

Guide for Municipalities on Processing Embedded Generator Applications 1 MW and Larger

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Compiled by:	Dr Gerhard Botha (technical specialist)		
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- Bernhardt Lamour (Nelson Mandela Bay Metro)
- Marlyn Hendricks (City of Cape Town)
- Shane Prins (City of Cape Town)
- Vally Padayachee (AMEU Strategic Advisor)

The following people contributed to and/or reviewed the document:

- Babalwa Mboho (GIZ)
- Basetsana Molefiane (GIZ)
- Brendan Dawson (RTG Solutions)
- Daniel Goldstuck (Sustainpower)
- De Villiers Botha (SAPVIA / SolarEFF)
- Eleni Papantoniou (MPE Engineering)
- Geeven Moodley (Digsilent Buyisa)
- Ismail Jeffreys (City of Cape Town)
- Jonathan Horne (MPE Engineering)
- Josh Dippenaar (Sustainable Energy Africa)
- Mark Borchers (Sustainable Energy Africa)
- Nicola Cencelli (independent)
- Nicolaas Faure van Schalkwyk (Solar Training Centre/SUNCybernetics)
- Peter Lilje (MPE Engineering)
- Philipp Vanicek (GIZ)
- Ryno van der Riet (City of Cape Town)
- Sanjeeth Sewchurran (eThekweni Metro)
- Zoë Lincoln (TNEI)

Disclaimer: This Guide is intended to help Distributors in processing generator applications. Guide users are responsible for ensuring all relevant legislation, regulations and other compliances have been adhered to. Neither the authors or contributors, nor any organisation associated with the development of this Guide are liable for any loss or damages that may occur as a result of using this Guide.

Comments on the document are welcomed, and should be submitted to:

admin@sseg.co.za and support@sseg.org.za (please include both emails)

How to use this document

This is a reference document, and is not designed to be read cover-to-cover. The below graphic helps readers locate sections of relevance more easily.

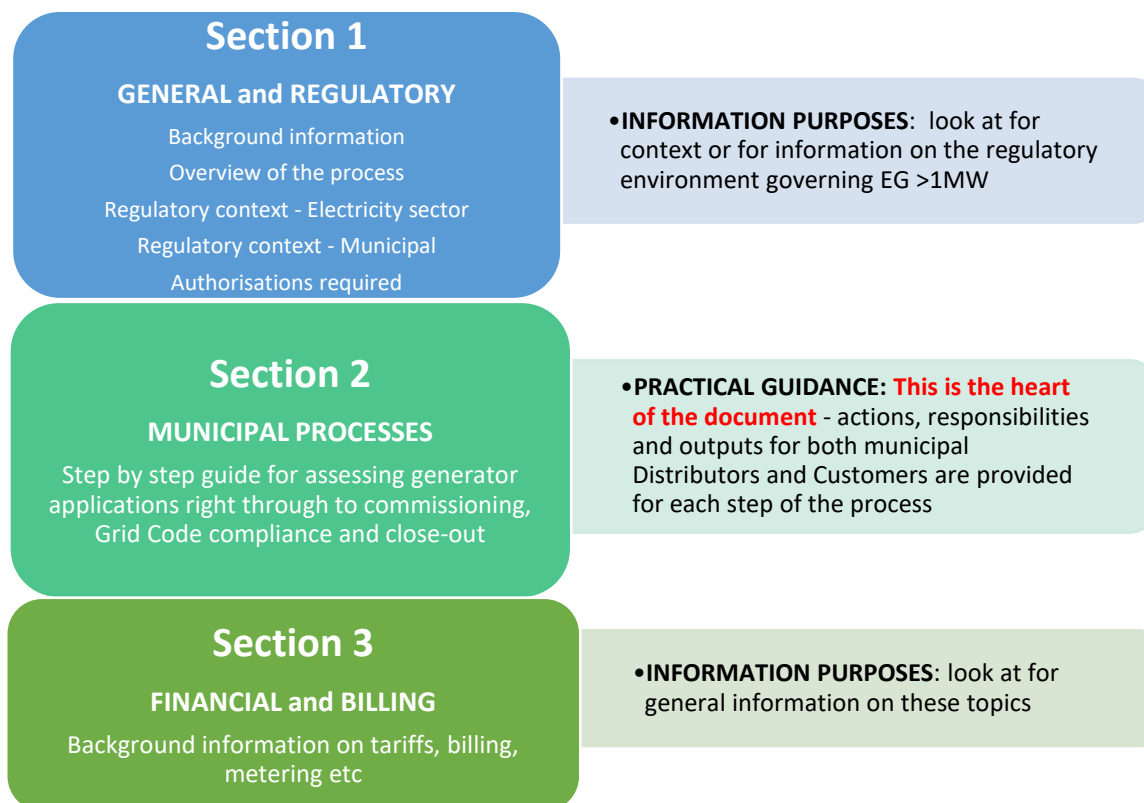


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Definitions

General Definitions

After Diversity Maximum Demand	Statistical value that is used to design networks considering that there is diversity in the demand from customers in the network.
Behind the Meter Generator	A Generator installed on a Customer's premises, i.e. will primarily feed the Customer's own load, before exporting. May also be referred to as Onsite Generation.
Contract Works	Means the portion of the Connection to be undertaken by the Customer in accordance with the conditions of the Self-Build Agreement to be concluded between the Customer and the Distributor.
Distribution Code	Legal set of documents compiled to establish the reciprocal obligations of industry participants around the use of the DS and operation thereof.
Embedded Generation	A legal entity that operates one or more unit(s) that is connected to the Distribution System. Alternatively, a legal entity that desires to connect one or more unit(s) to the Distribution System.
EMT Simulations	EMT simulations are used to evaluate stability of the network and results are provided as waveforms.
Grid Code (GC)	Legal set of documents compiled to establish the reciprocal obligations of industry participants around the use of the TS and operation of the interconnected power system (IPS). May also include reference to the Distribution Code, the Renewable Power Plant Connection Code and/or the Battery Energy Storage Facility Code.
Grid Code Compliance (GCC)	Process or status of complying with all relevant requirements from the South African Grid Code.
Grid Following (Inverter)	Traditional inverter that injects current into the grid based on the preset requirements, e.g. at a certain power factor, or droop control.
Grid Forming (Inverter)	Inverters with advanced control that may assist the grid with faster responses to grid variations, e.g. voltage change.
Grid Impact Study	Simulation study to evaluate the impact of a generator on the network – may be limited to impact at the Point of Connection (PoC), or on broader network beyond the PoC.
Hosting Capacity	Capacity of the grid (Transmission level) or network (Distribution level) to accommodate generators, i.e. how much generation can be connected without the need to upgrade any grid components.
Network Impact Study (NIS)	General term for simulation studies to evaluate the impact of a generator on the Distributor network (sometimes used interchangeably with 'Grid Impact Study').
Network Hosting Study	Simulation study to determine the generation hosting capacity of the network.
Onsite Generation	See "Behind-the-Meter"
Operational Notification	Written permission granted by the Distributor for the Customer to commence with commissioning, or commercial operation.

RMS Simulations	RMS simulations are phasor-type simulations, where only the magnitude and phase of the network variables are evaluated. These are dynamic simulations to evaluate the stability of the network, but at a slower time scale than EMT simulations.
Point of connection	The electrical node(s) on the Network Service Provider's network where the embedded generator's electrical equipment is physically connected to the Network Service Provider's electrical equipment. (Eskom definition in document 240-61268576). The electrical node on a distribution system where a Customer's assets are physically connected to the Distributor's assets (SAGC).
Point of supply	Physical point on the electrical network where electricity is supplied to a customer.
Self-build	Means the planning, financing, insuring, land rights acquisition, design, engineering, procurement, supply, fabrication, construction, erection, installation, inspection, pre commissioning, testing, completion and commissioning of the Contract Works by the Customer, and on completion of the Contract Works the handover of the plant, facilities, equipment, assets and related designs, material guarantees/warranties, deeds and other documentation by the Customer to the Distributor.
Small Scale Embedded Generation	Embedded generator in category A (up to 1 MW).

Definitions of Parties Involved

The following parties have relevance to Customer/Generator applications for connection as referred to in this document:

Entity	Definition	Role
Consumer	A customer that consumes electricity only.	None in terms of this document
Customer	A customer of the Distributor, i.e. a traditional load or generator. In this document, Customer (capitalized) refers to the customer applying to connect a generator.	Initiate request to connect Drive the process Ensure continued adherence to the supply agreement
Developer	A natural person or a juristic person, whether in the public sector or the private sector, that carries out building and engineering operations to establish a development.	Drive the process
Distributor	A municipal licensee or its appointed representative that constructs, operates and maintains the distribution network.	Manage, maintain, operate and expand the network. Approve connection requests. Informs Eskom.
Distribution Network Operator (DNO)	The Distribution Network Operator (DNO) manages the operational aspects of the Distributor network. This mostly involves	Control and operate the distribution network

Entity	Definition	Role
	voltage regulation and thermal management of equipment.	
Eskom	State Owned Enterprise and main supplier of electricity in South Africa. It is (at the time of publication) a vertically integrated utility comprising of generation, the system operator, transmission and distribution.	Main supplier and owner of national grid
Financier	This refers to the entity that provides funding for the development and construction costs of the generator.	Fund the process Conduct due diligence
Generator (capitalized)	1. A Customer who connects a unit or group of units that generate electricity. The electricity may be consumed by a customer on-site, or wheeled to another customer elsewhere on the network, or sold directly to the Distributor or Eskom. 2. Generator may refer to a Prosumer or a pure generator, i.e. that only generates electricity for export.	Same as customer
generator (not capitalized)	A unit or group of units that generate electricity.	
Installer	The installer is the entity that does the physical installation work.	Install the equipment Ensure adherence to the Grid Code
Municipality / Municipal Distributor	Owner and licensee of the distribution network in the municipal area. May also be referred to as the Distributor or Network Service Provider (NSP).	Manage, maintain, operate and expand the network. Approve connection requests. Informs Eskom.
NERSA	A legal entity established in terms of the National Energy Regulation Act (Act 40 of 2004)	Regulate the electricity supply industry in South Africa
Network Service Provider	A legal entity that is licensed to provide network services through the ownership and maintenance of an electricity network.	Manage, maintain, operate and expand network. Approve connection requests Informs Eskom.
NTCSA	National Transmission Company of South Africa	Previously Eskom Transmission. See Transmission NSP
Other municipal Distributors		Interaction as required by wheeling agreements
Prosumer	A customer that both consumes and generates electricity.	Same as customer, but potentially on a different tariff

Entity	Definition	Role
	Generally, a net consumer, i.e. over a specific billing period they consume more electricity than they generate. Net consumption is not a pre-requisite. Battery energy storage facilities are also considered to be prosumers.	
Retailer	A legal entity licensed to engage in the retail buying and selling of electricity as a commercial activity, whether for the account of the person involved therein, or on behalf of someone else.	Comply to licensing conditions
Resellers	See Retailer	Although there may be a legal difference, technically, the same type of entity as a Retailer.
System Operator	The legal entity licensed to be responsible for short-term reliability of the integrated power system (IPS), and is in charge of controlling and operating the transmission system (TS) and dispatching generation (or balancing the supply and demand) in real time. The SO requires information on embedded generators connected to the network for appropriate forecasting and scheduling of power production. Aspects such as frequency control are the responsibility of the SO.	Control and operate the TS Dispatch generation Balance supply and demand
Traders	A legal entity licensed or registered to engage in the buying and selling of electricity as a commercial activity.	Comply to licensing conditions
Transmission Network Service Provider (TNSP)	A legal entity that is licensed to own and maintain a network on the TS.	

Acronyms

AC	Alternating Current
ADMD	After Diversity Maximum Demand
AGUP	Allowable Grid Unavailability Period
AMEU	Association of Municipal Electricity Utilities
ANSI	American National Standards Institute
AVR	Automatic Voltage Regulator
B-BBEE	Broad-based Black Economic Empowerment
BESF	Battery Energy Storage Facility (alternative to BESS)
BESFCC	Battery Energy Storage Facility Connection Code
BESS	Battery Energy Storage System (alternative to BESF)
BMS	Battery Management System
BTM	Behind the Meter
CB	Circuit Breaker
CBF	Circuit Breaker Failure (Protection Function)
CoC	Certificate of Compliance
CRA	Concept Release Approval
CSP	Concentrated Solar Power
CT	Current Transformer
CUOSA	Connection and Use of System Agreement
DC	Direct Current
DMRE	Department of Mineral Resources and Energy
DNO	Distribution Network Operator
DNP3	Distributed Network Protocol 3 (SCADA communication protocol)
DRA	Design Release Approval
DOE	Department of Energy
DS	Distribution System
DSO	Distribution System Operator
ECA	Electronic Communications Act
ECSA	Engineering Council of South Africa
EG	Embedded Generator
EIA	Environmental Impact Assessment
EMT	Electromagnetic Transient
EOSS	Energy One-Stop Shop
ERA	Electricity Regulation Act (Act No. 4 of 2006) as amended
ERA	Execution Release Approval
FAT	Factory Acceptance Test
FDS	Fire Detection System
GCAC	Grid Code Advisory Committee
GCS	Grid Code Secretariat
GFL	Grid Following
GFM	Grid Forming
ha	hectare

HV	High Voltage
HVRT	High Voltage Ride Through
IDP	Integrated Development Plan
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
IMD	Insulation Monitoring Device
IPP	Independent Power Plant / Producer
IPS	Interconnected Power System
IRP	Integrated Resource Plan
LV	Low Voltage
LVRT	Low Voltage Ride Through
MFMA	Municipal Finance Management Act
MV	Medium Voltage
MVA	MegaVolt-Ampere
NMD	Notified Maximum Demand
NERSA	National Energy Regulator of South Africa
NRS	National Rationalised Specification
NSP	Network Service Provider
OHL	Overhead Lines
OTI	Over-Temperature Indicator (transformer protection)
PGC	Point of Generator Connection
PCC	Point of Common Coupling
PCS	Power Conversion System (in the context of this document, mostly for BESS inverter)
P/f	Power-frequency (protection related)
PoC/POC	Point of Connection
PoD/POD	Point of Delivery
PoS/POS	Point of Supply
POTT	Permissive Overreach Transfer Trip (protection scheme)
PPA	Power Purchase Agreement
PPD	Protection Philosophy Document
PPP	Public-Private Partnership
PQ	Power Quality
PSS	Power System Stabilisers
PV	Photovoltaic
QoS	Quality of Supply
QoSS	Quality of Supply Standards
QoSSS	Quality of Supply and Service Standards
RCD	Residual Current Device
REF	Restricted Earth Fault (protection function)
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
REDZ	Renewable Energy Development Zone
REPP	Renewable Energy Power Producer
RETEC	Renewable Energy Technical Evaluation Committee
RMS	Root Mean Square
RPP	Renewable Power Plant

RPPGC	South African Grid Code for Renewable Power Plants
SAGC	South African Grid Code
SALGA	South African Local Government Association
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SIT	Site Integration Testing
SLD	Single Line Diagram
SO	System Operator
SoC	State of Charge (battery)
SSR	Sub-Synchronous Resonance
SSEG	Small-Scale Embedded Generator
THD	Total Harmonic Distortion
ToU	Time of Use
TS	Transmission System
UoS	Use of System
V	Volt (with appropriate prefix, e.g. k for kilo)
VA	Volt-Ampere (with appropriate prefix, e.g. k for kilo or M for Mega)
var	Volt-Ampere-Reactive (with appropriate prefix)
VOC	Volatile Organic Compound (gas detection)
VRT	Voltage Ride Through
VT	Voltage Transformer
W	Watt (with appropriate prefix)

Regulatory Documents and Standards

Primary Legally Binding Documents

Document	Notes
South African Grid Code (SAGC) — Network Code	NERSA, 2022, or latest version
South African Grid Code — Information Exchange Code	NERSA, 2022, or latest version
South African Grid Code — Transmission Code	Referenced for non-renewable generators
RSA Distribution Code — Distribution Network Code	NERSA, 2022, or latest version
Renewable Power Plant (RPP) Grid Code (RPPGC)	Core compliance document for EG
Battery Energy Storage Facility Connection Code (BESFCC)	Primary document for BESS/BESF
NERSA Licence Conditions	Binding on all licensees

Legislation (Acts)

Act	Notes
Electricity Regulation Act No. 4 of 2006 (ERA) , as amended — including Schedule 2 (amended 17 Jan 2023, Govt Gazette No. 47877)	Central enabling legislation
National Energy Regulation Act, Act 40 of 2004	Establishes NERSA
Municipal Finance Management Act No. 56 of 2003 (MFMA)	Governs municipal procurement
Municipal Systems Act	Referenced for connection obligations
National Environmental Management Act No. 107 of 1998	EIA requirements
Preferential Procurement Policy Framework Act, 2000	Procurement (B-BBEE, local content)
Subdivision of Agricultural Land Act 70 of 1970	Land use
National Building Regulations and Standards Act 103 of 1977	Construction sign-off
National Forests Act 84 of 1988	Environmental authorisations
Astronomy Geographic Advantage Act 21 of 2007 (AGA Act)	Site-specific permit
Civil Aviation Act 13 of 2009	Wind facility approvals
Mineral and Petroleum Resources Development Act 28 of 2002 (MPRDA) — Section 53	Land use near mining/petroleum areas
Electronic Communications Act 36 of 2005 (ECA)	Communications infrastructure approvals
Municipal Fiscal Powers and Functions Amendment Act 4 of 2024	Development charges

Regulations and Government Notices

Document	Notes
Electricity Regulations on New Generation Capacity — Regulation 5 (New Generation Regulations)	ERA Section 34 Ministerial Determination process
Municipal Supply Chain Management Regulations — Regulation 37	Unsolicited bids
EIA Regulations Listing Notices GNR 544, GNR 545, GNR 546	Environmental activity thresholds for renewable energy
ERA Schedule 2 Licensing Exemption and Registration Notice (Govt Gazette No. 47877, 17 January 2023)	Registration/licensing thresholds
National Treasury MFMA Circular No. 118 (June 2022)	Legal framework for municipal procurement of generation capacity
National Treasury PPP Manual and Practice Notes	PPP framework

South African National Standards and Industry Specifications (SANS/NRS)

Standard	Subject
NRS 047	Electricity Supply: Quality of Service
NRS 048-2	Electricity Supply: Quality of Supply (compatibility levels, limits, measurement)
NRS 048-4	Simplified apportioning method for power quality emission limits
NRA 048	Other sections of the NRS 048 series that may be applicable to the Distributor
NRS 057 / SANS 474	Code of Practice for Electricity Metering
NRS 069:2018	Network connection charges and cost apportionment
NRS 097-1	Grid Interconnection of Embedded Generation, Part 1: Utility Interface (<i>pending publication</i>)
NRS 097-2-1 (2026)	SSEG: Utility Interface Requirements
NRS 097-2-3 (2023)	SSEG: Simplified utility connection criteria for LV-connected generators
NRS 118:2025	Grid impact study requirements (<i>new series, in development</i>)
SANS 10142 (Parts 1–4)	The Wiring of Premises (electrical installation compliance)
SANS 10142-2	Wiring of Premises — larger installations
SANS 10400-T	Fire protection in buildings (BESS fire detection and suppression)

IEC Standards

Standard	Subject
IEC 60255	Protective Relays (relay function codes — used with ANSI C37.2)
IEC 61000-3-3	Voltage flicker: equipment up to 16 A
IEC 61000-3-5	Voltage flicker: equipment above 16 A
IEC 61000-3-6	Harmonic emission limits for HV and MV systems
IEC 61000-3-7	Voltage flicker emission limits for MV and HV systems
IEC 61000-3-13	Voltage unbalance emission limits for MV and HV systems
IEC 61000-4-30	Power quality measurement methods (Class A instruments required)

IEC 61850	SCADA/communication protocol for substation automation
IEC 62446	PV system documentation requirements

IEEE Standards

Standard	Subject
IEEE 242	Recommended Practice for Protection and Coordination of Industrial/Commercial Power Systems
IEEE 1547	Standard for Interconnection of Distributed Energy Resources

Other Referenced Documents (Informative / Industry Practice)

Document	Notes
Eskom Standard 240-61268576 — <i>Standard for the Interconnection of Embedded Generation</i> (Eskom, 2018)	Used as design basis until NRS 097-1 is published
GCS — Renewable Power Plant Grid Code Compliance Test Guideline, Version 3.0 (RSA Grid Code Secretariat, undated)	Compliance testing process and reporting formats
MPE P13906 — Recommended Practice for Grid Code Compliance Studies for Renewable Energy Power Plants and Hybrid Power Plants (MPE, 2021)	Simulation guideline
EG Grid Impact Study Specification Guideline	
NERSA Registration Application Procedure (NERSA, 2022)	Registration process
NERSA Registration Application Form (NERSA, 2022)	
NERSA Generation Licensing and Registration FAQ (NERSA, 2020)	
National Treasury GTAC PPP Manual	PPP guidance
City of Cape Town Interconnection Standard	Example municipal standard (footnote reference)
EIA Guideline for Renewable Energy Projects (Dept of Environmental Affairs, 2013)	Environmental impact assessment thresholds
Energy Action Plan Update, January 2023 (South African Government)	Reduced EIA and NERSA registration timeframes
ANSI C37.2	Standard for relay function numbering (used alongside IEC 60255)

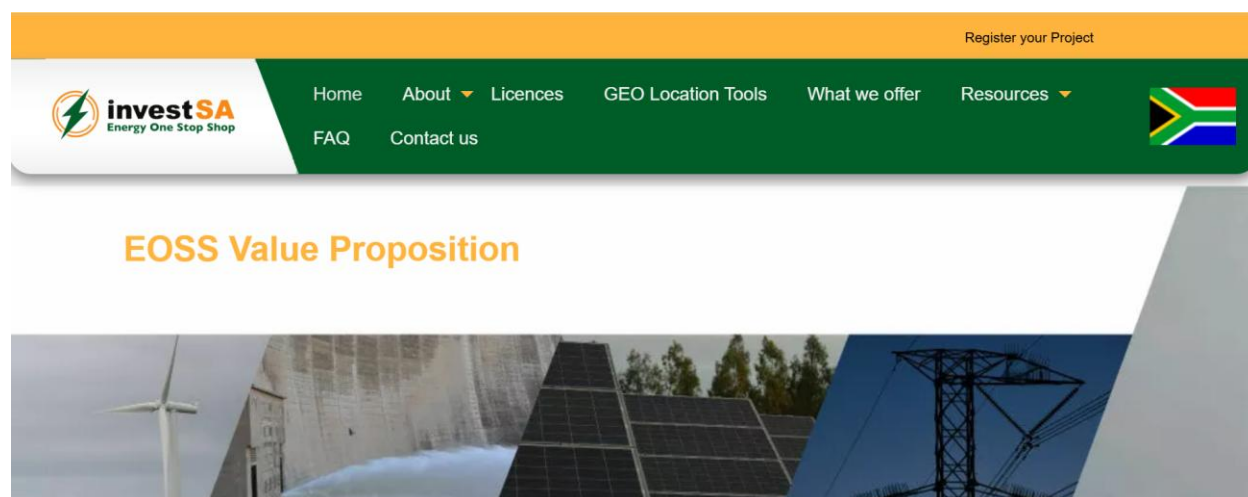
In the event of conflict, the Grid Code and NERSA licence conditions shall prevail.

1 Introduction

Municipalities are experiencing a sharp rise in applications to connect generators to distribution systems. The size of generation applications has until recently been largely within the Small-Scale Embedded Generator (SSEG) < 1 MW range. However, recent amendments to the Electricity Regulation Act Schedule 2 (reduced licensing requirements) have resulted in many more larger generator connection applications.

In terms of the clause 4(1) of the Distribution Code, Distribution Network Code (NERSA, 2022), Distributors are obliged to consider connection applications from such generators, whether they have processes and policies in place for this or not¹. While many of these Distributors have processes to enable Small Scale Embedded Generators (SSEG) – i.e. below 1 MW - to connect, this is often not the case for larger generators, and the regulatory and technical environment is substantially different for such generators. This guide provides support to municipal Distributors in this regard. The focus is on the electrical aspects of (renewable) generators² connecting to municipal networks. However, non-electrical compliances and considerations are also noted, and further references provided.

Since the first publication of this guideline, government developed a website (Energy One Stop Shop – EOSS) to support the application process for all embedded generators, provided at <https://energyoss.gov.za/>. This website is intended to cover the full process, however, at the time of publication of this document, the focus of this supporting website is on the permitting processes, e.g. environmental impact assessment, etc. This guideline document attempts to provide a full overview of the entire process, with references to appropriate related documents and information sources, such as the EOSS website.



¹ *Legal Framework Applicable to Embedded Generation in South African Municipalities*. Pinsent Masons for Sustainable Energy Africa, September 2022. Available at www.sseg.org.za

² At the time of publication, non-renewable generators have to follow the SAGC – Transmission Code. Some aspects for licensing etc. may differ from this document. It is, however, unlikely that large non-renewable generators will require connection to the municipal network. Updates to the existing RPP Code as well as non-renewable generation codes are underway.

Users of this guideline are encouraged to also visit this site for further support. In the event of any discrepancies, the EOSS website information would likely take precedence, due to the continuous updates on both the regulatory side as well as the website.

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1.1 Purpose of this document

The document is primarily intended to support municipal Distributors with assessing applications for the connection of generators 1MW and larger. However, it also provides useful information to prospective Generators/Customers (or Developers and IPPs) regarding what is permissible and various criteria and processes that are involved in considering generator connection applications.

The following is covered for the relevant parties:

1. Distributor
 - a. The process to be followed to enable generator applications
 - b. Proposed steps to follow to assess the application
 - c. Assessing the network capacity
 - d. Role in the evaluation of Grid Code compliance
 - e. Overview of regulatory processes
2. Generator/Customer
 - a. Understand the process that the Distributor will follow
 - b. Checklist of the Distributor requirements
 - c. Grid/network and Grid Code compliance studies overview
 - d. Overview of regulatory processes

Note that the document remains a guide. As such, Distributors may modify, add, or remove steps and requirements as is necessary according to their operational requirements. The intent is to cover all processes to be followed, but some aspects may not be covered in detail since they may already be in place or covered elsewhere, e.g. regulatory approvals for Rights-of-Way, etc.

It remains the responsibility of prospective Generators/Customers to make sure all regulatory, technical, procedural and other aspects are suitably adhered to in terms of national and municipal frameworks and requirements.

This document does not cover off-grid applications and/or installations.

1.2 Regulatory overview

This section provides a brief overview of the relevant regulatory aspects. It is not exhaustive since many aspects are already covered in the standard operation of the Distributor business. Generators need to comply to these regulatory requirements as applicable. More detail of the non-technical regulations is provided in section 2.4.

Note that the current RPP Grid Code does not make a distinction between Generators who sell energy, and embedded generators largely for self-consumption. Where unclear, Grid Code requirements are to be applied at the Generator point of connection, not at the Customer point of connection.

1.2.1 General rights and obligations of Distributors and Generators/Customers³

In terms of the ERA and Grid Code – specifically the Network Code - licensed Distributors have an obligation to allow access to generators in connecting to the network and may not refuse to permit an EG facility to connect provided such access would not violate any technical and safety requirements as set out in the relevant Grid Codes, license conditions and tariff schedules.

If the licensed Distributor is unable to provide access to the network at the point of connection applied for, it must provide reasons and advise the customer of alternative options available, which includes increasing the capacity of an existing connection.

Each Distributor is required in terms of clause 4(2) of the Distribution Network Code to make available to the customers the 'Customer Connection Information Guide' which shall cover as a minimum:

- the process to follow when applying for supply at the specific Distributor;
- information requirements of the Distributor from the customer to implement an appropriate connection; and
- the process and related timeframes which follow the application.

Municipal Distributors have the duty to develop electricity services policies relating to, inter alia, the connection of generation systems to the distribution system and to pass and implement by-laws with respect to the electricity distribution functions.

If there is no policy document or by-law issued by a municipal Distributor governing the application process for generation systems, the application for connection should be dealt with in accordance with the Distribution Network Code, the RPP Code, the BESF Code, the ERA, the Municipal Systems Act and NRS 047 as amended.

The absence of a policy document regulating the application process for connection of an EG facility 1 MW or larger is insufficient grounds for the municipal Distributor to refuse to consider the connection to the municipality's distribution system. An application for connection can be submitted in accordance with the provisions of the Distribution Code.

Clause 4(4) of the Distribution Network Code states that the Generator/Customer must enter into a Connection Agreement with the licensed Distributor before any actual connection to the distribution system can take place. This will require that Generators/Customers comply with all municipal requirements, including application and assessment processes. This also implies that, amongst other activities, appropriate studies are done to ascertain whether Customers, including Generators, can be connected

³ This section is largely informed by *Legal Framework applicable to Embedded Generation in South African Municipalities*. September 2022. Pinsent Masons, for the Municipal Embedded Generation Support Programme, available at www.sseg.org.za.

1.2.2 NERSA licensing / registration

According to the latest Schedule 2 of the ERA⁴ the following registration and licensing exemptions exist for EG:

- Exempt from NERSA registration and licensing:
 - EG primarily for self-consumption (not for wheeling/export) up to 100 kW
 - EG for wheeling/export up to 100 kW
- Require NERSA registration but exempt from licensing:
 - EG primarily for self-consumption over 100 kW
 - EG for wheeling/export over 100 kW

EG of any size are exempt from NERSA licensing. The above applies whether the EG has storage or not.

All EG, irrespective of size, need to comply with the Codes and Distributor requirements, and the Distributor needs to keep a record of these systems.

Although registration is a simpler and quicker process than licensing, there are still requirements to be complied with and the process can take time⁵.

More details on NERSA's registration process and requirements for Generators/Customers and Distributors are provided in Appendix F.

Note: Although the regulations are not clear on licensing and registration of BESF, it is understood that stand-alone BESF should be treated as a generator and should comply with licensing or registration requirements based on their output in kW and self-consumption characteristics, as indicated above.

1.2.3 Feasibility of the project

At the time of publication of this document, NERSA will consider the feasibility when assessing the registration application as per Clause 9.2(b) of the application for registration procedure. It is not clear what is involved in this assessment by NERSA.

1.2.4 ERA Section 34 determination⁶

The determinations deal with the procurement of new generation capacity by organs of state and ensures all procurement is in line with the Integrated Resource Plan (IRP). When NERSA considers an application for a generation license, a primary measure is to check for evidence of compliance with the national Integrated Resource Plan (IRP). However, with the amendment to Schedule 2 all EG for self-consumption is exempt from licensing.

⁴ First released on 15 December 2022 with a re-release on 17 January 2023 with a minor correction. Available here: [Electricity Regulation Act: Amendment: Licensing Exemption and Registration Notice. Govt Gazette No 47877, 17 January 2023](#)

⁵ Note that the recent Energy Action Plan Update, January 2023 released by the South African Government states that NERSA registration timeframes have now been reduced from 4 months to 19 days.

⁶ Further information is available in *National Treasury MFMA Circular No. 118, Municipal Finance Management Act No. 56 of 2003: Legal Framework for Procurement of New Generation Energy Capacity by Municipalities and Municipal Entities* (June 2022)

For municipal own-procurement (municipal owned or via an IPP), legal analyses indicate that a Section 34 Ministerial Determination is not required for generators > 1MW⁷ (as long as individual generators are below any licensing threshold that is set in Schedule 2 of the ERA), but note that DMRE still considers it necessary (in terms of Regulation 5 of the New Generation Regulations). Such application to the Minister should be in accordance with Regulation 5 of the Electricity Regulations on New Generation Capacity⁸, including feasibility studies, proof of compliance with the MFMA and other municipal regulations, and proof of alignment with the municipal IDP.

1.2.5 Other regulatory requirements

Municipal Distributors should be aware that requirements additional to the Grid Code are implied by the Distributor's license conditions, such as safety of staff and the general public.

Installation safety remains the responsibility of the Distributor, delegated to the owner or tenant via responsibility for the Certificate of Compliance. To this effect, compliance to the relevant documents from the SANS 10142-series are required, including SANS 10142-2 for larger installations.

⁷ For example, *Constitutional and Legislative Competence and Authority of Municipalities to Procure or Buy New Generation Capacity - Part B: Overview Legal Framework*. Western Cape provincial Government MER Programme – Energy Projects Report, November 2021, and *Legal Framework Applicable to Embedded Generation in South African Municipalities*. Pinsent Masons for Sustainable Energy Africa, September 2022.

⁸ Electricity Regulations on New Generation Capacity,
https://www.gov.za/sites/default/files/gcis_document/201409/34262rg9530gon399.pdf

1.3 Size categories

In terms of the RPPGC and BESFCC, Table 1 lists the following size categories to apply to renewable power plants and battery energy storage facilities:

Table 1: Generator size categories according to SAGC (merged classifications from RE and BESF Codes).

Category	Subcategory	Size	
A	A1	Up to and including 13.8 kW	Up to 1000 kW
	A2	Greater than 13.8 and less than 100 kW	
	A3	Greater than 100 and less than 1000 kW	
B ⁹	B1	From 1 up to and excluding 5 MW	1-20 MW
	B2	From 5 up to and excluding 20 MW	
C		Anything above and including 20 MW	

These size categories are important since some Grid Code requirements differ between the categories.

The size referred to in Table 1 refers to the rated AC capacity of the generator installation, and not the anticipated net export capacity.

The term ‘small-scale embedded generation’ (SSEG) refers to category A generators.

Note that while some regulatory documents classify generators according to their apparent power rating (in kVA or MVA), others classify them only based on their active power output (in kW or MW). In many instances the two can be used interchangeably. However, for consistency it is recommended that municipalities communicate with prospective Generators/Customers based on the active power (MW) output of the generator, with the understanding that reactive power (Mvar) range shall meet the applicable requirements of the Grid Code and apparent power (MVA) shall remain within the rating of all associated equipment and applicable Grid Code category requirements.

⁹ Category B is subdivided at 5 MW in the BESFCC only (at the time of publication), but certain requirements, e.g. power quality, follows the same categorisation in the RPPGC.

1.4 Overview of the process: From application to compliance sign-off

The high-level process below comprises nine steps and includes both Distributor and Developer processes and/or responsibilities.

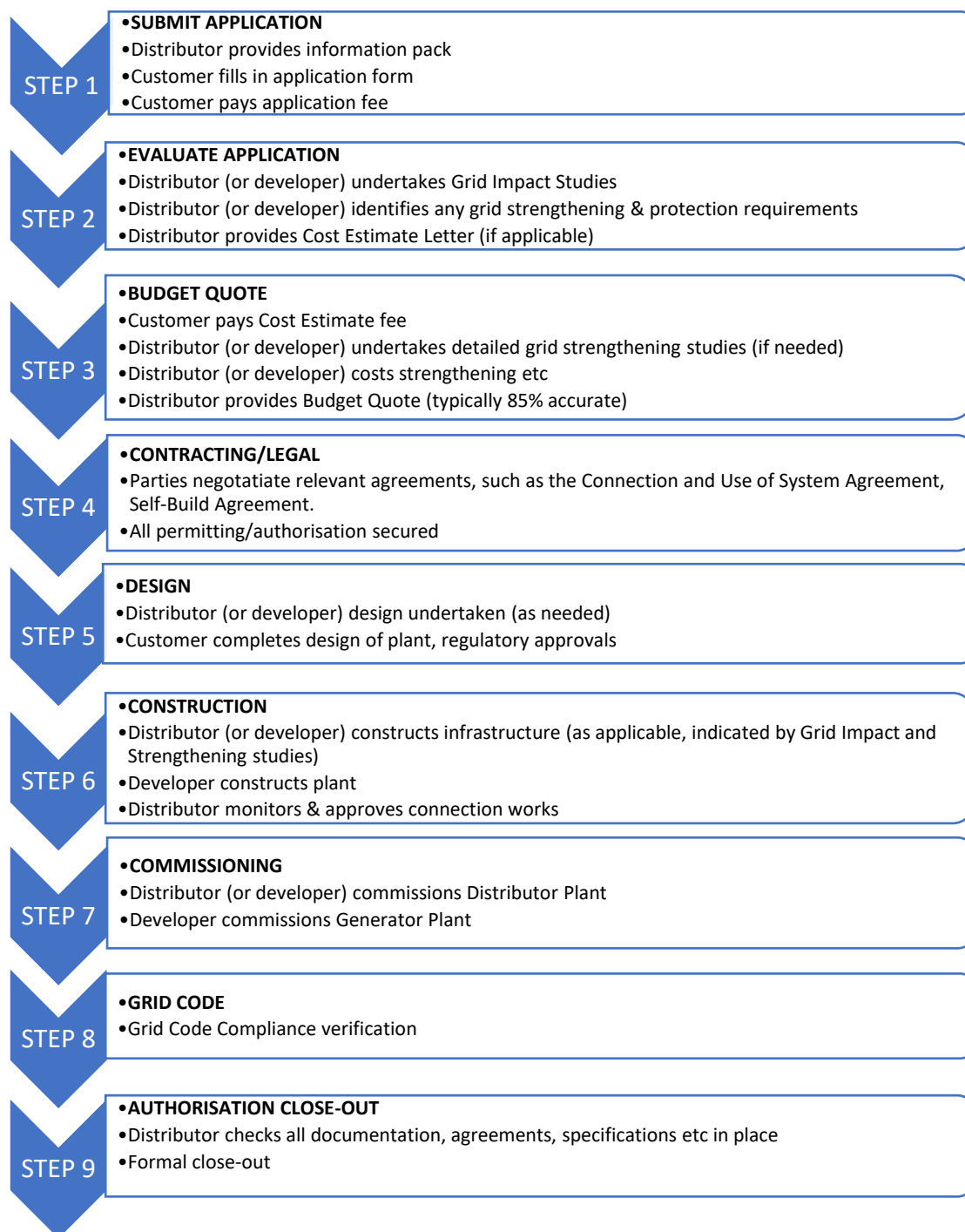
Note that a self-build option also exists, where the Developer will take over some design and construction responsibilities¹⁰. The assets' ownership will transfer to the Distributor once the project is completed.

The expected benefits are improved efficiency by both increasing the speed of execution, as well as potential reduced costs of new assets. Note that the Distributor will remain responsible for the quality of such works and will approve and sign off on all steps (as if the Distributor executed the project internally).

A further reduction of steps may occur, for example to combine steps 2 and 3 for smaller and/simpler EG projects, where no network upgrades or strengthening is required.

At a high level, the process is shown below.

¹⁰ Note that the normal Distributor standards and quality assurance processes apply, and the Distributor remains responsible.



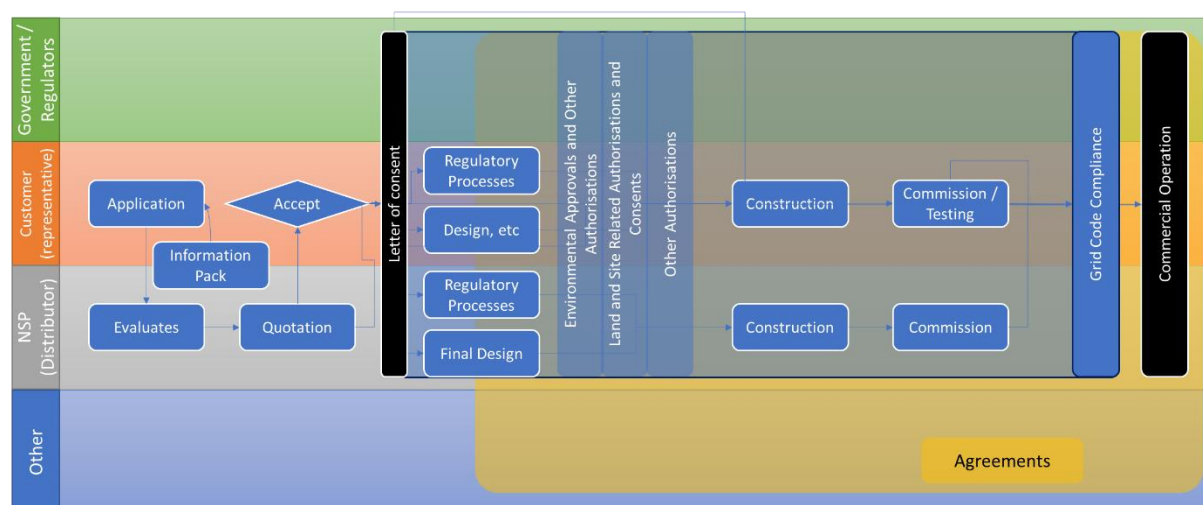


Figure 1: High-Level overview of process (showing progression and relevant party for different steps)

1.5 Municipal own procurement processes¹¹

For municipal own procurement (municipal-owned or IPP power purchase) a competitive process is required as per the MFMA. Criteria for considering unsolicited bids are articulated in section 113 of the MFMA and Regulation 37 of Municipal Supply Chain Management Regulations. Power purchase is unlikely to meet these criteria, and the procurement process should uphold fair, equitable, transparent, competitive and cost-effective principles.

Any PPA with a duration longer than 3 years needs to comply with MFMA Section 33 processes, including requirements around public notices and consulting relevant national and provincial government departments (specific Distributor supply chain policies may also include other conditions in this regard).

Expenditure by municipalities must not only be according to sound procedures but must be included in council approved budgets, considering both capital costs and operational costs.

Specific Distributor Supply Chain Management Policies may also have relevant provisions regarding such procurement.

Procurement should be in terms of the Preferential Procurement Policy Framework Act, 2000, and associated Regulations, including B-BBEE and local content provisions. Exemptions may be applied for from Department of Trade, Industry and Competition, although in the past these have seldom been granted. Local content requirements are being revised with a view to facilitating generation development¹².

¹¹ Further information is available in *National Treasury MFMA Circular No. 118, Municipal Finance Management Act No. 56 of 2003: Legal Framework for Procurement of New Generation Energy Capacity by Municipalities and Municipal Entities* (June 2022).

¹² Address by President Cyril Ramaphosa on actions to address the electricity crisis, 25 July 2022.

1.5.1 Public Private Partnership (PPP)

Where the performance of a municipal function by a private party takes place, this may be considered a PPP and the MFMA and Treasury Guidelines in this regard should be followed. Where the municipal Distributor is an offtaker of power generated, this is unlikely to be considered a PPP. Similarly, the use of municipal land for an IPP where the Distributor is an offtaker does not on its own classify this arrangement as a PPP.

The difference between PPPs and traditional government infrastructure projects

A PPP is defined as a contract between a public-sector institution and a private party, where the private party performs a function that is usually provided by the public sector and/or uses state property by agreement. Most of the project risk (technical, financial and operational) is transferred to the private party. The public sector pays for a full set of services, including new infrastructure, maintenance and facilities management, through monthly or annual payments. In a traditional (non-PPP) government project, the public sector pays for the capital and operating costs, and carries the risks of cost overruns and late delivery. (Source: *National Treasury PPP Manual and Practice Notes*).

1.6 Other considerations

This section contains a brief discussion on other issues related to EG on municipal networks.

1.6.1 Self-consumption

Self-consumption generation refers to the condition where the generator is sized mainly to support the existing load and export to the network is secondary – if it takes place at all. Customers with such characteristics are also called prosumers. The generator may typically be sized for the customer's expected base load (during peak generation). It would typically be installed to reduce the electricity bill. In the South African context, this may also include the use of storage to allow stand-by operation during interruptions (such as load-shedding).

Customers should note that self-consumption will potentially have less impact on the network and enable a simpler assessment process than for generators exporting all of their power. The network impact is reduced since the maximum instantaneous generation rejection is limited to relatively small values in line with the load size, i.e. if the network is adequate for the load it should be able to accommodate the

generator. Note that a grid impact study will still be required – even where customers do not export onto the network (e.g. to assess generator rejection impact etc).

When is a Grid Impact Study required

According to the Distribution Network Code, a grid impact study is required for any new connection. However, the NRS 097-2-3 provides guidelines (simplified connection criteria) which serves as a proxy for a grid impact study. Furthermore, the NRS 097-2-3 guideline only accounts for installations up to 1 MW and hence all generators larger than 1 MW OR generators falling beyond the NRS 097-2-3 requirements or limitations, require a grid impact study.

With the significant increase in “Behind the Meter” installations, proposals have been sent to the GCAC to amend the grid code with better guidance and requirements for these installations.

An NRS working group has been established to consider the various aspects of grid impact studies (NRS 118, under development).

Self-consumption is not a requirement for customers to connect.

Four-quadrant metering should be installed. For Distributors that do not have any four-quadrant meters available, an export block device may be applicable as an interim measure. Export may be allowed at a later stage only when a four-quadrant meter can be installed. It is recommended that the Distributor monitors the meter for possible reverse feed, even in the presence of reverse block devices.

Note on export/reverse blocking: Note that while EG with reverse blocking can have reduced impact on the grid, the Grid Code still applies and grid impact studies are still needed.

1.6.2 Peak-load capacity

Peak-load in a power system context refers to the load during peak demand. Thermal generators (e.g. coal, gas, biomass) can be dispatched during peak load conditions and support the grid during these periods. Similarly, storage facilities may be able to support peak load.

Therefore, dispatchable, and partially dispatchable embedded generation should be encouraged as this could potentially support the network and alleviate the impact of loadshedding. This could include generators having some form of storage.

The use of grid-forming (GFM) inverters may also be considered to assist in grid support and stability. Note that GFM may be able to provide benefits, especially in weaker networks. However, exact requirements along with benefits and potential disadvantages should be discussed with the Distributor.

1.6.3 Upgrading of existing SSEG to >1 MW

Where an existing generator of up to 1MW (i.e. an SSEG) wishes to upgrade output capacity to greater than 1 MW, this guideline proposes that the total size of the generator needs to be considered in assessing the application – not just that of the additional capacity. The *full* application process therefore needs to be followed for the Customer’s total generation capacity. This refers to grid impacts, agreements, regulatory authorisations etc.

Note that there is no consensus on this topic in the industry – and guidance from NERSA is required.

1.6.4 Ancillary Services

Ancillary services refer to any function provided by grid-connected generators¹³ that assists the network in some way, e.g. voltage control or frequency control. Voltage control is usually implemented via reactive power control or transformer tap-changer control and can be managed by the Distribution Network Operator (DNO) or the System Operator (SO). Frequency control is a system-wide phenomenon and typically managed by the SO.

Apart from reactive power control and frequency response control, both the risk mitigation and recent government procurement programmes require that the generators provide additional ancillary services, namely instantaneous reserve and regulating reserve.

These requirements are in the RPP Grid Code but have not been enforced operationally before. The appropriateness of EG installed for self-consumption to comply with these requirements is under debate, and future regulatory revisions may modify such requirements. Any Customer wishing to install such a generator should enquire with the SO and/or NERSA about these requirements as part of their process. In the interim, should ancillary services be required beyond standard generator capability requirements listed in the Grid Code, these will be contracted specifically by the SO.

All battery storage facilities of category B2 and larger must have the capability to provide ancillary services by default.

¹³ Ancillary services may also refer to the grid stability support provided by e.g. large industrial loads, etc. This is however, not applicable in the current context.

Institutional Capacity / Human Resources

Initial implications for municipal institutional capacity of dealing with increased applications for large generators to connect can be significant. Potential areas requiring attention in different municipal departments are noted below:

1. Technical (Evaluation of Application):

a. Planning

Staff capacity will be needed to undertake the following:

- i. Network data capture and quality checking
- ii. Evaluation of grid impact studies

Should the Distributor wish to do the studies themselves, they will also require staff as follows:

- iii. Network studies, including loadflow and fault analysis

b. Protection and SCADA requirements

c. Quality of Supply: Capture, analyse and interpret data. Additional power quality monitors will also be required.

d. Network control: Give effect to DNO/DSO requirements in terms of the Grid Codes.

e. Maintenance: It is not anticipated that significant additional infrastructure will be required; therefore, staff capacity issues are unlikely, at least in the short term.

However, ensuring adequate training for maintenance in the presence of EG is essential.

2. Finance:

a. Tariffs: extra demands are likely to be limited, although additional tariff structures may be required as a once-off design. A wheeling tariff will be required where wheeling is allowed.

b. Metering and billing: Small increases in workload are likely. However, with appropriate database and smart system setup, this increase should remain manageable.

c. Budgets and quotes: Issuing more quotes will be necessary. This will require cooperation with the electricity planning department.

d. If the municipal Distributor intends to enter into PPAs with Customers installing generators, a competitive procurement process will be needed in accordance with the MFMA, which will place additional demands on staff resources.

e. Wheeling: allowing wheeling may result in additional workload; at least a wheeling agreement will be required in addition to other agreements. Apart from the tariff, additional data management will be required.

3. Legal:

There may be a significant increase in the number of agreements required over and above the standard Connection Agreement. This may have implications for staff capacity over time as more generators are connected.

Municipal own generation or IPP procurement:

This is a significant endeavour and typically will require substantial allocation of staff capacity, often need external expert support, and require staff training to manage such processes.

1.7 Life cycle costing considerations

The Customer should consider life-cycle costing in their feasibility assessment. The purpose of life-cycle planning is to ensure that the total cost of ownership of an installation is considered. Often, the capital costs are included and most other aspects are overlooked, e.g. maintenance. An important aspect often omitted is the decommissioning, removal and site restoration costs.

Aspects such as decommissioning, waste management and site restoration, including financial provisions for these tasks, would typically be included in the environmental management plan. It is the Distributor's prerogative to request these details.

1.8 Assumptions regarding Distributor capabilities

It is assumed that the relevant Distributor already has a suitable process in place to deal with SSEG¹⁴, based mainly the NRS 097-2-suite of documents (NRS, 2024) (NRS, 2023). This guide focusses on the additional aspects when dealing with generator applications larger than 1 MW.

¹⁴ Where a Distributor does not have a process in place for SSEG, contact the SSEG support team for assistance: support@sseg.org.za.

2 Municipal Processes

This section contains the steps to be followed by a Distributor from the time a Customer intending to install a generator (hereinafter referred to as the 'Customer') applies for a connection point, up to the time of Commercial Operation. High-level descriptions of the Customer processes that may occur in parallel to the Distributor processes are also provided. No proposed timelines are provided at this stage and may be added in a future revision of this document.

The processes assumes that no hosting capacity study has been done, i.e. the Distributor does not know how much generation can be accommodated at various levels in the network. This means that each application is reviewed on its own, taking other installed and approved generator installations into account. A hosting capacity study should ideally be done along with the periodic network development planning exercises, as it will allow for more rapid generator application assessment.

This steps in this section may form the basis for a customised internal municipal guideline.

2.1 Step 1: Application

APPLICATION STAGE SUMMARY:

The Distributor provides the customer with necessary forms and information, and the customer completes the application form enabling the assessment to proceed.

Distributor:

- Provides information pack to customer, including the application form
- Invoices the customer for the application fee (as applicable)

Customer:

- Completes the application form for generator
- Submits the completed application form
- Pays the application fee

Initial interactions with the Customer should be handled by the Customer Care department (or equivalent section), who will communicate internally with the Network Planning Department. Future interactions may be between the Network Planning Department and the Customer directly. The process starts when a Customer applies for a generator connection point. This application is required in all cases:

1. New generator application – Customer has no supply point yet
2. New generator application – the Customer only has a load supply point (Point of Supply)
3. Amended generator application – the existing generator capacity is increased (or decreased)

Grid stability and network interference are likely to change at the point of connection, hence grid impact studies are required.

The Distributor should ensure that the Customer understands the process via the provision of an information pack.

Once the application fee has been paid, the application will be processed, generally by the Distributor's Network Planning Department. The customer will receive a Cost Estimate Letter after the evaluation of the application (Step 2).

NOTE: Other departments / sections will also need to be advised, e.g. quality of supply, protection, legal, metering and billing. It is important that the relevant people be informed of the generator application as soon as possible to prevent delays later in the project. It is useful to include these sections and timeline for the process in an internal municipal guideline.

2.1.1 Application Pack

The base set of documents that the customer should receive are the following:

1. *Connection application form*

No application can be processed without a certain minimum set of information, as specified in the application form for larger generators. Critical information includes location/address, generation technology, intended/preferred point of connection to existing infrastructure (if known), capacity of generator, intended maximum export capacity, whether storage will be installed as part of the generation facility and whether charging will be required from the grid.

[A template application form can be found here.](#)

2. *Invoice for the application fee¹⁵*

The Distributor should apply an appropriate application fee, which would:

- a. Cover the costs incurred by the Distributor in assessing the application and providing a Cost Estimate Letter (see Step 2)
- b. Act as a guarantee that the customer is serious about the application

3. *Information pack*

This document pack should include a guideline regarding the processes and technical requirements that the customer needs to meet to connect successfully (e.g. extracts of this document). It should also contain a set of generic legal agreements which will be applicable. See Section 2.4 for a list of possible agreements as well as sources for examples.

The information pack provided should include as a minimum:

- a. Guideline for Municipalities on Processing Embedded Generator Applications Larger than 1 MW (e.g. this document)
- b. Connection and Use of System Agreement (CUOSA) ([template here](#))
- c. Self-Build Agreement (should the Customer be required to build infrastructure within a Municipal substation)
- d. Wheeling agreement (if applicable - this may be embedded into the CUOSA)
- e. Distribution Network Code (NERSA, 2022)
- f. Other applicable technical, legal, financial and operational agreements (unique to each Distributor)

¹⁵ As an example, Eskom's 2025/26 fees on application to produce a Cost Estimate Letter are shown here:

>1 – 10MVA/MW (Major process)	R 33 346.41 + VAT = R38 348
> 10 MVA/MW – 50 MVA/MW (Large)	R 68 375.36 + VAT = R78 632
> 50 MVA/MW <=100MVA/MW	R 101 852.18 + VAT = R117 130

- g. Applicable tariff structures
- h. [Grid impact study information/specification and requirements](#)
- i. Grid Code Compliance Requirements (NERSA, 2022)
- j. Policy regarding the allocation or reservation of hosting capacity space on the network.
- k. Expected timeframes for the processing of the application. Whilst the practical timeframes depend on various aspects, e.g. data availability, staff complement, etc, the following timeframes are proposed:
 - i. Acknowledgement of application should be within 48 hours (basically automatic).
 - ii. SSEG – 30 days to process and advise Customer.
 - iii. Larger than 5 MW - 2 months and advise Customer.

2.2 Step 2: Evaluate Application

EVALUATION STAGE SUMMARY:

This step undertakes studies to determine if the generator can connect to the network or if grid strengthening is required, as well as assessing protection, power quality and maintenance implications. A key output is a Cost Estimate Letter (non-binding) to enable the customer to estimate project financial feasibility.

Distributor (many of these may also be outsourced to the Customer):

- Undertakes Grid Impact Study
- Undertakes short-circuit studies
- Evaluates protection coordination (see Appendix G for more details)
- Undertakes quality of supply apportioning and expected resonance screening
- Assesses maintenance implications
- Assesses metering implications
- Issues Cost Estimate Letter to Customer

Customer:

- Accepts Cost Estimate Letter (or explores/discusses other options)
- Acknowledgement of protection and power quality parameters/implications

Aspects included in the evaluation are summarised in Figure 2.

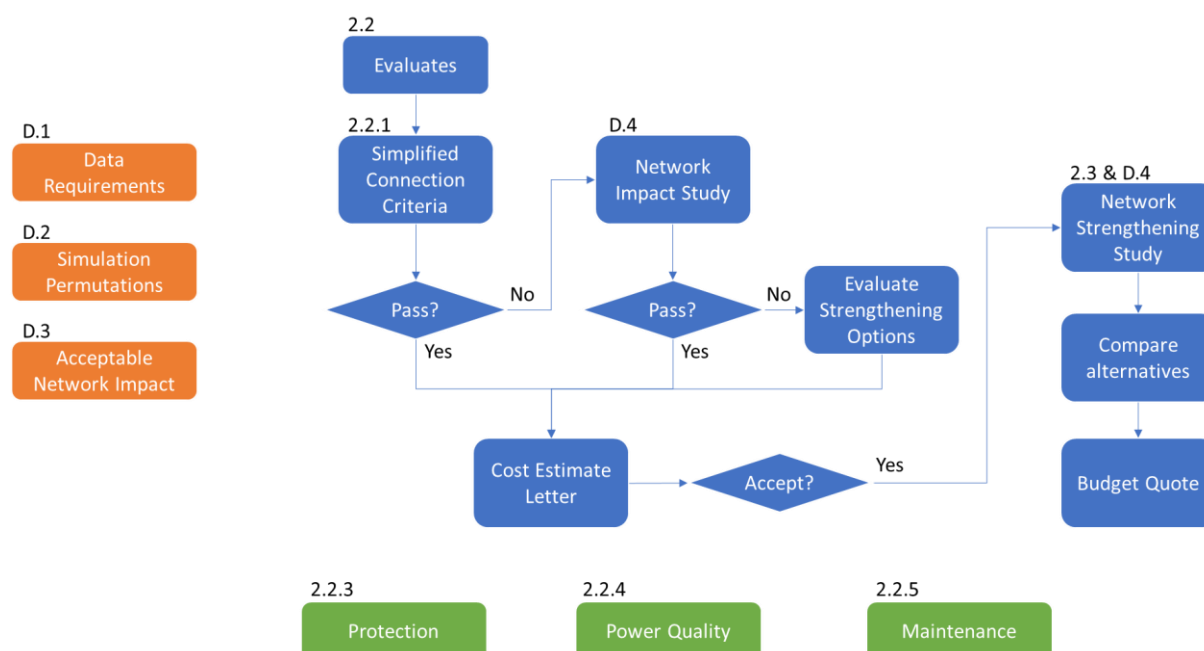


Figure 2: Distributor evaluation process and components ('D' refers to Appendix D, numbers to section numbers in the document)

2.2.1 Grid Impact Study

For all generators >1MW simulation studies need to be done to evaluate the impact on the network in the area. This requires sufficiently detailed information of the surrounding network. This is called the Grid Impact Study¹⁶. High-level guidance is provided in Appendix D.

The Grid Impact Study should:

1. Check for impact on the network in the area to see if the generator can be connected without grid strengthening, or if such strengthening is necessary
2. Deliver basic information on grid strengthening to enable an indicative Cost Estimate Letter so Customers can assess financial feasibility of the project.

Note that existing generators are considered during this phase of the evaluation, but other applications that are not at Budget Quote fee payment stage (Step 3) are typically not considered.

¹⁶ Note on terminology: It should be noted that, internationally, the concepts and terms "grid impact study," "network impact study," and "system impact study" are often used interchangeably with largely similar meanings. However, in the South African context, a "grid impact study" may entail limiting the scope to the Point of Connection (PoC), whereas a "network impact study" typically looks beyond and upstream of the PoC. Our recommendation is that any of these studies, including those referred to as "grid impact studies," should always consider and include the upstream network during modeling and simulations to ensure a comprehensive assessment and be in line with international standard practice.

NRS 097-2-3 Simplified Connection Criteria for generators <1MW

For small-scale embedded generators (SSEGs) with a capacity of less than 1 MW, a simplified connection assessment as outlined in NRS 097-2-3 may be used as an alternative to comprehensive grid impact studies. NRS 097-2-3 addresses the generator's individual impact at the Point of Connection (PoC) and also considers the cumulative impact of multiple embedded generators within a defined network segment (i.e. hosting capacity), including the relevant MV feeder.

A key outcome of a hosting capacity study is the establishment of internal, network-specific simplified connection criteria tailored for generators exceeding 1 MW.

If the proposed connection point and/or surrounding network does not have sufficient capacity for the generator to connect, the customer should be advised that (a) the process will take longer and (b) the cost to connect may be significantly higher as network upgrades are needed. An indication of such costs will be given in the Cost Estimate Letter.

The customer should also be given options to reduce their impact on the network (e.g. by installing a smaller system) to potentially avoid the need for upgrades.

Fair share of hosting capacity: Municipalities may elect to allocate network capacity for generation connections on a “first-come, first-served” basis, or to apportion quantities of network capacity to customers such that the total available capacity can be fairly shared amongst many or all customers, should they wish to connect a generator at a later stage. Assessments should also consider how much of other customers’ fair share of the network generator hosting capacity is used, since this affects the potential cost of connection for future customers. Currently there are no guidelines in place for sharing of hosting capacity or network upgrade costs, and no legal requirements exist in this regard.

The Municipal Fiscal Powers and Functions Amendment Act 4 of 2024 provides further guidance on Development Charges. Example documents can be found on the <https://www.sseq.org.za> website.

An overview of the network study evaluation process is provided in Figure 2. This figure also indicates Data requirements, Simulation Permutations and Acceptable Grid Impact, as well as relevant departments that need to be consulted during the evaluation process, i.e. Protection, Power Quality, Network Control and Maintenance.

2.2.2 Who should undertake the Grid Impact Studies?

While some municipal distributors will undertake all aspects of impact studies in-house, many do not have the necessary staff capability or software. Note that, aligning with the EG Grid Impact Study Guideline, customer classification will determine the extent of studies required. Also note that the Grid Impact Study is the responsibility of the Distributor, even if it is outsourced as proposed in the following three options:

1. **Grid Impact Studies done in-house:** provided the Distributor has sufficient staff with appropriate training and experience using a suitable software package. Associated costs are covered by the application fee.

2. **Outsource to specialist company:** the Distributor may outsource the Grid Impact Study to a specialist company. Associated costs are covered by the application fee.

NOTE: This may imply a more costly application fee, since external consultants may be more expensive than internal staff. This should be a pass-through cost to the Customer.

3. **The Customer's engineering team does the Grid Impact Study:**
 - a. The Distributor will provide the customer with the *Embedded Generation Grid Impact Study Specification Guideline*¹⁷ which sets out the work to be undertaken.
 - b. The Distributor's planning department will provide the necessary network information for the studies to be done. Network information may need to cover additional parts of the network up to the Eskom point of delivery to evaluate changes in the agreement with Eskom as well. The latter ensures the Customer has sufficient data to conduct a thorough assessment.
 - c. The Distributor will evaluate the study to determine if the generator can connect without adverse impact on the grid. This evaluation must adhere to the criteria outlined in the [EG Grid Impact Study Guideline](#)¹⁸.

It is noted that there may be conflict of interest when Customers have their own specialists to conduct the Grid Impact or Strengthening Studies. For this reason, sign-off by an independent ECSA registered professional¹⁹ is required for these studies – paid for by the Customer - along with any internal reviews that the Distributor conducts (e.g. technical and financial evaluation committee reviews). The Distributor retains final approval authority, in line with the Guideline's emphasis on network stability.

Furthermore, the study may be done to the POC or include a larger part of the network. In order to confirm the impact of multiple generators, the impact on the larger part of the network is required, which can often only be done by the Distributor (or via a specialist company).

Ideally, each Distributor should do a hosting capacity study to determine at a high level how much generation can be accommodated at various parts of the network¹⁸.

Note: In the case that the Customer does the Grid Impact Study, it is possible that the Grid Strengthening Study (Step 3, which may involve the distributor) is included to make it a combined study. The proposed solution will still have to be evaluated by the Distributor and be accepted at the relevant technical and commercial committees.

2.2.3 Protection

Protection forms a critical component of the Grid Impact Study and overall connection assessment.

The Distributor shall evaluate whether the proposed embedded generator (EG):

- Maintains fault levels within existing equipment ratings;

¹⁷ Available at <https://www.sseg.org.za/grid-impact-study-specification-guide/>

¹⁸ A new NRS document series (NRS 118) has been initiated to support Distributors and Customers with system study requirements. It is likely to replace the current Guideline once completed.

¹⁹ Ideally, the independent professionally registered person should be procured by the Distributor to reduce conflict of interest. However, the code of conduct for professionally registered persons mitigates the risk.

- Allows correct protection coordination under typical system conditions, including credible contingencies;
- Does not compromise the safety of personnel or equipment;
- Does not adversely impact municipal protection schemes.

Any required updates to protection settings or upgrades to protection equipment shall be identified during the Grid Impact Study and included in the scope of work of the party undertaking the study. Where protection upgrades are required, these shall be reflected in the Cost Estimate Letter.

Fault Levels

As part of the Grid Impact Study, fault levels shall be calculated under relevant network configurations to ensure that:

- Breaker making and breaking ratings are not exceeded;
- Busbar and transformer short-circuit withstand ratings are not exceeded;
- Protection sensitivity is adequate under both maximum and minimum fault levels.

These results inform protection settings and, where necessary, selection or upgrading of protection equipment.

Protection Coordination

A protection coordination study shall be undertaken to ensure:

- Correct operation of protection under all credible network conditions;
- Proper grading with upstream and downstream protection;
- Avoidance of nuisance tripping.

Auto-Reclosers

Where auto-reclosers are installed upstream of the generator, reclosing times shall be coordinated with the anti-islanding requirements of the EG.

Unless otherwise specified, generators shall disconnect from an islanded network within 2 seconds. Upstream reclosing times shall therefore exceed this duration to prevent out-of-sync re-energisation.

Directional Relays

Where export is permitted, the Distributor shall confirm whether directional protection is required to:

- Maintain correct grading;
- Prevent unintended reverse power tripping;
- Support export control schemes where applicable.

Directional elements shall be appropriately configured to avoid blocking permitted export.

Summary of Appendix G Requirements

Appendix G provides detailed technical protection requirements applicable to embedded generators larger than 1 MVA. These include, inter alia:

- Single-contingency (n-1) protection compliance;
- Maximum fault clearance time limits at the Point of Connection;
- Zero-sequence current decoupling requirements (Category B and C);
- Additional protection functions for Category C generators;
- Anti-islanding and synchronism check requirements;
- Protection interlocking and communication requirements;
- Commissioning and verification requirements prior to energisation;
- Firmware and control update notification requirements for inverter-based generators.

Detailed protection philosophy approval and settings verification are undertaken during the design and commissioning stages (Step 5 and Step 7).

Appendix G shall be read in conjunction with applicable Grid Code, NRS standards and related interconnection standards²⁰.

In general, the impact on Distributor protection is minimal and the majority of additional requirements are the responsibility of the Customer. Appendix G is provided with additional information for the Customer and should be read in conjunction with the future NRS 097-1.

²⁰ Example: the City of Cape Town Interconnection Standard: <https://www.sseg.org.za/technical-standard-for-the-interconnection-of-embedded-generation-cape-town/>

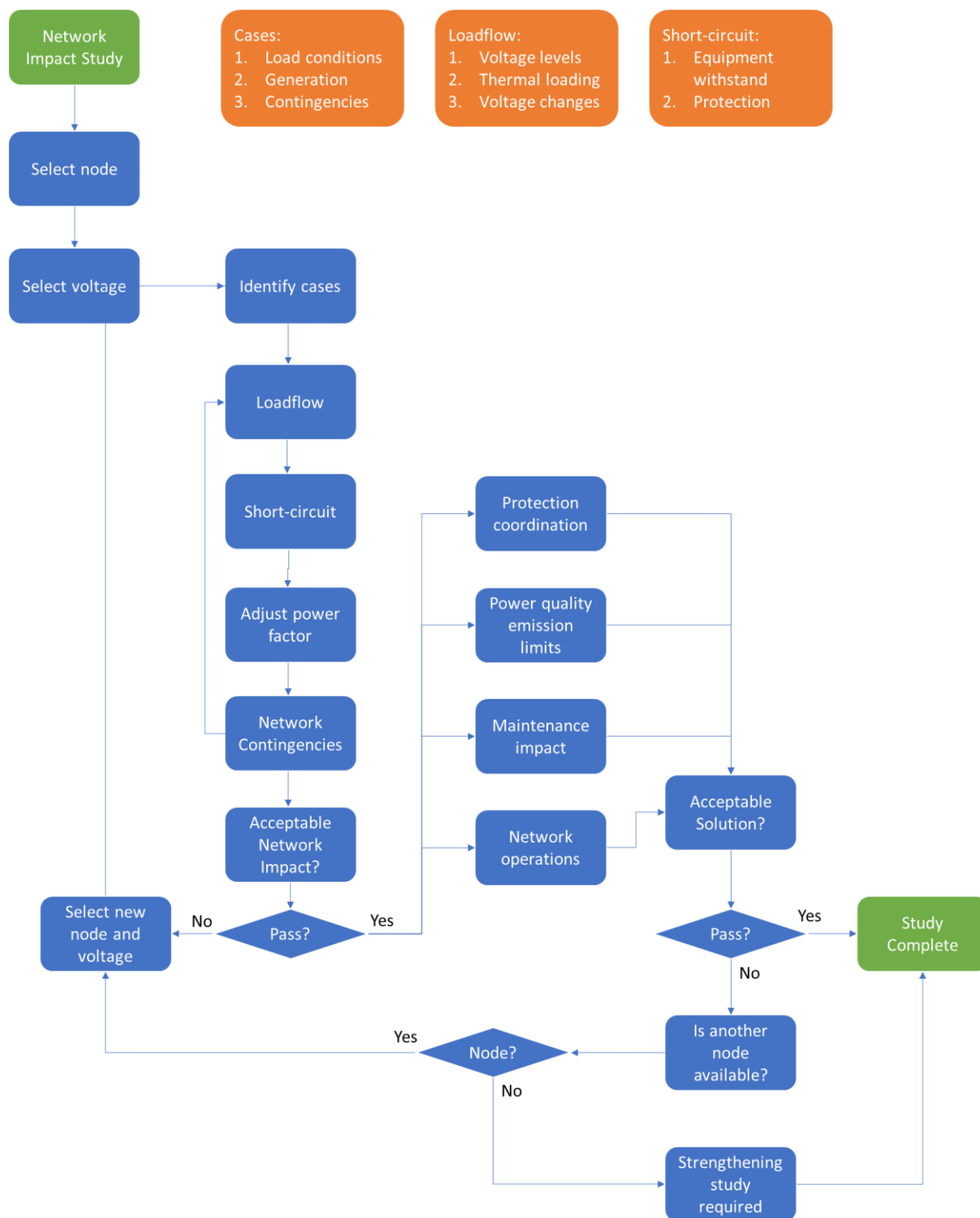


Figure 3: Overview of grid (network) impact study process.

2.2.4 Quality of supply (power quality)

The RPP Grid Code stipulates specific requirements from the Distributor in terms of power quality. Non-renewable generators should be managed in a similar manner, since these requirements are well described in the RPP Grid Code. The Connection Agreement allows for appropriate collaboration between the different parties even in the absence of specific Grid Code requirements (e.g. for non-renewable generators). The three key aspects are:

1. Background power quality levels
2. Recording power quality going forward
3. Allocating appropriate emission limits to the customer (apportioning)

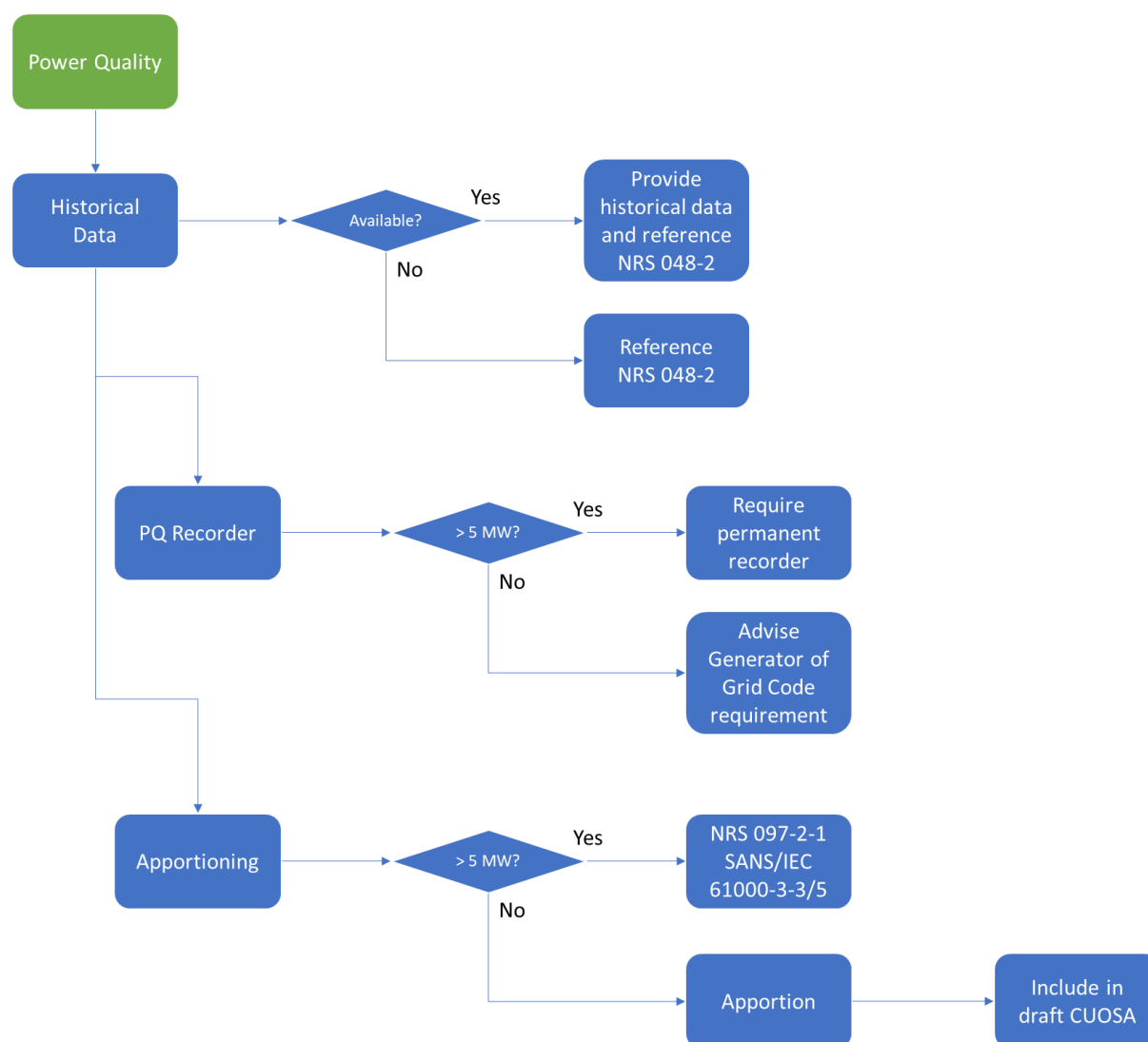


Figure 4: Power Quality aspects.

Background Levels

The Distribution System Operator (DSO) should supply background power quality information (i.e. historical information), including reliability of the network. This may be at the closest node in the network where a PQ recorder is available. If no suitable power quality data is available, the Customer is referred to the NRS 048-2 compatibility levels. Note that all generators must be designed to withstand the NRS 048-2 compatibility levels, including appropriate response when these levels are exceeded, e.g. disconnect from the system to protect themselves.

The background levels should be provided to the Customer along with the Cost Estimate Letter.

Monitoring

It is required that generators larger than 5 MW all have PQ recorders installed at the PoC²¹. This may also be at the customer's cost, and should be included in the Budget Quote (see Step 3). In line with Grid Code and legal requirements, these instruments must be compliant to IEC 61000-4-30.

Such installation should be undertaken with or before generator installation.

Note that it is the Customer's responsibility to monitor power quality at the PoC (monitoring may be periodic or ongoing/permanent – the latter is suggested for EG>5MW) and they should be informed of this responsibility. This requirement should also be included in the relevant Distributor policy documents.

Apportioning

The RPP Grid Code requires that apportioning for power quality parameters be done for all generators larger than 5 MW following the IEC 61000-3-6/7/13 (or as simplified in NRS 048-4) documents. Apportioning shall be done for voltage harmonics, voltage flicker and voltage unbalance. Other parameters may be added to a Connection Agreement based on particular local network performance, such as inter-harmonics, rapid voltage changes etc.

The quality of supply parameters and emission limits needs to be included in the Connection and Use of System agreement with the Customer. Apportioned power quality emissions levels should be provided along with the Cost Estimate Letter.

Note: Where the Distributor's PoD with Eskom may be affected, e.g. reverse power flow to Eskom, it may be required to update the Connection and Use of System agreement between the Distributor and Eskom. In this case, the power quality emission limits from the Distributor may change. This needs to be considered when calculating the emission limits for the generator.

2.2.5 Maintenance

The impact of network extensions and/or strengthening on maintenance requirements should be assessed. The following impacts should be considered:

- additional equipment that requires more personnel to maintain
- additional spares requirements (new network equipment should be the same as existing equipment as far as possible so that existing spares will be sufficient)

²¹ The Distributor may also require this of smaller generators should they consider this necessary (in which case it should be specified in their policy and by-law). As per clause 9(3) of the RPPGC, the RPP shall monitor and report the power quality. In view of the simplified power quality requirements for units smaller than 5 MW, it is recommended to require the permanent PQ recorder only for larger units.

Note: appropriate policies to prevent continuation of outdated equipment should be in place.

New equipment may also have special maintenance requirements, e.g. if new breakers are SF6 insulated. This should be discussed and agreed with the maintenance/operational department, as well as operational philosophies.

For a network point that may not have high enough reliability, the potential improvement of network interruption and dip performance should be considered, which may be addressed via improved maintenance philosophies.

2.2.6 Other considerations

Loadshedding

Where a generator should preferably not be subjected to loadshedding, the connection point may need to change to ensure that loads may be disconnected while the generator remains connected (if there is sufficient export capacity). This can be dealt with on a case-by-case basis.

Grid availability

It is good practice to agree on the expected availability of the grid connection point. This is often referred to as the allowed grid unavailability period (AGUP) per year. Penalties for less availability may be appropriate in some circumstances e.g. in the Power Purchase Agreement (PPA).

Since loadshedding is outside the control of the Distributor, it should be excluded from AGUP.

Ramp rate(s)

Although the voltage changes are evaluated during the Grid Impact Study, it is better to prevent such voltage changes. Therefore, appropriate ramp rates should be set where the generator can control this, e.g. for wind generation tripping off during overspeed conditions, or PV during partially cloudy days.

Battery charging

The potential impact of generators with battery storage, especially after a long interruption, needs to be evaluated. In general, the charging rate should be limited to the ADMD value (and in terms of NRS097-2-3, 25% of ADMD or breaker capacity). Distributors may require charging to be delayed or staggered and would be informed by amongst others the grid impact studies.

Note that a smaller value than the ADMD may be appropriate in congested networks.

2.2.7 Network operations

The Network Operations Department need to consider the impact of the generator under normal and contingency scenarios. The following list provides guidance on the key aspects (not an exhaustive list):

1. The daily voltage variations - This may require updating tap-changer settings, or control voltage levels upstream in the network.
2. Change in power flow - This is evaluated during the Grid Impact Study and some network contingencies may require specific operating procedures, e.g. requesting a reduction in power output or changing the reactive power control of the generator.

3. Loadshedding impacts - Generators will reduce the load that is switched out per block during loadshedding. It may also be desirable to exclude generators from loadshedding schedules to rather assist the Grid.

2.2.8 Cost Estimate Letter

The **cost estimate** to the customer should take the following into account:

1. Connection equipment required for construction of the point of connection.
2. Indicative grid strengthening costs²² (if applicable)
3. Protection & control equipment.
4. Design and project management time required from the Distributor to develop and supervise the connection works.
5. The new meter (if applicable): A four-quadrant meter is required to monitor active and reactive power in both directions each. Note that time of use for each of these quadrants is also required (where Time of Use tariffs is a requirement from NERSA).
6. Administrative charges to change the customer to a new tariff (if applicable).
7. Anticipated reduction in equipment lifespan (if deemed necessary) e.g. due to possible DC current injection and additional harmonic current injection.
8. The Distributor may ask each customer to pay towards future network upgrades, i.e. the connection fee could include a proportional cost of e.g. future transformer replacements, and/or conductor upgrades. Ring-fencing on the municipal financial system is a possible option to support this.

The letter should clarify power quality emissions level apportionment, and should clearly state that the cost estimate is non-binding. Should the Customer accept the Cost Estimate Letter and choose to proceed and where strengthening is required, a Grid Strengthening Study will need to be undertaken (see Step 3).

Reserving capacity: *The Cost Estimate Letter does not guarantee that the generator will be able to connect at the proposed point of connection. For example, should another generator apply to connect to the same network, the available capacity is allocated to the generator who accepts the Budget Quotation first, i.e. pays the Budget Quote fee.*

This will depend on the pricing philosophy, i.e. where the Distributor can fund most of the network upgrades with a long-term cost-recovery plan, they may not wait for Budget Quote acceptance before allocating network capacity.

²² A table with costs is provided in Appendix A to assist with the calculation of indicative strengthening costs (Appendix A costs need to be adjusted for inflation etc).

2.2.9 Deliverables and Outputs from Step 2

A report detailing the results of the Grid Impact Study should be compiled and provided to the Distributor and Customer.

Outputs:

1. Internal outputs (for Distributor):
 - a. Grid Impact Study and recommendations
 - b. Indicative grid strengthening options (if relevant)
 - c. Power Quality information and apportioned emission levels
 - d. Protection impacts and expected upgrades / adjustments required
 - e. Any potential maintenance impacts
 - f. Metering changes/implications
 - g. Details of the calculation of the Cost Estimate for future reference
 - h. All internal departments/sections sign-off on proposed Cost Estimate
 - i. Any issues/concerns raised by other Distributor departments/sections
2. External outputs (for Customer):
 - a. Cost Estimate Letter, including indicative grid strengthening options and costs (if relevant)
 - b. Protection settings that may be required
 - c. Background power quality and reliability levels at the PoC
 - d. Apportioned power quality emission levels

2.3 Step 3: Budget Quote (Grid Strengthening Studies)

BUDGET QUOTE EVALUATION STAGE SUMMARY:

The key component of this step is undertaking the Grid Strengthening Study (only if strengthening was shown to be necessary in Step 2). If no strengthening is necessary, the Budget Quote can be prepared for the customer with little additional work. The Budget Quote can then be issued, which, upon acceptance by the Customer, enables the detailed contracting, design and construction work to proceed (Steps 4 onwards).

Distributor:

- Issues Budget Quote fee invoice to Customer
- Undertakes (or outsources) detailed Grid Strengthening Study (as relevant)
- Issues Budget Quote to Customer

Customer:

- Pays Budget Quote fee
- Accepts Budget Quote in writing

When the Customer accepts the Cost Estimate Letter, the municipal Distributor invoices for the Budget Quote fee²³ to cover the work involved in undertaking any detailed studies necessary to enable the Budget Quote to be issued. This quote should have a high certainty level²⁴ to allow the customer to secure funding. Standard Development Charges may assist in reducing the time required to prepare a Budget Quote. A reconciliation of costs when the project is completed may be done in many cases. However, the principle of standard Development Charges may result in a fairer approach, in which case no reconciliation will be required (i.e. customers in locations with higher costs are not disadvantaged).

The Budget Quote fee should reflect the work needed in preparation of the Budget Quote: if no grid strengthening study is required (as determined in Step 2) the fee should be reduced as the Distributor has minimal work to do in preparing the Budget Quote. If grid strengthening study is required, the fee should be adequate to cover this.

Once the Budget Quote fee is paid:

- network capacity allocation can be reserved for the Customer (with a time validity limit, aligned with NERSA registration timeframes if applicable)
- any grid strengthening studies can commence

Grid strengthening studies should build on the indicative strengthening findings from the Step 2 study, reviewing different options to select the best one, and establishing adequately detailed equipment characteristics to enable accurate costing.

²³ Note that the **Cost Estimate Letter** is a non-binding estimate of the cost implications for the Customer/Generator, including initial estimate of grid strengthening cost if applicable. The **Budget Quote fee** covers the work involved in establishing costs with adequate certainty – including grid strengthening study costs if relevant – such strengthening costs are then presented in the **Budget Quote**. Costs to be reconciled after completion of the connection.

²⁴ Eskom typically issues this quote with an 85% confidence level.

A Note on Who Pays for the Infrastructure Upgrades

As explained in NRS 069:2018 section 6.4.3 Table 1, assets paid for by the customer and transferred to the municipal Distributor cannot be included in the asset base on which the Distributor makes a financial return. Over time this will erode the municipal asset base and can have an impact on recovery of refurbishment or maintenance costs.

Although NRS 069 specifically states that it is not applicable to generators, it is recommended that the legal principle of not making revenue on assets that the customer paid for should be applied regarding generators too.

Ideally the asset is paid for by the Distributor, and the cost of grid expansion is recovered over time through tariff charges, or if the Customer pays, they are compensated over time (based on connection charges).

The NRS 069 speaks of cost apportionment of grid expansions that could benefit future Customers and highlights refunds to initial Customers (including reference to the Distribution Code, specifically the Distribution Tariff Code).

The use of standard Development Charges, as provided for in [The Municipal Fiscal Powers and Functions Amendment Act 4 of 2024](#), may override this requirement.

*Also refer to the note on **Reserving Capacity** on p42.*

If any department (protection, power quality, maintenance) has not yet given their inputs, it needs to be covered in this Step. Ensure that inputs given, or concerns raised previously by these departments/sections are adequately addressed during this stage.

2.3.1 Deliverables and Outputs from Step 3

Outputs:

1. Internal outputs (for Distributor):
 - a. Compile detailed planning outputs from Grid Impact Study (Step 2), power quality, protection and maintenance assessments, i.e. all equipment requirements as well as voltage, current ratings of the equipment, fault levels
 - b. Detailed outputs of the Grid Strengthening Study (if relevant) including equipment requirements, ratings and characteristics to enable accurate costing
 - c. Record of the calculations behind the Budget Quote provided to the customer, including:
 - i. Details of strengthening equipment costs
 - ii. Construction and management costs
 - iii. PQ metering
 - iv. All other costs covered by the Cost Estimate Letter, to the necessary level of accuracy
 - d. Internal departments/sections sign-off on Budget Quote or future work.
2. External outputs (for Customer):
 - a. Budget Quote
 - b. Copies of Network Studies

2.4 Step 4: Contracting/ Legal compliance and authorisations²⁵

CONTRACTING STAGE SUMMARY:

Various agreements need to be in place (depending on the specific situation) between the Distributor and Customer, and other existing agreements may need amending. In addition, environmental and land-use authorisations need to be obtained by the Customer.

Distributor:

- Issues relevant generic agreements to Customer
- Issues Letter of Consent to Connect for Customer's NERSA registration/licensing application (if required)
- Checks environmental and necessary land-use authorisations obtained by customer

Customer:

- Signs relevant agreements
- Applies to NERSA for registration/licensing (if required)
- Obtains necessary environmental and land-use authorisations

All relevant draft agreements should be supplied to the Customer as soon as possible; at the latest with the initial cost estimate.

The following agreements should be signed or legal requirements met before the Concept Release Approval (CRA) can be obtained:

- Environmental and other authorisations
- Land use authorisations
- Consent of Use

The following agreements should be signed or legal requirements met before the Design Release Approval (DRA) can be obtained:

- Letter of Consent for NERSA application
- PPA (generator-customer)
- Self-Build Agreement

Any outstanding and all other agreements should be concluded before Execution Release Approval (ERA) can be obtained.

The different approvals can be described as follows:

- Concept technical evaluation generally resulting in Concept Release Approval (CRA)

²⁵ Examples of agreements can be found online, e.g. <https://www.sseg.org.za/category/business-models/wheeling/> or developed via the SSEG project (<https://www.sseg.org.za/connection-and-use-of-system-agreement-for-eg-1mw-and-larger/>).

- Detail technical and financial evaluation generally resulting in Design Release Approval (DRA)
- Final evaluation and approvals, including acceptance of budget quote conditions for those aspects managed by the Distributor generally resulting in the Execution Release Approval (ERA)

The most common agreements and authorisations that need to be considered and complied with amongst the involved parties are discussed below.

Possible permutations of connection options and agreement requirements are provided in Appendix B.

2.4.1 Connection Agreement (Distributor-Customer)

Clause 3.2 of the Distribution Network Code specifically requires a Connection Agreement with Customers. The purpose of this Connection Agreement is to govern the application, construction, testing and commissioning process and clearly indicate the requirements for both parties. The Distribution Network Code requires that it include at least the following:

1. Project planning data,
2. Inspection, testing and commissioning programs,
3. Electrical diagrams and
4. Any other information the Distributor may deem necessary to proceed with the processing of the application for connection

In practice, these requirements are usually contained in the budget quote when all data has been gathered and processed.

Notes:

1. Point 4 infers that the processing of the Customer application and finalising the Connection Agreement have interdependencies. Final approvals cannot be given until all required agreements have been signed off, irrespective of physical installation and/or commissioning progress.
2. This should not be confused with the Connection and Use of System Agreement; it is rather similar to the Implementation Agreement, except that it focusses on the technical aspects of the project. This agreement contains the formal application and initial discussions between the Distributor and the Customer.

2.4.2 Implementation Agreement (Distributor-Customer)

In some cases, an implementation agreement between the Distributor and Customer/developer may be applicable to establish the process and timelines for construction, commissioning etc. This is particularly important where coordination between municipal network strengthening, self-build and/or generator construction is needed.

The implementation agreement can only be concluded once the application has been processed and the proposed steps been identified, e.g. whether network strengthening is required, if the Customer opts for self-build etc. However, this should be agreed upon and signed by all parties before the project continues.

2.4.3 Letter of Consent for NERSA application

A letter of consent to connect from the Distributor is required for both license and registration applications to NERSA by the Customer – if these are needed (note that this is not the Cost Estimate Letter

or Budget Quote). This would normally be issued by the Distributor upon the Customer's acceptance of the Budget Quote.

2.4.4 PPA (generator-customer)

A power purchase agreement (PPA) may be in place between two independent parties – a generator and their customer. The Distributor is not involved in such agreements (unless they are the offtaker), but they (and/or Eskom) would have a wheeling agreement with these parties. In this case, the Distributor should include appropriate clauses in the Connection Agreement and/or wheeling agreement, including having no obligation to purchase energy if a PPA should lapse.

2.4.5 Self-Build Agreement

This agreement shall outline the requirements, conditions and process to be followed by Customers who elect to self-build their connection infrastructure to the Distribution network. The agreement is limited to the Distribution scope of works for the various Customer connection projects.

The agreement serves as a guide to both contracting parties clearly identifying those activities and tasks which should be managed by the respective parties, i.e.:

- Outline all applicable process/es to be followed during any MV/LV Self Build project from customer application, commissioning, close out of project to asset handover.
- Identify the Distributor control points during the life of a self-build project.
- Identify the risks associated with such projects and the mitigating strategies.
- Serve as a reference point for all MV/LV standards and specifications that are applicable to the works undertaken by the Developer on behalf of the Distributor.
- Outline the standard Distributor governance process for approvals of similar projects, e.g.:
 - Concept technical evaluation generally resulting in Concept Release Approval (CRA)
 - Financial evaluation generally resulting in Design Release Approval (DRA)
 - Final evaluation and approvals, including acceptance of budget quote conditions for those aspects managed by the Distributor generally resulting in the Execution Release Approval (ERA)

Note that the Distributor should clearly define the conditions under which the MV/LV self-build option will be allowed. Along with this, a copy of the standard governance process should be provided to allow the Customer to plan appropriately.

2.4.6 Supply Agreement

The supply agreement refers to the agreement of the Distributor to supply electricity to the Customer. This is replaced by the Connection and Use of System Agreement.

2.4.7 Connection and Use of System Agreement (CUOSA)

The connection and use of system agreement (CUOSA) is the main agreement between the Distributor and the Customer. It includes all technical, legal and financial aspects governing the relationship between the Distributor and the Customer.

Distributor-wheeling customer Connection Agreement

A customer that purchases the electricity from a generator via wheeling also needs an updated Connection (and Use of System) agreement, since the relationship between the Distributor and this customer changes.

This may be included as an annexure in the Connection and Use of System Agreement.

Previously, the Connection Agreement and Use of System Agreement was combined. However, in some cases 'use of system' aspects may be extracted into a separate agreement for specific Generator/Customer combinations for practical reasons. It is recommended to have a single combined Connection and Use of System Agreement for Customers.

An example for a separate UoS could be when a third-party installs a generator onto a privately owned network, e.g. large factory or residential estate.

2.4.8 Operations Agreement (Distributor-Customer)

An Operations Agreement is required to ensure all parties understand each other's responsibilities during the operational phase. Alternatively, operational responsibilities may be included in the Connection and Use of System Agreement.

2.4.9 Wheeling Agreement (Generator-Distributor-Customer)

A Wheeling Agreement will include the fees and costs for using the DSO network for all parties involved, i.e. the generator, the DSO as well as the end customer(s). Note that this may include power quality parameters and reliability requirements or information as well. The Wheeling Arrangement may be captured in separate bilateral parts in the Connection and Use of System Agreement, and the Electricity Supply Agreement.

Useful resources can be found at <https://www.sseg.org.za/category/business-models/wheeling/>.

2.4.10 Trading Agreement

The trader acts as a middleman between Generators and Customers. This means the trader will manage all relevant agreements for their listed Generators and Customers, i.e. power purchase agreements, selling (tariff) agreements. This arrangement can have significant advantages for Distributors since the trader can have a single agreement with the Distributor that relates to many Generators and Customers.

Where applicable, a separate agreement needs to be entered into over and above the PPA.

To date NERSA has issued few trading licenses.

2.4.11 Reseller Agreement

A reseller is regarded as a middleman in the distribution of the electricity, for example residential estates with a bulk supply. A Reseller should have a license from NERSA and the electricity regulation act prohibits that the sale of electricity at a higher tariff than the Distributor in whose area they are located.

2.4.12 PPP (Public Private Partnership)

The reader is referred to the *National Treasury PPP Manual and Practice Notes*²⁶.

2.4.13 Potential amendment of Distributor-Eskom agreement

Due to the potential impact at higher voltage levels (higher up in the network) of additional embedded generation capacity, it may be necessary to review or amend the Connection Agreement with Eskom. This would typically occur if the Customer/Generator connects at the Distributor's Point of Delivery (from Eskom) or if the power flow is changed significantly in the network.

In such cases where reverse feed will occur into the Eskom grid, a similar process will need to be followed for an amended connection point with Eskom. Note that these costs need to be considered in the Budget Quote, i.e. costs may be passed through to the Customer.

2.4.14 Environmental and other authorisations^{27, 28}

Environmental authorisations required by Customers are clarified in the National Environmental Management Act No. 107 of 1998 and Environmental Impact Assessment Regulations Listings Notices. Such authorisations are necessary before construction. Authorisations may involve a Basic Assessment or comprehensive assessment (i.e. Scoping and Environmental Impact Reporting Process), depending on various conditions such as generator size, land requirement, whether it utilises existing infrastructure or not, whether it is in an urban area or not, and whether it falls within a Renewable Energy Development Zone²⁹.

Note: a brief description of some of the environmental or other authorisations is provided in this section, but the reader is referred to the [Energy One Stop Shop](#) website for more comprehensive information and guidance³⁰.

As a general guide, the following apply³¹:

- **No environmental assessment required:** generators under 10MW, on land <1ha, and involves distribution/transmission infrastructure below 33kV outside an urban area, or below 275kV in an urban area
- **Basic environmental assessment required:** generators between 10 and 20MW, or that cover between 1ha, and 20ha, or involve infrastructure over 33kV outside an urban area or over 275kV in an urban area

²⁶ <https://www.gtac.gov.za/wp-content/uploads/2022/03/GTACs-Public-Private-Partnership-Manual-Module-1-South-African-Regulations-for-PPPs.pdf>

²⁷ Further information is available in *National Treasury MFMA Circular No. 118, Municipal Finance Management Act No. 56 of 2003: Legal Framework for Procurement of New Generation Energy Capacity by Municipalities and Municipal Entities* (June 2022).

²⁸ This section is high-level and EIA Specialist Companies should assist as applicable.

²⁹ Due to an in-depth Strategic Environmental Assessments conducted in determining the Renewable Energy Development Zones (REDZ), the decision-making timeframes are significantly reduced for such zones.

³⁰ <https://energyoss.gov.za/>

³¹ See EIA GUIDELINE FOR RENEWABLE ENERGY PROJECTS, Dept of Environmental Affairs, 2013, and associated Activity Listings GNR 544, GNR545 and GNR546 for a more complete set of criteria.

- **Comprehensive environmental impact assessment required:** generators over 20MW, or larger than 20ha (among other Listing Notices), or that involve infrastructure over 275kV

Based on the above, rooftop solar PV projects are unlikely to require an environmental assessment. Multi-MW ground-mounted solar generators are likely to take enough land area to trigger an environmental assessment (~1.6 MW per ha of land). Greenfield sites / vacant land usually requires a comprehensive assessment.

There is a national focus on reducing the environmental regulatory requirements for solar projects in areas of low and medium environmental sensitivity³². Normally, a Basic Environmental Assessment process can take around 8 months for final approval by a Competent Authority (including a public participation process) and a Comprehensive Environmental Assessment 16 months. However, the January 2023 Energy Action Plan update states that “Embedded Generation projects have been gazetted as Strategic Integrated Projects, reducing timeframes for environmental authorisations to 57 days”³³.

The Competent Authority is normally the province (although in certain circumstances it may be the Minister).

Other authorisations that may include but are not limited to:

- Water use license (assessment included in the EIA) – associated with significant use of water, storage of water, discharge into water resources and altering of watercourses, amongst other criteria. Should this authorisation be necessary, specialist studies will need to be undertaken, and approval will take at least 90 days. It should be noted that solar and wind projects generally do not require large amounts of water.
- Biodiversity permit (this need is identified during the EIA) – associated with threatened or protected species. The permit should be applied for before construction and can take 20-30 working days.
- National Heritage Resources Permit (this is part of the EIA) – associated with impact on a national heritage resource. Where applicable, authorisation is required before developing the project, and approval is part of the environmental authorisation.
- Approval in terms of the Astronomy Geographic Act – where the site may affect areas declared uniquely suited to optical or radio astronomy.
- Civil aviation approval – where the plant may impact a runway or airport, a Glint and Glare Assessment may be needed.
- Mineral and Petroleum Resources Development Regulations - where the use of land may impact on petroleum resource development. Approval is not required outside of mining areas. Approval is required prior to using the land, and timeframes are uncertain, but the process may take 6 months.
- Electronic communications approvals – in terms of the Electronic Communications Act 36 of 2005, these may be applicable where ‘electronic communications network facilities’ pass over private property or interfere with buildings to be erected.

³² Address by President Cyril Ramaphosa on actions to address the electricity crisis, Union Buildings, Tshwane, 25 July 2022

³³ Energy Action Plan Update, <https://www.sanews.gov.za/south-africa/presidency-releases-energy-action-plan-update> . South African Government.

- Atmospheric emissions, waste management, and community hazard management authorisations may be needed in the case of generators with harmful atmospheric emissions, utilise waste as a feedstock (biogas or biomass generators), or store hazardous material such as fuel, respectively³⁴.

As a part of the process of obtaining necessary approvals, required specialist studies may also include traffic impact, decommissioning and disposal, groundwater, tourism, noise, visual, agricultural potential, and socio-economic assessments.

Where projects include batteries, a battery energy storage system assessment must be conducted, and it must be flagged in the environmental assessment.

2.4.15 Land use authorisations

Land zoning and subdivision

A change in zoning may be necessary to establish a generator on a piece of land, such as to a suitable 'Utility' zoning. Any such changes need to be consistent with the municipal or provincial Spatial Development Framework. Typically, a rooftop solar PV system (e.g. on a mall) will not require a zoning change as the principal site activity has not changed. A solar generator developed on vacant land will typically require rezoning, or as a minimum, a Consent of Use associated with the current zoning of the property. Depending on the original zoning, an environmental impact assessment may be triggered.

Subdivision of agricultural land is subject to more stringent approvals in terms of the Subdivision of Agricultural Land Act 70 of 1970. This normally take 3 to 6 months, but could take longer.

Note that the Energy Action Plan update of January 2023 states that land use authorisations for energy projects have been prioritised, and timeframes reduced to 30 days³⁵.

Depending on the site location, and the traversing of neighbouring property to access required infrastructure, servitudes may also need to be registered by the Customer.

Note that land use is often regarded as one of the more problematic aspects, unless the Customer already owns the land. Long-term lease and use of land permissions will be required to be registered at the Deeds office.

National Building Regulations

Building plan approvals are necessary for site development, which may take between 30 and 60 days.

The built structure needs to be signed off by a suitably qualified person, e.g. ECSA registered civil engineer. The requirements should be set or confirmed in terms of the National Building Regulations and Standards Act.

Wind load can play a significant role, even for PV systems, and should not be disregarded.

³⁴ Goldblatt M. *Mapping of authorisation processes for renewable energy projects*, 2015. PDG

³⁵ Energy Action Plan Update, January 2023 (page 9). South African Government.

Municipal land³⁶

Leasing or otherwise using municipal land is regulated by the MFMA and associated Regulations, and relevant municipal by-laws where established. Depending on the value and length of a land lease, different conditions for approval apply, ranging from simple Council approval to more complex processes involving public participation.

2.4.16 Consent of Use

Consent of Use agreements are required in the following instances:

1. When property is rented / leased and does not belong to the Customer (Generator). The Consent of Use agreement is then between the Customer and the legal landowner. This should be confirmed by the Distributor before the budget quote can be issued.
2. When rezoning is not done, e.g. on vacant land. The spatial planning department will provide the required permissions.

2.5 Step 5: Design

2.5.1 Step 5A: Distributor Network Design

NETWORK DESIGN STAGE SUMMARY:

If grid strengthening or upgrades are necessary for the generator to connect, detailed design can commence once the Budget Quote is accepted. This Step is skipped if no such changes are required. Interconnection equipment design also takes place in this step.

Distributor:

- Select and specify equipment to be procured and installed
- Provide necessary guidance to customer to design and install interconnection equipment
- Proceed with procurement

Where grid strengthening or upgrades are necessary for the generator to connect, detailed design can commence once the Budget Quote is accepted. The Grid Strengthening Study provides key parameters to inform detailed design. The design department process is no different to any other network upgrade process.

In addition to strengthening design work, interconnection equipment needs to be designed. Municipalities may elect to perform the design and upgrade work for any interconnection equipment which will be owned and operated by themselves, but it is recommended that they require customers to

³⁶ Further information is available in *National Treasury MFMA Circular No. 118, Municipal Finance Management Act No. 56 of 2003: Legal Framework for Procurement of New Generation Energy Capacity by Municipalities and Municipal Entities* (June 2022).

perform this work in accordance with the Distributor's specification. In this case it may be necessary to prepare instructions, procedures and specifications for the customer's team to take this forward.

During the design stage, all equipment requirements are converted to specifications, e.g. insulation coordination, protection selection and coordination, transformer specifications etc.

Should a dedicated transformer be selected for a customer, this transformer may be specified for harmonics and small DC current injection. This may allow for a higher embedded generator penetration capacity for the same transformer capital costs.

Protection coordination may include that the relays and breakers cannot be unidirectional and should operate for a fault in any direction.

Design also includes revised Single Line Diagrams, layouts (if necessary), external services, and civil works, particularly if network reinforcement is needed.

These outputs will allow procurement to proceed.

2.5.2 Step 5B: Generator Planning and Design (Including Grid Code Compliance Studies)

GENERATOR PLANNING AND DESIGN STAGE SUMMARY:

The Customer undertakes all necessary design work, including generator and collector network, and performs simulations to check Grid Code compliance of designs. Equipment is also specified in this step.

Customer:

- Undertake the necessary studies for PoC impact (Grid Impact)
- Undertake impact assessments for generator collector network and infrastructure
- Undertake interconnection equipment design if required (see Step 5A)
- Undertake Grid Code Compliance Simulations
- Design generator and related infrastructure
- Specify equipment

2.5.2.1 *Grid Impact Study*

This Grid Impact Study is limited to evaluating the effect of the generator at the proposed point of connection (PoC). The studies will evaluate the expected voltage regulation and rapid voltage changes at the point of connection, assuming a Thevenin equivalent circuit for the upstream network. This study can be seen, and undertaken, as a subset of the Grid Impact Study that is required by the Distributor (see section 2.2), although such a PoC impact study is a default requirement for the Customer.

2.5.2.2 Generator Planning and Design

Generator design should comply with [Eskom standard 240-61268576, \(Standard for the Interconnection of Embedded Generation\)](#) (Eskom, 2018) until NRS 097-1 is published.

Part of the generator planning and design is to ensure that all associated equipment that is selected is appropriately sized. This process is similar to the Grid Impact Study, except here the focus is on the new generator collector network and infrastructure. Note that transformers should be specified appropriately for the increased harmonic loading on the transformers.

This design work is entirely the responsibility of the Customer, and the Distributor is not required or advised to review, approve or accept designs for equipment beyond the Customer PoC.

Simulations

The following simulation studies should be done by the Customer to check that designs align with Grid Code compliance:

1. Loadflow studies to confirm the following:
 - a. Voltage levels in the Customer /Generator plant remain within acceptable levels,
 - b. Loading on all relevant feeders, cables, and transformers to ensure no equipment is overloaded.
2. Loss evaluation to ensure optimal collector network design and equipment selection.
3. Short-circuit study to evaluate the capabilities of existing equipment (including circuit breakers).

Based on the design and simulation work, equipment should be specified so procurement can proceed.

2.6 Step 6: Construction

Construction of municipal assets (grid strengthening and interconnection equipment) as well as generator equipment is undertaken in this step.

DISTRIBUTOR NETWORK CONSTRUCTION SUMMARY:

Distributor:

- Procure and install new metering equipment
- If strengthening required:
 - Upgrade and/or update protection
 - Procure and install new equipment
- If strengthening required and Self-Build selected:
 - Review type-test certificates
 - Review/attend acceptance testing (FAT, SAT, SIT etc).
 - Quality assurance of construction works

GENERATOR PLANT CONSTRUCTION SUMMARY:

Distributor:

- Allow access to connection point for Customer equipment connection
- Review integration equipment installation
- Witness key points during construction

Customer:

- Procure equipment and construct
- Quality assurance during construction (acceptance testing)
- If strengthening required and Self-Build selected:
 - Provide all relevant type-test certificates
 - Invite and arrange viewing / attendance of acceptance testing (FAT, SAT, SIT etc)

Once designs are complete and appropriate approvals have been given, the construction can commence.

2.6.1 Acceptance testing

During the construction phase, there are tests and quality assurance processes which prove that the equipment is fit for purpose. Depending on the size of the installation and some specific equipment items, different tests may be required. It is the responsibility of the Customer to identify and specify which are applicable. Examples of these tests are:

- Factory Acceptance Testing (FAT) is the testing that's conducted by the manufacturer in the factory prior to shipping to site.
- Site Acceptance Testing (SAT) is the testing that's conducted in the field either by the vendor or by the on-site commissioning team. These are the standalone tests of the equipment to confirm no damage during shipping or installation.
- Site Integration Testing (SIT) is the testing conducted on-site to confirm equipment functions as a subsystem or system.

- Type Testing is the testing that is done on one piece of equipment, for example in an accredited test laboratory, and accepted as representative of other equipment that are manufactured in the same way and to the same specifications.

Some tests may form part of the pre-commissioning or commissioning tests.

2.6.2 Construction of municipal network assets

The construction phase will follow the same procedure as any other Distributor construction project, e.g. new lines or transformers. Many Distributors will outsource this work. In the case of Self-Build arrangement – where the customer constructs network components that will become part of the Distributor’s network - the Distributor remains responsible for all quality assurance and attending/witnessing relevant tests. The Distributor will be required to approve equipment installation according to the Distributor’s own standards. Key aspects of such standards should be included in the Connection Agreement.

Internal quality checks, e.g. Clerk of Works inspections, remain the responsibility of the Distributor.

Part of the construction phase includes installing the necessary municipal metering, and potentially upgrading or updating protection equipment in the case of grid strengthening.

Once the municipal network construction is complete, the Customer should be notified in writing.

2.6.3 Generator construction

The customer will procure and install the necessary generation equipment and undertake quality assurance during construction. The Distributor will review integration equipment installation as well as participate in key milestones during the process.

The municipal Distributor should allow access to their substation for cabling termination to the outgoing feeder to the Customer PoC.

2.7 Step7: Commissioning

COMMISSIONING STAGE SUMMARY:

This step covers all of the checks involved in delivering a fully commissioned generator. These are largely the responsibility of the Customer, but the Distributor will want to witness key checks and receive the necessary commissioning documentation.

Distributor:

- Provide Customer with written permission to enable commissioning to proceed
- Attend aspects of generator commissioning (e.g. anti-islanding)
- Check commissioning documentation submitted (commissioning report, anti-islanding certification)
- Provide Customer written permission for Commercial Operation

Customer:

- Pre-commissioning checklist (internal)
- Pre-commissioning tests (internal)
- Commissioning tests (internal)
- Commissioning checks with Distributor present (e.g. anti-islanding)
- Provide documentation to Distributor (commissioning report, anti-islanding certification)

Commissioning is the process of bringing the newly installed generator and associated equipment into service and confirming that all operational requirements are met.

2.7.1 Pre-commissioning

Pre-commissioning is done by the Customer to verify that each piece of equipment meets the technical requirements of the project. Pre-commissioning activities test equipment as standalone items. Tests during pre-commissioning don't necessarily operate the equipment as a system yet. Each piece of equipment is individually confirmed to be ready for further commissioning tests.

The set and sequence of tests depend on the installation, i.e. the type and number of equipment items installed. A pre-commissioning procedure and checklist should be compiled to ensure that everybody knows what will happen, as well as what to do should tests go wrong. The safety aspects during pre-commissioning are extremely important, especially since some protection aspects have not yet been fully tested and commissioned.

During pre-commissioning, the entire installation is checked to ensure that everything is installed correctly and is able to operate individually as expected. The following list contains examples of typical electrical tests:

- Grounding and bonding checks- confirm the integrity of the earthing system that sufficient bonding between metallic parts is done; by measuring the resistance of bonds.
- Cold loop checks- confirm that all cable and conductors are terminated to the correct terminal blocks.
- Megger checks- apply a voltage across the cable conductor and insulation to confirm that the cable has not been damaged or punctured to degrade the dielectric properties of the cable.

- Test DC voltage and polarity- confirm that the DC voltage is of the correct magnitude and polarity at the inverter input, or battery connection points.
- Hot loop checks- confirm calibration settings and ranges of control loops. This confirms that ranges and setpoints are correct for each control point.
- AC phase checks- verify the installation of each electrical phase in the correct order using a phase rotation meter.
- Transformer checks-
 - Take oil samples before and after energization. The samples are compared to see if any differences could indicate an internal problem within the transformer.
 - Winding resistance measurements are taken as well to measure insulation resistance.
 - Transformer ratios are measured once tap changes are set to confirm that the primary and secondary windings are correct.
 - Open circuit tests- conducted to measure the no-load current losses.
 - Short-circuit tests performed with reduced voltage to the primary winding to measure full-load current losses.
- During protection relay testing, primary and secondary injections are performed on CTs and VTs to verify relay settings are correct.
- Interlock verification (where installed)- interlocks are verified by operating equipment with no bus voltage applied. Different operating configurations are selected to verify that interlocks are functioning correctly before applying any bus power to the system.
- Battery discharge tests– confirm how many hours of rated voltage and current can be supplied during charge and discharge cycles.

The Distributor may require submission of all test reports and certificates prior to commissioning.

2.7.2 Commissioning tests

Once pre-commissioning is complete, commissioning can commence where multiple pieces of equipment are tested together to function as one system.

Written permission (Operational Notification for Commissioning) should be provided by the Distributor before synchronisation of the generator with the distribution system is attempted, and the Customer should ensure that such permission has been obtained.

The set and sequence of tests depend on the installation. A commissioning procedure and checklist should be compiled, as well as to provide clarity on what to do if things do go wrong.

It is also at this point that certain safety aspects may be tested in the presence of Distributor staff, such as the anti-islanding function. Note that the SANS 10142 Certificate of Compliance (electrical installation) should check this as well.

2.7.3 Grid Code Compliance testing coordination

Practical verification of Grid Code compliance takes place after commissioning. More details are provided in section 2.8.

2.7.4 Documentation

IEC 62446 provides the full set of documentation required for a PV installation. The main items are listed below. In the absence of similar documentation for other technologies, the below is the recommended minimum list of documentation to be provided by the Installer to the Customer:

- System data
 - Basic system information
 - System designer information
 - System installer information
- Wiring diagrams
 - General
 - Array – general specifications (PV-only)
 - PV string information (PV-only)
 - Array electrical details (PV-only)
 - AC system
 - Earthing and overvoltage protection
- String layout (PV-only)
- Datasheets
- Mechanical design information
- Emergency systems
- Operation and maintenance information
- Test results and commissioning data

The Distributor will require relevant test results and commissioning data, and proof that anti-islanding operates correctly.

2.7.5 Commercial Operation

Once the Distributor has received all required documentation and successful commissioning has been demonstrated, written permission to begin Commercial Operation may be given (Operational Notification for Commercial Operation).

2.8 Step 8: Grid Code Compliance

GRID CODE COMPLIANCE (GCC) STAGE SUMMARY:

This step undertakes all checks to achieve compliance with the Grid Code, including the necessary simulation models, on-site tests and longer-term measurements.

Customer:

- Pre-Construction:
 - Compile model of the generator or Battery Energy Storage Facility for Grid Code Compliance simulations
 - Confirm Grid Code Compliance via simulations
- Post-Construction:
 - Submit test procedure to Distributor/RETEC
 - Conduct compliance testing dry run
 - Conduct compliance tests with Distributor/RETEC
 - Submit compliance reports to Distributor/RETEC
- Post-Commercial Operation Date (when commissioning is complete):
 - Undertake RMS and EMT modelling
 - Submit RMS and EMT modelling reports to Distributor/RETEC
 - Undertake power quality compliance assessment
 - Submit power quality compliance reports to Distributor/RETEC

Distributor:

- Allocate power quality emissions limits to generators (if >5 MW)
- Confirm that Grid Code compliance is achieved (with RETEC)
- Sign off on power quality assessment

The Grid Code is a set of documents that govern the access to the transmission system (TS) or the distribution system (DS) and operation of the interconnected power system (IPS). All parties need to comply to the provisions of the relevant Grid Code(s); this section deals with the requirements for the renewable embedded power plants.

Compliance to the Grid Code refers to the entire facility and not individual units or turbines. Amendments to ERA Schedule 2 do not relax any Grid Code requirements.

Note: *The RPP Grid Code was written with large generators in mind – typically over 20 MVA. The appropriateness of requiring grid support and SCADA functionality, for example, for generators of under 5 or 10 MW as is currently required in the Code is under consideration. Should a 2 MW self-consumption PV installation on a mall be required to support the network in a similar manner to a 100 MW plant? Why include SCADA capabilities when the municipal Distributor is unlikely to ever have such functionality in place? Nevertheless, the Grid Code in its current form is legally binding, which is reflected in this document.*

Exemptions may be applied for in terms of the relevant governance codes. *Note that permanent exemption requests are seldom approved.*

Responsibility for compliance

Responsibility for Grid Code compliance lies with the Customer. The Renewable Energy Technical Evaluation Committee (RETEC) undertakes compliance assessments and submit results to NERSA who then certify compliance. The role of the Distributor in the compliance verification process is limited.

Compliance tests every 6 years

In terms of the RPP Grid Code Appendix 9, the compliance assessment tests need to be repeated every 6 years. The results are submitted by the Customer to RETEC and the relevant Distributor for approval in each cycle.

It is recommended that the Distributor has an internal process to continuously monitor compliance in terms of impact on the network, e.g. protection coordination, power quality etc.

2.8.1 Control/support requirements of different size generators

Larger units have significantly more requirements in terms of grid support and grid stability than the smaller generator units. These are shown in Table 2. In Section 13 of the RPP Grid Code, RPP Availability, Forecast, and SCADA only applies to units larger than 1 MW.

Table 2: Control functions required of RPPs (Table 4 of the RPP Grid Code).

Control function	Category A3	Category B	Category C
Frequency control			X
Absolute production constraint	X	X	X
Delta production constraint			X
Power gradient constant	X	X	X
Q control		X	X
Power factor control		X	X
Voltage control		X	X

2.8.2 Renewable Energy Technical Evaluation Committee (RETEC)

Grid Code compliance is evaluated by RETEC, previously consisting of members from Eskom, NERSA and municipal Distributors. It is done in phases in conjunction with the Distributor: starting with a set of simulations and measured field data taken during commissioning.

Note that NERSA has accountability to approve the Grid Code compliance status, based on RETEC advice. RETEC remains responsible for reviewing all Grid Code compliance aspects. The Distributor's inputs are often requested, e.g. for power quality.

2.8.3 Grid Code compliance aspects and process

There are several different aspects to Grid Code compliance. An important guide in this regard is the Grid Code Secretariat document titled *Renewable Power Plant Grid Code Compliance Test Guideline* (GCS, undated), which includes reporting formats. Appendix E provides more information, and key aspects are summarised below for convenience.

Note that the Customer is responsible and accountable for Grid Code compliance. All steps are to be done by the Customer to the satisfaction of RETEC. The Distributor may assist in reviewing the results when requested by RETEC.

GCC simulation

A simulation model of the generator is compiled and a range of simulations performed, including around frequency tolerance and support, reactive power capabilities, voltage ride-through and harmonic resonance screening.

Testing of compliance during commissioning

Some commissioning tests also form part of Grid Code compliance (see Step7: Commissioning).

Dry run

This is an internal customer process where all compliance requirements tests are pre-checked in preparation for formal RETEC evaluation.

Compliance testing

Testing is undertaken in the presence of RETEC delegates, including active power constraint, power curtailment during frequency variations, reactive power control, power factor control and voltage control function.

In addition, voltage ride-through and power quality tests are undertaken over a longer time period.

Voltage ride-through requirements are deemed compliant based on the simulation results. However, should any non-compliance be detected by the Distributor or the Customer, this shall be addressed and corrected. The timeline for corrections should be agreed between both parties, including NERSA (via RETEC/GCAC).

For units up to 5 MW, Grid Code compliance can be confirmed by way of type test certificates, i.e. NRS 097-2-1 for harmonic emissions and SANS/IEC61000-3-3/5 for voltage flicker emissions.

For units of 5 MW and larger, the power quality compliance must be measured within 6 months. The Customer must show, by analysis of the power quality measurements, that the plant complies with the emission limits. Appendix 13 of the RPPGC provides more guidance on the power quality compliance aspects.

RMS (phasor type) and EMT models

These models need to be compiled and run to replicate a range of relevant generator performance characteristics.

Power quality

It is the Distributor's responsibility to allocate power quality emissions limits to generators larger than 5 MW. For smaller generators (less than 5 MVA) NRS 097-2-1 may be used. At least one weeks' worth of measured power quality data is needed for compliance verification. The current practice is that the

Distributor needs to sign-off on the power quality assessment before Grid Code compliance will be verified and issued by RETEC.

2.9 Step 9: Authorisation Close-Out

AUTHORISATIONS SUMMARY:

The Distributor checks that all the necessary authorisations, agreements and compliances are in place before close-out.

Customer:

- Provides all related information (as per previous sections)

Distributor:

- Checks documentation received
- Formal close-out and informs customer

In this step the Distributor checks all aspects relating to the compliance of the Customer. It includes confirming the following:

- Network assets have been constructed to their standards, and that they have the necessary certificates and specifications in their possession.
- Necessary agreements are in place (connection, wheeling etc).
- NERSA registration or licensing completed if relevant.
- Commissioning report complete.
- Grid Code compliance report submitted to RETEC.
- Letter provided by the Grid Code Secretariat that they are satisfied that all Grid Code requirements have been met.
- Environmental, land use and other authorisations are in place and validated by the necessary authorities.
- Written permission for Commercial Operation has been issued.

Appendix C provides a checklist which supports this close-out process.

3 Financial and billing considerations

Embedded Generators have an impact on the Distributor financial situation. The two key aspects to consider are developing distribution Use of System charges for generators, as well as recovering the costs for additional infrastructure that may be required to connect larger generators to the distribution network. These impacts are briefly discussed in terms of the tariffs, metering and billing, and budgets and quotes.

3.1 Tariffs

Managing the integration of several large generators is not a historical competency of most Distributors and they typically will require additional capacity to manage these operations. Protection and quality of supply require dedicated staff and sections that cooperate closely with the planning section. Costs for additional staff members will need to be included in budgets and recovered through cost-reflective tariffs.

Most Distributors do not have NERSA-approved Use of System tariffs for generators and wheeling customers. Distributors need to determine Use of System tariffs and submit them for approved by NERSA in order to connect generators to the network.

For prosumers (i.e. customers with generators for the primary purpose of self-consumption), cost-reflective basic charges are critical to ensure cost recovery of fixed assets and services, despite reduced consumption. Export credits are also an important element of a prosumer tariff to compensate customers for feeding electricity into the network. Many Distributors are already implementing export credits in line with the principle of avoided costs (i.e. export credit compensation should align with the value of what the Distributor would have paid for that unit of energy from the wholesale market). The principle of export cost compensation in line with avoided cost is suitable for larger than 1 MW generators.

3.2 Metering and billing

Large customers are often already on an appropriate metering and billing system, including appropriate “smart” meters (4-quadrant meters) that can both monitor the import and export as well as implement ToU tariffs. Should the Customer not have an appropriate meter installed, this should be installed as part of the application before the generator commissioning can take place. Distributor billing systems are often a hindrance to the implementation of export credits. Upgrading billing systems to accommodate exported power can be challenging but remains a critical task which should be prioritized.

3.3 Budgets and quotes

Budgeting for future network requirements, e.g. extension, refurbishment, etc. also needs to consider the impact of more generators on the network. Internal policies and procedures need to be developed to determine how such capital projects are funded by new Generators³⁷. These types of studies are typically done as part of network development plans.

The methodology used to calculate connection charges must be approved by NERSA, in line with NRS 069 and the Distribution Tariff Code. If the Transmission System requires modifications to connect the generator, any changes in such charges to the Distributor should be passed through to that Customer.

³⁷ Infrastructure development capital cost recovery policies of [Cape Town](#) and [George](#) can be referred to for examples of such approaches.

4 References

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Appendix A – Indicative Cost of Equipment

The following list provides indicative costs of equipment in 2022 that can support cost estimate determination. A costing tool is also available online: <https://www.sseg.org.za/asset-costing-tool/>.

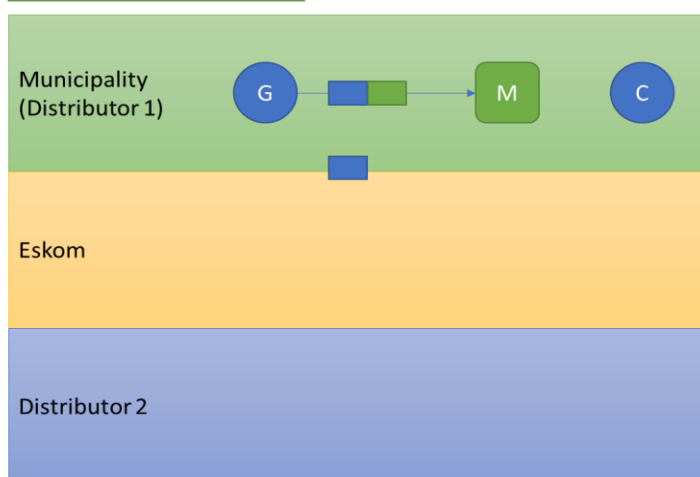
Major summarized item	UoM	Cost per unit
HV Incomer bays - Outdoor	each	R 3 440 000
HV outdoor Busbar, bussectionalizers & related shared infrastructure	Lot	R 13 490 000
HV Outdoor Feeder breakers	each	R 4 290 000
HV cable feeder length	km	R 7 346 640
HV line feeder length	km	R 2 840 000
HV/33kV transformers	each	R 13 270 000
HV/11kV transformers	each	R 13 270 000
33 kV incomer bays (Main sub)	each	R 1 690 000
33 kV busbar (Main sub) (incl. all building works & common services)	Lot	R 9 070 000
33 kV outdoor feeders (Main sub)	each	R 1 580 000
33kV cables	km	R 4 500 000
33KV OHL	km	R 468 445
33/11kV transformers	each	R 9 050 000
11kV incomers - main sub	each	R 860 000
11kV busbars - main sub (incl. all building works & common services)	Lot	R 6 460 000
11kV Feeders - main sub	each	R 760 000
11kV primary feeder ring	km	R 1 090 000
11kV incomers - switching sub	each	R 571 000
11kV busbars - switching sub (incl. all building works & common services)	Lot	R 3 349 000

11kV Feeders - switching sub	each	R	500 000
11kV secondary feeder ring	km	R	720 000
Ring main unit with CT/VT unit	each	R	394 000
11kV/400V minisub	each	R	541 000
4-core LV feeder	km	R	610 000
LV Kiosk	each	R	13 100
11kV Overhead line	km	R	360 342
Pole transformer	each	R	101 921
LV overhead line	km	R	609 222

Appendix B – Connection Configurations and Agreement Options

Permutations of connection options and associated agreement requirements are provided here.

Customer/Generator selling power to the municipal Distributor

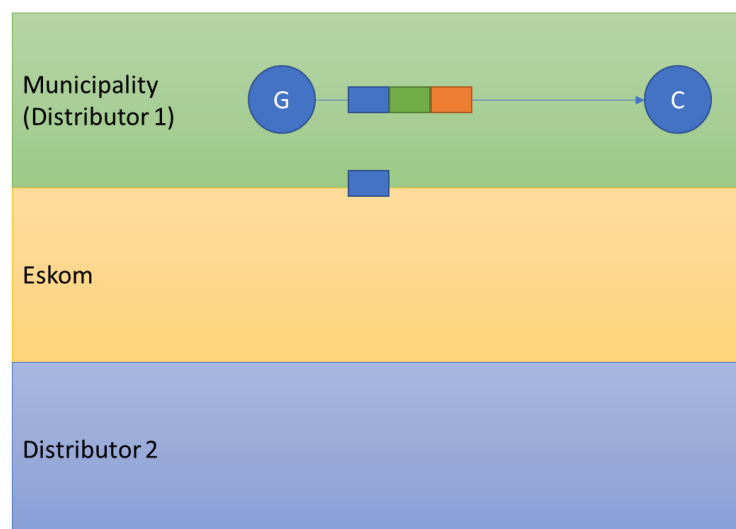


The Customer/Generator sells power to the municipal Distributor:

- Connection Agreement (Distributor-Customer/Generator)
- PPA (generator-municipality)

If the generator size is significant, the Connection Agreement between the municipal Distributor and Eskom may require amendment.

Customer/Generator in a municipal network wheeling to a customer in the same network



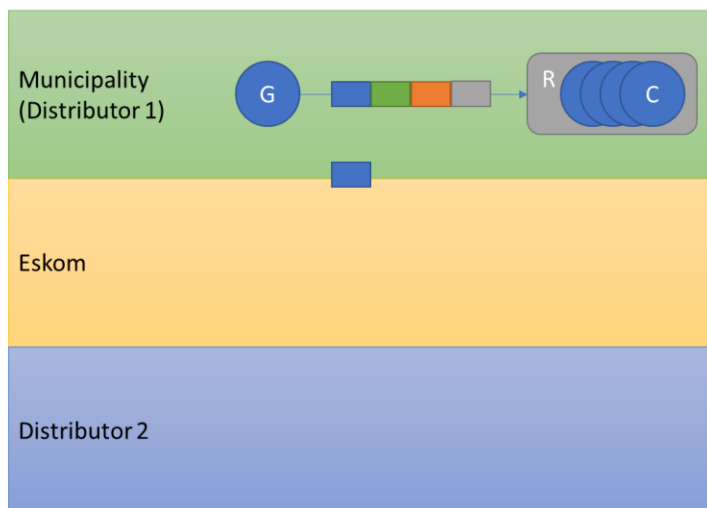
Generator wheels to a customer – both in the same municipal distribution network:

- Connection Agreement (Distributor-Generator)
- PPA (Generator-customer)
- Wheeling agreement (Generator-Distributor-customer)

The existing Connection Agreement between the municipal Distributor and the customer is amended.

If the generator size is significant, the Connection Agreement between the municipal Distributor and Eskom may require amendment.

Customer/Generator in a municipal network wheeling to a trader in the same network

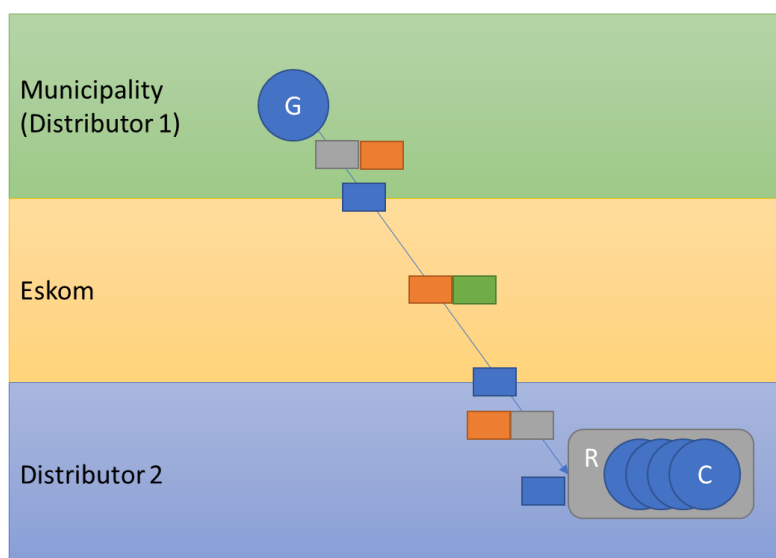


Customer/Generator wheels to trader – both on same distribution network:

- Connection Agreement (Distributor-Generator)
- PPA (Generator-trader)
- Wheeling agreement (Generator-Distributor-trader)
- Trading agreement (trader-Distributor)

If the generator size is significant, the Connection Agreement between the municipal Distributor and Eskom may require amendment.

Customer/Generator in a municipal network wheeling across the Eskom network to a customer in another distributor's network



Customer/Generator in municipal network wheels across Eskom network to a trader on a different Distributor's network:

- Connection Agreement (Distributor 1 -Generator)
- PPA (Generator-trader)
- Wheeling agreements:
 - Generator-Distributor 1
 - Generator-Eskom
 - Generator-Distributor 2
- Connection Agreement (Distributor 2 – trader)
- Trading agreement (trader-Distributor)

Connection Agreement between Eskom and each municipal Distributor will need amendment.

Appendix C – Checklist for Processing Embedded Generator Applications

This appendix contains template Checklists for processing embedded generators applications larger than 1 MW. By stepping through the items in each list the Distributor will cover necessary areas in the assessment of the application.

Distributor Processes

This section covers the Distributor process.

Application	Yes	N/A	Comments/notes
Customer sent fill information pack, forms and application fee invoice			
Application received and complete			
Application fee paid			
Evaluate Application			
Grid Impact Study			
Other necessary studies undertaken (short-circuit, protection coordination, QoS background and apportioning etc)			
Cost Estimate Letter issued			
Cost Estimate Letter accepted			
Grid strengthening study			
<i>Internal Departments sign-off</i>			
Planning			
Protection			
Power Quality			
Maintenance			
(other)			
Budget Quote issued			
Budget Quote accepted			
<i>NERSA letter of consent</i>			
Letter of consent issued (for registration/license)			

Agreements / Contractual	Yes	N/A	Comments/notes
Implementation Agreement			
Letter of Consent for use of Distribution network			
PPA			
Connection			
Supply (amended)			
Use of System Agreement (UoS)			
Operations Agreement			

Wheeling			
Trading			
PPP (Public Private Partnership)			
(other)			

Environmental, land use and other approvals	Yes	N/A	Comments/notes
ENVIRONMENTAL APPROVALS AND OTHER AUTHORISATIONS			
Environmental authorisation and environmental management plan			
Water Use License / Entitlements			
Biodiversity Permit for a restricted activity			
Heritage Resources Assessment and Permits			
National Forests Act 84 of 1988.			
(other)			
LAND AND SITE RELATED AUTHORISATIONS AND CONSENTS			
Subdivision of Agricultural Land Act 70 of 1970			
National Building Regulations and Standards Act 103 of 1977			
Municipal site-specific land authorisations (i.e. zoning)			
(other)			
OTHER AUTHORISATIONS			
Astronomy Geographic Advantage Act 21 of 2007, (AGA Act) permit			
Civil Aviation Act 13 of 2009 approval for a wind facility			
Mineral Petroleum Resources Development Act 28 of 2002 (MPRDA)- Section 53 approval			
Electronic Communications Act 36 of 2005 (ECA)			
DMRE ERA Section 34 Ministerial Determination			
(other)			

Design – Distributor network	Yes	N/A	Comments/notes
Technical specification and approval - Distributor assets and integration assets			
Capital approval			
Procurement			
Guidance, specs etc provided to customer regarding interconnection equipment			

Construction – Distributor network	Yes	N/A	Comments/notes
Metering equipment			
Strengthening – upgrade protection			
Strengthening – equipment installation			
Construction – Customer plant/equipment			
Type test certificates provided			
Acceptance testing attendance			

Commissioning	Yes	N/A	Comments/notes
Pre-commissioning report check			
Permission to synchronise generator for commissioning purposes issued			
Attendance at commissioning (e.g. anti-islanding)			
Documentation received (commissioning report, anti-islanding certificate, CoC, engineering sign-off of electrical, civil, mechanical designs etc)			
Permission for Commercial Operation issued			

Grid Code Compliance

Grid Code compliance is the Customer/Generator responsibility to prove. RETEC will evaluate and finally recommend to NERSA to issue the compliance status.

Grid Code Compliance – Distributor responsibilities	Yes	N/A	Comments/notes
Allocate power quality emissions limits			
Grid Code compliance achieved (with RETEC)			
Sign off on power quality assessment			

The below checklist is primarily for use by the Customer.

See also the Grid Code Secretariat document titled [Renewable Power Plant Grid Code Compliance Test Guideline - Version 3.0](#) (GCS, undated).

Grid Code Compliance - Customer	Yes	N/A	Comments/notes
Simulations			
LVRT and HVRT			
Active and Reactive Power Capabilities			
Active, Reactive and Voltage Control Capabilities			
Dynamic Reactive Current Support			
Rapid Voltage Fluctuations			
Tolerance of Frequency and Frequency support			
Short-circuit studies			

Protection coordination			
Islanding			
Ancillary Services			
Instantaneous Reserve			
Regulating Reserve			
Ramp Rates			
Testing			
Power Assessment:			
Absolute Active Power Constraint			
Active Power Gradient Constraint			
Active Power Curtailment during Frequency Deviations			
Reactive Power (Q) Full Capability of the Plant ($P_{available}$ above 50%)			
Reactive power Full Capability of the Plant at 20% Pmax)			
Power Plant Control Modes			
Reactive Power (Q) Control at $P_{available}$			
Power Factor Control			
Voltage Control			
SCADA Testing			
Power Quality			
Meets emission limits			
Filter required and installed			
RMS model (usually Digsilent PowerFactory)			
EMT model (usually PSCAD)			
RETEC			
RETEC approval			

Appendix D – Summary of Aspects Related to the Grid Impact Study and Grid Strengthening Study

The reader is referred to the *Grid Impact Study Specification Guideline*³⁸ which enables the specification of such studies to be undertaken by the customer or consultant, as well as assisting with the evaluation of such studies.

Note that, irrespective of the amount of export anticipated or allowed, certain conditions still need to be considered, e.g.:

- Voltage changes (potentially flicker)
- Harmonic resonance screening.
- Significant reduction of load in a certain area (during peak generation scenarios) where voltage regulation in the upstream network may also be affected.
- Operational impacts – especially under contingency conditions.
- Also consider whether generators will be shed during loadshedding conditions, especially generators that may assist the network during these conditions.

³⁸ Available at <https://www.sseg.org.za/wp-content/uploads/2022/10/Grid-Impact-Study-Specification-Guide-Rev2.0.pdf>

Appendix E - Grid Code Compliance Tests and Process

This appendix deals with different aspects of Grid Code Compliance from the RPP and BESF Grid Code Perspective. In the absence of specific guidance for other generation types (i.e. non-renewable generators), these requirements should be applied. Also see the SAGC, Network Code.

E.1 GCC simulations

A suitable simulation model of the generator plant needs to be compiled. This is usually done as part of the design stage (see section 2.5.2). To do the Grid Code compliance simulations, all control functions that will be included in the plant need to be added to the base model used for design. The following key simulations are then done and presented in report format:

- Tolerance of Frequency and Frequency support
- Active and Reactive Power Capabilities
- Active and Reactive Power, and Voltage Control Capabilities
- Dynamic Reactive Current Support
- Low Voltage Ride Through and High Voltage Ride Through Capabilities
- Harmonic resonance screening (needs to be done in conjunction with the Distributor)

The following studies, which form part of the design of the generator plant phase, are also included during this phase of simulation studies.

- Short-circuit studies
- Rapid Voltage Fluctuations
- Protection coordination

Apart from the 3 times resonance screening, the latest version of the Grid Code does not require power quality simulation to prove Grid Code Compliance, and such compliance is proven by using on-site measurements of all steady-state power quality parameters:

- Voltage and current harmonics,
- Voltage unbalance,
- Voltage flicker.

Note that power quality recorders will also record voltage dips and interruptions. Such information is used during the RMS and EMT model validation (see sections E.5 and E.6).

A simulation guideline is provided as a separate document - [*P13906 Recommended Practice for Grid Code Compliance Studies for Renewable Energy Power Plants and Hybrid Power Plants*](#) (MPE, 2021)

E.2 Testing of Grid Code Compliance (During Commissioning)

Some of the testing for Grid Code compliance requirements forms part of the commissioning process. However, these two different processes should not be confused.

The Grid Code compliance aspects are discussed in sections E.3 to E.7.

An overview of commissioning of the generator installation is dealt with in section 2.7.

E.3 Dry Run

This is an internal process to test all the Grid Code requirements that will be conducted during the compliance process with RETEC. A test procedure is compiled and submitted to RETEC by the Generator for approval. Once approved, the test procedure is then performed internally to evaluate compliance before the formal test commences.

More details can be found in the Grid Code Secretariat document titled [Renewable Power Plant Grid Code Compliance Test Guideline - Version 3.0](#) (GCS, undated).

E.4 Compliance testing

Compliance testing is done similar to the Dry Run, but in the presence of RETEC delegates. A formal report is submitted to RETEC after testing. Subsequently, NERSA will approve the report and Grid Code compliance of the installation.

More details and reporting formats can be found in the Grid Code Secretariat document titled [Renewable Power Plant Grid Code Compliance Test Guideline - Version 3.0](#) (GCS, undated). Key tests are summarised below for information. Also refer to Appendix 2 of the SAGC Network Code (NERSA, 2022) and Appendix 3 of the SAGC Information Exchange Code (NERSA, 2022).

The following tests are conducted:

- Absolute active power constraint
- Delta production active power constraint
- Active power gradient constraint
- Power curtailment during frequency variations
 - Frequency Controller Response Performance: Under-frequency
 - Frequency Controller Response Performance: Over-frequency
- Reactive power control function category B and C
 - Reactive power control at Pmax
 - Reactive power control at fixed Power of 20% Pmax
- Power factor control
- Voltage control function
 - Test 1: Set the Droop to 4%: $(Q_{max})/4\% U_n$
 - Test 2: Set the Droop to 8%: $(Q_{max})/8\% U_n$
- Testing of SCADA Grid Code Compliance

In addition to the above, the following compliance checks are done over a longer time period:

1. Low Voltage Ride Through and High Voltage Ride Through Capabilities

The LVRT and HVRT cannot be tested due to the impact on the network and neighbouring customers. The results of the simulation studies are accepted until proven incorrect.

The response of the installation is monitored during normal operations, when faults do occur on the network. Based on the response of the plant during such conditions, a non-compliance may be flagged (if it is the case).

2. Power Quality

Grid Code Compliance for power quality is proven by using on-site measurements only after commissioning. These are done according to Appendix 13 of the RPP Grid Code.

The report for power quality compliance is sent to the Distributor for approval, before RETEC and NERSA will consider the compliance.

E.5 RMS models

The required dynamic models must operate under Root Mean Square (RMS) or phasor-domain simulation and Electromagnetic Transient (EMT) simulation to replicate the performance of the RPP facility or individual units for analysis of the following network aspects:

- (a) RPP impact on network voltage stability
- (b) RPP impact on QOS at PoC
- (c) RPP switching transients' impact on network performance
- (d) RPP impact on breakers TRV (Transient Recovery Voltage)
- (e) RPP impact on network insulation co-ordination requirements
- (f) RPP impact on network protection co-ordination
- (g) RPP FRT (Fault Ride Through) capability for different types of faults and positions
- (h) RPP response to various system phenomena such as:
 - (i) switching on the network
 - (ii) power swings
 - (iii) small signal instabilities

These models are tested against the commissioning test results and recordings of real events. Section 14 of the RPP code provides details on how the models are to be validated.

E.6 EMT models

EMT models must include all parameters required for EMT simulations such as positive, negative and zero sequence impedances for all elements, magnetising curves, losses and tap changer data for transformers as well as positions of surge arresters and their V/I characteristics. EMT models must also include all protection and control functions of the plant.

These models are tested against the commissioning test results and recordings of real events. Section 14 of the RPPGC and Section 13 of the BESFCC provides details on how the models are to be validated.

E.7 Power Quality

Note the Distributor's responsibility to allocate the power quality emission limits to all generators larger than 5 MW.

Compliance to the Grid Code requirements for units smaller than 5 MW is achieved via NRS 097-2-1 and IEC 61000-3-3 or IEC 61000-3-5 certification of the generator. This means that individual units are tested according to these standards. For inverters (individual units) larger than 1 MW, this can be achieved by testing to similar standards, such as IEEE 1547 and the above IEC documents.

Installations larger than 5 MW require a suitable measurement data set and analysis in terms of the apportioned values. This requires at least one week of measured data.

Note that the Distributor must sign off on the power quality assessment before Grid Code compliance will be issued.

Appendix F - NERSA Requirements for Generators and Distributors

In terms of ERA Schedule 2 (15 December 2022 updated 17 January 2023)³⁹ the following registration and licensing requirements apply:

- Exempt from NERSA registration and licensing:
 - EG primarily for self-consumption (not for wheeling/export) up to 100 kW
 - EG for wheeling/export up to 100 kW
- Require NERSA registration but exempt from licensing:
 - EG primarily for self-consumption over 100 kW
 - EG for wheeling/export over 100 kW

Additional notes:

- EG of any size are exempt from NERSA licensing.
- The above applies whether the EG has storage or not.
- All EG, irrespective of size, need to comply with the Codes and Distributor requirements, and the Distributor needs to keep a record of these systems.
- Although the regulations are not clear on licensing and registration of stand-alone BESF, it is understood that such BESF should be treated as a generator and should comply with registration requirements based on their maximum output in kW and self-consumption characteristics, as indicated above.

For generators required to register, NERSA has the following documents available on their website (at the time of publication):

- APPLICATION FOR REGISTRATION OF AN ELECTRICITY GENERATION FACILITY IN TERMS OF SCHEDULE 2 OF THE ELECTRICITY REGULATION ACT, 2006 (ACT NO. 4 OF 2006) (NERSA, 2022) (*Note this applies for all generators larger than 100 kW*).
- REGISTRATION PROCEDURE IN TERMS OF SCHEDULE 2 OF THE ELECTRICITY REGULATION ACT, 2006 (ACT NO. 4 OF 2006) (NERSA, 2022)

F.1 Requirements for generators

The requirements for generators that NERSA may check compliance with are listed in section 12 of the registration procedure (these are all included and covered in processes described in this document):

12. STANDARD CONDITIONS FOR REGISTERED FACILITIES

12.1 The registered facilities shall comply with the following technical standards and/or specifications issued in terms of the Act:

(a) NRS 097 Parts 1 and 2: Grid Interconnection of Embedded Generation

(b) South African Grid Codes

³⁹ [Electricity Regulation Act: Amendment: Licensing Exemption and Registration Notice. Govt Gazette No 47877, 17 January 2023](#)

(c) South African Grid Code Requirements for Renewable Power Plants

(d) SANS 10142 Parts 1 to 4: The Wiring of Premises

(e) NRS 047: Electricity Supply: Quality of Service

(f) NRS 048: Electricity Supply: Quality of Supply

(g) NRS 057/SANS 474: Code of Practice for Electricity Metering.

F.2 Requirements of the Distributor (Network Service Provider)

The requirements for the Distributor are listed in sections 10 and 11 of the NERSA registration procedure.

10.1 The NSP shall not unreasonably deny grid connection to an eligible generator in accordance with section 21(3) of the Act, which states:

“A transmission or distribution licensee must, to the extent provided for in the licence, provide non-discriminatory access to the transmission and distribution power systems to third parties.”

10.2 Any dispute between an eligible generator and the NSP may be referred to NERSA in writing for resolution.

10.3 The NSP shall take all necessary steps to ensure the safety of their operating personnel with regard to generation. As a minimum, notices must be placed on the circuits where this generation is available so that they are visible to the operators. The locations must be marked on all operating diagrams.

10.4 The NSP must ensure that the generation facilities install appropriate protection and metering at the connection point.

10.5 The NSP must maintain a database of all generation facilities within its area. The database shall incorporate, as a minimum, the following information:

a) The technology of the generation

b) The capacity installed

c) Its location (both on the network and GPS)

d) Whether there is energy storage associated with it

e) The customer’s name and account number.

10.6 The NSPs must report the following information to NERSA on an annual basis (within three (3) months after their financial year-end), or as and when necessary:

(a) The number of installations for each technology

(b) The total capacity for each technology installed

(c) The total energy each technology has generated onto their system in each ‘Time-of-Use tariff’ metered time period

(d) Complaints that they have received from customers on the same circuit, as the generation facility, about quality of supply

(e) All safety-related incidents involving this generation

(f) The tariffs applicable to these installations (if energy is sold to the municipality).

11.1 The HoD: ELC shall submit an annual report (calendar year) to the Electricity Subcommittee on the registered generation facilities in the Republic of South Africa for noting. This report shall, as a minimum, contain the:

a) total registered capacity of registered generation facilities;

b) complaints relating to registered generation facilities; and

c) incidents/accidents that occurred as a result of these generation facilities.

11.2 The report shall be shared with the public by publishing it on the NERSA website. If necessary, the report shall also be shared with other Government entities

Appendix G – Protection Aspects

This appendix provides detailed guidance on protection considerations, outlining essential protection philosophies and requirements. Information provided here should be considered or used during the Evaluate Application stage, as well as throughout the design, commissioning, and operational phases of the project.

G.1 Grid Focus Point Definitions

The following grid focus points are defined:

Point of Common Coupling (PCC) – The closest common point shared between the embedded generator owner and another NSP customer.

Point of Connection (POC) – the grid ownership boundary point.

Point of Generator Connection (PGC) – The embedded generator connection point.

The grid focus points are illustrated in the Figure 5.

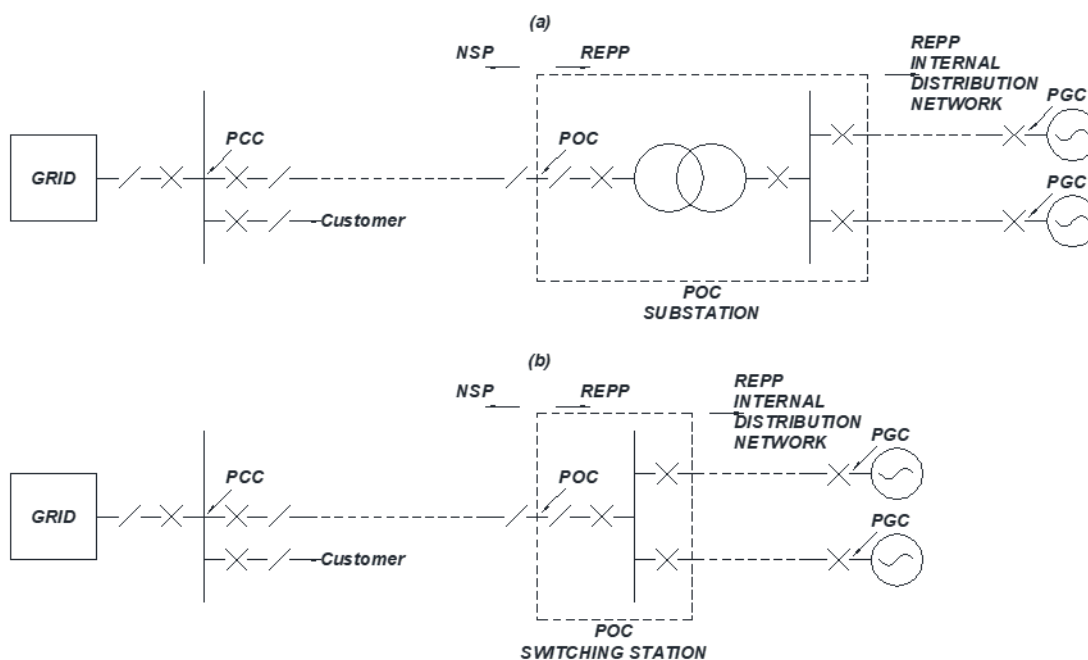


Figure 5: Illustration of reference points for Impact determination (Source 1: RTG Solutions 2020).

G.2 EG Categorisation

The EG capacity and categorisations are according to [2].

This Appendix applies primarily to Category B and Category C generators as defined in the SAGC.

Category A generators (≤ 1 MW) shall comply with NRS 097-2-1 unless otherwise required by the Distributor.

Where overlap exists between this Appendix and NRS 097, the stricter requirement shall apply.

G.3 General Requirements

Since each EG is unique in configuration, coupling, and being embedded also in application, it is essential that a protection specialist be employed to analyse the grid and carry out a protection study in order to ensure that all types of faults which are possible are cleared in a fast and selective manner without compromising the selectivity of the protection equipment. Fast and selective protection equipment such as cable/line differential protection and transformer high-set over-current are to be considered for all high-impact and high-exposure components, such as overhead lines and exposed cables.

In addition, the NSP grid must be protected from exposure to faults which have an impact on the power quality of the NSP supply to other customers. NRS 048 limits are applicable and must be adhered to.

Safety considerations are essential for operation of the NSP's grid, and include the implementation of functions such as anti-islanding on the inverters, and sync check for all EG circuit-breakers and NSP circuit-breakers where there is a risk of coupling two out-of-sync systems together, since this poses a high PQ impact risk to the NSP, and a high equipment damage risk to the EG owner.

G.4 Typical Protection Arrangements — Worked Examples and SLDs

This section provides illustrative single-line diagrams (SLDs) for typical Category B and Category C embedded generator protection arrangements. The diagrams are informative; actual designs shall be developed by a qualified protection specialist based on a site-specific protection study.

The SLDs use relay function codes per IEC 60255 / ANSI C37.2 (referred to interchangeably throughout the South African Grid Code suite). The function codes most relevant to embedded generator protection are summarised in Table G-1 below.

Table G-1: Relay Function Codes Relevant to EG Protection (IEC 60255 / ANSI C37.2)

Code	Function	Cat.	Notes / Application
21	Distance / Impedance	B, C	Line protection; accelerated tripping with comms
25	Synchronism Check	B, C	Prevent out-of-sync CB closing at POC and collector CBs
27	Phase Under-Voltage	C	Detect voltage collapse; islanding detection support
50N	Instantaneous Earth Fault	B, C	Fast clearance of earth faults; required at transformer LV

Code	Function	Cat.	Notes / Application
51	Time-Overcurrent (Phase)	B, C	Backup overcurrent; must be graded with upstream NSP relay
51N	Time-Overcurrent (Earth)	B, C	Backup earth fault; grading with upstream SEF if OHL
59	Phase Over-Voltage	C	Detect voltage swells and ferroresonance
59N	Residual (Zero-Seq) Over-Voltage	C	Earth fault detection; complement to sensitive earth fault
64	Earth Fault (High-Impedance)	B, C	Generator stator earth fault; bus differential backup
67	Directional Overcurrent	B, C	Ensure correct grading when export is permitted
79	Auto-Reclose (inhibit)	B, C	Auto-reclose shall be inhibited on all EG-connected CBs
81O	Over-Frequency	C	Detect grid frequency exceedance per SAGC limits
81U	Under-Frequency	C	Detect grid frequency deficit per SAGC limits
87L	Line Differential	C	Unit protection for dedicated HV line to POC; via fibre
87T	Transformer Differential	B, C	Unit protection for each unit transformer; 87T + REF
SEF	Sensitive Earth Fault	C (OHL)	Required where overhead lines couple EG to NSP grid
CBF	Circuit Breaker Failure	B, C	Backup trip if POC CB fails to operate

Table G-1: Relay function codes and applicability by EG category. Cat. B = 1–10 MVA; Cat. C = >10 MVA.

G.4.1 Category B: Inverter-Based EG — Dedicated MV Connection (1–10 MVA)

The arrangement in Figure G-1 is representative of a rooftop or ground-mount PV installation in the 1–10 MVA range, with a dedicated medium-voltage connection to the NSP's MV network. The EG owner is

responsible for all equipment from the unit inverter terminals through the unit transformer to the Point of Connection (POC).

Key protection characteristics for this arrangement:

- The POC circuit breaker (CB-P) shall incorporate synchronism check (ANSI 25) functionality and auto-reclose inhibit (79-inhibit). No auto-reclose shall be permitted on any EG-connected circuit breaker.
- The main protection relay at the POC shall include, as a minimum: overcurrent (51/67), earth fault (50N/51N), under- and over-voltage (27/59), and under- and over-frequency (81U/81O) elements. For Category B, the additional voltage and frequency functions listed in Appendix G Section 1.2.2 are not mandated at the POC but are typically included within the inverter's internal protection.
- A backup relay, powered from an independent DC supply, shall be installed to achieve the single-contingency (n-1) protection requirement. It shall use independent current and voltage inputs (separate CTs/VTs where practicable) and an independent trip coil on CB-P.
- Each unit transformer shall be fitted with transformer differential (87T) and restricted earth fault (REF/64) protection. Buchholz and Over-Temperature Indicator (OTI) protection shall be included for oil-cooled transformers.
- All unit transformers for Category B and C shall use a delta-winding on the HV (collector) side to achieve zero-sequence current decoupling from the NSP grid, as required by Appendix G Section 1.2.3.
- Revenue metering shall be four-quadrant (active and reactive power, both import and export) with Time-of-Use (TOU) recording capability. The meter should be located at or adjacent to the POC.

NOTE: *Where the POC is also the PCC (i.e., no other customers share the NSP feeder), the POC protection requirements shall be agreed with the NSP, as the protective relay and CT/VT specifications may be subject to NSP equipment standardisation requirements.*

Figure G-1: Typical Category B Protection Arrangement
(Inverter-Based EG, 1–10 MVA, Dedicated MV Connection)

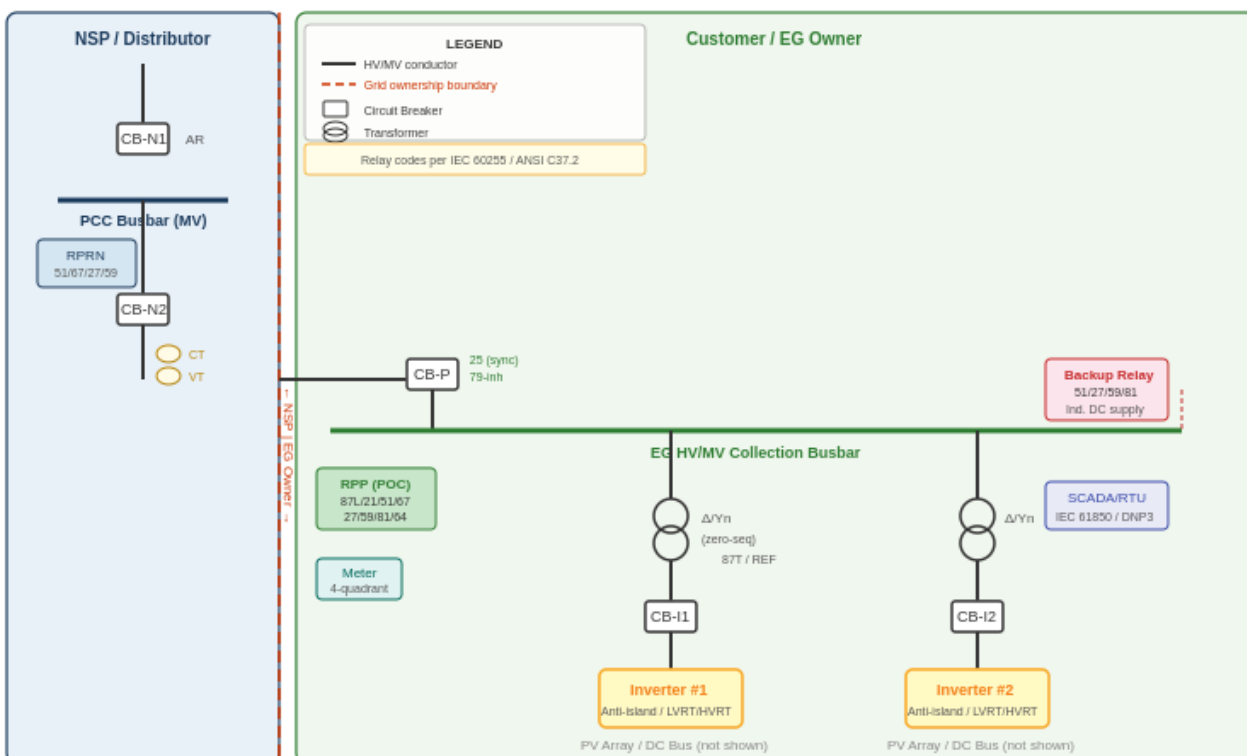


Figure G-1: Typical Category B protection arrangement — inverter-based EG with dedicated MV connection. Relay codes per IEC 60255 / ANSI C37.2. Layout is illustrative; actual configuration subject to protection study.

G.4.2 Category C: Inverter-Based EG — Dedicated HV Connection (>10 MVA)

Figure G-2 shows a representative arrangement for a large utility-scale PV installation connecting at HV with a dedicated line to the NSP's HV network. At this scale, full unit protection with communication-assisted schemes is expected.

Key protection characteristics for this arrangement, in addition to those applicable to Category B:

- Line differential protection (ANSI 87L) shall be applied on the dedicated HV connection between the EG substation and the NSP's PCC busbar. This requires a dedicated communication channel, typically optical fibre. The NSP shall specify the communication interface and protocol. Where the line length and topology preclude 87L, a distance scheme (21) with permissive overreach transfer trip (POTT) or a directional comparison scheme may be substituted, subject to NSP approval.
- The following additional protection functions are mandatory at the POC for Category C (per Appendix G Section 1.2.2): phase under-voltage (27), phase over-voltage (59), residual over-voltage (59N), over-frequency (81O), under-frequency (81U), and sensitive earth fault (SEF) where overhead lines are used.

- Circuit breaker failure (CBF) protection shall be applied at the POC circuit breaker. On CBF operation, a transfer trip shall be sent to the NSP's upstream circuit breaker, and all EG unit inverters shall be tripped.
- Auto-reclose shall be inhibited (79-inhibit) on all circuit breakers in the EG collector network and at the POC. The NSP may permit auto-reclose on their upstream circuit breaker only after verifying that the EG has disconnected (via SCADA/telemetry).
- A permanent power quality (PQ) recorder complying with IEC 61000-04-30, Class A accuracy, shall be installed at or near the PCC. This recorder shall be the property of the EG owner but its data shall be accessible to the NSP. The requirement for a permanent PQ recorder applies to all Category C generators (and is recommended for Category B2 and above).
- SCADA interface to the NSP shall be provided per IEC 61850 or a protocol approved by the NSP (e.g. DNP3). Minimum signals required: active power output, reactive power, frequency at POC, voltage at POC, CB-P status, and all protection relay alarm/trip indications.

NOTE: *The protection specialist shall confirm with the NSP whether the existing upstream relays and circuit breakers are rated and configured to accommodate the EG's fault level contribution. Where upgrades are required, these shall be reflected in the Cost Estimate Letter and Budget Quote (see Steps 2 and 3 of the main Guide).*

Figure G-2: Typical Category C Protection Arrangement
(Inverter-Based EG, >10 MVA, Dedicated HV Connection with Full Unit Protection)

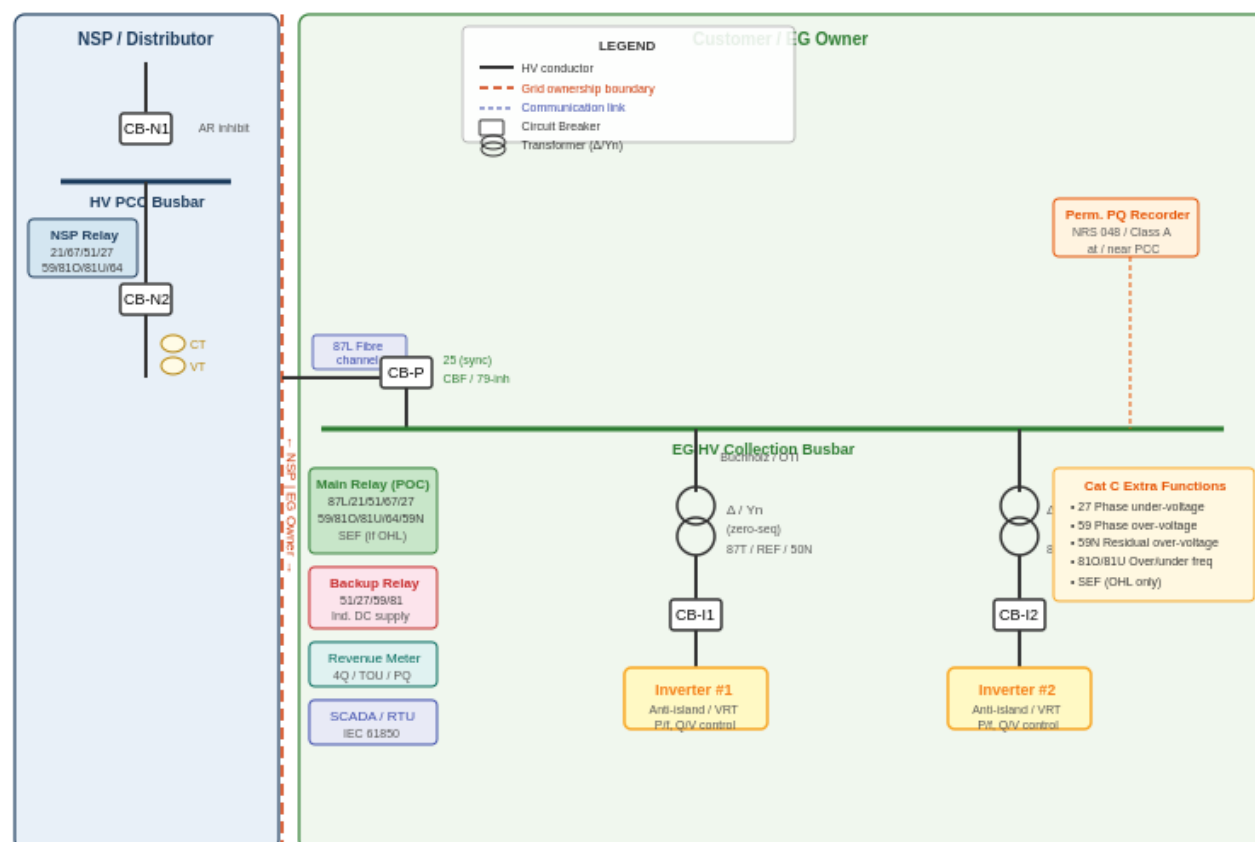


Figure G-2: Typical Category C protection arrangement — utility-scale inverter-based EG with dedicated HV connection and full unit protection. Relay codes per IEC 60255 / ANSI C37.2.

G.4.3 Protection Philosophy Document

Before detailed design commences, the EG owner shall prepare and submit a Protection Philosophy Document (PPD) to the NSP for approval. The PPD shall cover, as a minimum:

- Scope and boundary of the EG protection system (POC, unit transformers, inverter protection, DC-side protection for BESS where applicable);
- Fault level data received from the NSP and used in the protection study;
- List of protection functions and relay types selected, with reference to the requirements of Appendix G and the applicable Grid Code;
- Single-contingency (n-1) compliance demonstration: identification of each redundant element and the independent trip path for each credible contingency;
- Proposed relay settings (high-level at PPD stage; detailed settings submitted before commissioning);
- Proposed communication scheme for unit protection (87L, POTT, or equivalent);

- Anti-islanding detection method and coordination with upstream auto-reclose settings;
- Synchronism check settings and interlocking scheme at the POC.

The NSP's approval of the PPD shall be obtained prior to procurement of protection equipment. Changes to the PPD after approval shall require re-submission to the NSP.

G.4.4 Commissioning and Verification Requirements Prior to Energisation

This section addresses the gap identified in the main body summary of Appendix G requirements. The following verification activities shall be completed before the EG is energised onto the NSP grid. These activities complement the commissioning steps described in Step 7 of the main Guide.

G.4.4.1 Pre-Energisation Protection Checks

Prior to energisation, the EG owner shall demonstrate to the NSP's satisfaction:

- Secondary injection testing of all protection relays: each protection function shall be tested by secondary injection to confirm correct operation at the specified pick-up level and within the required time.
- Primary injection testing of CT circuits: polarity and ratio of all CTs shall be verified by primary injection.
- VT polarity and phase rotation verification at each relay input.
- Trip circuit continuity testing: each trip coil shall be tested end-to-end to verify the complete trip path from relay output to circuit breaker operation.
- Independent DC supply verification: the backup relay's independent DC supply (Battery B) shall be verified functional with Battery A, and vice versa.
- Communication scheme testing: for 87L or POTT schemes, end-to-end communication channel availability and latency shall be verified and recorded.
- Anti-islanding function testing: the anti-islanding detection shall be tested in accordance with the inverter manufacturer's commissioning procedure, and the trip-to-grid CB time verified against the requirement of Appendix G.
- Synchronism check calibration: the sync-check relay's voltage difference, angle difference, and slip frequency settings shall be verified by test.
- SCADA/RTU signal list verification: all signals listed in the NSP-approved SCADA specification shall be tested end-to-end.

A commissioning test record shall be compiled and submitted to the NSP. The NSP shall issue written consent (Operational Notification for Commissioning) before grid-parallel operation commences.

G.4.4.2 Firmware and Control Update Notification — Inverter-Based Generators

This section also addresses a gap identified in the main body summary. Inverter-based generators (including BESS) rely on software-embedded protection functions (anti-islanding, LVRT/HVRT, P/f and Q/V control). Firmware updates may alter the behaviour of these functions.

The following obligations apply to the EG owner for the operational lifetime of the generator:

- The EG owner shall notify the NSP in writing at least 30 days before applying a firmware or software update to any inverter, Power Conversion System (PCS), or Battery Management System (BMS) that may affect any protection or control function listed in the approved Protection Philosophy Document.
- The notification shall include: the manufacturer, model, current firmware version, proposed firmware version, a summary of changes relevant to protection and grid interaction functions, and the proposed update date and method.
- The NSP may, within 20 days of receiving the notification, request additional information or a re-verification test of affected functions. If no response is received within 20 days, the update may proceed.
- Following a firmware update affecting any protection function, the EG owner shall conduct a repeat of the relevant secondary injection tests and submit updated commissioning test records to the NSP within 30 days of the update.
- A firmware change log shall be maintained by the EG owner and made available to the NSP on request.

NOTE: *Firmware updates that are explicitly documented by the manufacturer as having no impact on protection or grid interaction functions (e.g. cosmetic or user-interface changes only) are excluded from this notification requirement, provided the EG owner retains a copy of the manufacturer's release notes confirming this.*

G.5 Battery Energy Storage Facility (BESS/BESF) Protection Requirements

This section provides protection requirements specific to Battery Energy Storage Facilities (BESF, also referred to as BESS) connecting to municipal distribution networks in Category B or Category C. These requirements are in addition to, and do not replace, those of the Battery Energy Storage Facility Connection Code (BESFCC) and the RPP Grid Code where these apply.

All general requirements of Appendix G apply to BESS/BESF installations. This section identifies additional or modified requirements arising from the unique characteristics of battery storage systems: bidirectional power flow, DC energy storage, thermal risk, and software-dependent operation.

Important: Regulatory Framework for BESS/BESF

BESS/BESF installations shall comply with the Battery Energy Storage Facility Connection Code (BESFCC) as the primary document. This Appendix G section provides guidance on aspects of particular relevance to the Distributor and Customer when processing and implementing a BESS/BESF connection in the municipal context. Where this guidance conflicts with the BESFCC, the BESFCC shall prevail.

G.5.1 Technology Context and Scope

BESS/BESF systems relevant to this Guide include standalone battery storage and hybrid systems combining PV generation with battery storage (PV+BESS). They connect to the NSP's distribution network via a Power Conversion System (PCS) — a bidirectional AC/DC converter — which is functionally analogous

to an inverter in a PV plant. The PCS is supervised by a Battery Management System (BMS) that monitors cell-level parameters and enforces operating limits.

The following topological arrangements are encountered in Category B and C BESS applications:

- Standalone BESS — battery and PCS only, with no co-located generation. The system imports energy from the grid for storage and exports on dispatch.
- AC-coupled PV+BESS — PV inverters and BESS PCS share a common AC busbar, each with an independent grid connection transformer.
- DC-coupled PV+BESS — PV arrays and battery modules share a common DC bus, with a single PCS interfacing to the AC collector network.

Figure G-3 illustrates a representative AC-coupled PV+BESS protection arrangement for a Category B or C installation. The AC side protection philosophy mirrors that of a standalone PV installation (see Figures G-1 and G-2), with BESS-specific additions on the DC and safety systems.

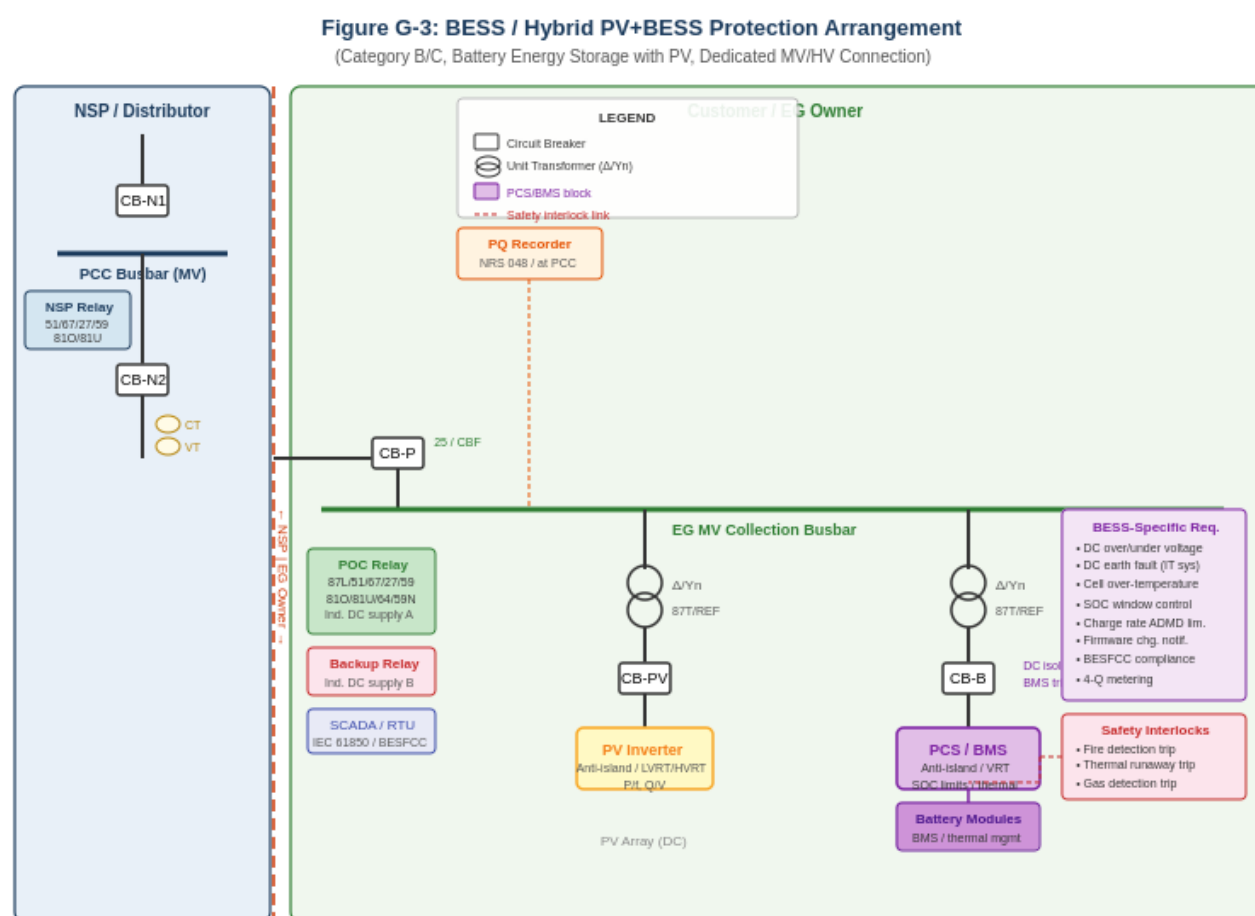


Figure G-3: Typical BESS / Hybrid PV+BESS protection arrangement (Category B/C). AC protection philosophy as per Figures G-1/G-2. BESS-specific protections shown in purple and red. Relay codes per IEC 60255 / ANSI C37.2.

G.5.2 AC-Side Protection Requirements

The AC-side protection requirements for BESS/BESF are identical to those for inverter-based PV generation as described in Appendix G Sections 1.2.1 through 1.2.7, and in Section G.4 of this supplementary guidance. The following points are emphasised for BESS:

- Bidirectional power flow: The BESS PCS operates in both import (charging) and export (discharging) modes. All directional protection elements (ANSI 67, 67N) shall be configured to operate correctly in both power flow directions. The protection coordinator shall verify that directional elements do not block fault clearance during charging mode.
- Synchronism check: The sync-check relay (25) at the POC CB shall function correctly irrespective of whether the BESS is in charging, discharging, or standby mode. This is particularly important for systems that may operate in islanded mode: the re-synchronisation sequence must be defined and tested.
- Anti-islanding: Anti-islanding detection shall be active at all times, including during charging operation. The PCS manufacturer shall confirm that anti-islanding remains effective when the BESS is importing power (negative output current from the PCS perspective).
- Voltage Ride-Through (VRT): The PCS shall comply with the LVRT and HVRT profiles specified in the SAGC RPP Grid Code. During a low-voltage event, the system shall not inadvertently switch from discharge to charge mode in a manner that worsens the voltage event on the NSP network.
- Four-quadrant metering: Revenue metering shall record energy imported and exported in both active power directions, and reactive power in all four quadrants. This is essential for tariff application and non-technical loss detection.

G.5.3 DC-Side Protection Requirements

The DC side of a BESS presents protection challenges that are not present in PV-only installations, primarily because the battery can sustain a DC fault with significant energy for an extended duration. The following DC-side protection requirements apply:

G.5.3.1 DC Bus Over- and Under-Voltage

The BMS and PCS shall continuously monitor the DC bus voltage and shall initiate a controlled shutdown if the voltage exceeds the manufacturer's specified maximum or falls below the minimum. DC bus protection shall be independent of any AC-side protection function.

G.5.3.2 DC Earth Fault and Insulation Monitoring

The DC system shall be operated as an IT (isolated earth) system, with an Insulation Monitoring Device (IMD) continuously measuring insulation resistance between the DC poles and earth. The IMD shall:

- Provide a continuous, real-time insulation resistance measurement;
- Generate an alarm at a first-level threshold (typically $\geq 1 \text{ M}\Omega$, to be specified in the protection study);
- Generate a trip command at a second-level threshold (typically $\leq 100 \text{ k}\Omega$, to be specified in the protection study);
- Remain functional with the PCS in all operating states, including standby.

Where multiple battery strings are connected to a common DC bus, each string shall have its own DC fuses or DC circuit breakers capable of interrupting the maximum prospective DC fault current under all battery State-of-Charge (SoC) conditions.

G.5.3.3 Thermal Runaway and Fire Detection

Thermal runaway is a condition in which an exothermic chemical reaction within one or more battery cells accelerates uncontrollably, potentially leading to fire or explosion. The following safeguards shall be provided:

- Cell and module temperature monitoring: The BMS shall monitor the temperature of each cell or module (at a sensor density consistent with the manufacturer's specification and the applicable IEC standard). A two-level alarm/trip threshold shall be configured.
- Gas detection: Volatile organic compound (VOC) and/or hydrogen gas detectors shall be installed within the battery enclosure. On detection of abnormal gas concentration, a hardwired trip signal shall be sent directly to the PCS AC circuit breaker (CB-B in Figure G-3), independent of the BMS software.
- Fire detection and suppression: A dedicated fire detection system (smoke and/or heat detectors) shall be installed. The fire system shall be interlocked with the PCS CB such that a fire alarm causes immediate and irreversible (latched) disconnection of the BESS from the AC grid. Resetting of the latch shall require manual intervention on site.
- Emergency DC isolation: A manually operable DC isolation device (lockable in the open position) shall be installed and clearly labelled on each battery string. The location and operation of this device shall be communicated to the NSP and included in the emergency response plan.

NOTE: *The fire detection and suppression system shall comply with SANS 10400-T and any relevant municipal fire by-laws. The Distributor shall confirm with the local fire authority the requirement for automatic suppression systems for the specific battery chemistry and enclosure type.*

G.5.4 State-of-Charge Management and Charge Rate Limiting

The following requirements apply to the interaction between the BESS operating regime and the NSP's network:

- SoC window: The BMS shall enforce operating limits that prevent the battery from being charged above a maximum SoC (SoCmax) or discharged below a minimum SoC (SoCmin). These limits are set to preserve battery life and are not NSP requirements, but the SCADA system shall make the current SoC visible to the NSP.
- Post-interruption charge rate: Following restoration of the NSP supply after an interruption (e.g. after loadshedding or a fault), the BESS shall not charge at a rate exceeding the ADMD value agreed with the NSP (see main Guide Section 2.2, Battery Charging). The NSP shall specify the maximum post-interruption charge rate in the Connection Agreement. Where the ADMD of the specific customer connection point may be exceeded by simultaneous BESS charging and load demand, the NSP may require a lower charge rate limit or demand-based charging control.
- Charging schedule: For large BESS installations (Category B2 and above), the NSP may require the EG owner to submit a proposed charging schedule as part of the Grid Impact Study review. The NSP may require staggered charging if multiple BESS installations are connected to the same feeder.

G.5.5 BESS/BESF Protection Requirements Summary Table

Table G-2 summarises the BESS-specific protection and operational requirements. Requirements that are common to all inverter-based EG are not repeated here; refer to Table G-1 and the existing Appendix G sections.

Table G-2: BESS/BESF-Specific Protection and Operational Requirements

Requirement	System Responsible	Cat.	Guidance Notes
DC Bus Over-Voltage	BMS + PCS	B, C	Protect DC bus; PCS crowbar or CB trip

Requirement	System Responsible	Cat.	Guidance Notes
DC Bus Under-Voltage	BMS + PCS	B, C	Detect string/module loss; graceful shutdown
DC Earth Fault	IMD / RCD	B, C	IT-earthed DC system; insulation monitoring device required
Cell Over-Temperature	BMS	B, C	Individual cell or module thermal monitoring; trip + alarm
Thermal Runaway Detection	BMS + sensors	B, C	Gas (VOC/H ₂) and temperature sensors; fire system interlock
Fire / Gas Detection Trip	External FDS	B, C	Hardwired trip to PCS CB independent of BMS logic
SOC Window Limits	BMS	B, C	Prevent charging above SoCmax or discharging below SoCmin
Charge Rate Limiting	BMS / PCS	B, C	Post-interruption charge rate $\leq$ ADMD value (NSP-specified)
Anti-Islanding	PCS	B, C	Same requirements as inverter-based EG; active detection
LVRT / HVRT	PCS	B, C	Same VRT profile as PV inverter per SAGC / BESFCC
Synchronism Check (discharge)	PCS / relay	B, C	Prevent out-of-sync re-connection after islanding event
Four-Quadrant Metering	Revenue meter	B, C	Import AND export in both P and Q; TOU recording required
SCADA / BMS Telemetry	RTU / BESFCC	B, C	SOC, power, temperature, alarms visible to NSP SCADA
Firmware Notification Change	EG Owner	B, C	Notify NSP ≥ 30 days before PCS firmware update
Decommissioning Interlock	EG Owner	B, C	Defined DC isolation and earthing procedure required

Table G-2: BESS/BESF protection requirements in addition to general EG protection requirements.

G.5.6 Roles and Responsibilities — BESS/BESF

The roles and responsibilities described in Appendix G Section 1.3 apply to BESS/BESF installations. The following clarifications are specific to BESS:

Aspect	NSP / Distributor	EG Owner / Customer
DC-side data	- Specify maximum fault current the PCS CB must interrupt - Confirm earthing philosophy of NSP AC network	Provide DC bus voltage range, battery string configuration, prospective DC fault current
BMS interface	- Specify SCADA signals required from BMS: SoC, temperature, alarms, trip status - Specify communication protocol (IEC 61850, DNP3, or equivalent)	- Provide BMS data over specified communication interface - Ensure BMS alarms are accessible to NSP control room
Charge rate limiting	- Specify maximum post-interruption charge rate (ADMD-based) - Specify any time-of-use charging constraints	- Implement charge rate limiter in PCS/BMS - Demonstrate compliance during commissioning
Fire/thermal safety	- Confirm local fire authority requirements - Specify any NSP requirements for emergency DC isolation access	- Install fire detection and suppression per SANS 10400-T - Provide emergency DC isolation procedure to NSP - Include fire system in commissioning test programme
Firmware updates	- Review firmware update notifications within 20 days - Request re-verification tests if required	- Notify NSP ≥ 30 days before PCS/BMS firmware update affecting protection/control - Maintain firmware change log
Decommissioning	- Specify grid disconnection sequence for decommissioning - Confirm wayleave/servitude requirements for battery removal	- Prepare decommissioning plan (battery chemistry, waste classification, transport) - Include DC isolation procedure in decommissioning plan

Table G-3: BESS/BESF roles and responsibilities for protection-related aspects.

G.6 Particular Requirements

G.6.1 Introduction

The requirements in this section are in addition to [1] and do not replace these.

All licenced service providers are required to provide services conforming to the South African Quality of Supply Standard [6]. Therefore, any EG which causes the NSP to fail in meeting this power quality conformity as a result of pollution generated by the EG may be required to correct this. Pollution, as defined in [6] includes dips as a result of faults within the EG's network, as well as dips resulting from sudden disconnection of the EG.

G.6.2 General Protection Philosophy

In addition to the requirements of the [1], all protection requirements for clearance of faults within the EG network as well as the EG's component parts of the POC are to be met under the condition of a single contingency. This implies that any single piece of equipment failure must not prevent the stipulated fault clearance times from being met. Typical single contingency conditions are:

- Protection relay failure;
- Circuit-breaker failure; and
- DC Supply to protection equipment failure.

Redundancy in the form of dual main, or main and backup protection, dual DC supplies, etc must therefore be included in the design. Upstream backup (for example, NSP upstream protection) is an acceptable form of redundancy where no common element is required for fault clearance, as long as the redundant device ensures clearance of the fault within the stipulated time per Table 5. No fault which may cause physical damage to the NSP's system, which is not covered in some way by redundant protection (which could thus be sustained under single contingency conditions) may be allowed, and must be addressed in the detailed system architecture.

In addition to fault clearance time requirements and the requirements stipulated in [1], the following additional protection functions are required to be included at the POC for EG of the categories indicated:

Additional EG Protection functions:

- Phase under-voltage;
- Phase over-voltage;
- Residual over-voltage;
- Over-frequency;
- Under-frequency; and
- Sensitive earth fault (where overhead lines are used to couple the EG grid to the NSP).

Table 3: EG Grid Protection requirements per category.

Category	EG Additional Protection Functions
CAT A	No
CAT B	No
Cat C	Yes

G.6.3 Zero-Sequence Current Coupling and Fault Level Contribution

All plants of category B and C are to be designed such that there is no zero-sequence current coupling between the EG and the NSP. Various methods are suitable, including the use of Delta/Star transformers.

Table 4: EG Zero Sequence current coupling requirement per category.

Category	Zero Sequence Current decoupling required
CAT A	No
CAT B	Yes
CAT C	Yes

G.6.4 Maximum Fault Clearing Times at the Point of Connection

In order to ensure that the EG minimises negative impact on the NSP grid power quality, the following maximum fault clearance times under contingency conditions as defined in Section 5.6 shall apply:

Table 5: Maximum Fault Clearance Times for voltage step limit at POC.

POC Voltage Dip/Swell Limit	Total Fault Clearance Time
<0.10 p.u.	<1000ms
<0.20 p.u.	<500ms
>0.20 p.u.	<100ms

*Note: this requirement is for fault clearance by the protection equipment in non-redundant (i.e. (n-0) mode – no loss of main unit protection) mode. That is, for a fault which has an impact on the POC voltage as defined in the first column of the above table, the protection equipment must clear the fault in the time defined in the second column.

For Cat B and C, If a proposed EG configuration will result in internal (to the EG) system faults with a fault impact of greater than 0.20 p.u. for longer than 100ms, or a switching impact of greater than 0.20 p.u. for longer than 1 cycle, the connection will not be allowed, and the topology, design and size of the EG must be reconsidered.

NOTE: These are guidelines internal to the generation plant. Each Distributor should evaluate the impact at the POC and network in line with the Grid Impact Study Guideline.

G.6.5 Protection Requirements at the Point of Connection

POC protection requirements are to ensure the disconnection of a generator sub-system fault under contingency conditions in the time defined in Table 3.

Where the POC is also the PCC, protection requirements are to be specified by the NSP, as this forms part of the NSP's protection system. EG will need to consult with the NSP in this regard, as often specific compatible products are required.

Where the POC is a dedicated connection, this must at least subscribe to the fault clearance requirements under contingency conditions as defined in Table 16.

At the POC, all primary plant (busbars, switchgear, transformers, etc) within this section are to be covered by unit and backup protection equipment.

G.6.6 Protection Requirements at Point of Common Coupling and the Point of Connection

The PCC and POC protection requirements are to be specified by the NSP, as this forms part of the NSP's protection system. EG will need to consult with the NSP in this regard, as often specific compatible products are required.

The point of common coupling is generally identified as the closest point in the NSP's grid which is also coupled to another EG or Consumer. However, as this point may change as grids are developed, [2] dictates that the NSP nominate this point.

G.6.7 Grid Protective Interlocking Requirements

Protective interlocks are required for the following conditions:

- Master trip devices or functions are required to trip and lock out (prevent re-energisation from remote) of any equipment which has had a unit protection operation. Unit protection devices include, but are not limited to:
 - i. Differential protection;
 - ii. Restricted Earth Fault protection;
 - iii. Arc Flash detection;
 - iv. Transformer Buchholz/Surge protection;
 - v. Bus protection; and
 - vi. CB Failure.
- Operation of a master trip shall be latching by mechanical means and may only be reset locally at the protection scheme.
- Interlocked lockouts are to be communicated to the remote supply or receiving site such that inadvertent energization is prevented.

G.6.8 Safety Interlocking Requirements

[2] Requires that, unless otherwise agreed with the NSP, islanding of the EG must be detected and the EG shut down within the stipulated time (anti-island detection and protection).

Where EG is approved by the NSP for operating in islanded mode, safety interlocks are required to be implemented such that:

- The energization sequence of an EG is met under all conditions (for local interlocking, inter-locking to prevent overriding of EG energisation sequences must be implemented by mechanical means independent of electrical devices;
- No out-of-sync closing is possible for synchronous machines on any EG in-line circuit-breaker;
- Auto-reclosing is inhibited automatically for control closing of equipment.

- Out of sync closing shall be prevented for all circuit-breakers which, if closed out of sync, would have an NSP grid voltage impact of greater than 0.03p.u. by the following means:
 - i. Synchronism checking (by means of a synchronism verification device which monitors the voltage on both sides of an open circuit-breaker);
 - ii. Interlocking of circuit-breakers in order to prevent out-of-sequence energization. This includes interlocking between POC circuit-breakers, upstream NSP circuit-breakers and downstream EG plant circuit-breakers.

Note: both of the above methods are to be applied on each circuit-breaker.

Where EG is to be operated in a split system (islanded with internal grid split), all circuit-breakers which are to be used to split the system must include sync-check functionality as defined above. In order to limit the number of circuit-breakers which require the sync check functionality, interlocking may also be used to force re-coupling of a split system at only particular circuit-breakers, and these must then include the sync-check protection functionality.

G.6.9 Protective Communication Requirements

Protective and safety interlock communications are required between the EG and the NSP as follows:

- EG/NSP unit protection communication (e.g. for line differential, accelerated impedance schemes);
- Safety interlocks (e.g. remote earth on);
- Signalling of plant status for e.g. Ready-to-Energise signals; and
- Any other protection communication requirements required by the NSP, published and approved by the Regulator.

G.7 Responsibilities and Roles

With respect to the grid protection design, configuration and settings, the following roles and responsibilities are defined for the key role-players:

G.7.1 NSP responsibilities

The NSP shall:

- a) Provide all data required of the NSP grid up to the POC, including:
 - i. Maximum and minimum fault levels (both 3-phase and single-phase);
 - ii. System Impedance Ratio;
 - iii. Upstream time-based protection settings;
 - iv. Clear requirements for unit protection equipment at the NSP upstream supply, where the unit protection equipment is to be upgraded;
 - v. Exact interface requirements where existing protection equipment must be interfaced to;

- vi. Clear SCADA interface details such as telecommunications interface detail and protocol;
- b) Only require equipment replacement or upgrading where absolutely necessary in order to comply with the SAGC for REPP.
- c) Provide detailed designs for upgrade of protection and control equipment to the EG owner where upgrades or replacement are required.

1.3.2 EG owner responsibilities:

The EG Owner shall:

- a) Upgrade or replace NSP protection and control equipment in accordance with the NSPs requirements, where such equipment is required in order to ensure compliance with the SAGC for REPP, at the EG's expense and based on designs provided by the NSP.
- b) Ensure that the complete private grid containing the EG complies with the SAGC for REPP, including protection, metering and visibility requirements as required by the NSP.
- c) Carry out a grid impact assessment and protection study for the complete EG grid, including the NSP's upstream grid portion to the POC or PCC, as required by the NSP. These studies are to be to the approval of the NSP or the NSP's appointed agent.

1.3.3 Joint Responsibilities/Coordination:

The NSP and EG Owner shall, in all aspects, carry out the respective roles without hindrance to the other party, and shall ensure that all information required for the successful integration of the EG grid into the NSP's network is shared timeously.

The NSP and EG owner shall ensure that the design of the POC protection and control is according to the SAGC for REPP.

Appendix H – Informative Summaries

Table 6: Overview of stakeholders and their tasks and responsibilities.

Stakeholder	Tasks and Responsibilities	Deliverables
Distributor (Municipality/NSP)	• Provide information pack to customers • Invoice application fees • Undertake/oversee Grid Impact Studies • Identify grid strengthening requirements • Issue Cost Estimate Letter • Undertake detailed grid strengthening studies • Cost strengthening • Provide Budget Quote • Negotiate relevant agreements (CUOSA, Self-Build) • Ensure permitting/authorisation secured • Undertake/oversee design (as needed) • Construct infrastructure (or oversee) • Monitor and approve connection works • Commission the plant (or oversee)	• Information pack • Cost Estimate Letter • Budget Quote • Relevant agreements • Design documents • Constructed infrastructure • Commissioned plant • Verification of Grid Code Compliance • Authorisation Close-Out

Stakeholder	Tasks and Responsibilities	Deliverables
	• Grid Code Compliance verification • Check documentation, agreements, specifications are in place • Issue formal close-out • Provide Letter of Consent for NERSA application • Check environmental/land-use authorisations • Allocate Power Quality emission limits • Maintenance of municipal metering • Notify customer of status/actions	
Customer/Generator	• Fill in application form • Pay fees • Undertake generator/collector network design • Undertake PoC impact studies • Undertake impact assessments • Design interconnection equipment	• Completed application form • Payment of fees • Signed agreements • Design documents • Constructed generator plant • Compliance with Grid Code • Permits/authorizations

Stakeholder	Tasks and Responsibilities	Deliverables
	• Undertake Grid Code Compliance Simulations • Construct generator plant • Comply with grid code • Provide type-test certificates (if applicable) • Attend acceptance testing (if applicable) • Complete environmental authorizations • Provide documentation	
NERSA	• Licensing and Registration	• Licensing decisions • Registration decisions
RETEC	• Undertakes compliance assessments and submits results to NERSA	• Compliance Assessment results

Table 7: Overview of the purpose and key aspects of each agreement.

Agreement	Parties Involved	Purpose	Key Aspects
Connection Agreement (Distributor-Customer)	Distributor, Customer/Generator	Governs the application, construction, testing, and commissioning process.	Requirements for both parties, project planning data, inspection/testing programs, electrical diagrams.
Implementation Agreement (Distributor-Customer)	Distributor, Customer/Developer	Establishes process and timelines for construction, commissioning, etc. Especially important where coordination is needed.	Coordination between municipal network strengthening, self-build, and/or generator construction, only agreed upon after application is processed.
Self-Build Agreement	Distributor, Customer	Outlines requirements, conditions, and processes for Customers who self-build their connection infrastructure.	Distribution scope of works, identification of control points, risks, mitigation strategies, standard governance process.
PPA (Generator-Customer)	Generator, Customer	Power purchase agreement (if the generator is selling power directly to another customer). The Distributor is NOT a direct party.	Distributor should include clauses in the Connection Agreement about energy purchase obligations if the PPA lapses.

Agreement	Parties Involved	Purpose	Key Aspects
Supply Agreement	Distributor, Customer	<i>Replaced by the Connection and Use of System Agreement.</i>	
Connection and Use of System Agreement (CUOSA)	Distributor, Customer	Main agreement between Distributor and Customer, covering technical, legal, and financial aspects.	All aspects governing the relationship between the Distributor and the Customer.
Operations Agreement (Distributor-Customer)	Distributor, Customer	Ensure parties understand each other's responsibilities during the operational phase.	Operational responsibilities, potentially included in the CUOSA.
Wheeling Agreement (Generator-Distributor-Customer)	Generator, Distributor, Customer	Fees and costs for using the DSO network for wheeling.	Power quality parameters, reliability requirements, captured bilaterally in CUOSA/Electricity Supply Agreement.
Reseller Agreement	Reseller	A reseller (bulk customer) needs to be licenced and have an agreement with NERSA	There might be a reseller agreement over and above normal customer/supplier relationship, a reseller is regarded as a middleman for the distribution of the electricity. The electricity

Agreement	Parties Involved	Purpose	Key Aspects
			regulation act prohibits that the sale of electricity at a higher tariff than the Distributor in whose area they are located.

Notes:

- This table provides a high-level comparison. The specific terms and conditions of each agreement will vary based on the individual circumstances.
- The guideline emphasises the importance of consulting legal professionals when drafting and reviewing these agreements.

Table 8: Summary of main agreements and specific project aspects.

Key Aspect	Connection Agreement	Implementation Agreement	Self-Build Agreement	PPA (Gen-Cust)	CUOSA	Operations Agreement	Wheeling Agreement	Reseller Agreement
Technical Specifications	X	X	X		X	X	X	
Project Timeline	X	X	X					
Construction & Installation	X	X	X					
Commissioning & Testing	X	X	X					
Roles & Responsibilities	X	X	X		X	X		
Fees & Costs	X				X		X	(Reseller fee)
Operational Procedures					X	X		
Metering & Billing					X		X	(Tariffs sold by Reseller)

Key Aspect	Reseller Agreement	Wheeling Agreement	Operations Agreement	CUOSA	PPA (Gen-Cust)	Self-Build Agreement	Implementation Agreement	Connection Agreement
Grid Code Compliance				X				X
Power Purchase/Sale Terms	X				X			
Use of System Charges		X		X				

Notes:

- This table is based on the descriptions in the document. The actual coverage within each agreement can vary.
- Legal counsel should always be consulted to ensure agreements adequately address all relevant aspects for specific projects.

End