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

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Revision 1.2

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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.

Section 1

GENERAL and REGULATORY

Background information
Overview of the process
Regulatory context - Electricity sector
Regulatory context - Municipal
Authorisations required

- **INFORMATION PURPOSES**: look at for context or for information on the regulatory environment governing EG >1MW

Section 2

MUNICIPAL PROCESSES

Step by step guide for assessing generator applications right through to commissioning, Grid Code compliance and close-out

- **PRACTICAL GUIDANCE: This is the heart of the document** - actions, responsibilities and outputs for both municipal Distributors and Customers are provided for each step of the process

Section 3

FINANCIAL and BILLING

Background information on tariffs, billing, metering etc

- **INFORMATION PURPOSES**: look at for general information on these topics

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Definitions

General Definitions

After Diversity Maximum Demand	Statistical value that is used to design networks taking into account that there is diversity in the demand from customers in the network.
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.
Distribution Code	Legal set of documents compiled to establish the reciprocal obligations of industry participants around the use of the DS and operation thereof.
EMT Simulations	EMT simulations are used to evaluate stability of the network and results are provided as waveforms.
Grid Code	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.
Grid Code Compliance	Process or status of complying with all relevant requirements from the South African Grid Code.
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, 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 Study	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.
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.
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
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
Consumer	A customer that consumes electricity only.	None in terms of this document
Prosumer	A customer that both consumes and generates electricity. 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.	Same as customer
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 of group of units that generate electricity.	
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.
Installer	The installer is the entity that does the physical installation work.	Install the equipment Ensure adherence to the Grid Code
Financier	This refers to the entity that provides funding for the development and construction costs of the generator.	Fund the process Conduct due diligence
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.

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.
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
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
Distribution Network Operator	The Distribution Network Operator (DNO) manages the operational aspects of their network. This mostly involves voltage regulation and thermal management of equipment.	Control and operate the distribution network
Transmission Network Service Provider	A legal entity that is licensed to own and maintain a network on the TS.	
Other municipal Distributors		Interaction as required by wheeling agreements
Traders	A legal entity licensed or registered to engage in the buying and selling of electricity as a commercial activity.	Comply to licensing conditions
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	
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

Acronyms

AC	Alternating Current
ADMD	After Diversity Maximum Demand
AGUP	Allowable Grid Unavailability Period
AMEU	Association of Municipal Electricity Utilities
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)
CUOSA	Connection and Use of System Agreement
DC	Direct Current
DMRE	Department of Mineral Resources and Energy
DOE	Department of Energy
DNO	Distribution Network Operator
DS	Distribution System
DSO	Distribution System Operator
ECSA	Engineering Council of South Africa
EG	Embedded Generator
EIA	Environmental Impact Assessment
ERA	Electricity Regulation Act (Act No. 4 of 2006) as amended
EMT	Electromagnetic Transient
ERA	Electricity Regulation Act
FAT	Factory Acceptance Testing
GCAC	Grid Code Advisory Committee
GCS	Grid Code Secretariat
ha	hectare
IDP	Integrated Development Plan
IPP	Independent Power Producer
IPS	Interconnected Power System
IRP	Integrated Resource Plan
kV	kilovolt
kW	kilowatt
LV	Low Voltage
MFMA	Municipal Finance Management Act
MW	Megawatt
MV	MegaVolt
MVA	MegaVolt-Amperes
MVar	MegaVolt-Amperes reactive power
NMD	Notified Maximum Demand
NERSA	National Energy Regulator of South Africa
NSP	Network Service Provider
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
REDZ	Renewable Energy Development Zone

RETEC	Renewable Energy Technical Evaluation Committee
RMS	Root Mean Square
RPP	Renewable Power Plant
RPPGC	South African Grid Code for Renewable Power Plants
PoC	Point of Connection
PoD	Point of Delivery
PoS	Point of Supply
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PQ	Power Quality
PV	Photovoltaic
SAGC	South African Grid Code
SALGA	South African Local Government Association
SAT	Site Acceptance Testing
SIT	Site Integration Testing
SO	System Operator
SSEG	Small-scale Embedded Generator
ToU	Time of Use
TS	Transmission System
UoS	Use of System

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) has 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 not[1]. 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) generators[2] connecting to municipal networks. However, non-electrical compliances and considerations are also noted, and further references provided.

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

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[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. It is anticipated that a new code under development will address all generator aspects in one document.

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 (specifically 2.4.12 and 2.4.13).

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/Customers[3]

In terms of the ERA and Grid 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 paragraph 4(2) of the Distribution 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 effect 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 and the ERA, as amended.

[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.

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.

Paragraph 4.4 of the Distribution 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

1.2.2 NERSA licensing / registration

According to the December 2022 Schedule 2 of the ERA[4] the following registration and licensing exemptions exist for EG:

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

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 several months.

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 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.

[4] Electricity Regulation Act: Amendment: Licensing Exemption and Registration Notice. Govt Gazette No 47757, 15 December 2022)

1.2.4 ERA Section 34 determination[5]

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 are exempt from licensing.

For municipal own-procurement (municipal owned or via an IPP), legal analyses indicate that a Section 34 Ministerial Determination is not required for generators > 1MW[6] (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 New Generation Regulations, 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.

[5] 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)

[6] 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.

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.

<table>
<tr><th>Category</th><th>Subcategory</th><th colspan="2">Size</th></tr>
<tr><td rowspan="3">A</td><td>A1</td><td>Up to and including 13.8 kW</td><td rowspan="3">Up to 1000 kW</td></tr>
<tr><td>A2</td><td>Greater than 13.8 and less than 100 kW</td></tr>
<tr><td>A3</td><td>Greater than 100 and less than 1000 kW</td></tr>
<tr><td rowspan="2">B[7]</td><td>B1</td><td>From 1 up to and excluding 5 MW</td><td rowspan="2">1-20 MW</td></tr>
<tr><td>B2</td><td>From 5 up to and excluding 20 MW</td></tr>
<tr><td colspan="2">C</td><td colspan="2">Anything above and including 20 MW</td></tr>
</table>

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, it is recommended for consistency 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.

[7] 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

At a high level, the process comprises nine steps as shown below:

STEP 1:
- **SUBMIT APPLICATION**
- Distributor provides information pack
- Customer fills in application form
- Customer pays application fee

STEP 2
- **EVALUATE APPLICATION**
- Distributor (or developer) undertakes Grid Impact Studies
- Distributor identifies any grid strengthening requirements
- Distributor provides Cost Estimate Letter

STEP 3
- **BUDGET QUOTE**
- Customer pays Budget Quote fee
- Distributor (or developer) undertakes detailed grid strengthening studies (if needed)
- Distributor costs strengthening etc
- Distributor provides Budget Quote (typically 85% accurate)

STEP 4
- **CONTRACTING/LEGAL**
- Parties negotatiate relevant agreements, such as the Connection Agreement, Use of System Agreement, Self-Build Agreement.
- All permitting/authorisation secured

STEP 5
- **DESIGN**
- Distributor design undertaken (as needed)
- Customer completes design of plant, regulatory approvals

STEP 6
- **CONSTRUCTION**
- Distributor constructs infrastructure (as applicable, indicated by Grid Impact and Strengthening studies)
- Customer constructs plant
- Distributor monitors & approves connection works

STEP 7
- **COMMISSIONING**
- Generator Plant Commissioning

STEP 8
- **GRID CODE**
- Grid Code Compliance verification

STEP 9
- **AUTHORISATION CLOSE-OUT**
- Distributor checks all documentation, agreements, specifications etc in place
- Formal close-out

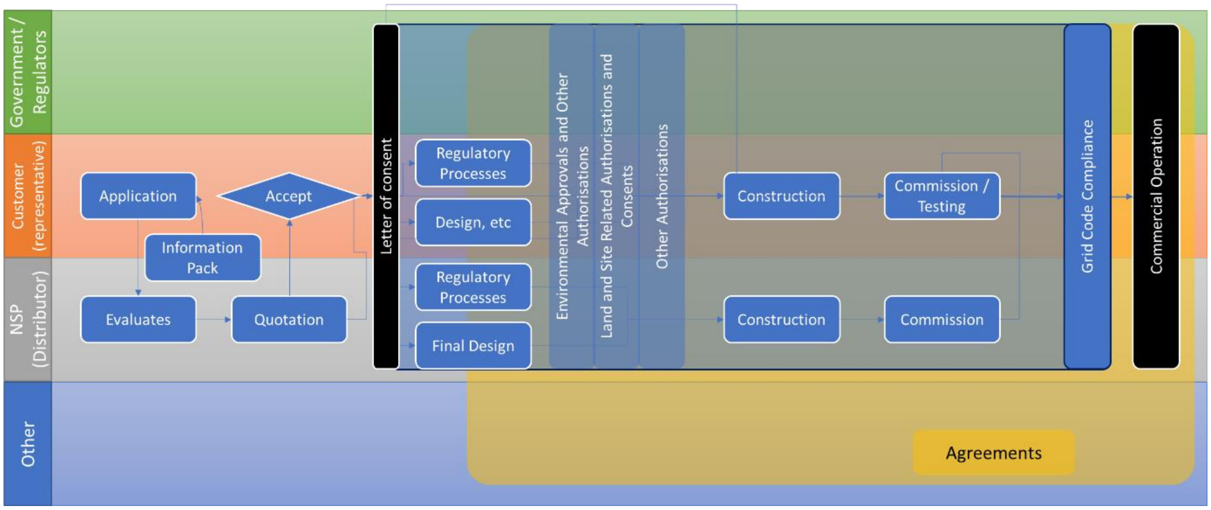

Figure 1: High-Level overview of process (showing progression and relevant party for different steps)

1.5 Municipal own procurement processes[8]

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 development[9].

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[8] 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).

[9] 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 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).

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.

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, 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.

1.6.4 Ancillary Services

Ancillary services refer to any function provided by grid-connected generators[10] 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 up must have the capability to provide ancillary services by default.

[10] 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 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 endeavor 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 SSEG[11], based mainly the NRS097-2-suite of documents (NRS, 2020) (NRS, 2014). This guide focusses on the additional aspects when dealing with generator applications larger than 1 MW.

[11] 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 is 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 fee*[12]
   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.

   The information pack provided should include:

   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)
   g. Applicable tariff structures

[12] As an example, Eskom's 2022/23 fees on application to produce a Cost Estimate Letter are shown here:

> 1 MVA/MW ≤10 MVA/MW (major process)	R26 052.17+VAT =R29 960.00
> 10 MVA/MW ≤50 MVA/MW (Large)	R 66 991.30 + VAT = R77 040.00
> 50 MVA/MW (Very large)	R 100 521.74 + VAT = R115 600.00

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

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
- 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.

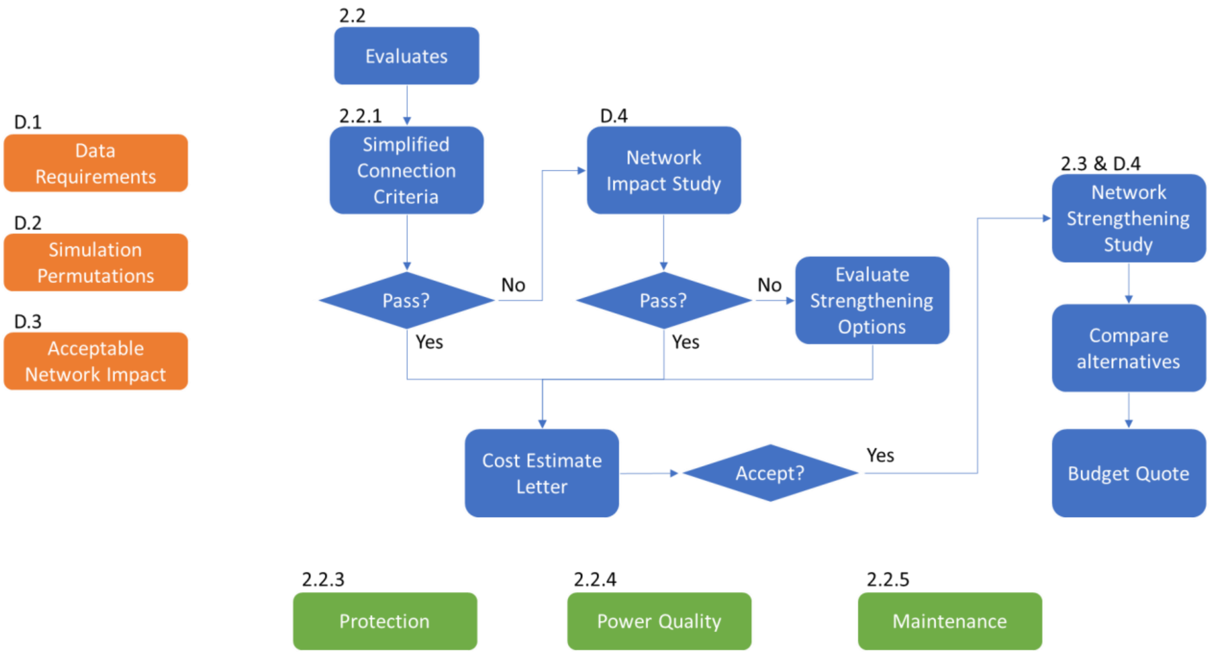

Figure 2: Distributor evaluation process and components ('D' refers to Appendix D, numbers to section numbers in the document)

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 Study[13]. 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.

[13] Note on terminology: Grid Impact Studies can also be termed Network Studies, or Network Impact Studies – there appears to be no standard way of using these terms – either locally or internationally. In this document 'Grid Impact Studies' will be used since this is the term familiar to many Distributors.

NRS097-2-3 Simplified Connection Criteria for generators <1MW

Small-scale embedded generators (i.e. <1MW) may be evaluated by following a simplified connection criteria assessment as per the NRS097-2-3[14] instead of doing grid impact studies. The NRS097-2-3 covers generator impact at the PoC but also considers the cumulative grid impact (i.e. hosting capacity) of all other embedded generators on that section of the network, including on the relevant MV feeder.

One of the outputs of a hosting capacity study would be to determine internal, network-specific, simplified connection criteria for generators larger than 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.*

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. Three options are identified:

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.

[14] The NRS 097-2-3 criteria may be adapted for local Distributor conditions. Note that the use of the NRS097-2-3 in evaluating generator connections should be documented in a municipal policy document, which should also clarify any adaptations to the NRS097-2-3 criteria.

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 *Grid Impact Study Specification Guideline*[15] 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.
    c. The Distributor will evaluate the study to determine if the generator can connect without adverse impact on the grid.

    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 professional[16] 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).

Note: In the case that the Customer does the Grid Impact Study, it is possible that the Grid Strengthening Study (Step 3) 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 aspects include monitoring fault levels as well as to ensure protection coordination. The Distributor need to evaluate the requirements for updated protection settings or even protection upgrades during the Grid Impact Study. This should be included in the scope of work of the party undertaking the study.

Fault Levels

As part of the Grid Impact Studies, fault levels are calculated under all conditions to ensure they remain within existing equipment specifications. These results provide an input into the protection settings and selection of protection equipment. Fault current withstand and breaker rupturing values should be considered to ensure that the system may be operated safely.

Protection Coordination

Protection coordination studies need to be done separately to ensure correct operation of protection for the various network conditions as well as prevent nuisance tripping where possible.

Auto-reclosers

If there are reclosers upstream of the generator, the speed of closing should be coordinated with the anti-islanding requirement of the generator. The standard anti-islanding requirement is that generators disconnect from an islanded network within 2 s. Therefore, reclosing times should be longer than 2 s.

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[15] Available at https://www.sseg.org.za/grid-impact-study-specification-guide/

[16] 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.

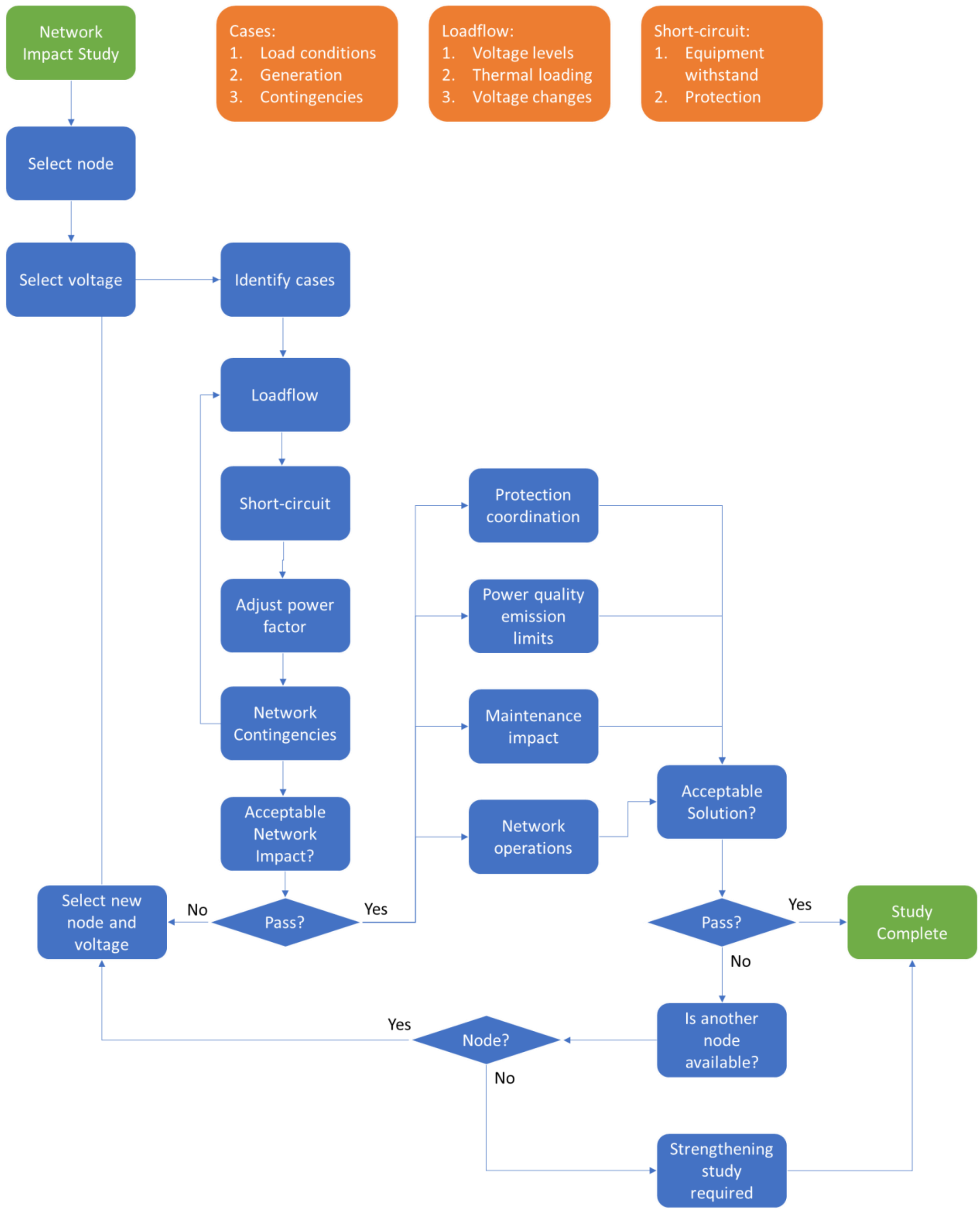

Figure 3: Grid (network) impact study process.

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)

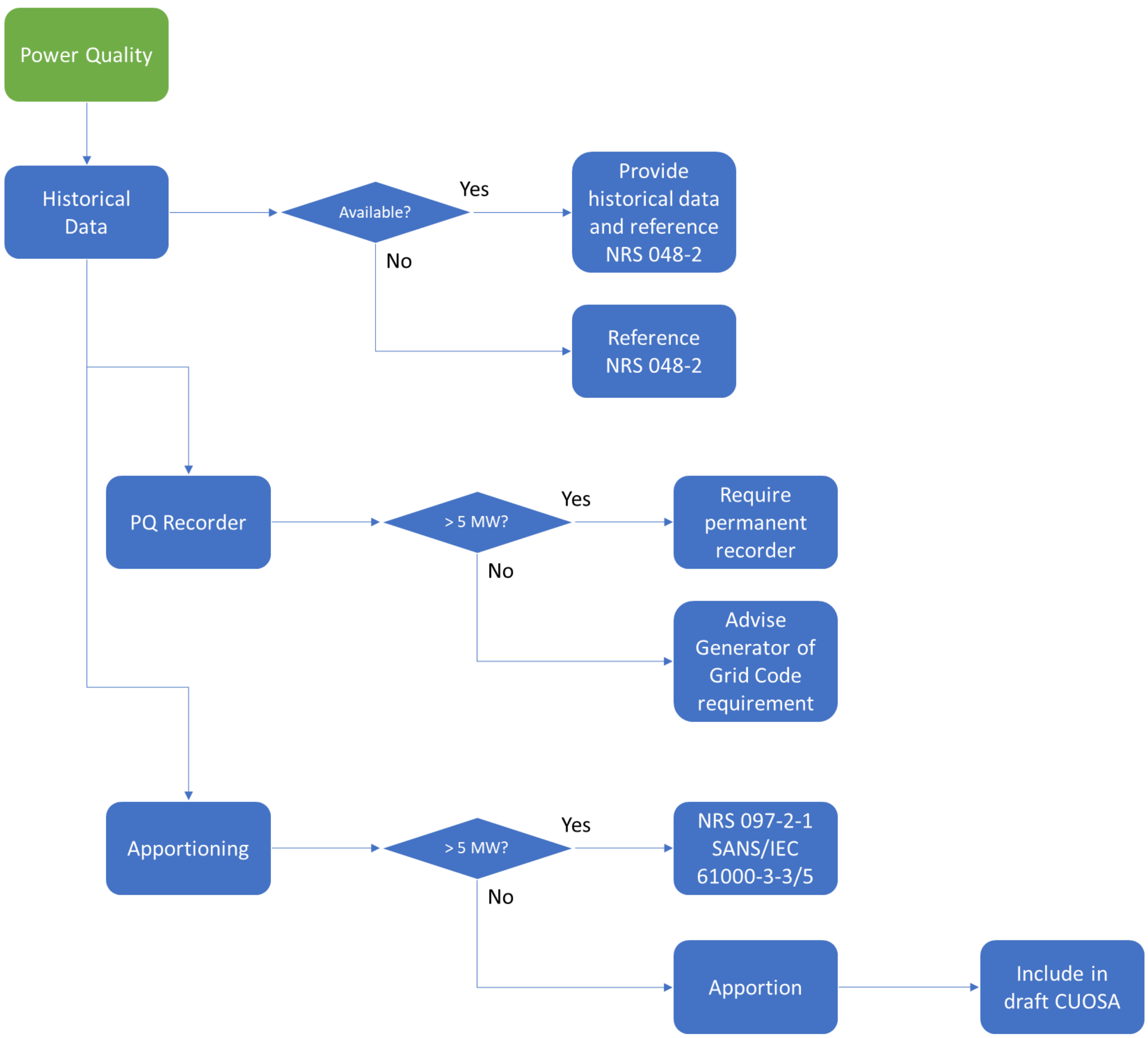

Figure 4: Power Quality aspects.

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 PoC[17]. 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 taken into account 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)

[17] 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.

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 costs[18] (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.

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)

[18] A table with costs is provided in **Error! Reference source not found.** to assist with the calculation of indicative strengthening c osts (Appendix A costs need to be adjusted for inflation etc).

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 fee[19] 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 level[20] to allow the customer to secure funding.

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

[19] 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**.

[20] Eskom typically issues this quote with an 85% confidence level.

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.

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 also highlights refunds to initial Customers (including reference to the distribution code).

Also refer to the note on ***Reserving Capacity*** *on p32.*

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 authorisations

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

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

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

2.4.1 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 upgrading and generator construction is needed.

2.4.2 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.

2.4.3 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.

2.4.4 Connection Agreement (Distributor-Customer)

The purpose of such a Connection Agreement is to govern the performance of both parties at the point of connection. This was previously called the Supply Agreement. Clause 3.2 of the Distribution Network Code specifically requires a Connection Agreement with Customers, which shall 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

   Note that 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.

In addition, the following aspects should also be included in the generator Connection Agreement:

1. Power factor/reactive power requirements
2. Power quality requirements
3. Applicable tariffs for use of the system, including for example reliability fees
4. Legal responsibilities

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 significantly.

2.4.5 Supply Agreement

See Connection Agreement in section 2.4.4.

2.4.6 Use of System Agreement (UoS)

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.

2.4.7 Operations Agreement (Distributor-Customer)

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

2.4.8 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.

2.4.9 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.

To date NERSA has issued few trading licenses.

A trading agreement indicates a reseller ("middleman") in the distribution of the electricity. Where applicable, a separate agreement needs to be entered into over and above the PPA. Currently, the electricity regulation act prohibits that a trader sells electricity at a higher tariff than the Distributor in whose area they are located.

2.4.10 PPP (Public Private Partnership)

(To be added in further editions of this document)

2.4.11 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 taken into account in the Budget Quote, i.e. costs may be passed-through to the Customer.

2.4.12 Environmental and other authorisations[21]

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

[21] 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).

not, whether it is in an urban area or not, and whether it falls within a Renewable Energy Development Zone[22]. As a general guide, the following apply[23]:

- **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 >1ha, or involve infrastructure over 33kV outside an urban area or over 275kV in an urban area
- **Comprehensive environmental impact assessment required**: generators over 20MW, 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.

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

There is a national focus on reducing the environmental regulatory requirements for solar projects in areas of low and medium environmental sensitivity[24].

Other authorisations that may apply include:

- 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.

[22] 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.
[23] 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.
[24] Address by President Cyril Ramaphosa on actions to address the electricity crisis, Union Buildings, Tshwane, 25 July 2022

- 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.
- 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, respectively[25].

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.

2.4.13 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 principle site activity has not changed. A solar generator developed on vacant land will typically require rezoning. 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 may take 3 to 6 months.

Depending on the site location, 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 may also 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.

[25] Goldblatt M. *Mapping of authorisation processes for renewable energy projects*, 2015. PDG

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

Municipal land[26]

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.

2.5 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 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.

[26] 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).

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 NRS097-1 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 depends 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 depends 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 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 - Version 3.0* (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 1MW. For smaller generators (less than 1 MVA) NRS097-2-1 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 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 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 Generators[27]. 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. 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.

[27] 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.

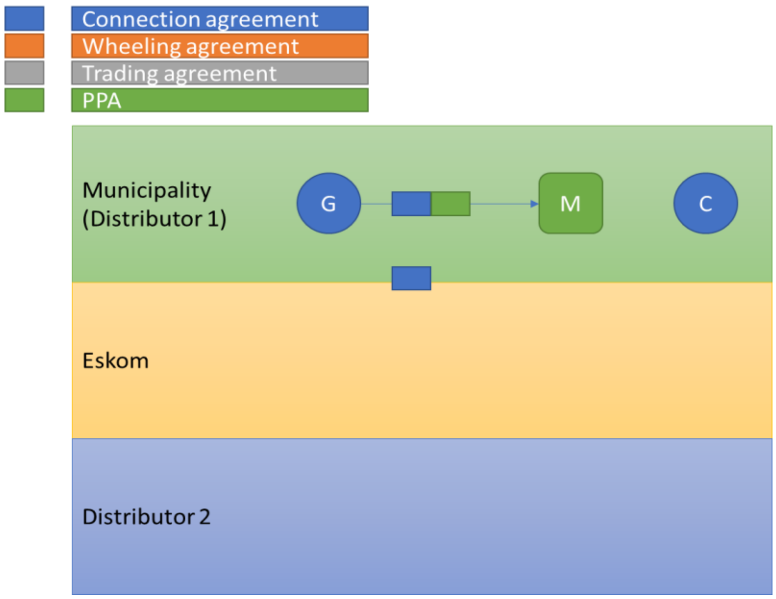
Major summarized item (for detailed cost calculation, refer to detailed costing sheet for substation works or MV/LV reticulation works	UoM	Cost per unit
HV Incomer bays - Outdoor	each	R 3 440 000
HV outdoor Busbar, bussectionalizers & related shared infrastructure	Lot	R 13 490 000
HV Outdoor Feeder breakers	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

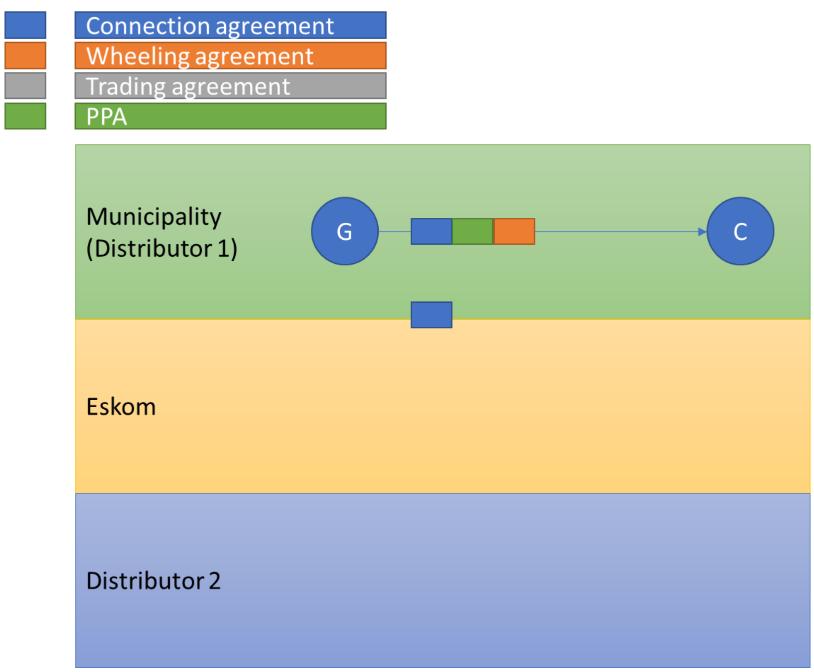


The Customer/Generator sells power to the municipal Distributor:

- 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



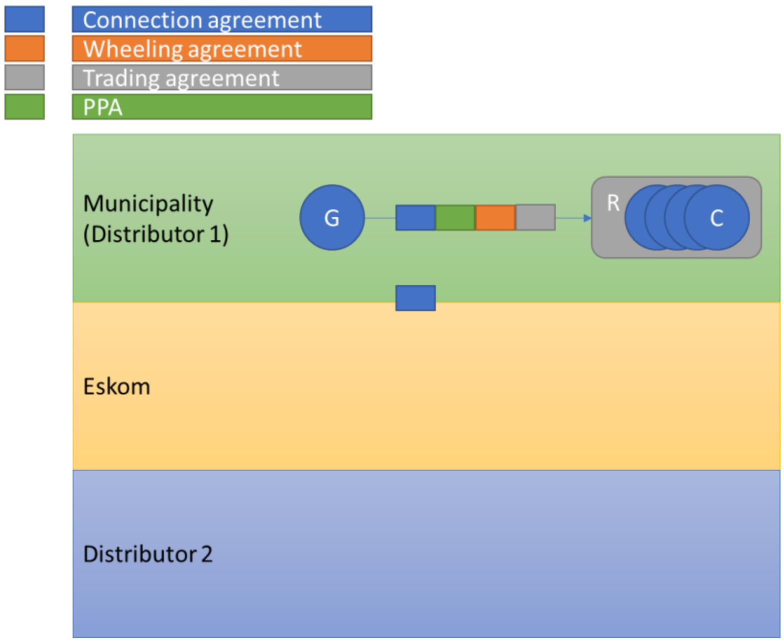
Generator wheels to a customer – both in the same municipal distribution network:

- 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

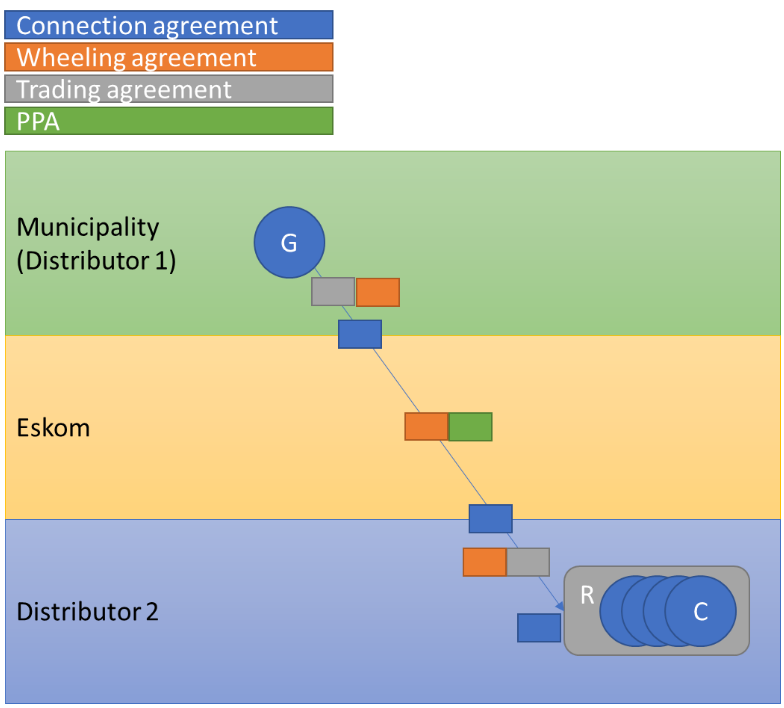


Customer/Generator wheels to trader – both on same distribution network:

- 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			
Internal Departments sign-off			
Planning			
Protection			
Power Quality			
Maintenance			
(other)			
Budget Quote issued			
Budget Quote accepted			
NERSA letter of consent			
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
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

This section provides an overview of key aspects of relevant grid studies. More comprehensive information is provided in the *Grid Impact Study Specification Guideline*[28] 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.

D.1 Data Requirements for grid studies

Information required for such studies should cover the surrounding network to at least one voltage level above the PoC. Data shall be accompanied by appropriate single line drawings.

Relevant network data:

- The surrounding network data, at least up to one voltage level above the proposed point of connection:
  - Fault level at the infeed of the equivalent network.
  - X/R ratio at the infeed of the equivalent network.
  - All cable and conductor parameters, including impedance per length, length of cable or conductor, topology with dimensions, thermal limits.
  - Relevant transformer parameters, including percentage impedance, winding and core losses, tap changer settings (transformer test sheets).
  - Network loading profiles.
  - Lumped loads in relevant network areas.
  - Other generation in the relevant network (generic information per generation type).
  - A list of network contingencies that the Distributor deems realistic (as planned).

D.2 Network Study Simulation and Permutations

A suitable selection of cases needs to be simulated in the network studies, taking the following into account:

1. Load conditions (at least high and low load)
2. Generation conditions (maximum and minimum generation)
3. Network contingencies

The network operational conditions (voltage levels, loading of equipment etc) need to be within acceptable levels for all these cases.

D.2.1 Acceptable Grid Impact

The following conditions need to be confirmed to ensure the impact on the network is manageable:

[28] Available at https://www.sseg.org.za/grid-impact-study-specification-guide/

1. Steady-state network conditions:
    a. Voltage regulation
    b. Thermal loading
2. Fault levels:
    a. Impact on network protection and equipment ratings
    b. Impact on neighbouring customers' protection and ratings
    c. Maximum fault level withstand capabilities of all equipment
3. Voltage changes (at all nodes in the network):
   The requirements can differ. Based on e.g. VDE-AR-N-4105 (2018) recommendations, the voltage change due to <u>all</u> EG connected on an LV network should be limited to 3%. As the generators become larger at higher voltage levels (and further apart), this could be increased to 3% or even 5% per generator.
   The recommendation is as follows for 100% generation rejection during network normal conditions:
    a. On LV networks, ≤1% per generator
    b. On short MV networks with large numbers of customers (high density networks), <1% per generator
    c. On longer MV networks with lower numbers of customers (low density networks), <3% per generator
    d. On higher voltages, <3% per generator
    e. On higher voltages and if the generator is dispatchable, the voltage change at unity power factor can increase to 5%, as long as the voltage change at 0.95 pf (absorbing) remains <3%

   The recommendation is as follows for 100% generation rejection during any credible network contingency:
    a. On LV networks, ≤1% per generator (no change)
    b. On short MV networks with large numbers of customers (high density networks), <1% per generator (no change)
    c. On longer MV networks with lower numbers of customers (low density networks), <5% per generator
    d. On higher voltages, <5% per generator
    e. On higher voltages and if the generator is dispatchable, the voltage change at unity power factor can increase to 6%, as long as the voltage change at 0.95 pf (absorbing) remains <5%
4. Feedback into network:
   The maximum energy fed back from the LV to the MV network should be limited to 75% of the transformer rating to protect the Distributor's distribution transformers.
    - Note that this is for possible DC injection from inverters and does not take harmonic loading into account. Municipalities are advised to discuss the harmonic impact with the suppliers of their transformers.
    - At higher voltage levels (MV), the generator should have its own transformer connecting to the network and the impact of feeding back into the network is evaluated using points 1 to 3.

D.2.2 Undertaking the Grid Impact and Strengthening Studies

The typical aspects to be taken into account for a detailed Grid Impact Study are the following:

1. Select an appropriate node on the network where the installation can connect.
   In practice this will be a node closest to the planned installation that can successfully transfer the energy generated.
2. Select an appropriate voltage level for the point of connection:
   a. SSEG (up to 1 MW) generally connect at LV
   b. Generators >1MW and < 20 MW generally connect at MV
   c. Generators larger than 20 MW generally at HV
3. Evaluate network capacity:
   a. Voltage levels in surrounding network and one voltage level up
   b. Thermal capacity of lines and transformers in surrounding network and one voltage level up
   c. Voltage changes at all nodes in the surrounding network and one voltage level up
4. Evaluate fault levels for all study cases
   a. The recommended short-circuit calculation method is according to IEC60909.
5. Adjust generation power factor for maximum leading and lagging and review point 3.
6. Evaluate appropriate network contingencies and review points 3 and 4.
7. Consider alternative point of connection and / or different voltage level.
8. Consider the reliability of the point of connection, i.e. the frequency and duration of interruptions of this network point. Improved reliability may be required by the Customer/Generator and may be funded via a special reliability charge as part of the tariff. (Also see AGUP in section 2.2.4).
9. Consider possible change in demand at Eskom Point(s) of Delivery (inform Eskom if relevant, including consideration of Connection Agreement amendments).

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%: (Qmax)/4% Un
    - Test 2: Set the Droop to 8%: (Qmax)/8% Un
- 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 larger than 1 MW, this can be achieved by testing to similar standards, such as IEEE 1547 or IEEE 519 and the above IEC documents.

Units 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 (December 2022)[29] the following registration and licensing requirements apply:

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

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

[29] Electricity Regulation Act: Amendment: Licensing Exemption and Registration Notice. Govt Gazette No 47757, 15 December 2022)

(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

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End