in MVA at the connection point with only synchronous EG systems connected;

P_{RMWi} is the MW rating of the EG system to be connected;

N is the number of nearby asynchronous EG systems; and

The EG system index is given by i.

A.3. Minimum Short Circuit Ratio (MSCR)

The MSCR method as detailed in AEMO's System Strength Impact Assessment Guidelines is based on the following premises:

(a) The Available Fault Level after connection of the proposed EG system is compared against the minimum SCR/fault level for which it is capable of stable operation.

(b) The headroom (or margin) between the two values (Distribution System Strength versus the EG system's requirements) provides an initial indication of the connection point capability to host the EG system and, therefore, the likelihood of an *adverse system strength impact* as defined in System Strength Impact Assessment Guidelines.

Annex B – Rotating generating unit data requirements (normative)

The information detailed in Table 23 shall be provided for each EG system proposed to be installed:

Table 23 EG unit Information

Item	Data Description[2]	Units
1	Type of generator	Text
2	Connection arrangement (Delta or Star/Wye)	Text
3	Rotor type (Round Rotor or Salient Pole)	Text
4	Nominal rated output	kVA, kW & kvar
5	Nominal terminal voltage (line to neutral)	V or kV
6	Highest voltage (line to neutral)	V or kV
7	Rated lightning impulse withstand voltage	kVp
8	Rate short duration power frequency withstand voltage	kV
9	Maximum current	kA
10	Rated short time withstand current	kA for Seconds
11	Ambient conditions under which Item 9 & 10 currents apply	Text
12	Synchronous reactance – D Axis (Xd)	PU
13	Synchronous reactance – Q Axis (Xq)	PU
14	Transient reactance – D Axis (X'd)	PU
15	Transient reactance – Q Axis (X'q)	PU
16	Subtransient reactance – D Axis (X"d)	PU
17	Subtransient reactance – Q Axis (X"q)	PU
18	Open circuit transient time constant – D Axis	Seconds
19	Open circuit transient time constant – Q Axis	Seconds
20	Open circuit subtransient time constant – D Axis	Seconds
21	Open circuit subtransient time constant – Q Axis	Seconds
22	Armature resistance	PU
23	Negative sequence resistance	PU
24	Locked rotor impedance (resistance & reactance)	PU

[2] Where the Data Item Unit is identified as PU it shall be the PU value calculated on a base of the EG unit nominal terminal voltage and nominal EG unit kVA rating.

Item	Data Description[2]	Units
25	Zero sequence reactance	PU
26	Grounding impedance (resistance & reactance)	Ohms
27	Saturation co-efficient at 1.0PU and 1.2PU	-
28	Mechanical inertia constant	Seconds
29	Fault contribution from the EG unit(s) at the Distribution System boundary	kA
30	Description of the proposed voltage, active power (P) and reactive power (Q) control system including details of the operation and performance of the system under normal conditions, fault conditions, and Distribution System disturbance conditions	Text
31	System SLD	Text and Diagrams

Annex C – Photovoltaic Inverter Energy System data requirements (normative)

The following information shall be provided for each IES EG unit proposed to be installed:

Table 24 Inverter Data Requirements

Item	Data Description	Units
1	Inverter model and associated data sheets	Text
2	Inverter islanding protection details	Text
4	Inverter reactive control capabilities	Text
5	Panel capacity	kW
6	Inverter capacity	kVA
7	Information on inverter configuration – single or three-phase systems, number of inverters, electrical schematic if embedded in sub-boards	Text and Diagrams
8	Battery details, planned operating modes and dispatch schedule (if applicable)	Text and Diagrams
9	System SLD	Text and Diagrams

Annex D – AEMO data point requirements (informative)

The following is an example of power station data required by AEMO.

Table 25 AEMO Example Power Station Data Requirements

Data Type	Data Type
General power station data	Unit gross MW, Mvar, kV.
	EG system transformer MW, Mvar, kV.
	Unit auxiliary load MW & Mvar.
	EG system Connection Point MW and Mvar.
	Bus kV, frequency
	EG system transformer tap position.
Wind farm specific data	Wind farm MW output
	Number of wind turbines available.
	Number of wind turbines in operation.
	Control scheme set points.
	Air pressure or humidity (if available).
	Metrology station and turbine nacelle measurements of:
	Wind speed (instantaneous and/or 5/10 minute average).
	Wind direction (instantaneous and/or 5/10 minute average).
	Ambient temperature.
Solar farm specific data	Global horizontal irradiance
	Global inclined irradiance
	Ambient temperature
	Wind speed
	Wind direction
	Relative humidity
	Barometric pressure
	Module surface temperature
	Active power control set point
	Number of inverters available
Solar farms with tracking technology	Direct normal Irradiance
	Actual tracking slope angle
	Actual tracking azimuth angle
	Tracking fraction of modules / concentrators not on track

The Distributor may be required to prove additional data to AEMO.

Table 26 AEMO Example Distributor Data Requirements

NSP / TNSP Data	
Substation Data	Primary and secondary bus kV, frequency.
	Main transformer MW, Mvar, kV.
	Main transformer tap position
	Major load MW, Mvar.
	SVC, Synchronous Condenser, and reactive plant Mvar.
	Status of all transmission circuit breakers and system significant isolators / disconnectors, including capacitor bank and reactor circuit breakers.
	Status of all significant sub transmission circuit breakers, isolators, disconnectors etc. – These will generally include sub transmission line switches, transformer secondary voltage switches, bus tie/coupler circuit breakers and significant reactive plant circuit breaker.
	Status of Substation Automated Control Schemes
Transmission and sub-transmission Line Data	Line MW, Mvar, kV at both ends
	Transmission line MW, Mvar, kV
	DC Transmission Line DC kV, Amps, MW.
AREA Data	System frequency (at the 1 second rate), minimum of 2 independent, geographically diverse sources.
	Time error (at the 4 second rate)
	Ambient temperature (at the 1 minute rate) from each climatically diverse area.
	Status of area or regional automated control schemes
Additional SCADA Data	Control scheme status, including armed, enabled, activated, tripping
	Reactive plant dynamic data, including control values and operating mode
	Status of devices connecting additional control schemes to the Network.

The following table lists AEMO data commands for registered participants under the NER that can be dispatched. These commands may come via the AEMO Electricity Market Management System (EMMS) or Automatic Generation Control (AGC).

Table 27 AEMO Dispatch Commands

Name	Description
Commitment Instructions	For generating units with bid dispatch inflexibility profiles
Semi-Dispatch Interval Flag Status	For semi-scheduled generating units
Dispatch Instructions	Dispatch target data

Annex E – Connection arrangement requirements - Class A1 and Class A2 (informative)

E.1. Inverter Energy Systems

	Class A1 IES systems		Class A2 IES systems	
	Non-Export	Export	Non-Export	Export
Level 1 Backup protection[1]	Yes	Yes	Yes	Yes
HV NVD protection	Yes[2]	Yes[2]	Yes	Yes
Grid Isolation Device Required	No	No	Yes	Yes
Distribution System Technical Assessment required	Yes	Yes	Yes	Yes
Power quality to AS/NZS 61000 series requirements	Yes	Yes	Yes	Yes
Communications / SCADA interface	No	No	No	Yes
Fault level contribution to the Distribution System included in the Technical Assessment	No	No	No	No
RPEQ for both design & commissioning	Yes	Yes	Yes	Yes

1. Level 1 backup protection – Over and under voltage, over and under frequency and rate of change of frequency.
2. Exempt if IEC62116 compliant.

E.2. Rotating machine systems

	Class A1 rotating machine systems				Class A2 rotating machine systems			
	Limited parallel Operation		Continuous parallel Operation		Limited parallel Operation		Continuous parallel Operation	
	Bumpless Transfer	Standby	Non-Export	Export	Bumpless Transfer	Standby	Non-Export	Export
Level 1 Backup protection[1]	No	Yes	Yes	Yes	No	Yes	Yes	Yes
HV NVD protection	No	No	Yes	Yes	No	No	Yes	Yes
Reverse power flow controls[2]	No	No	Yes[2]	No	No	No	Yes[2]	No
Voltage Controlled Overcurrent	No	No	No	Yes	No	No	No	Yes
Grid Isolation Device Required	No	No	No	No	No	Yes	Yes	Yes
Distribution System Technical Assessment required	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Power quality to AS/NZS61000 series requirements	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Communications / SCADA interface	No	No	No	No	No	No	Yes	Yes
Fault level contribution to the Distribution System included in the Technical Assessment[3]	No	Yes	Yes	Yes	No	Yes	Yes	Yes
RPEQ for both design & commissioning	No	Yes	Yes	Yes	No	Yes	Yes	Yes

1. Level 1 backup protection – Over and under voltage, over and under frequency and rate of change of frequency.
2. Zero power limit for non-export systems, power limiting controls for partial-export systems.
3. Fault current contribution is dependent on size, number and hours of operation.