UTILITY REGULATORY AUTHORITY

Mauritius National Grid Code

Distribution Code

Version December 2022

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DISTRIBUTION CODE

DC 1 OBJECTIVE AND SCOPE

The objective of the **Distribution Code** is to establish the rules, procedures, requirement and standards that govern the operation, maintenance and development of the **Distribution System** to ensure an efficient, co-ordinated and economical system for electricity distribution. It also sets out procedures and requirements for the **Distribution Licensee's** and all **Users** of the **Distribution System.**

The **Distribution Licensee** and existing and potential **Users** connected to or seeking to connect to the **Distribution System** shall comply with the relevant sections of the **Distribution Code,** including **Distributed Generators** and **Customers.**

Users connected to the **Distribution System** shall comply with the **Distribution Code.**

The **Interconnection Boundary** of the **Transmission and Distribution Systems** shall be as defined in Section TC 1.1 of the **Transmission Code.**

DC 2 GENERAL REQUIREMENTS

This **Distribution Code** contains the procedures to provide an adequate, safe and efficient electricity distribution service to all parts of Mauritius, taking into account a wide range of **Normal** and **Contingency Conditions**. It is however necessary to recognize that the **Distribution Code** cannot address every possible situation. Where such unforeseen situations occur the **Distribution Licensee** shall act as a reasonable and prudent operator in the pursuance of any or a combination of the following general requirements to protect the safety of the public and employees:

a. the need to preserve the integrity of the **System**;

b. to prevent damage to the **System**;

c. compliance with conditions under its **License**;

d. compliance with the Electricity Act 2005 and its amendment;

e. compliance with the **Distribution Code.**

Users shall provide such reasonable co-operation and assistance as the **System Operator** reasonably request in pursuance of the general requirements in this Section DC 2

DC 3 DISTRIBUTION SYSTEM PLANNING

DC 3.1 Purpose and Scope

The **Distribution Licensee** with the **Single Buyer** will be responsible for planning the development of the Distribution **System.**

The **Authority** will provide the System Operator with policy guidelines from the **Ministry** for the development of the system such as policy objectives regarding the use of primary energy sources for generating electricity, future technologies, etc.

The **Single Buyer** will also develop procedures for development of an **Integrated Resource Plan**, engaging key electricity sector stakeholders in a collaborative process.

The objective of the long-term **Integrated Resource Planning (IRP)** is to define the development (upgrading and expansion) of the **Transmission and Distribution Systems** as well as the indicative incorporation of new generation resources based on policy guidelines provided by the **Ministry**, in order to guarantee the quality and reliability of electricity supply for the nation and the economic players.

The **Distribution Licensee** and the **Transmission Licensee**, as it corresponds, shall be responsible for the implementation of the upgrading and expansion of the **Transmission and Distribution Systems** as defined in the **IRP**.

The **Single Buyer** shall elaborate the long-term **IRP** according to the procedures and information requirements established in section SOC 1 of the **System Operations Code**.

The **System Operator** is also responsible for the short-term planning (Operation Planning) as required by section SOC 2 of the **System Operations Code**.

The IRP horizon analysis shall be 10 years and the plan shall be updated yearly with the most recent updated information available such as policy guidelines, load forecasts, expected commercial operational date of key ongoing projects, fuel prices, new generation technologies and prices, etc.

In the elaboration of the **IRP,** the **Single Buyer** shall specifically consider the location of renewable and other generation sources.

This section DC 2 specifies the following criteria, processes and information that will be used by the **Single Buyer** in the fulfilment of its planning duties:

a) Distribution System Planning Criteria
b) Planning Studies, and
c) Data Requirements

DC 3.2 Distribution System Planning Criteria

DC 3.2.1 Principles

The **Distribution System** planning criteria shall be based on the requirement to comply with statutory requirements in DC 3.2. Where no statutory requirements exist, the criteria shall be based on **Prudent Utility Practice** and relevant international standards.

The overriding principle in the planning process of the **Distribution System** is the responsibility of the **Distribution Licensee** to "*maintain any installation, apparatus or premises relating to his license in such condition as to enable it to provide safe, adequate and efficient electricity service*", as set forth in the **Act.**

DC 3.2.2 Planning Criteria

The **Distribution Licensee** and **Single Buyer** shall adopt the following criteria to perform the **Distribution System** planning:

a) The **Distribution System** shall be designed in such a manner that all spur lines with load above 100 Amperes and 22 kV feeders have a back-up supply from the **System.**
b) The number of switching operations shall be kept to a minimum so as to enable fast restoration of supply.
c) The feeder's loading under **Normal Conditions** shall be limited to 50% of conductor nominal current rating.
d) The voltage limit shall be within statutorily prescribed limits under **Normal Conditions.** Voltage regulation at the nominal value of 230 V for single-phase supply and 400 V for three-phase supply shall be within ±6% at the **Interconnection Boundary.**

e) The closed busbar configuration at 22 kV in the **Distribution System Substations,** where required**,** shall satisfy the **N-1 Security Criterion.** This requires operating the tap changers on parallel transformers in the master-slave configuration in order to ensure that all tapping is carried out in unison.

DC 3.2.3 Voltage Criteria

The **Distribution System** shall be designed to ensure that under **Normal** and **Contingency Conditions**, voltages at all **Interconnection Boundaries** and buses are within the following ranges:

a) between +6% and -6% of nominal voltage under **Normal Conditions** at **MV** busbars;
b) between +6% and -6% of nominal voltage under **Normal Conditions** at **LV** busbars;
c) between +10 and-10% of nominal voltage under **Contingency Conditions** at **LV** and **MV** busbars.

DC 3.2.4 Load Power Factor

The **Distribution System** shall be planned for a **Demand** load consumption with **Power Factor** between 0. 90 leading to 0.90 lagging under **Normal Conditions**.

DC 3.3 Studies for Interconnection

DC 3.3.1 General

The **Distribution Licensee** in collaboration with the **Single Buyer** and the **System Operator,** if required**,** shall undertake **Distribution System** interconnection studies whenever required to:

a. Determine particular interconnection requirements for any **Users' System,** submitted in accordance with the interconnection application process, including any reinforcement, **Protection** or **Power Quality** improvement requirements; and

b. Determine the interconnection requirements for any **Generating Station**, submitted in accordance with the interconnection application process, including any reinforcement, **Protection** or **Power Quality** improvement requirements.

All technical data required for the interconnection studies to the **Distribution System** (as well as other information) shall be provided by the applicant to the **Distribution Licensee**, who will flow the information to the **Single Buyer,** if needed. The **Distribution Licensee** shall coordinate, as needed, with the **System Operator** and the **Single Buyer** for the provision of additional data required to carry out the interconnection studies. The **Distribution Licensee** shall contact the **Large Customer** directly for additional technical information related to his request for interconnection.

The **Distribution Licensee** shall coordinate with the **System Operator** specific requirements for the interconnection of large loads to the MV system (e.g. protection studies and specifications), and require its assistance in the elaboration of some studies. However, the **Distribution Licensee** should remain ultimately responsible for the execution of the studies and for the coordination and communication with the applicant.

All information exchange among licensees shall be properly recorded.

DC 3.3.2 Demand Forecasts

The **Distribution Licensee** and the **Single Buyer** shall be responsible for the elaboration of the load forecasts.

The **Distribution System** expansion plan shall be mainly guided by inputs from a **Spatial Load Forecast**, the construction of new substations and requests of connection of **Customers** to the **MV** network.

The load forecast methodology shall also consider the increasing number of connected **Distributed Generation** projects.

The **Spatial Load Forecast** shall be supported by the Geographical Information System of the whole **Grid**.

The Geographical Information System shall store virtual information relating to the physical aspects of the transmission and distribution networks. It shall permit the viewing, understanding, questioning, interpreting and visualizing of data in many ways that reveal relationships, patterns and trends in the form of maps, reports and charts. These capabilities of the Geographical Information System shall assist in load forecasting and transmission and distribution planning activities

System planning simulation software shall use the outputs of the proposed Geographical Information System so as to enable the conduct of detailed technical studies of the **Distribution System**. It is expected that the Geographical Information System shall support other activities of the **Distribution** and **Transmission Licensees** such as asset management.

The Geographical Information System shall support the development of a consumption forecast using an econometric regression methodology. This forecast of unit consumption is then to be developed into a peak demand forecast for each substation which shall inform the planning studies.

DC 3.3.3 Load Flow Studies

The **Distribution Licensee** in collaboration with the **Single Buyer** and/or **System Operator,** if required**,** shall undertake load flow studies using appropriate **Models.**

Load flows shall be analysed at least for peak and minimum feeder loads, based on the feeder metering data or **SCADA** data where metering data is not available calculated from the 30-minute averages. The calculation of the forecasts at a feeder level shall be based on regression analysis and forecast forward for an appropriate period to ensure that all network components are operating within their design parameters for the forecast period.

Load flows shall model the contingency scenarios planned for in the network design and shall be undertaken to ensure that all network components are operating within their design parameters for all plausible scenarios of supply network reconfiguration. Short term and emergency ratings of **Plant** may be used if it is considered that the timescale for restoration to normal operation shall align with the manufacturers' guidance on such ratings, or other parameters as determined by the **Distribution Licensee**.

DC 3.3.4 Voltage Regulation Studies

The **Distribution Licensee** in collaboration with the **Single Buyer** and/or **System Operator,** if required**,** shall undertake voltage regulation studies to determine the voltages at all **Interconnection Boundaries** using appropriate modelling tools and verify the compliance with the limits in DC 3.2.3. Such studies shall be used to determine the impact of any **Demand** or **Generation** interconnection, **System** expansion or reinforcement.

The planning of the **Distribution System** voltage regulation shall take into account 5 years **Demand** forecasts and include the use of:

a. power transformer tap changers to maintain bus bars at within acceptable ranges;

b. voltage regulation of **Distributed Generators** and **Energy Storage Units**;

c. capacitors (fixed capacitor banks should be sized on present requirements rather than growth forecasts to avoid over voltage); or

d. upgrade of conductor size

The **Distribution System** shall be planned considering voltage control on the secondary sides of the 66/22kV transformers using tap changers.

Capacitors may be used to provide voltage improvement on the Distribution System in the following cases:

a. reducing the lagging component of circuit current;

b. increasing the voltage level at the load;

c. improving voltage regulation, if the capacitors are properly switched;

d. reducing **Active Power** and **Reactive Power** losses in the system because of reduction in current;

Suitable **Equipment** and procedures shall be employed where required to ensure that excessively high voltages are not experienced at **Interconnection Boundaries** during periods of light load or abnormal operating conditions, or due to the active power injection of **Distributed Generators**.

Voltage drops shall be assessed at peak feeder **Demand** based on the 15-minute average of the feeder metering data, or **SCADA** data where metering data is not available, to ensure that the design voltage at the **User Interconnection Boundary** meets the voltage requirements set forth in **DC 3.2.3**.

The voltage profiles shall be assessed for planned **Contingency Conditions** and shall be such that the design voltage at **User's Interconnection Boundaries** meets the voltage requirements of this **Distribution Code** for all plausible **Distribution System** configurations.

Any extension or interconnection to the **Distribution System** shall be designed in such a way that it does not adversely affect the voltage control employed on the **Distribution System**.

DC 3.3.5 Short Circuit Studies

The **Distribution Licensee** in collaboration with the **Single Buyer** and/or **System Operator,** if required, shall undertake fault current level studies at all switching points on the **Distribution System** where fault interrupting devices are located. The studies shall determine the three phase and single phase to ground short circuit levels for the most stringent conditions.

The **Distribution System** shall be designed to ensure that the short-circuit fault current shall be limited to the declared manufacturers' ratings of all switches, fuses, circuit breakers and other **Protection** devices in terms of both **Breaking Capacity** and **Making Capacity**.

Where it is identified that the design **Breaking Capacity** or **Making Capacity** is likely to be exceeded, the non-compliance shall be documented and the plant shall be subject to appropriate operational restrictions until compliance is achieved.

The **Distribution Licensee** and **Users,** including **Distributed Generators,** will exchange information on fault infeed levels at **Interconnection Boundaries.** This shall include:

a. the maximum and minimum three-phase and line to ground fault infeeds; and

b. the X/R ratio under short circuit conditions.

Unless the **Distribution Licensee** agrees otherwise, it is not acceptable for a **User** or **Distributed Generator** to limit the fault current infeed at the **Interconnection Boundary** through the use of **Protection** and associated **Equipment** if the failure of that protection and associated **Equipment** could cause the **Distribution System** to operate outside its short circuit rating.

DC 3.3.6 System Losses Studies

System losses studies shall be performed to quantify the **Active Power** losses in the **Distribution System** and determine optimum **Distribution System** open points to provide an acceptable balance between reduced losses and **Distribution System** reliability.

Where investment in the **Distribution System** is required, lower loss solutions, in terms of plant and **Distribution System** configuration shall be evaluated as part of the alternative solutions and appropriate allowances made in the economic appraisal for any benefit arising from the adoption of such solutions.

DC 3.3.7 Reliability Studies

Reliability studies shall be carried out by the **Distribution Licensee** to determine the theoretical levels of System Average Interruption Duration Index (**SAIDI)** and System Average Interruption Frequency Index (**SAIFI**) for the **Distribution System** using average fault rates for the **Distribution System** components. These studies shall be used to determine optimum **Distribution System** configurations when undertaking any interconnection, extension to or reinforcement of the **Distribution System.**

The **SAIDI** and **SAIFI** indices are defined as follows according to the IEEE Standard 1366-2012:

The SAIDI is the average outage duration for each customer served. It is measured in units of time, minutes or hours, and is calculated as:

$$\mathrm{SAIDI} = \frac{\text{Sum of customer minutes of interruption}}{\text{Total number of customers served}}$$

The SAIFI is the average number of interruptions that a customer would experience. It is measured in units of interruptions per customer, usually over the course of a year, and is calculated as:

$$\mathrm{SAIFI} = \frac{\text{Sum of total number of customers interrupted}}{\text{Number of customers served}}$$

The **SAIDI** and **SAIFI** indices shall be reported to the **Authority**. The reporting and computation methodology of the **SAIFI** and **SAIDI** shall be approved by the **Authority.**

DC 3.3.8 System Earthing

System Earthing shall be designed in accordance with the **Distribution System Construction Manual** and the relevant regulations**,** and with the following purposes:

a. To protect life from danger or electric shock, and property from damage.
b. To limit the voltage upon a circuit when exposed to higher voltages than that for which the circuit is designed.
c. To limit the voltage on a circuit which might otherwise occur through exposure to lightning.

DC 3.4 Standard Planning Data

DC 3.4.1 Energy and Demand Forecast

Where the **Distribution Licensee** considers it necessary for the purpose of interconnection studies, the **User** connected at **MV** shall provide the **Distribution Licensee** with its Energy and **Demand** forecasts at each **Interconnection Boundary** at least for the five succeeding years.

This forecast data, for the first year shall include monthly Energy and **Demand** forecasts, while the remaining two years shall include only annual forecasts.

The **Users** shall provide the net and gross values of energy and **Demand** forecast. The net values shall be less the output of the User **Distributed Generation**, if applicable.

The following factors shall be taken into account by the **Distribution Licensee** and **Users** when forecasting demand:

a. Historical **Demand** Data;

b. **Demand** trends;

c. **Customer's** own Generation Schedules, if applicable; and

d. **Demand** transfer capability where the same **Demand** can be supplied from alternate **User** interconnection points.

e. Proposed new activities

Energy and **Active Power Demand** forecasts of **Users** connected at **Low Voltage** shall be produced by the **Distribution Licensee.**

DC 3.4.2 Distribution System Data

The **Distribution Licensee** shall make available to the **Single Buyer** and the **System Operator** all the data relevant to the **Distribution System**. This network data shall include at least the following:

a. Transformers - The primary input data for transformers includes MVA rating, primary and secondary winding voltages, windings interconnection, sequence impedances, X/R ratio, tap ranges, tap settings, emergency ratings.
b. **Electric Lines or Electrical Conductors** -The primary input data required among other things are rated line voltage, conductor type, and type of construction, thermal ratings, emergency rating, and sequence impedances.
c. **Distributed Generating Units** shall be modelled by their **Active Power** and **Reactive Power** capabilities for steady state analyses. For dynamic analysis more detailed **Models** are required for the **Generating Units** and their controls, that allow to represent the dynamic behaviour of the **Generating Station** to large changes in the **System** voltage and frequency. The **DGS** shall be represented using the information specified in DC 4.6.1.
d. Other parameters - In order to develop a **Grid** reliability data base outage rates and durations for all major **Equipment** are also required.

DC 3.4.3 User System Data

For **Users** connected at **Low Voltage** the following data shall be provided to the **Distribution Licensee**;

a. Maximum power requirement (kVA or kW)

b. Type and number of significant load items (cookers, showers, motors, and welders, electric vehicle, etc.)

For **Users** connected at **Medium Voltage** the following data shall be provided to the **Distribution Licensee**;

a) All types of loads

(i) Maximum **Active Power** requirements.

(ii) Maximum and minimum **Reactive Power** requirement.

(iii) Type of load and control arrangements (e.g. type of motor start, controlled rectifier or large motor drives).

(iv) Maximum load on each phase.

(v) Maximum harmonic currents that may be imposed on the **Distribution System**.

(vi) Details of cyclic load variations or fluctuating loads (as below).

Users connected to the **MV** network having **Electrical Facilities** undergoing two or more phases of development, shall provide the information above for each phase of development.

b) **Disturbing Loads**

Comprehensive schedule of installed new **Equipment** including details of **Disturbing Loads**.

These are loads which have the potential to introduce harmonics, flicker or unbalance to the **System**. This could adversely affect the supply quality to other **Customers**. **Disturbing Loads** could be non-linear loads, power converters/regulators and loads with a widely fluctuating **Demand**. The type of load information required for motive power loads, welding **Equipment**, harmonic producing or non-linear loads and generating **Equipment** can be obtained from the **Distribution Licensee** on request.

In the case of compensating **Equipment** associated with **Disturbing Loads**, details and mode of **Operation** to be provided so as to ensure compliance with emission limits specified in DC 6.

c) Fluctuating Loads

Details of cyclic variation, and where applicable the duty cycle, of **Active Power** (and **Reactive Power** if appropriate), in particular:

(i) The rates of change of **Active Power** and **Reactive Power**, both increasing and decreasing;

(ii) The shortest repetitive time interval between fluctuations in **Active Power** and **Reactive Power**; and

(iii) The magnitude of the largest step changes in **Active Power** and **Reactive Power**, both increasing and decreasing

In some cases, more detailed information may be required to permit a full assessment of the effect of the **User's** load on the **Distribution System**. Such information may include an indication of the pattern of load build-up schedule and a proposed **Commissioning** programme. This information shall be specifically requested by the **Distribution Licensee** when necessary and shall be provided by the **User** within a reasonable time.

DC 4 DISTRIBUTED GENERATION

DC 4.1 Introduction

Section DC 4 of the **Distribution Code** is applicable to all existing or prospective **Distributed Generators**, all of which are connected to the **LV** or **MV Distribution System.** Requirements apply to all **Generating Stations,** including **Synchronous** and **Asynchronous Generating Stations** and **Power Park Stations** unless otherwise more specifically defined in this **Distribution Code. Customers** with **Stand-by Generating Units** who are connected to the **Distribution System** shall also comply with clause DC 4.13.

In addition to meeting the requirements of DC 4, **Distributed Generators** shall also comply with the requirements all relevant sections of the **National Grid Code.**

The **Distributed Generator** shall initiate discussions at a sufficiently early stage in design to allow the **Distribution Licensee** to examine the impact of the **Generating Unit(s)** on the **Distribution System.**

The **Distribution Licensee** shall be responsible for all the aspects related to the **Distributed Generators** interconnections to the **Distribution System**, including the information exchange and connection process with the users, the elaboration and maintenance of the **DG Grid Code**, technical design specifications, safety requirements, monitoring of standards compliance and elaboration of studies needed to authorize the interconnection. The **Distribution Licensee**, may request assistance of the **System Operator** and / or **Single Buyer** when studying DG interconnections that may have an impact in the **Distribution Network**, including dynamic performance studies of DG generation. The requirements for telecommunications and control of DG generation shall be defined by the **System Operator**.

The **Distribution Licensee** may refuse permission for the connection of a **Distributed Generating Unit** to the **Distribution System** or require the revision of the design, technical parameters or nominal capacity of the **Distributed Generation Unit**, or impose certain restrictions in order to ensure the security and quality of supply standards as specified in DC 3.2. In such instances, the **Distribution Licensee** shall provide sufficient supporting information to justify the refusal or the required revisions. The **Authority** shall be informed before any refusal notice is given to a **Distributed Generator** that requested an **Interconnection** to the **MV or LV Distribution System**

DC 4.2 Distributed Generation Interconnection

DC 4.2.1 SSDG and MSDG Grid Codes

The **Distribution Licensee** shall produce a document (**DG Grid Code**) for each category of **Distributed Generation** containing:

a. Procedural aspects: the detailed procedures to be followed by the **Generator**, the **Distribution Licensee,** the **System Operator** and other parties in order to connect the **Distributed Generator** to the grid, starting from the submission of the application to the **Distribution Licensee** to the signature of the **Connection Agreement, ESPA, or PPA.** and subsequent Proclamation by the President of the Republic as the case may be; and,
b. Technical aspects: all the safety, design, construction, testing, commissioning, and administrative requirements for the connection of the **Distributed Generators** to the **Distribution System.**

The **DG Grid Code** as applicable for each category of **Distributed Generation** shall be approved by the Authority.

DC 4.2.2 DG Grid Code Technical aspects

The purpose of the technical aspects of the **DG Grid Code** is to provide guidance on the connection of a **Distributed Generating Station** to the **Distribution System.** It is intended to address all aspects of the connection process from standards of functionality to site commissioning, such that **Users**, **Equipment** manufacturers and **Generators** shall be aware of the requirements of the **Distribution Licensee** and the **System Operator** before the **Distributed Generating Station** shall be accepted for connection to the **Distribution System.**

The technical aspects of the **DG Grid Code** shall:

a. include requirements for the **Distributed Generation** installations that shall be compatible (equal or better) with those set out in the corresponding sections of this **DG Grid Code.**
b. be aimed at facilitating the connection of a **Distributed Generator** whilst maintaining the integrity of the **Distribution System**, both in terms of safety and supply quality. It shall cover all **Distributing Generating Stations** within the scope of Section DC 4, irrespective of the type of **Plant** and **Apparatus** used to convert any primary energy source into electrical energy.

The technical aspects of the **DG Grid Code** shall at least contain the following:

a. Safety, Isolation and Switching Requirements
    I. Rules for working on **Low Voltage** (**LV**) grid based on Occupational Safety and Health Act 2005.
    II. Safety Concerns
    III. Labelling and information to be displayed on **Electrical Facilities**
    IV. Information plate
b. Standards, guidelines and norms applicable to the components and materials of the **Electrical Facilities** and the design of **Distributed Generating Stations.**
c. Certification of installation and compliance with the **Distribution Code** and the standards, norms and guidelines in item b) above.
d. Detailed construction and design specifications for **MSDG 2** and **MSDG 3**, including:
    I. Switchgear arrangement
    II. **Interconnection Facility** Description
    III. Interconnection Transformer Specifications
    IV. Mineral insulating oil for transformers
    V. Typical **HV** switchgear panel and protection guidelines
    VI. **Protection** Specifications
    VII. Communication Requirement
    VIII. Typical 22kV switchgear room layout

DC 4.2.3 Generator's responsibility

Distributed Generators shall comply with the corresponding **DG Grid Code** in Section DC 4.2.1 and the corresponding **License.**

DC 4.3 Determination of significance

A **Distributed Generating Station** shall comply with the requirements on the basis of the voltage level of their connection point and their maximum capacity according to the categories set out in the following paragraph.

The **Distributed Generating Station** within the following categories shall be considered as significant:

a. **Small-Scale Distributed Generator** (**SSDG**): **Distributed Generating Station** connected to the 230 single - phase/400 V three-phase **Distribution System** and has a maximum **Registered Capacity** of 50 kW;
b. **Medium-Scale Distributed Generator 1** (**MSDG 1**): **Distributed Generating Station** with **Registered Capacity** greater than 50 kW but not exceeding 500 kW and connected to the 22 kV **Distribution System** through a dedicated transformer;
c. **Medium-Scale Distributed Generator 2** (**MSDG 2**): **Distributed Generating Station** with Registered Capacity greater than 500 kW but not exceeding 4 MW and connected to the 22 kV **Distribution System** through a MV switchgear panel (MV metering) and a step-up interconnection transformer;
d. **Medium-Scale Distributed Generator 3** (**MSDG 3**): **Distributed Generating Station** with **Registered Capacity** greater than 4MW but not exceeding 10MW and connected through a dedicated 22kV line to the 22 kV section of the **Transmission System**;

A **Generating Station** with **Registered Capacity** greater than 4MW but not exceeding 10MW and connected through a dedicated line to the 22 kV section of the **Transmission System** shall comply with the requirements of the **Distribution Code** applicable to MSDG 3.

Notwithstanding the above general categories, the Distribution Licensee may authorize after a complete technical evaluation, a DG generator between 50 kW and 500 kW to connect to the 22kV Distribution System through MV switchgear without the need of a dedicated transformer. In these cases, the MSDG 2 is applicable

A typical Interconnection layout for MSDG 1 is provided in DC 21.4.1. Typical medium voltage switchgear panel and protection drawings for MSDG 2 and 3 are presented in DC 21.4.2 for Generating Stations using both synchronous and induction machines and inverter-based generation. A typical connection diagram of a MSDG 3 scheme via a dedicated feeder line is shown in DC 21.4.2.

DC 4.4 Connection Capacity

DC 4.4.1 Feasibility

The feasibility to connect a **Distributed Generating Station** to the **Distribution System** shall be confirmed by a study to determine the impact of the interconnection of the **Grid**, which shall be conducted by the **Distribution Licensee** in collaboration with the **System Operator**, if required, on a case-to-case basis.

The possibility of interconnecting a **Variable Renewable Generating Station** to the **Distribution System** shall be subject to the maximum amount of variable renewable energy-based power generation that can be accommodated in the **Distribution System** while maintaining the **Total System's** stability and security.

DC 4.4.2 Connection studies

a. Connection of **SSDG**: Applications shall be allocated to the relevant feeder and distribution transformer where the **Distributed Generator** shall be connected. During the analysis stage, if the maximum allowed capacity is found to have been already attained for the feeder or transformer, the applications shall not be entertained unless the **Distributed Generator** opts for a **Network Review**.
b. Connection of **MSDG1, MSDG2** and **MSDG3**: If any works in the distribution

network are necessary, the Distribution Licensee and the Single Buyer shall determine what **Grid** modifications (reinforcements or extensions) are required, if any, to connect the **DGS** by conducting the necessary studies. The description of the required **Grid** modifications shall be communicated to the **Distributed Generator**, detailing who shall be the **Party** (**Single Buyer and Distribution Licensee,** or the **Distributed Generator**) responsible for execution of each of the works and who shall be the **Party** (**Single Buyer and Distribution Licensee,** or the Distributed **Generator**) responsible for payment of each of the works, subject to approval of the **Authority.**

DC 4.4.3 Capacity allocation

Capacity allocation to feeders for **Distributed Generators** (**SSDG, MSDG 1 and MSDG 2**) shall be done according to the rules and procedures as approved by the **Authority** and to provisions of the **Connection Agreement**

DC 4.5 Specific Rules for Distributed Generators

The integrity of the **Distribution System** and the security and quality of supply to existing **Users** shall not fall below standard as a result of the **Distributed Generators** operating in parallel (synchronized) with the **Distribution System.** Conditions for **Operation** shall guarantee the safety of:

- Members of general public
- Personnel
- **Distribution Equipment**

Supply quality to other **Customers** shall not fall below standard as a result of the presence or **Operation** of the **Distributed Generating Units.**

Where a **Distributed Generating Unit** is to be installed as per the **Electricity Act and its amendments** in a premise with the possibility of **Parallel Operation,** the **Distribution Licensee** shall inspect the **Distributed Generating Station Electrical Facilities** to ensure that the requirements of the **National Grid Code** are met. The **Distribution Licensee** may require a demonstration by **Operation** of the **Distributed Generator. Parallel Operation** of the **DG** shall be allowed only if authorized by the **Distribution Licensee** and the **System Operator as per prevailing scheme and policy.**

DC 4.6 Provision of Information

DC 4.6.1 Information required from Generators

Distributed Generators shall provide to the **Distribution Licensee** and the **Single Buyer Licensee**, via the forms defined by the **Distribution Licensee**, information on the **Distributed Generating Station** and the proposed interface arrangements between the **Distributed Generating Station** and the **Distribution System**.

The details of information required shall vary depending on the type and size of the **Distributed Generating Unit** and the characteristics of the **Interconnection Boundary.** This information shall be provided by the **Distributed Generator** at the reasonable request of the **Distribution Licensee.**

The **Distribution Licensee** and **Single Buyer** shall use the information provided by the **Distributed Generator** to produce a **Model** of the **DGS** to determine a technically acceptable method of connection. If the **Distribution Licensee** and/or **Single Buyer** reasonably concludes that the nature of the proposed connection or changes to an existing connection requires more detailed analysis then further information than that specified in this Section DC 4.6.1 may be required.

The information required by the **Distribution Licensee** and **Single Buyer** before entering into an agreement to connect any **Distributed Generating Station** to the **Distribution System** is specified below.

DC 4.6.1.1 Distributed Generating Station Data

a) User System Data Schedule in DC 20.1
b) Fault Infeed Data Schedule in DC 20.2
c) Terminal Voltage (kV)
d) Rated kVA
e) Rated kW
f) **P-Q Capability Diagram.**
g) Type of **Generating Station** – synchronous, asynchronous, etc.
h) Type of primary energy resource;
i) Anticipated operating regime of generation e.g. continuous, intermittent, peak shaving;
j) Method of voltage control
k) **Distributed Generating Unit** transformer resistance, reactance, MVA rating, tap changer arrangement, vector group, **Earthing**;
l) Requirements for standby supplies
m) For **Synchronous** and **Asynchronous Generating Units**:
    i) Inertia Constant in MW sec/MVA (whole derive train)
    ii) Stator resistance
    iii) Direct Axis Reactance: Sub-transient, Transient and Synchronous
    iv) Time Constants: Sub-transient, Transient and Synchronous
    v) Zero Sequence Resistance and Reactance
    vi) Negative Sequence Resistance and Reactance

DC 4.6.1.2 Interface Arrangements

a. The means of synchronization between the **Distribution Licensee** and the **User**;
b. Details of the earthing system of the **Distributed Generating Station**;
c. The means of connection and disconnection which are to be employed; and
d. Precautions to be taken to ensure the continuance of safe conditions if any earthed neutral point of the **Distributed Generators'** system becomes disconnected from earth.

DC 4.6.2 Additional information required from MSDG 2 and MSDG 3

Additional information may be required from **Distributed Generators** with **Registered Capacity** larger than 2 MW and connected to the 22kV **Distribution System.** This may include:

a) Single line diagram of the **Distributed Generating Station** and the **Interconnection Site.**
b) **Models** of the **Distributed Generating Units** in the form of transfer function block diagram including parameters and nonlinearities of:
    i) **Distributed Generating Units** in **Synchronous** and **Asynchronous Distributed Generating Stations**: **AC** machine, the excitation system, automatic voltage regulator and power plant controller; and prime mover and speed governor.
    ii) **Distributed Generating Units** in **Power Park Stations**: **Generating Unit Model** including **Active** and **Reactive Power** controls, **LVRT** and **HVRT** capability, limiters and any relevant controller influencing the interactions of the **Distributed Generating Unit** with the **Grid.**

The dynamic **Models** shall be provided in the digital format required by the power system simulation software used by the **System Operator** and **Single Buyer.** They must not require a simulation time step of less than 5 ms. Details of the software version shall be provided by the **System Operator** and/or **Single Buyer** upon request.

c) Harmonic current emissions for individual harmonics up to the 50th order.
d) Steady state capability
   iii) **Registered Capacity** and **Minimum Load** of each **Distributed Generating Unit** and **Distributed Generating Station** in MW.
   iv) **Distributed Generating Unit** and **Power Station Auxiliaries' Active** and **Reactive Power Demand**, at **Registered Capacity** and under **Minimum Load.**
e) Positive and zero sequence parameters and rated capabilities of power transformers, lines, cables, reactors, capacitors and other relevant **Equipment** connected between the terminals of the Distributed **Generating Unit** and the **Interconnection Boundary.**

In normal circumstances the information specified above shall enable the **Distribution Licensee** with the support of the **System Operator** and/or **Single Buyer,** if needed, to assess the connection requirements. Occasionally additional information may be required. In such circumstances, the information shall be made available by the **Distributed Generator**, at the reasonable request of the **Distribution Licensee.**

DC 4.6.3 Information Provided by the Distribution Licensee

Where a **Distributed Generating Station** is intended for **Parallel Operation** with the **Distribution System** at least the following additional information shall be provided by the **Distribution Licensee** to the **Distributed Generator**:

a. Settings of the **Protection** relays of the feeder on which the **Distributed Generation** is to be connected, and of any other relay with which coordination is required
b. **Equipment**, cabling, switchgear, metering requirements
c. **Distributed Generator's Substation** site and building requirements (dimensions, access, planning permission, **Earthing**, lighting, air conditioning and heating among others)

DC 4.7 Technical Requirements

DC 4.7.1 Design

DC 4.7.1.1 Connection Arrangements

The **DGS** shall be connected to the **System** as follows:

a) A **SSDG** shall be connected to the 230/400 V Distribution System
b) A **MSDG** 1 shall be connected to the 22 kV **Distribution System.** Whenever possible, the connection shall be through a dedicated 22/0.415 kV transformer.
c) A **MSDG 2 or MSDG 3** shall be connected to the 22 kV **Distribution System** through a 22kV switchgear panel (MV metering) and a step-up interconnection transformer

DC 4.7.1.2 Interconnection transformer

The **MSDG 1, MSDG 2**, and **MSDG 3** interconnection transformer shall be of vector group Dyn11 (Delta on the **Grid** side and star on the **DGS** side). The delta winding on the **Distribution System** side ensures that:

i) The performance and sensitivity of the earth fault protection scheme at the **Distribution System** substation are not affected;

ii) Triple harmonics from the **Distributed Generating Station** do no reach the **Distribution System**; and

iii) The MSDG is provided some isolation from voltage sags due to single-line-to-ground faults, allowing it to better ride through voltage sags.

Alternative transformer vector groups may be used subject to the **Distribution Licensee** approval.

Detailed specifications of the interconnection transformer (when applicable) and switchgear shall be given by the **Distribution Licensee** in the corresponding **DG Grid Code.** The transformers and 22kV switchgear shall be approved by the **Distribution Licensee** prior to ordering.

DC 4.7.1.3 Earthing

When a **DGS** is operating in parallel with the **Distribution System**, there shall be no direct connection between the AC generator stator winding (or pole of the primary energy source in the case of a PV array or Fuel Cells) and the **Distribution System's** earth terminal.

The stator winding of an **AC Generating Unit** of a **SSDG** directly connected to the **LV Distribution System** without step-up transformer must not be earthed.

A **DC** source or **DC Generating Unit** could be earthed provided that the inverter separates the **AC** and **DC** sides by at least the equivalent of a safety isolating transformer. In such case, consideration shall then be given to the avoidance of corrosion on the **DC** side.

A TT earthing system is adopted in the **Distribution system.** The neutral and earth conductors must be kept separate throughout the installation, with the final earth terminal connected to a local earth electrode.

a. **SSDG**: **Earthing** shall be according to IEC 60364-5-55. For systems capable of operating in isolated generation, protection by automatic disconnection of supply shall not rely upon the connection to the earthed point of the utility supply system.
b. **MSDG 1**: **Earthing** shall be according to IEC 60364-5-54. For systems capable of operating in isolated generation, the neutral point of the **AC** generator must not be earthed during **Parallel Operation** with the **Distribution System**. When the **Distributed Generating Station** operates in isolation, the **Distributed Generating Unit** neutral-to-earth connection must be closed. The operation of the neutral-to-earth connection shall be carried out by an inter-locking system. The busbar system shall be equipped with visible lockable **Earthing Device**.
c. **MSDG 2** and **MSDG 3**: **Earthing** systems shall be designed, installed, tested and maintained according to BS 7354 (Code of Practice for Design of high voltage open terminal stations) and BS 7430 (Code of Practice for Protective Earthing of electrical installations). Steps must be taken to prevent the appearance of hazardous step and touch potential when earth faults occur on the 22kV **Grid.**

In all applicable **Electrical Facilities**, the 22 kV earth electrodes and **Low Voltage** earth electrodes shall be adequately separated to prevent dangerous earth potentials being transferred to the **Low Voltage Grid**.

Warning notice that: "CONDUCTORS MAY REMAIN LIVE WHEN ISOLATOR IS OPEN" shall be conspicuously displayed at the installation.

DC 4.7.1.4 Electromagnetic Emission and Immunity

The **DGS** shall comply with the requirements of IEC 61000.

DC 4.7.1.5 Surge Withstand Capability

The **Interconnection Facilities** shall have a surge withstand capability, both oscillatory and fast transient, in accordance with IEC 62305-3, the test levels of 1.5 kV. The design of control systems shall meet or exceed the surge withstand capability requirements of IEEE Standard C37.90.

DC 4.7.2 Distributed Generating Station Performance Requirements

a. **Distributed Generators** subject to **Dispatch** shall comply with the relevant sections of the **Generation Code**;
Protection associated with a **Distributed Generating Station** shall be required to co-ordinate with the **Distribution System Protection** settings and shall not be changed without agreement from the **Distribution Licensee.**

e) Each **Distributed Generating Unit** shall, as a minimum, operate continuously at normal rated output at the **System** frequencies in the range of 49.25Hz to 50.75Hz (50 Hz ±1.5%).

f) Each **Distributed Generating Unit** shall, as a minimum, remain synchronized to the **Distribution System** during a **Rate of Change of Frequency** of values up to and including plus or minus 2.5 Hz per second measured as a rolling average over 500 ms, and adjust the loss of mains protection according to the values in Table 3 of Section DC 4.8.6.

g) Each **Distributed Generating Unit** shall, as a minimum, remain synchronized to the **Distribution System** at normal rated output at **Distribution System** voltages within the ranges specified for **Normal Conditions** in DC 3.2.3.

h) After a single **Contingency** or under **System Emergency** conditions, frequency and voltage may go out of normal limits but still inside operational acceptable values. In those cases, the **Distributed Generating Station** shall comply with the following:
   1. **SSDG** may disconnect from the Distribution System for Distribution System voltages outside the range specified in DC 4.7.2.g).
   2. **MSDG 1, MSDG 2,** and **MSDG 3** must be able to operate within the range specified for **Contingency Conditions** in DC 3.2.3.

i) The **DGS Electrical Facilities** shall be able to withstand the following fault levels at the **Interconnection Boundary** during at least 1 s, unless otherwise instructed by the **System Operator** or **Distribution Licensee:**

Table 1 DGS fault levels

Nominal three-phase voltage	Maximum short circuit current
400 V	18 kA
22 kV	16 kA

j) Each **Distributed Generating Unit** shall have the **Reactive Power** capability specified in Table 2 measured at the **Point of Delivery** for **Grid** voltages within the range for **Normal Conditions** defined in DC 3.2.3.

Table 2 DGS Reactive Power capability required at the Distributed Generating Unit terminals across the statutory range of nominal voltage.

Generator	Required Reactive Power Capability
SSDG and **MSDG 1**	Between 0.95 leading and 0.95 lagging power factor at **Registered Capacity**
MSDG 2 and **MSDG 3**	Between 0.90 lagging and 0.90 leading power factor at **Registered Capacity** measured at **Point of Delivery**

	The resulting **Reactive Power** requirement at **Registered Capacity** shall be available from 20% of the **Registered Capacity.**

DC 4.8 Protection Requirements

DC 4.8.1 Scope

The **Protection** requirements set forth in this section are mandatory for all **DGSs**, irrespective of the **Generation** technology used.

DC 4.8.2 General Requirements

The coordination and selectivity of the **Protection** system must be safeguarded even with the connection of new **Distributed Generation** to the **Distribution System.** To satisfy this condition, the **Distributed Generator** shall install the **Protection Equipment** listed in DC 4.8 and the settings of those **Protections** shall be proposed by the **Distributed Generator** and accepted by the **Distribution Licensee.**

In case of short circuits in the **DGS** side, the **DGS** shall adjust its **Protections** in such a way that they shall avoid unnecessary trips in the **Distribution System** side of the **Interconnection Boundary** and at the same time avoid that the incident propagates to the rest of the **Distribution** or **Transmission Systems**.

In case of incidents originated outside the **DGS Electrical Facilities**, such as short circuits in the **Distribution System**, abnormal voltage or frequency excursions, the **Distributed Generating Station** shall give priority to the **Grid Protections** to solve the incident and act accordingly with the coordination and selectivity principles of the **Protection** system.

The **Protection** system shall provide protection against fault occurring on both the **Distribution System** and the **DGS Electrical Facilities.** The **Protection** system shall provide protection against short circuit, earth faults and overloading conditions and also prevent the **Islanding** of the part of the **Distribution System** to which it is connected.

In addition, the **Distributed Generator** must provide any additional **Protection** functions necessary to adequately protect all equipment and personnel. The settings of the additional **Protection** systems shall be appropriately defined so as to prevent unnecessary trips during remote disturbances that affect the voltage and frequency of the **Distribution** or **Transmission Systems.** Any modifications in the **Protection** settings carried out by the **Distributed Generator** shall be communicated to and accepted by the **Distribution Licensee.**

DC 4.8.3 Availability of Protection

The **Distributed Generator** shall ensure that all its **Electrical Facilities** are protected and that all elements of the **Protection**, including associated inter-tripping, are operational at all times. Unavailability of the **Protection** shall require the **Distributed Generating Station** to be taken out of service.

The **DGS** shall be protected against

a) Overload.

b) Short circuit within the **DGS Electrical Facilities.**

c) Earth faults in the close vicinity of the **DGS Electrical Facilities.**

d) Overcurrent.

e) Abnormal voltages (Table 3 below)

f) Abnormal frequencies (Table 3 below)

g) Lightning.

h) Loss of mains including Rate of Change of Frequency (ROCOF) and/or voltage vector shift **Protection.**

DC 4.8.4 DC Functions of Protection Apparatus

All **Protection** apparatus functions shall operate down to a level of 50% of the nominal **DC** supply voltage of the **DC** system, or the system must be able to safely disconnect and shutdown when operation conditions are outside the nominal operating **DC** voltage specified in the **DC** system specifications.

DC 4.8.5 Protection Flagging, Indications and Alarms

All **Protection** devices supplied to satisfy the **Distribution Licensee** requirements shall be equipped with operation indicators. Such indicators shall be sufficient to enable the determination of which devices caused a particular trip.

Any failure of the **Distributed Generating Station**'s tripping supplies, **Protection** apparatus and **Circuit Breaker** trip coils shall be supervised within the **Distributed Generator's** installation, and the **Distributed Generator** shall be responsible for prompt action to be taken to remedy such failure.

DC 4.8.6 Trip settings

Distributed Generating Units shall not supply power to the **Distribution System** after the formation of a **Power Island.** The **DGS** may only be operated during such outages to supply its own load (isolated generation) with a visibly open tie to the **Distribution System.** The **DG** shall be disconnected from the **Distribution System** within 0.5 seconds of the formation of a **Power Island** as shown for the loss of mains **Protection** in Table 3.

The trip settings must comply with the values stated in Table 3. These trip settings are indicative and may be subject to change upon request of the **Distribution Licensee** for the safe interconnection to the **Grid.**

Table 3. Protection trip settings

Protection	Symbol	SSDG		MSDG 1, 2 and 3	
		Trip setting	Clearance time	Trip setting	Clearance time
Overvoltage (a)	U>>	230 V +10%	0.2 s	230 V +10%	0.2 s
Overvoltage	U>	230 V +6%	1.5 s	230 V +6%	1.5 s
Undervoltage	U<	230 V –10%	1.5 s	230 V – 10%	3.0 s
Over frequency	f>	50 Hz +2%	0.5 s	52 Hz	0.5 s
Underfrequency	f<	50 Hz -6%	3.0 s	47 Hz	3.0 s
Loss of mains	df/dt (RoCoF)	2.5 Hz/s	0.5 s	2.5 Hz/s	0.5 s
	Vector shift	10 degrees	0.5 s	10 degrees	0.5 s

NOTES:

- Voltage and frequency are referenced to the terminals of the **Generating Unit**
- If the **DG** can generate higher voltage than the U> trip setting, the U>> overvoltage setting is also required.

DC 4.8.7 Re-connection

Following a **Protection** initiated disconnection, the **DGS** shall remain disconnected from the **Grid** until the voltage and frequency at the **Interconnection Boundary** has remained within the limits for **Normal Conditions** for at least 3 minutes.

Automatic reconnection is only allowed when disconnection was due to operating parameters being outside the ranges stated in DC 4.7.2.h), not if disconnection was caused by any **Apparatus** within the **DGS** installation failing to work or operate correctly.

DC 4.8.8 Synchronizing AC generators

The **Distributed Generator** shall provide and install automatic synchronizing **Equipment**. A **Synchronism-Check Relay** shall be provided on all generator circuit breakers and any other circuit breakers, that are capable of connecting the **DGS** plant to the **Distribution System**. **Synchronism-Check Relay Interlocks** shall be provided.

DC 4.9 Additional Protection requirements for MSDG 2 and MSDG3

DC 4.9.1 Inter-tripping Protection for DGS of Registered Capacity equal to or greater than 1 MW

The inter-tripping scheme is to be designed and pre-wired, subject to the requirement of the **System Operator** or **Distribution Licensee**, such that tripping of the interconnecting feeder circuit breaker in the **Distribution System** 22 kV **Substation** results in the tripping of the CB1 in DC 21.4.2. The tripping of the **Distribution System** 22 kV **Circuit Breaker** shall be a tripping due to **Protection** relay action at the **Distribution System** 22 kV **Substation** level. Manual opening and tripping due to **Protection** relay of CB1 in DC 21.4.2 shall not cause tripping of corresponding **Circuit Breaker** at the **Distribution System** 22 kV **Substation**. However, the above scheme shall be wired but disabled initially for **Registered Capacity** up to 4MW only.

The communication scheme shall be set as per section DC 4.17.

DC 4.9.1.1 Inter-tripping requirements for solar PV Distributed Generating Stations

The following indicative tripping scheme shall be implemented for MSDG installations employing solar PV systems:

> (1) During the day, upon tripping of the 22 kV **Circuit Breaker** at the respective **Distribution Licensee** substation on fault, **System Control Engineer** or designated representative shall open CB1 in DC 21.4.2 remotely.
>
> CB1 in DC 21.4.2 intertrips CB2 and all other outgoing circuit breakers.
>
> Upon supply restoration, the **System Control Engineer** or designated representative shall reclose CB1 in DC 21.4.2 remotely and liaise with the contact person at the MSDG site to reclose CB2 in DC 21.4.2 locally.
>
> (2) During the night, upon tripping of the 22 kV circuit breaker at the respective **Distribution Licensee Substation** on fault, the **System Control Engineer** or designated representative shall not open CB1 as there is no PV generation at night, and hence no-fault contribution due to the PV installation.
>
> (3) In case of abnormal setup (MSDG shifted to another feeder), the **System Control Engineer** or its designated representative shall adopt the same philosophy as above.

DC 4.9.2 Protection against relay malfunction

The watchdog function of the protection relay protection must issue an alarm in case there is a malfunction.

For **DGS** of **Registered Capacity** greater than 1000 kW, this alarm signal, if required by the **System Operator** or **Distribution Licensee**, shall be transmitted to the interconnecting **Distribution System Substation** via the fibre optic channel or wireless communication.

DC 4.9.3 Protection Settings: Grading and Discrimination

For **DGS** of **Registered Capacity** above 500 kW, the **Distributed Generator** shall submit to the **Distribution Licensee** appropriate settings for grading and discrimination of the interconnecting **Protection** (22 kV **Circuit Breaker** at the **Distribution System** side of the **Interconnection Boundary**) with the upstream **Distribution System Substation Protecti**on.

The **Distributed Generator** shall also submit to the **Distribution Licensee** the Fault current contribution (both single phase to earth and three phase) from the **Distributed Generating Station** to faults on the **Distribution System**.

The **Distribution Licensee** shall provide the relevant **Grid** information to the **Generator** for the purpose of the **Protection** study.

DC 4.9.4 Additional Protection and Safety requirements

In addition to mandatory safety interlocks as per IEC 62271-200, for metal-enclosed **MV** switchgear, appropriate interlocking mechanism shall be incorporated between the **Circuit Breakers** on the **Distribution System** and **DGS** side as a measure of protection against an incorrect sequence of manoeuvres by operating personnel. This interlocking mechanism shall prevent the possibility of mechanically closing the CB1 in DC 21.4.2 onto a live busbar on the **User** side via a mechanical or electrical interlocking system between CB1 in DC 21.4.2 and the **Distributed Generating Unit** transformer **Circuit Breaker** (CB2 in DC 21.4.2) and any other outgoing circuit breakers. The **Distribution Licensee** may request additional interlocking and **Protection** systems for safety reasons.

The **Distributed Generator** shall demonstrate the incorporation of the above safety interlocking mechanism both at design and **Commissioning** stages.

In case the **DGS** contains synchronous and/or induction machines, additional measures listed below are required:

- A dead-bus/live-line **Synchronism- Check Relay** shall be provided to prevent remote/electrical closure of **Interconnection Circuit Breaker** (CB1 in DC 21.4.2) as long as the **DGS**-side 22 kV busbar is energized.
- A **Synchronism-Check Relay** shall be provided on all **Distributed Generating Station** circuit breakers and any other circuit breakers (including **Low Voltage Circuit Breakers**), unless interlocked, that are capable of connecting the **DGS** to the **Distribution System**.

DC 4.10 Black Start Capability

Distributed Generators shall notify the **System Operator** and the **Distribution Licensee** if its **Generating Station** has a **Black Start Capability** (ability to restart the **Generating Unit** in the absence of incoming power from the **Grid**), unless the **Distributed Generator** has previously notified the **System Operator** accordingly under the **Generation Code**.

DC 4.11 Power Quality

The **DG Electrical Facilities** shall not cause excessive voltage excursions nor cause the voltage to drop below or rise above the range maintained by the **System Operator**. A **DGS** shall not produce excessive distortion to the sinusoidal voltage or current waves, and shall comply with DC 6.

DC 4.12 Testing and Commissioning

DC 4.12.1 General requirements

The **Distributed Generator** shall perform the testing and pre-commissioning phases of the **DGS** as per relevant standards norms. The **Distributed Generator** shall provide the **Distribution Licensee** with a Testing and Pre-commissioning program, approved by the **Distribution Licensee** if reasonable in the circumstances, to allow Testing and Pre-commissioning to be coordinated.

The **Distributed Generator** shall keep written records of test results and **Protection** settings. The **Distributed Generator** shall regularly maintain the **Protection** systems in accordance with good electrical industry practice.

The **Distribution Licensee** has the right to require the **Distribution Generator** to perform tests on *ad-hoc* basis for purposes such as ascertaining level of **Harmonic Distortion**, voltage rise, **Protection** operation in the context of **System** changes, **Fault** investigation and **Protection** changes.

The **Distribution Licensee** shall be assisted by the **System Operator** during the tests.

DC 4.12.2 Specific Requirements for SSDG and MSDG 1

Testing and Pre-Commissioning of the **SSDG** and **MSDG 1 Electrical Facilities** shall be performed by an **Installer.**

DC 4.12.3 Specific Requirements for MSDG 2 and MSDG 3

DC 4.12.3.1 Testing and Pre-Commissioning

For **Greenfield** project the **Distributed Generator** shall submit appropriate testing and pre-commissioning procedures and plans as per applicable standard for the **DGS Electrical Facilities** to the **Distribution Licensee** for approval at least 3 (three) months prior to the scheduled **Commercial Operation Date**.

Testing and Pre-Commissioning of the facility shall be performed by the **Distributed Generator** under the supervision of a **Registered Professional Engineers (**for **MSDG 2)** or **Independent Engineers (for MSDG 3)** in their relevant fields. The Registered Professional Engineers or Independent Engineers, as the case may be, shall certify the test and results and confirm that the installation complies with the **National Grid Code** requirements.

It is the responsibility of the **Distributed Generator** to ensure that all required tests are performed to ensure compliance with Section DC 4.

a) Testing Phase

At least the following tests shall be performed on:

1) All **Distributed Generating Units**
   i. Functional Test;
   ii. Insulation resistance testing; and
   iii. Performance verifications;
   iv. 6-hour test run with the **Distributed Generating Unit** connected to the **Grid**
   v. Verification of the settings of all the Protection relays/systems;

vi. Checking/proving of all safety Equipment;
vii. Voltage phasing checks between the **Distributed Generating Unit** and the **Substation** to which it is connected, and the Grid;
viii. Proving of all inter-tripping circuits between the **Distributed Generating Unit** and the **Distribution System Equipment.**
ix. **Earthing** test at the **Distributed** Generating Station switchyard;

2) Solar photovoltaic **Generating Stations** only
   i. **Earthing** continuity of array frame to earth and connection to main earthing terminal
   ii. Polarity of each module string
   iii. PV string Open-Circuit Voltage (Voc) Test;
   iv. PV Short Circuit current (Isc) Test;
   v. PV array insulation Test;
   vi. Operational Test PV string current;
   vii. Functional Test;
   viii. Insulation resistance testing; and
   ix. Performance verifications;

3) Wind **Distributed Generating Stations** only:
   i. Demonstration of **Distributed Generating Unit** vibration level below acceptable level.
   ii. Test of trip function when **Distributed Generating Unit** is generating and grid loss occur
   iii. Test of over speed trip of each **Distributed Generating Unit**
   iv. Test of yaw drives
   v. Functional test
   vi. Performance verification

4) Thermal and hydro **Distributed Generating Stations** only:
   i. **Automatic Voltage Regulator** (**AVR**) setting and adjusting in both stand-still condition and with the **Distributed Generating Unit** running at full speed no load condition;
   ii. **Governor Control System** checks, including a 10% (or the percentage as specified by the manufacturer) over-speed test;

b) Pre-Commissioning Phase

The Pre-Commissioning tests shall be performed in the presence of the **Distribution Licensee** with the assistance of the **System Operator.**

The **Distribution Licensee** has the right to request the **Distributed Generator** to perform additional tests which **Distribution Licensee** may find necessary to ensure integrity of the **Distribution System**.

Pre-Commissioning shall be performed for **Active Power** levels of at least 20% of the **Registered Capacity,** where applicable.

The pre-commissioning of the electrical system shall include at least the following:

i. Demonstration of satisfactory operation of power measurement equipment
ii. Functional tests of **Protection** relays and verification of settings
iii. Demonstration of satisfactory operation of internal reticulation, and step-up transformer
iv. Pressure tests on 22 kV switchgear
v. Reactive Power Capability.
vi. Power Quality Test as per IEC 61400-21

vii. Anti-islanding Protection test
viii. Test of the facility to withstand a step load change

DC 4.12.3.2 Power Quality

After satisfactory testing and pre-commissioning of the **DGS** and submission of the Certificate of Installation, the **Distribution Licensee** with assistance of the **System Operator** shall perform tests to ensure that the **DGS** is compliant with the **Power Quality** requirements set forth in Section DC 4.11 of this **Distribution Code.**

DC 4.12.4 Certification

DC 4.12.4.1 Certificate of Installation

An **Installer** (for **SSDG** and **MSDG 1**) or **Registered Professional Engineer** (for **MSDG 2** and **MSDG 3** of **Registered Capacity** up to 4MW) or **Independent Engineer** (for **MSDG 3** of Registered Capacity above 4MW), as the case may be, shall inspect and test the installation for compliance with existing requirements and standards and report the results to the **Distribution Licensee.** The **Distributed Generator** shall then submit to the **Distribution Licensee** a Certificate of Installation duly filled and signed by the Installer, **Registered Professional Engineer** or the **Independent Engineer** as the case may be.

DC 4.12.4.2 Certificate of Compliance of MSDG 1, MSDG 2 and MSDG 3

In case of compliance of an **MSDG 1**, **MSDG 2,** and **MSDG 3** to the requirements of the **Distribution Code** after performing the tests in DC 4.12.3.2, the **Distribution Licensee** shall then issue a Certificate of Compliance to the **Distributed Generator** confirming that the installation:

a) complies with the requirements of this **Distribution Code**, and
b) has been found to be fit for connection to the **Distribution System.**

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DC 4.13 Standby Generating Units

Parallel Operation with the **Distribution System** shall not be permitted for **Standby Generating Units** unless there is a specific agreement with the **System Operator** or **Distribution Licensee** for **Parallel Operation**.

If the **System Operator** authorizes or requires the **Parallel Operation** of a **Stand-by Generating Unit** with the **Distribution System**, the **Stand-by Generating Unit** shall comply with all the requirements for **Distributed Generators** set forth in the **Distribution Code** and other relevant parts of the **National Grid Code.**

Customers with **Stand-by Generating Units** shall ensure that any part of the installation supplied by the **Stand-by Generating Unit** has first been disconnected from the **Distribution System** and remains disconnected while the **Stand-by Generating Unit** is connected to the **User's System.** Methods of changeover and interlocking shall meet these requirements.

Warning signs must be affixed at the **LV** and **MV** poles, pillars, transformers where a **Standby Generating Unit** is connected.

DC 4.14 Compliance with the Distribution Code

In case of non-compliance with any of the technical provisions of this **Distribution Code**, the **Distribution Licensee** shall inform the **Distributed Generator** in writing of the discrepancies. The **Distributed Generator** shall have the following times to rectify the discrepancies:

1. 60 days for SSDG
2. 90 days for MSDG 1, MSDG 2 and MSDG 3

Failing to do that, the **Distribution Licensee** shall be entitled to disconnect the **Distributed Generator**.

The **Distribution Licensee** shall be entitled to disconnect the **DGS** without prior notification if the installation conditions are harmful or creates unavoidable risks for the safety.

The **Distribution Licensee** shall not be responsible for any damage if such disconnection requires the disconnection of other loads associated or connected to the same connection as the **DGS**.

Reconnection of the **DGS** shall require that the **Distribution Licensee** certifies that the installation complies with this **Distribution Code**.

DC 4.15 Additional Requirements for MSDG 2 and MSDG 3

The requirements of DC 4.15 shall be met by all **MSDG 2** and **MSDG 3**.

DC 4.15.1 Uninterruptible Power Supply

The **Distributed Generating Station** shall have a secured AC auxiliary source of supply protected by surge and lightning devices. An online uninterruptible power supply (**UPS**) is required and it shall have adequate capacity to ensure that the protection, measurement, control and communication systems operate without interruption for a minimum duration of at least 3 hours after loss of **Distribution System** power supply. The **Distributed Generator** shall submit the calculations in the determination of the sizing of the **UPS**. In the event of loss of the secured auxiliary supply, all the **Distributed Generator**'s 22 kV **Circuit Breakers** shall be tripped until remedial actions are taken. The **UPS** system shall be installed on the **Distributed Generator** side and be maintained accordingly by the **Distributed Generator**. The **UPS** shall be equipped with a bypass switch/system that shall allow continuous operation during maintenance on the **UPS**.

In **Distributed Generating Stations** of **Registered Capacity** equal to or greater than 1 MW, all **Equipment** used for the transmission of signals and commands (PLC, modem, router, etc.) between the **Distributed Generating Stations** and the **Distribution Licensee's** control system shall be supplied from a separate UPS than the one stated in the previous paragraph. All associated requirements shall also be applicable to this separate UPS.

DC 4.15.2 Indication, Alarms and Instrumentation

The alarm and trip facilities on **DGS** side of the **Interconnection Boundary** shall have local indication and, for **DGS** with **Registered Capacity** equal to or greater than 1 MW, an additional set of potential-free contacts for onward transmission of the alarm/trip signals to the **Distribution System Substation**.

The following panel instrumentation and other fittings are required in addition to other standard **Equipment** required or implied for the type of panel and scheme functionality:

a. Transducer fed voltmeter, ammeter, MW, MVAr, indicating import and export, and appropriate test blocks for current and voltage circuits.

b. Suitable test facilities shall be provided for the secondary injection of current/relay testing and for any other tests as reasonably required by the **Distribution Licensee**.

External indicator lamps, for **DGS** of **Registered Capacity** greater than 200kW, shall be installed to indicate parallel operation of the **DGS** with **Distribution System**. A lighted red lamp shall indicate **Parallel Operation** while a lighted green lamp shall indicate isolated operation.

All required equipment for the above shall be procured, installed, tested, commissioned and maintained by the **Distributed Generator**.

DC 4.15.3 Generation Schedule

DGS connected to the **MV** system with **Registered Capacity** greater than 2 MW shall submit a **Distributed Generation** forecast to the Distribution Licensee and the **System Operator.** This forecast shall be in accordance to the requirements of section SOC 4.2.4 of the **System Operations Code.** This requirement can be withdrawn/redefined if so agreed between the **System Operator** and the **Distributed Generator** in each particular case.

DC 4.15.4 Preventive and corrective maintenance

The provisions of DC 4.15.4 apply to **DGS** with **Registered Capacity** greater **than 1 MW.**

DC 4.15.4.1 Generator Maintenance

A **DGS** with **Registered Capacity** greater than 1 MW connected to the **MV** network shall submit its preventive maintenance plan to the **System Operator** for its approval every year for the following year, in the dates required by the **System Operator** and any modification thereof as per the requirements established in section SOC 4.3 of the **System Operations Code**.

DC 4.15.4.2 Network maintenance

The **Distribution Licensee** shall communicate its maintenance plans to the **System Operator** and the **DGSs** connected to the **MV** network on the same terms that apply to all **Users** of the **Distribution System**.

The **Distribution Licensee** shall communicate its maintenance plans by mail, or any other agreed channel, to DGs connected to the MV network at least one week before the planned maintenance action takes place.

Maintenance works or any faults occurring on the feeder to which the MSDG is connected may prevent the **Distributed Generator** from exporting. No compensation shall apply for any loss of generation due to preventive and corrective maintenance in the Distribution System network

DC 4.15.5 Distributed Generating Station Performance Requirements

DC 4.15.5.1 Fault Ride Through Requirements

The **DGS** shall remain connected to the **Distribution System** for **System** voltage dips on any or all phases, where the **Distribution System** voltage measured at the **Point of Delivery** remains above the blue line in the voltage duration profile in Figure 1 for **Synchronous** and **Asynchronous Generating Stations**, and above the blue line in the voltage duration profile in Figure 2 for **Power Park Stations.**

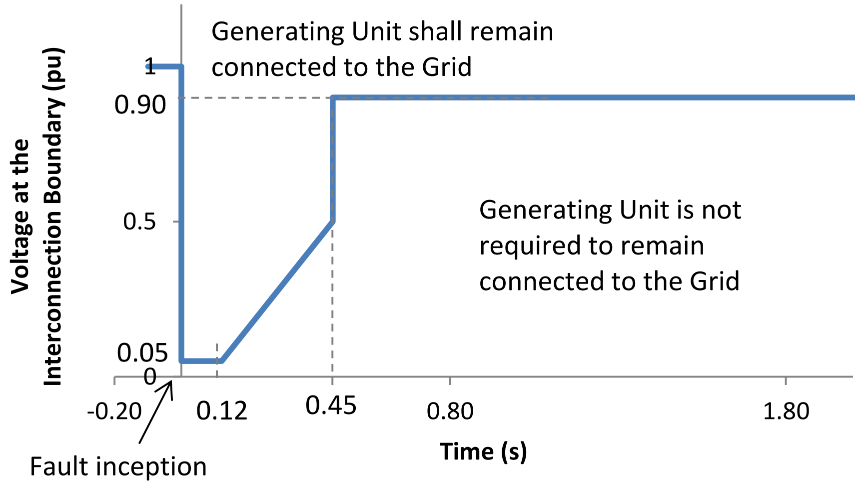


Figure 1. Fault Ride Through requirement for MSDG 2 **and** MSDG 3 Synchronous **and** Asynchronous Generating Stations.

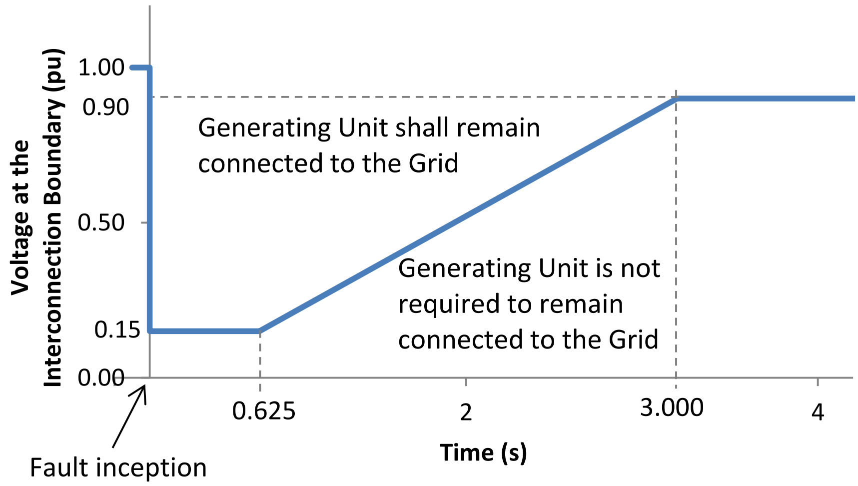


Figure 2. Fault Ride Through requirement for MSDG 2 and MSDG 3 Power Park Stations.

In addition to remaining connected to the **Distribution System**, the **DGS** shall have the technical capability to provide the following:

a- During a **Distribution System** voltage dip, the **DGS** shall provide **Active Power** in proportion to retained voltage and maximise reactive current to the **Distribution System**, within the technological and design limitations of the **DGS** and without exceeding its design limits. The maximisation of reactive current shall continue until the **Distribution System** voltage recovers within the range for **Normal Conditions.**

b- A different **LVRT** curve for the DGS may be required by when duly justified by the **Distribution Licensee** to ensure the **System** reliability and security. In such case, the **LVRT** curve shall be coordinated with the settings of the **Under-Voltage Relays** in Table 3 to ensure grid support during fault conditions.

DC 4.15.5.2 Frequency Response

In case of frequency deviations in the **Distribution System**, the **DGS** shall be designed to be capable to provide power-frequency response in order to contribute to the stabilization of the frequency.

A **DGS** of **Registered Capacity** greater or equal to 1 MW shall be able to provide a frequency response as displayed in Figure 3 below.

The **Distributed Generating Units** of a **DGS,** excluding **Electricity Storage Units,** shall be able to provide at least the **Active Power** output response to frequency changes displayed in Figure 3.

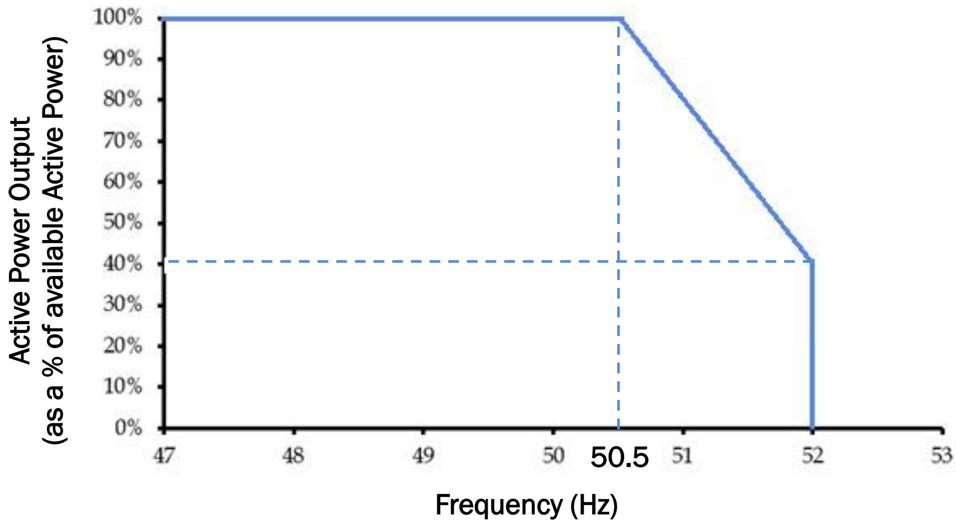


Figure 3: Frequency response requirements for MSDG 2 and MSDG 3.

When System Frequency is above 50.5 Hz, a DGS shall reduce its power output as per Figure 3 and the output power is only allowed to increase again as soon as the frequency is back at 50.5Hz or below.

All **DGSs** shall disconnect within 0.5 seconds from the **System** in case the **System's** frequency is above 52Hz or below 47Hz, according to the **Protection** settings specified in Section DC 4.8.6.

DC 4.15.5.3 Reactive Power Control

A **DGS** of **Registered Capacity** equal to or greater than 1 MW shall be equipped with **Reactive Power** control functions capable of controlling the **Reactive Power** supplied by the **DGS** at the **Interconnection Boundary.** The **Reactive Power** control functions shall be mutually exclusive, which means that only one of the two functions mentioned below can be activated at a time:

a) Power Factor Control

b) **Reactive Power** Control

If required by the **Distribution Licensee** on a case by case basis, a voltage control mode may also be required.

The operating modes and the operating set point shall be determined by the **Distribution Licensee** and shall not be changed by the **Distributed Generator** unless instructed by the **Distribution Licensee.**

DC 4.15.5.4 Ramp Rate Limits

A **DGS** of **Registered Capacity** equal to or greater than 1 MW shall have a maximum ramp rate (up and down) equal to the **DGS Registered Capacity** (MW) divided by 5 for 1-minute ramps under **Normal Conditions.**

The limit for positive ramps only applies during start-up and for negative ramps only apply during shut down of the **DGS.**

The ramp rate settings shall be approved by the **System Operator** prior to testing and commissioning of the system on the network. For any subsequent change, a minimum of two weeks' notice shall be given. Implementation by the **Distributed Generator** shall be done within two weeks of formal request and approved by the **Distribution Licensee**.

DC 4.16 Installer

A **DGS** shall be installed by an **Installer** in accordance with the instructions issued by the manufacturer.

In designing a connection for a **DGS**, the **Installer** must consider at least the following aspects:

a. the maximum demand (and the **Distributed Generating Unit** output);
b. the type of **Earthing** arrangement;
c. the nature of the supply;
d. external influences;
e. compatibility, maintainability and accessibility;
f. **Protection** against electric shock;
g. **Protection** against thermal effects;
h. **Protection** against overcurrent;
i. isolation and switching;
j. selection and installation issues.

The **Installer** must affix a label clearly indicating the next scheduled maintenance of the installations and inform the **Distribution Licensee**, who shall add the information to a **DGS** register.

The **Installer** must be skilled in the field of **DGS Electrical Facilities** and possess an approved certificate.

DC 4.17 Communication Requirements for MSDG 2 and MSDG 3

DC 4.17.1 Communication system setup

An **MSDG 2** with **Registered Capacity** greater than or equal to 1 MW or **MSDG 3** shall install communication **Equipment** for secured transfer of operating data and **Protection** and control signals via:

a. Fibre optics cable as per **DG INTERCONNECTION REQUIREMENTS** for **DGS** of **Registered Capacity** equal to or greater than 1 MW.
b. 4G/LTE (using VPN) or Microwave link or any other communication system acceptable to the **System Operator** as back-up communication channel for **DGS** of **Registered Capacity** equal to or greater than 1MW;

In those cases where the installation of fibre optic cable is not feasible or advisable because of high risk of damaging cane fire below the cable and there is no alternative routing for the fibre optic cable at a reasonable cost, the communication can be based only on the 4G/LTE (using VPN) and Microwave link, subject to approval by the **Distribution Licensee** for each particular case.

The **Distributed Generator** shall bear the cost for the installation of the communication system from the **DGS** to the corresponding **Substation** and shall install, test, commission and maintain the system (this includes equipment in the **Distribution System** side of the **Interconnection Boundary** and in the corresponding 66 kV-to-22 kV **Substation**). At the 66kV-to-22kV substation, the **Distributed**

Generator shall install a cabin, with access from outside the Substation boundary, to install its communication equipment. The cabin shall be termite proof and cross ventilated.

A **LV** supply (230 V ± 6%) shall be provided by the **Distribution Licensee** in the 66 kV-to-22 kV **Substation** subsequent to application for supply and payment of relevant fees by the **Distributed Generator.** However, given that this **LV** supply may be subject to unavoidable voltage disturbances and variations, the **Distributed Generator** shall ensure that all appropriate measures have been catered on his side for the protection of his communication system which may be sensitive to such power quality issues. In addition, the **Distributed Generator** shall be responsible for the maintenance of the communication equipment at the **Distribution Licensee Substation.** The **Distribution Licensee**'s liability shall be up to the **LV** supply and shall not bear any liability for damage in the **Distributed Generator**'s communication **Equipment.**

Relevant information for the operation of the **System** shall be transmitted in real time to the **System Control Centre** through the RTU (remote terminal unit) available at the **Distribution System Substation.**

DC 4.17.2 Communication Equipment

The **Distributed Generator** shall install a communication **Equipment** having the following features:

i. One-way communication from the **Transmission Substation (**66kV-to-22kV Substation**)** to the **DGS** of 22kV **Circuit Breaker** status (open/close);

ii. One–way communication from the **DGS** to the **Transmission System Substation** (66kV-to-22kV Substation) of:

a. Interconnection, transformer and generator **Circuit Breakers** Status (open/close)
b. Alarms (list of warnings/alarms shall be determined at discussion stage with the **Distribution Licensee**):
   1. Protection Operated
   2. Protection relay not healthy
   3. SF6 Alarm (if available)
   4. UPS Alarms
   5. Door Alarm (Switchgear room door on CEB side)
   6. Inter-tripping signal
   7. Remote/Local signal (Circuit Breaker CEB (CB1))
   8. Other Alarms (grouped)
c. **MW**, **MVAr** (at the **Point of Delivery**)
d. Voltage level of the **DGS** 22kV busbar (any line-to-line voltage)
e. Current (at the **Point of Delivery**) (any phase current)

iii. Remote control **Equipment** shall be provided only for **DGS** with **Registered Capacity** 1MW and above:

a. Load Break Switch OPEN CTRL command for each incomer (if available).
b. Load Break Switch CLOSE CTRL command for each incomer (if available).
c. **Distribution Licensee Circuit Breaker** (CB1 in DC 21.4.2) OPEN CTRL command.
d. **Distribution Licensee Circuit Breaker** (CB1 in DC 21.4.2) CLOSE CTRL command.

iv. Optical Fibre

The Optical fibre shall connect the **DGS** and the 22kV feeder's **Substation** on which the **DGS** is **Interconnected**. The **Distributed Generator** shall bear the cost of the procurement, installation and commissioning of the fibre optic link.

v. Wireless Communications

Where wireless communications are used, either as main or backup communication channel or as replacement of the fibre optic channel wherever authorized, it shall comply with any requirements approved by the **Distribution Licensee** and in particular with the following minimum characteristics:

a. Use the latest 3G/4G/LTE or newer communication technologies for the bands of frequency used in the Republic of Mauritius;
b. Use Microwave link as main channel and the latest 3G/4G/LTE as backup channel. Should any of the channel fail, switching to the other channel shall be seamless. In addition, SLA of 4 hours (Service Level Agreement) between the Distributed Generator and the Service Provider shall be applicable on the communication equipment to cater for their failure and link loss. The Distributed Generator shall provide a copy of the SLA to the Distribution Licensee.
c. Alternatively, communication equipment/Gateway/Router having dual SIM slot capability and using latest 3G/4G/LTE can be used. This shall allow to remove carrier dependency and swapping network operators seamlessly if the primary run into trouble. SLA of 4 hours (Service Level Agreement) between the Distributed Generator and the Service Provider shall be applicable on the communication equipment to cater for their failure and link loss. The Distributed Generator shall provide a copy of the SLA to the Distribution Licensee.
d. Furthermore, all channels using 3G/4G/LTE technology shall deployed and configured in VPN tunnel mode (virtual private network) for increased end-to-end security.
e. Be equipped with at least two routers, each capable of accommodating two SIM cards from different network operators and automatic switching between operators in case of unsuccessful transmission. The two routers shall be set up as one main and one hot standby router. This setup shall ensure redundancy both at the level of equipment and Service Provider.
f. Be capable of transmitting data at a rate of at least 85 kbps downloading and 42 kbps uploading.
g. Have a configuration interface protected by password;
h. Be capable of using VPN tunnels using, at least, technology Open VPN; and
i. Be equipped with support auto recovery mechanism.

DC 5 DISTRIBUTION SYSTEM INTERCONNECTION

DC 5.1 Introduction

This section of the **Distribution Code** specifies the normal method of interconnection to the **Distribution System** and the minimum technical, design and operational criteria which must be complied with by any **User** or prospective **User**.

For the purpose of this section of the **Distribution Code**, **User** refers to both **Distributed Generators** and **Customers** connected to the **Distribution System**.

In addition, details specific to each **User**'s interconnection may be set out in a separate **IA, ESPA, CA or PPA.** The interconnection conditions set out in these agreements are complementary to this **Distribution Code.**

All interconnection costs and responsibility shall normally be borne by the **User** connected to the **Distribution System** unless otherwise specified by an **IA, ESPA, CA** or **PPA** or policy or as dictated by the **Authority.**

DC 5.2 Objective

The objective of this section of the **Distribution Code** is to ensure that by specifying minimum technical, design and operational criteria the basic rules for interconnection to the **Distribution System** shall enable the **Licensee** in its capacity as the **Distribution Licensee** to comply with its statutory and License obligations.

DC 5.3 Scope

DC 5 applies to the following:

a. **Distribution Licensee** at the **Interconnection Boundaries**;

b. **Customers** directly connected to the **Distribution System**, and

c. **Distributed Generators.**

DC 5.4 Method of Interconnection

The **Distribution Licensee,** in collaboration with the **Single Buyer** and/or **System Operator,** if required**,** shall determine the optimum interconnection method on the basis of technical and economic factors, including:

a. Geographical considerations including proximity to the **Distribution System**;

b. Maximum **Demand** to be supplied;

c. **Generating Station Registered Capacity**;

d. Supply voltage;

e. Reliability considerations;

f. Standby or auxiliary power requirements;

g. Substation configuration; and

h. Costs.

The studies to be undertaken to determine the works required to facilitate an interconnection are those outlined in Section DC 2. These studies serve to ensure that for any new interconnection the proposed **Customer(s)** and all existing **Customers** receive a supply within the statutory parameters.

Multiple **Interconnections Boundaries** shall not be provided to the same **User.** No interconnection of the **Users** from two different **Interconnection Boundaries** shall be allowed unless specifically detailed in the **IA**, **ESPA, CA** or **PPA**, and appropriate safeguards put in place, including changeover **Equipment.**

The connection of Customers shall be according to the Distribution Licensee's Construction Manual and the Distribution Licensee's Metering Specifications.

The provisions relating to interconnection to the **Distribution System** shall be contained in the **IA, ESPA, CA or PPA** with a **User** and include provisions relating to both the submission of information and reports relating to compliance with the relevant Interconnection Conditions for that **User**, **Safety Rules**, commissioning and periodic testing programs, **Operation Diagrams**, and approval to connect.

DC 5.4.1 Interconnections at Low Voltage

For **Low Voltage** interconnections, supply shall be provided at:

a. single phase 230 V; or

b. three phase 400 V

The information required for **Low Voltage** interconnections shall be a minimum of:

a. **Customer** name, address and contact details;

b. Location of proposed interconnection;

c. Type of interconnection (Residential, Commercial, Industrial and others);

d. Capacity required (if not known then type of use appliances etc.);

e. Identification of any large motors or welders.

The interconnection shall be made to an appropriate **Interconnection Boundary** on the **User** premises.

DC 5.4.2 Interconnection at Medium Voltage

The following information, (as applicable) shall be supplied by the **User** to the **Distribution Licensee** for interconnections at **Medium Voltage**, prior to the first energization of a User system:

a. Updated data with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for items such as **Demand**;
b. Details of the **Protection** arrangements and settings including **Protection** and control single line diagrams;
c. Copies of all **Safety Rules** and **Local Safety Procedures** applicable at **Users' Sites** which shall be used at the interface between the **System Operator** and the **User**;
d. Information to enable the **Distribution Licensee** to prepare **Site Responsibility Schedules** according to the provisions set out in DC 21.1;
e. An **Operation Diagram** for all **MV Apparatus** on the **User** side of the **Interconnection Boundary**;
f. The proposed name of the **User Site** (which shall not be the same as, or confusingly similar to, the name of any **Licensee Site** or of any other **User Site**);
g. A list of **Safety Coordinators**;
h. A list of the telephone numbers for **Joint System Incidents** at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorized to make binding decisions on behalf of the **User**;
i. A list of managers who have been duly authorized to sign **Site Responsibility Schedules** on behalf of the **User**; and
j. Information to enable **System Operator** to prepare the **Site Common Drawings.**

DC 5.5 Interconnection of Distributed Generators

Generator Interconnections to the **Distribution System** shall comply with the relevant requirements of the **Generation Code** and Section DC 4 of the **Distribution Code.**

The operator of a **Distributed Generating Station** shall operate and maintain the **Distributed Generating Units** in such a manner so as not to adversely affect the **Distribution System** and other **Users**, including but not limited to adverse effects voltage level or voltage waveform, power factor and frequency or produce adverse levels of voltage flicker and/or **Harmonic Distortion**.

DC 6 POWER QUALITY STANDARDS

DC 6.1 General provisions

All **Users** connected to the **Distribution System** shall maintain the voltage waveform quality at the **Interconnection Boundary** within the limits specified in this section.

DC 6.2 Harmonic Voltage and Current Distortion

Managing harmonics in the **System** is considered a joint responsibility involving both **Users** and the **Distribution Licensee.** Therefore, voltage and current **Harmonic Distortion** shall be controlled within the limits specified in this section.

The necessary data shall be exchanged between both **Parties** and the exchange of data shall not be unreasonably withheld. This data may consist of but is not limited to dependence of the **System** impedance with the frequency at the **Interconnection Boundary** and background distortion.

DC 6.2.1 Harmonic Voltage Distortion

The **Distribution Licensee** shall limit line-to-neutral voltage harmonics below the values recommended in the IEEE Standard 519 for the **Interconnection Boundaries** of all **Users,** and summarized in Table 4**.**

Table 4: Voltage distortion limits for the Distribution System as per IEEE Std. 519-2014.

Bus Voltage at the Interconnection Boundary, V	Individual Harmonic (%)	Total harmonic distortion, THD (%)
V ≤ 1.0 kV	5.0	8.0
1.0 kV < V ≤ 69.0 kV	3.0	5.0

All values in Table 4 should be in percent of the rated power frequency voltage at the **Interconnection Boundary**.

DC 6.2.2 Harmonic Current Distortion

Users connected to the **Distribution System** shall ensure that their harmonic current emissions at the **Interconnection Boundary** do not exceed the limits recommended in the IEEE Standard 519.

The harmonic currents at the **Interconnection Boundary** of **Users** of the **Distribution System** should comply with IEEE Std. 519-2014 for the lowest ratio of the short-circuit current available at the **Interconnection Boundary**, to the maximum fundamental load current. The key requirements of this clause are summarized below:

(a) The Total Harmonic Current Distortion (THD) or Total Demand Distortion (TDD) shall be less than 5% of the fundamental frequency current at rated current output.

(b) Each individual harmonic shall be limited to the percentages listed in which are expressed in percentage of the fundamental frequency current at rated current output.

(c) Even harmonics in these ranges shall be <25% of the odd harmonic limits listed.

Table 5: Current distortion limits for the Distribution System as per IEEE Std. 519-2014.

Odd Harmonic	Maximum Harmonic Current Distortion
3rd -9th	4.0%
11th -15th	2.0%
17th -21st	1.5%
23rd -33rd	0.6%
Above the 33rd	0.3%

DC 6.3 Voltage Fluctuations

Users shall ensure that their connection to the **Distribution System** does not result in the level of fluctuation of the supply voltage on the **Distribution System** at the **Interconnection Boundary** exceeding limits set out below. Any necessary data shall be exchanged between both parties and the exchange of data shall not be unreasonably withheld.

DC 6.3.1 Voltage Flicker

Users shall take responsibility for limiting voltage flicker caused by their **Electrical Facilities** to remain within the maximum values at the **Interconnection Boundary** specified in the IEC TR 61000-3-7 for **Users** connected at **Medium Voltage,** and in parts 3 and 11 of IEC TR 61000-3 for **Users** connected at **Low Voltage**.

DC 6.3.2 Voltage Changes

Users shall ensure that the disturbance levels introduced by their **Electrical Facilities** do not promote voltage changes at the **Interconnection Boundary** above the following values under **Normal Conditions**:

a) Voltage fluctuation limit for step changes which may occur repetitively should not exceed ± 1% around the nominal voltage under **Normal Conditions**
b) Voltage Fluctuation limit for occasional fluctuations other than step changes and infrequent planned switching events or outages should not exceed ±3% around the nominal voltage.
c) Voltage step changes caused by the connection to and disconnection from the **Distribution System** of a **Distributed Generating Station** or a **Customer** shall not exceed ±6% for unplanned outages such as **Faults.**

Where induction generators are used in a **Distributed Generating Station**, as in fixed speed wind turbines, they shall be fitted with soft starters to limit inrush currents to a maximum of 110 % the normal rated current. This reduces the magnitude of the step voltage changes which occur on starting.

DC 6.4 Phase Unbalance

The weekly 95 percentile of Phase (Voltage) Unbalance, calculated in accordance with IEC61000-4-30 and IEC61000-3-13, on the **Distribution System** shall be less than or equal to 1.3% unless abnormal conditions prevail.

The Phase Unbalance is calculated from the ratio of root mean square (rms) of negative phase sequence voltage to rms of positive phase sequence voltage, based on 10-minute average values, in accordance with IEC 61000-4-30.

DC 6.5 Exceptional Conditions

Some events such as **Major Incidents** and **Faults** on the **Transmission System, Distribution System,** or a **Distributed Generating Station**, can result in variations outside the normal power quality standards as outlined in DC 6. During these events, the **System Operator** shall be relieved of its obligation to comply with the System conditions in DC 6 , and inform the Authority accordingly.

DC 6.5.1 Limitation of DC Injection

A **Customer** or **Distributed Generator** should not inject a **DC** current greater than the 0.25 % of the rated AC output current per phase.

A **Customer** or **Distributed Generator** connected to the LV Distribution System should not inject a DC current greater than the largest value of 20 mA and 0.25% of the rated AC output current per phase.

DC 6.5.2 Voltage and Current Unbalance

The total voltage unbalance in the **Grid** shall be smaller than 2%, where the unbalance, $\mathrm{U_{unbalance}}$, is defined as the maximum deviation from the average of the three-phase voltages, Ua, Ub and Uc, divided by average of the three-phase voltages.

$$U_{unbalance} = \frac{\max\{U_a,U_b,U_c\} - U_{avg}(a,b,c)}{U_{avg}(a,b,c)} \times 100\%.$$

The contribution to the level of unbalance of the voltage at the **Interconnection Boundary** of a **Distributed Generating Station** shall be less than or equal to 1.3 %.

When considering three phase units, the contribution to the voltage unbalance can be described as

$$U_{unbalance} = \frac{\sqrt{3} I_{neg\ seq\ load} U_{line}}{S_{sc}}$$

or

$$I_{neg\ seq\ load} = \frac{\sqrt{3} U_{unbalance}(\%) U_{line}}{S_{sc}}$$

where

S_{sc} is the three-phase short circuit power

$I_{neg\ seq\ load}$ is the negative sequence of component loads

U_{line} is the line voltage

$U_{unbalance}$ is the voltage unbalance

In the absence of better information, S_{sc}shall be 2.5 MVA for Users connected to the **LV Grid.**

DC 7 ELECTRICAL FACILITIES RELATED TO INTERCONNECTION SITES

DC 7.1 General Requirements

All **Electrical Facilities** related to the **Users/Licensee** at the **Interconnection Boundary**, shall be compliant with the requirements in DC 7 and its subsections.

DC 7.2 Substation Electrical Facilities

All circuit breakers, switch disconnectors, earthing devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination at the **User/Licensee Interconnection Site** shall be constructed, installed and tested in accordance with the technical standards specified by the **Distribution Licensee**, and **Prudent Utility Practice.**

Plant and **Apparatus** shall be designed, manufactured and tested in premises certified in accordance with the quality assurance requirements of ISO 9001 or equivalent.

DC 7.3 Interconnection Boundaries

DC 7.3.1 Low Voltage and Medium Voltage Users Interconnection Boundaries

For **LV** and **MV** supplies, the Distribution Licensee's responsibility extends up to the User's **Interconnection Boundary** which is normally:

a) In major **LV** and **MV** installations (CT/PT connected): at the main fuses or **Circuit Breaker** of the Distribution Licensee.

b) In **LV** premises (single and three phase direct-connected supply): at the outgoing terminals of the **Distribution Licensee**'s Meter.

The **Distribution Licensee** shall develop an Installation Manual for LV customers. This manual shall comply with the requirements of the **Distribution Grid Code** and shall be approved by the **Authority.**

DC 7.3.2 Generator Interconnection Boundaries

The requirements for the design of **Interconnection Boundaries** between the **Distributed Generators** and the **System Operator** are set out in Section DC 4..

DC 7.3.3 Interconnection Boundaries to Transmission System

The **Distribution System** interconnection to the **Transmission System** shall comply with the relevant provisions of the **Transmission Code.**

DC 7.4 Protection Requirements

All **Protection Systems** and settings shall be in accordance with the **Distribution Licensee Protection** Policy.

The **Protection Systems** to be applied to **Distributed Generating Units** shall also comply with DC 4.8 and DC 4.9.

Protection of the **Distribution System** and **Customers** directly supplied from the **Distribution System** shall be designed, coordinated and tested to achieve the desired level of speed, sensitivity and discrimination to isolate the affected parts of the **System** while ensuring that the section isolated does not include parts of the **System** not directly affected by the fault, as far as possible in accordance with **Prudent Utility Practice**, and maintaining supplies to the remainder of the **System** within design parameters.

The **Distribution Licensee** shall be solely responsible for the **Protection** of the **Distribution System. Users** and **Distributed Generators** shall be solely responsible for the protection of the **User Systems** on their side of the Interconnection Boundary.

Users shall design their **Protection System** to ensure that no other **User** shall be affected for faults on their **Plant** and **Apparatus.**

The reliability of the protection scheme to initiate the successful tripping of the **Circuit Breakers** that are associated with the faulty **Equipment** shall be consistent with **Prudent Utility Practice**.

The **Distribution Licensee** and/or **System Operator** may require specific **Users** to provide other **Protection** schemes, designed and developed to minimize the risk and/or impact of disturbances on the **System.**

Where as part of the **IA, ESPA, CA** or **PPA**, a **User** is required to provide **Demand** disconnection as part of the **System Operators'** under frequency management process that includes the automatic disconnection of **Demand** then the relays shall comply with the Technical Requirements for Under Frequency Relays set forth in the **Transmission Code.**

DC 8 SITE RELATED CONDITIONS

DC 8.1 General

Responsibility for construction, commissioning, control, operation and maintenance responsibilities for the **Electrical Facilities** shall be according to the ownership of each facility, unless an agreement between the **Parties** specifies differently.

DC 8.2 Responsibilities for Safety

The **Distribution Licensee** and all the **Distribution System Users** shall comply with the relevant Electricity Regulations.

Before interconnection to the **Distribution System** at the **MV** level the **Distribution Licensee** and the **User** shall enter into a written agreement as to the **Safety Rules** to be used for work on **Plant** and/or **Apparatus** at the **Interconnection Boundary** as specified in the Safety Coordination section SOC 15 of the **System Operations Code.**

DC 8.3 Site Responsibility Schedules

In order to inform site operational staff and the **System Operator**'s **System Control Engineers** of agreed responsibilities for **Plant** and/or **Apparatus** at the **Interconnection Site** at the **MV** level, a Site Responsibility Schedule shall be produced for **System Operator** and **Users** with whom they interface.

The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in DC 21.1. These documents shall be included in the **IA, ESPA, CA or PPA.**

DC 8.4 Diagrams and Drawings

All **Users** connected to the **MV** and **LV Distribution System** shall produce Project Drawings, Operation Diagrams and Site Common Drawings, following the requirements of DC 8.4.1, DC 8.4.2 and DC 8.4.3.

The **Distribution Licensee** shall produce a **Distribution System** drawing as set forth in DC 8.4.4

DC 8.4.1 Project Drawings

Project Drawings of a **Distributed Generator** shall be reviewed by an **Installer** for **SSDG** and **MSDG 1** and **Registered Professional Engineer for MSDG 2** or **MSDG 3** with **Registered Capacity** up to 4MW **and Independent Engineer** for **MSDG 3** with **Registered Capacity above 4MW.**, while Project Drawings of other **Users** shall be reviewed directly by the **Distribution Licensee** and the **System Operator.**

In respect of **User**'s obligations relating to the drawings of a **Project**, the following shall apply:

(a) The **User** shall prepare and submit, with reasonable promptness and in such sequence as is consistent with the **Project** Completion Schedule set forth in the **IA, ESPA, CA or PPA**, 3 (three) copies each of all drawings to the **Installer**, **Registered Professional Engineer Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, for review;

(b) By submitting the drawings for review to the **Installer**, **Registered Professional Engineer , Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, the **User** shall be deemed to have represented that it has determined and verified that the design and engineering, including field construction criteria related thereto, are in conformity with the **National Grid Code** and **IA, ESPA, CA or PPA**;

(c) Within 15 (fifteen) days of the receipt of the **Project** Drawings, the **Installer**, **Registered Professional Engineer Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, shall review the **User**'s Drawings and convey its observations to the **User** with particular reference to their conformity or otherwise with the **Distribution Code** and **IA, ESPA, CA or PPA.** The **User** shall not be obliged to await the observations of the **Installer**, **Registered Professional Engineer Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, on the drawings submitted pursuant hereto beyond the said 15 (fifteen) days period and may begin construction works at its own discretion and risk;

(d) If the aforesaid observations of the **Installer**, **Registered Professional Engineer, Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, indicate that the drawings are not in conformity with the **Distribution Code** and **IA, ESPA, CA** or **PPA**, such Drawings shall be revised by the **User** and resubmitted to the **Installer**, **Registered Professional Engineer Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, for review. The **Installer**, **Registered Professional Engineer**, **Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, shall give its observations, if any, within 7 (seven) days of receipt of the revised drawings;

(e) No review and/or observation of the **Installer**, **Registered Professional Engineer, Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, and/or its failure to review and/or convey its observations on any drawings shall relieve **User** of its obligations and liabilities under the **Distribution Code** in any manner nor shall the **Installer**, **Registered Professional Engineer, Independent Engineer** or **Distribution Licensee** and **System Operator**, as the case may be, be liable for the same in any manner;

(f) Without prejudice to the foregoing provisions of this Section DC 8.4.1, the **User** shall submit to the **Distribution Licensee** and **System Operator** for review and comments, its **Project** drawings relating to the **User Interconnection Electrical Facilities, Protection** and control **Apparatus** and the **Distribution Electrical Facilities**, and the **Distribution Licensee** and **System Operator** shall have the right but not the obligation to undertake such review and provide its comments, if any, within 30 (thirty) days of the receipt of such drawings. The provisions of this Section DC 8.4.1 shall apply mutatis mutandis to the review and comments hereunder; and

(g) Within 90 (ninety) days of the Commercial Operation Date, the **User** shall furnish to the **Distribution Licensee** and **System Operator** a complete set of as-built drawings, in 2 (two) hard copies and electronic version in pdf format or in such other medium as may be acceptable to the **Distribution Licensee** and **System Operator**, reflecting the **User**'s as **Plant** and **Apparatus** actually designed, engineered and constructed, including an as-built survey illustrating the layout of the **Plant** and setback lines, if any, of the buildings and structures forming part of the Project Assets.

DC 8.4.2 Operation Diagrams

An **Operation Diagram** shall be prepared by the **User** for each **Interconnection Site** at which an **Interconnection Boundary** exists in accordance with DC 21.2.

The **Operation Diagram** shall include all **MV Apparatus** and the connections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in Section DC 15.. The nomenclature used shall conform to that used on the relevant **Interconnection Site** and circuit.

The **Operation Diagram** (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of **MV Apparatus** and related **Plant.**

DC 8.4.2.1 Validity of Operation Diagrams

The composite **Operation Diagram** prepared by the **User** shall be the definitive **Operation Diagram** for all operational and planning activities associated with the **Interconnection Site.** If a dispute arises as to the accuracy of the composite **Operation Diagram**, a meeting shall be held at the **Interconnection Site**, as soon as reasonably practicable, between **System Operator** and the **User**, to endeavour to resolve the matters in dispute.

DC 8.4.3 Site Common Drawings

DC 8.4.3.1 General

Site Common Drawings shall be prepared for each **Interconnection Site** and shall include **Interconnection Site** layout drawings, electrical layout drawings, common protection/control drawings and common services drawings.

The **User** shall prepare and submit to the **Distribution Licensee** Site Common Drawings for the **User** side of the **Interconnection Boundary.**

The **Distribution Licensee** shall then prepare, produce and distribute, using the information submitted by the **User**, **Site Common Drawings** for the complete **Interconnection Site.**

The System Operator shall receive a copy of the finalized **Site Common Drawings** for the **Interconnection Site.**

DC 8.4.3.2 Changes to Site Common Drawings

When the **Distribution Licensee** or a **User** becomes aware that it is necessary to change any aspect of the **Site Common Drawings** at an **Interconnection Site** it shall notify the other **Party** and amend the **Common Site Drawings** in accordance with the procedure set out in sub-section DC 8.4.3.

DC 8.4.3.3 Validity of Site Common Drawings

The **Site Common Drawings** for the complete **Interconnection Site** prepared by the **Distribution Licensee**, shall be the definitive **Site Common Drawings** for all operational and planning activities associated with the **Interconnection Site.** If a dispute arises as to the accuracy of the **Site Common Drawings**, a meeting shall be held at the **Site,** as soon as reasonably practicable, between the **Distribution Licensee** and the **User**, to endeavour to resolve the matters in dispute.

DC 8.4.4 Distribution System Drawings

The **Distribution Licensee** shall produce schematic drawings of the whole **Distribution System.** It shall be the responsibility of the **Distribution Licensee** to ensure that all its drawings and schematics are up to date

DC 8.5 Access

The provisions relating to access to **Distribution Licensee** Sites by **Users**, and to **User** Sites by the **System Operator or Distribution Licensee** shall be set out in each **IA, ESPA, CA** or **PPA** with the **System Operator** and each **User**.

Access shall be subject to the approval and conditions of the **System Operator,**

Distribution Licensee or **User**. Request shall be detailed and made 3 business days in advance for the **System Operator**, **Distribution Licensee** or **User** to make necessary arrangements.

DC 9 COMMUNICATIONS AND CONTROL

For the purpose of this section, the term **User** refers to **Distributed Generators** and **Customers** connected to the **MV Distribution System.**

In order to ensure control of the **Distribution System**, telecommunications between **User**(s) and the **System Operator** must be established if required by the **System Operator**.

Control telephony is the method by which a **User's** and **System Operator's Operations Engineers** or delegated representatives speak to one another for the purposes of control of the **Distribution System** in both normal and emergency situations.

At any **Interconnection Boundary** where the **Users** telephony **Equipment** is not capable of providing the required facilities or is otherwise incompatible with the **System Operators'** control telephony, the **User** shall install appropriate telephony **Equipment** to the specification of the **System Operator.** Details of the control telephony required shall be set out in the **IA, ESPA, CA or PPA.**

The **System Operator** shall provide a **SCADA** outstation interface **Equipment.** The **User** shall provide 4-20 mA signals of voltage, current, frequency, **Active Power** and **Reactive Power** measurement outputs and **Plant Circuit Breaker** positions and alarms to the **System Operator SCADA** outstation interface **Equipment** as required by the **System Operator.** The manner in which information is required to be presented to the outstation **Equipment** is set out in Section DC 21.3 (DC APPENDIX C: SCADA INTERFACING).

Power supply for the communication on the **Distribution Licensee** side of the **Interconnection Boundary** shall be metered and billed based on the applicable tariff.

DC 10 TESTING AND MONITORING

DC 10.1 Introduction

To ensure that the **Distribution System** is operated efficiently and within the **License** conditions and to meet statutory actions, the **Distribution Licensee** with the support of the **System Operator** shall organize and carry out testing and/or monitoring of the effect of **Users'** Electrical Facilities on the **Distribution System.**

The testing and/or monitoring procedures shall be developed to demonstrate compliance to all applicable requirements specified in this **Distribution Code** and any other applicable code or standard approved by the Authority, as applicable.

More extensive Special System Tests are outlined in Section DC 16.

DC 10.2 Objective

The objective of DC 10 is to specify the requirement to test and/or monitor the **Distribution System** to ensure that **Users** are not operating outside the technical parameters required by the **Distribution Code** and other relevant parts of the **National Grid Code.**

DC 10.3 **Procedure related to quality of supply**

The **System Operator** shall from time to time determine the need to test and/or monitor the quality of supply at various points of the **Distribution System.**

The requirement for specific testing and/or monitoring may be initiated by the receipt of complaints as to the quality of supply on the **Distribution System.**

In certain situations, the **System Operator** may require the testing and/or monitoring to take place at the **Point of Delivery** of a **User** from the **Distribution System.**

Where testing and/or monitoring is required at the **Interconnection Boundary**, the **System Operator** shall advise the involved **User** and shall make available the results of such tests to the **User.** These tests shall be performed by the **System Operator** at the **System Operator**'s cost.

Where the results of such tests show that the **User** is operating outside the technical parameters specified in the **Distribution Code** or other relevant part of the **National Grid Code**, the **User** shall be informed accordingly.

Where the **User** requests the **System Operator** to perform a retest, the retest shall be carried out at the **User**'s cost and witnessed by a **User** representative.

A **User** shown to be operating outside the limits specified in the **Distribution Code** or other relevant part of the **National Grid Code** shall rectify the situation or disconnect the **Apparatus** causing the problem from its **Electrical Facilities** connected to the **Distribution System** immediately or within such time as is agreed with the **System Operator**.

Continued failure to rectify the situation may result in the **User** being disconnected from the **Distribution System** either as a breach of the **Distribution Code,** other relevant part of the **National Grid Code** or other statutory requirement, where appropriate.

The **User** may conduct test(s) on the **User's** side of the **Interconnection Boundary** at the **User**'s cost; however, the **System Operator** shall be notified prior to such test(s).

DC 10.4 **Procedure Related to Interconnection Boundary Parameters**

The **System Operator** from time to time shall monitor the effect of the **User** on the **Distribution System.** The monitoring shall normally be related to the amount of **Active Power** and **Reactive Power** transferred across the **Interconnection Boundary**.

Where the **User** is exporting to or importing **Active Power** and **Reactive Power** from the **Distribution System** in excess of the levels set forth in the **IA, ESPA, CA or PPA** the **System Operator** shall inform the **User** and where appropriate demonstrate the results of such monitoring.

The **User** may request technical information on the method of monitoring and, if necessary, request another method reasonably acceptable to the **System Operator.**

Where the **User** requires **Active Power** and **Reactive Power** in excess of the physical capacity of the **Interconnection Boundary**, the **User** shall restrict power transfers to those specified in the **IA, ESPA, CA or PPA** until a modified **IA, ESPA, CA or PPA** has been applied and physically established. All costs to increase the physical capacity of the **Interconnection Boundary** shall be the responsibility of the **User.**

DC 11 DEMAND CONTROL (DISTRIBUTION SYSTEM USERS)

DC 11.1 **Introduction**

The **System Operator** shall establish the requirements for the **Users** and **Customers** of the **Distribution System**, in certain circumstances, to permit reductions in total **Demand** in the event of insufficient **Generation** being available to meet total

Demand or to avoid disconnection of **Customers** and **Users** or in the event of breakdown and/or overloading on any part of the **Transmission** and/or **Distribution Systems.**

The **Demand Control** procedures ensure that hardship to **Users** and **Customers** is minimized and that in so far as is practicable, all parties affected are treated equitably.

The **System Operator** and **Users** shall comply with the requirements established in section SOC 9 of the **System Operations Code.**

DC 12 OPERATIONAL COMMUNICATION

DC 12.1 Objective

The **System Operator** and **Users** shall exchange information so that the implications of an **Operation** and/or **Incident** can be considered and the possible risks arising from them can be assessed and appropriate actions taken by the relevant parties in order to maintain the integrity of the **Total System** and the **Users' Plant** and **Apparatus.**

For the purposed of this section, **Users** mean the **Distribution Licensee** and any user connected to the **Distribution System.**

The **System Operator** and **Users** shall comply with the requirements established in section SOC 11 of the **System Operations Code.**

DC 13 MAINTENANCE STANDARDS

All **Plant** and **Apparatus** on the **System** shall be operated and maintained in accordance with **Prudent Utility Practice** and in a manner that shall not pose a threat to the safety of employees or the public.

The **System Operator** shall establish a **Distribution System Maintenance Policy** which shall be reviewed and approved by the **Authority.**

The **Distribution Licensee** shall coordinate with the **System Operator** the scheduled maintenance of **MV** facilities in the **Distribution System.**

The **System Operator**, the **Distribution Licensee** and any **User** connected to the **Distribution System** shall comply with the requirements established in section SOC 12 of the **System Operations Code.**

DC 14 SWITCHING INSTRUCTIONS FOR MEDIUM VOLTAGE EQUIPMENT

Medium Voltage switching shall only be carried out with the permission of the **System Control Engineer** or its designated representatives except under **System Emergency.** Persons required to carry out **Medium Voltage** switching must be specifically certified and authorized by the **System Operator** to carry out such switching.

The **System Operator** shall comply with the requirements and procedures in section SOC 7 of the **System Operation Code.**

DC 15 NUMBERING AND NOMENCLATURE

DC 15.1 Introduction

This section sets out the responsibilities and procedures for notifying the relevant owners of the numbering and nomenclature of **Apparatus** at **Interconnection Boundaries.**

The numbering and nomenclature of **Apparatus** shall be included in the **Operation Diagram** prepared for each **Interconnection Site**.

DC 15.2 Objectives

The prime objective embodied in section DC 15 is to ensure that at any **Site** where there is an ownership boundary every item of **Apparatus** has numbering and/or nomenclature that has been mutually agreed and notified between the owners concerned to ensure, so far as is reasonably practicable the safe and effective **Operation** of the **Systems** involved and to reduce the risk of error.

DC 15.3 Procedure

DC 15.3.1 New Apparatus

When the **System Operator** or a **User** intends to install **Apparatus** on an **Interconnection Site**, the proposed numbering and/or nomenclature to be adopted for the **Apparatus** must be notified by the **System Operator** to the **User** or **User** to the **System Operator** as the case may be. The notification shall be made in writing to the relevant owners and shall consist of an **Operation Diagram** incorporating the proposed **Apparatus** to be installed and its proposed numbering and/or nomenclature. The notification shall be made at least three months prior to the proposed installation of the **Apparatus**.

The **System Operator** or **User** as the case may be shall respond in writing within one month of the receipt of the notification confirming both receipt and whether the proposed numbering and/or nomenclature is acceptable or, if not, what would be acceptable.

In the event that agreement cannot be reached between the **System Operator**, and the **User**, the **System Operator**, acting reasonably, shall have the right to determine the numbering and nomenclature to be applied at that site.

DC 15.3.2 Existing Apparatus

The **System Operator** and/or every **User** shall supply the other **Party** on request with details of the numbering and nomenclature of **Apparatus** on **Interconnection Sites**. The **System Operator** and every **User** shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature of its Apparatus on sites having an **Interconnection Boundary.**

DC 15.3.3 Changes to existing Apparatus

Where the **Distribution Licensee** or a **User** needs or wishes to change the existing numbering and/or nomenclature of any of its **Apparatus** on any **Interconnection Site**, the provisions of DC 15 shall apply with any amendments necessary to reflect that only a change is being made.

Where any **Party** changes the numbering and/or nomenclature of its **Apparatus**, which is the subject of DC 15, that party shall be responsible for the provision and erection of clear and unambiguous labelling.

DC 16 SPECIAL SYSTEM TESTS

DC 16.1 Introduction

This section of the **Distribution Code** sets out the responsibilities and procedures for arranging and carrying out **Special System Tests** which have or may have an effect on the **Distribution System** or **Users Systems. Special System Tests** are those tests which involve either simulated or the controlled application of irregular, unusual or extreme conditions on the **System** or any part of the **System**, but which do not include commissioning or re-commissioning test or any other tests of a minor nature.

If the **Special System Test** proposed by the **System Operator**, **Distribution Licensee** or the **User** connected to the **Distribution System** shall or may have an **Operational Effect** on the **Transmission System** then the provisions of the **Transmission Code** shall apply.

Special System Tests which have a minimal **Operational Effect** on the **Distribution System** or **Systems** of other **Users** shall not be subject to this procedure. Minimal **Operational Effect** shall be taken to mean variations in voltage, frequency and waveform distortion of a value not greater than the figures defined in the Planning and Interconnection sections of the **Distribution Code.**

The **Distribution Licensee** with the support of the **System Operator** shall organize and carry out the **Special System Tests.**

DC 16.2 Objective

The objectives of section DC 16 are to:

a. ensure that the procedures for arranging and carrying out **Special System Tests** are such that, so far as practicable, **Special System Tests** do not threaten the safety of personnel or the general public and cause minimum threat to the security of supplies, the integrity of **Plant** or **Apparatus** and are not detrimental to the **Distribution System** and **Users**; and

b. set out procedures to be followed for establishing and reporting **Special System Tests.**

DC 16.3 Procedure

DC 16.3.1 Proposal Notice

When a **User** intends to undertake a **Special System Test** which shall have or may have an **Operational Effect** on the **System** or other **User's Systems**, notice shall be provided one (1) month in advance of the proposed **System Test**, or as otherwise agreed by the **Distribution Licensee**, by the person proposing the **System Test** (the Test Proposer) to the **Distribution Licensee** and to those **Users** who may be affected by such a **System Test.**

When the **Distribution Licensee** intends to undertake a **Special System Test** which shall have or may have an **Operational Effect** on the **System** or other **User's Systems**, notice shall be provided one (1) month in advance of the proposed **System Test** to the **Transmission Licensee**, or as otherwise agreed, and to those **Users** who may be affected by such a **System Test.**

The proposal shall be in writing and shall contain details of the nature and purpose of the proposed **System Test** and shall indicate the extent and situation of the **Plant** or **Apparatus** involved.

If the information set out in the proposal notice is considered insufficient by the recipient, the recipient shall contact the Test Proposer with a written request for further information which shall be supplied as soon as reasonably practicable. The recipient of the proposal notice shall not be required to do anything under DC 16 until it is satisfied with the details supplied in the proposal or pursuant to a request for further information.

DC 16.3.2 Preliminary Notice and Establishment of Test Committee

The **System Operator** shall have overall co-ordination of the **System Test**, using the information supplied to it under Section DC 16 and shall identify in its reasonable estimation, which **Users** other than the **Test Proposer**, may be affected by the proposed **System Test.**

DC 16.3.3 Test Committee

A **Test Coordinator**, who shall be a suitably qualified person, shall be appointed by the **System Operator** and shall act as chairman of the **Test Committee**.

The **Distribution Licensee** shall convene a **Test Committee**, for a **Special System Test.** The number of **Test Committee** members shall be kept to the minimum number of persons compatible with affected **User** representation. The **System Operator,** the **Distribution Licensee,** the **Test Proposer** and all directly affected **Users** shall be represented in the **Test Committee.**

All **Users** identified under DC 16 shall be given in writing, by the **Test Coordinator**, a preliminary notice of the proposed **System Test.** The preliminary notice shall contain:

a. the details of the nature and purpose of the proposed **System Test**, the extent and situation of the **Plant** or **Apparatus** involved and the **Users** identified by the **Distribution Licensee**;

b. an invitation to the identified **Users** to nominate a suitably qualified person to be a member of the **Test Committee** for the proposed **System Test.**

The preliminary notices shall be sent within one month of the receipt of the proposal notice or the receipt of any further information requested.

As soon as possible after the expiry of this one-month period all relevant **Users** and the **Test Proposer** shall be notified by the **Test Coordinator** of the composition of the **Test Committee.**

A meeting of the **Test Committee** shall take place as soon as possible after the relevant **Users** and the **Test Proposer** have been notified of the composition of the **Test Committee.**

The **Test Committee** shall consider:

a. the details of the nature and purpose of the proposed **System Test** and other matters set out in the proposal notice;
b. the economic, operational and risk implications of the proposed **System Test**;
c. the possibility of combining the proposed **System Test** with any other tests and with **Plant** and/or **Apparatus** outages which arise pursuant to the operational planning requirements of the **System Operator** and **Users**; and
d. implications of the proposed **System Test** on the scheduling and dispatch of **Generating Stations**, insofar as it is able to do so.

Users identified under section DC 16 and the **System Operator**, whether or not they are represented on the **Test Committee**, shall supply the **Test Committee** upon written request the information the **Test Committee** reasonably requires in order to consider the proposed **System Test.**

The **Test Committee** shall be convened by the **Test Coordinator** when it is necessary to conduct its business, subject to the oversight of the **Distribution Licensee** in coordination with the **System Operator**.

DC 16.3.4 Proposal report

Within two months of its first meeting, the **Test Committee** shall produce a report, which in DC 16 is called a proposal report, which shall contain:

a. proposals for carrying out the **System Test** (including the manner in which the **System Test** is to be monitored);

b. an allocation of costs (including the costs that cannot be determined in advance of the test) to the **Parties involved in the test**, the general principle being that the **Test Proposer** shall bear the costs; and

c. such other matters as the **Test Committee** consider appropriate.

The proposal report may include requirements for possible indemnities to be given in respect of claims and losses that may arise from the **System Test**. All **System Test** procedures must comply with all applicable legislation.

If the **Test Committee** is unable to agree unanimously on any decision in preparing its proposal report, the proposed **System Test** shall not take place and the **Test Committee** shall be dissolved.

DC 16.3.5 Final Test Program

If the proposal report is approved by all recipients, the proposed **System Test** can proceed and at least one month prior to the date of the proposed **System Test**, the Test Committee shall submit to the **Distribution Licensee, System Operator** and all recipients of the proposal notice a program which in this section DC 16 shall be called a final test program stating any switching sequence and proposed timings, a list of those staff involved in the carrying out of the System Test (including those responsible for site safety) and such other matters as the Test Committee deem appropriate.

The final test program shall bind all recipients to act in accordance with the provisions contained in the program in relation to the proposed **System Test**.

Any problems with the proposed **System Test** which arise or are anticipated after the issue of the final test program and prior to the day of the proposed **System Test** must be notified to the **System Operator** as soon as possible in writing If the **System Operator** decides that these anticipated problems merit an amendment to or postponement of the **System Test** the **System Operator** shall notify any party involved in the **System Test** accordingly.

If on the day of the proposed **System Test** operating conditions on the **System** are such that any party involved in the proposed **System Test** wishes to delay or cancel the start or continuance of the **System Test**, they shall immediately inform the **System Operator** of this decision and the reasons for it. The **System Operator** shall then postpone or cancel, as the case may be, the **System Test** and shall if possible, agree with all **Parties** involved in the proposed **System Test** another suitable time and date or if the **System Operator** cannot reach such agreement, shall reconvene the **Test Committee** as soon as practicable which shall endeavour to arrange another suitable time and date and the relevant provisions of DC 16 shall apply.

DC 16.3.6 Final report

At the conclusion of the **System Test**, the **Test Proposer** shall be responsible for preparing a written report (the final report) of the **System Test** for submission to other members of the **Test Committee**.

The final report shall include a description of the **Plant** and/or **Apparatus**, tested and of the **System Test** carried out, together with the results, conclusions and recommendations.

The final report shall not be distributed to any party which is not represented on the **Test Committee** unless the Test Committee having considered the confidentiality issues, shall have unanimously approved such distribution.

When the final report has been submitted the **Test Committee** shall be dissolved.

DC 17 DISTRIBUTION METERING

DC 17.1 Purpose and Introduction

This section of the **Distribution Code** sets out the way in which power and energy flows shall be measured at an operational Interface.

This section of the **Distribution Code**:

a. Establishes the requirements for metering the **Active** and **Reactive Energy** and **Demand** input to and/or output from the **Distribution System**;
b. Sets out appropriate procedures for metering reading; and
c. Ensures that procedures are in place to manage disputed readings.

The **Distribution Licensee** shall be responsible for the procurement, installation, maintenance, calibration, and testing of meters and metering systems. The **Meter Laboratory** will provide support to the **Distribution Licensee** in the calibration and testing of meters and metering systems.

The **Distribution Licensee** shall be responsible for meter reading, billing, collection and customer claims.

The **Distribution Licensee** shall develop detailed metering specifications compliant with the requirements of the **Distribution Grid Code**

DC 17.2 Scope

This sub-section applies to:

a. the **Distribution Licensee**
b. **Users**
c. **Distributed Generators**

DC 17.3 Metering Requirements Distributed Generators

DC 17.3.1 Overall Accuracy

The required overall accuracy (maximum allowed values) of **Distributed Generator** metering is to be designed according to the following categories:

a. SSDG: 2.0%
b. MSDG-1: 2.0%
c. MSDG-2: 1.5%
d. MSDG-3: 0.5%

Existing installations may allow less stringent requirements according to already signed **Connection Agreement, ESPA or PPA.**

DC 17.3.2 Relevant Metering Policies, Standards, Specifications and Accuracy

Sample testing of meters must be done and certified by CEB **Meter Laboratory.**

The requirements in Table 6 shall apply to all metering systems installed in **Distributed Generation** facilities.

Table 6: Distributed Generation Metering Requirements

Item	SSDG (up to 50 kW)	MSDG-1 (greater than 50 kW and up to 500 kW)	MSDG-2 (greater than 500 kW and up to 4 MW)	MSDG-3 (greater than 4 MW and up to 10 MW)
Main meter	Separate registers for net energy export and import Installed by the Distribution Licensee on LV side	CT and VT (if required) connected Separate registers for net energy export and import Installed by the Distribution Licensee on LV side	CT and VT-connected Separate registers for net energy export and import Installed by the Distribution Licensee on HV side	same as MSDG-2
Back-up (Distribution Licensee) meter – Greenfield Project	N/A	N/A	CT and VT-connected Separate registers for net energy export and import Installed by the Distribution Licensee on HV side	same as MSDG-2
Secondary (production meter)	Measures gross SSDG production Installed by the Distribution Licensee on SSDG LV side (next to main meter and easily accessible)	CT connected Measures gross MSDG production Installed by the Distribution Licensee on MSDG LV side (next to main meter and easily accessible)	CT and VT (if required) connected Measures MSDG production Installed by the Distribution Licensee on MSDG LV side	same as MSDG-2
Back-up (optional-customer) meter	N/A	N/A	CT and VT connected Separate registers for net energy export and import Installed by customer on MSDG HV side	same as MSDG-2
Commissioning	Distribution Licensee in the presence of Customer	Distribution Licensee in the presence of Customer	Distribution Licensee in the presence of Customer	same as MSDG-2
Instrument Transformers	Distribution Licensee approval required before ordering CTs and VTs Meter Laboratory tests before installation	Distribution Licensee approval required before ordering CTs and VTs Meter Laboratory tests before installation	Distribution Licensee approval required before ordering CTs, VTs Meter Laboratory tests before installation	same as MSDG-2
Accuracy Class (all meters)	Overall accuracy = 2.0	Overall Accuracy = 2.0 CT of production Meter = 1.0	meter (active power) = 0.5 meter (reactive power) = 1.0 CTs = 0.5 VTs = 0.5 (0.2 for green field projects)	all meters and instrument transformers = 0.2

Instrument transformers shall conform to the standard IEC 61869. The detailed use of these standards in the testing of meters are set out in the document *"Meter Testing Protocol for the Electricity Sector in Mauritius"*

The precise position of the meters shall be set out in the corresponding **Connection Agreement, IA, ESPA or PPA** between the **Single Buyer** and the **Distributed Generator**

For MSDG 3 installations, the **Distribution Licensee** shall inspect the **Main Meter, Back-Up Meter** and **Secondary Meters** (as applicable according to **Table 6**) upon installation and at least once every year thereafter, and shall also check the certification of these meters through an accuracy test at least once every 4 (four) years thereafter or at any time the kWh readings of these meters and the **Distributed Generator Back-Up Meter** (if applicable) differ by an amount greater than 0.5%.

For MSDG 3 installations, the **Distributed Generator** shall inspect the **Distributed Generator Back-Up Meter** (as applicable according to **Table 6** both upon installation and at least once every year thereafter, and shall also check the certification of these meters through an accuracy test at least once every 4 (four) years thereafter or at any time the kWh readings of this meter and the **Distribution Licensee's** meters differ by an amount greater than 0.5%.

DC 17.3.3 Parameters for Meter Reading

The **Distributed Generator** and the **Distribution Licensee** shall provide and install appropriate **Metering System** (according to **Table 6**) that shall make a continuous recording on appropriate magnetic media or equivalent of the **Net Energy Output** of the **Distributed Generation Facility** as well as the production of the **Gross Energy Output** of the **Distributed Generator**.

The parameters to be metered shall be subject to the **Connection Agreement, IA, ESPA or PPA** between the **Distributed Generator** and the **Single Buyer**, shall be stored cumulatively on the meter, shall be accessible to the **Distributed Generator** and may consist of but are not limited to any or all of the following parameters:

a. Active Energy (Wh) OUT;

b. Active Energy (Wh) IN;

c. Reactive Energy (VARh) First Quadrant;

d. Reactive Energy (VARh) Fourth Quadrant;

e. Active Power Demand (W) OUT;

f. Active Power Demand (W) IN;

g. Reactive Power Demand (VAR) First Quadrant;

h. Reactive Power Demand (VAR) Fourth Quadrant.; and

i. Total Harmonic Distortion

All units shall be expressed at appropriate multiples determined by the maximum expected Demand.

DC 17.3.4 Frequency of Meter Reading

The Demand Interval shall be thirty (30) minutes, or otherwise mentioned in the **ESPA, CA, IA** or **PPA** and shall be set to start at the beginning of the hour. Demand shall be calculated by averaging the respective parameters over the stated Demand Interval.

DC 17.3.5 Metering Responsibility (Distributed Generators)

It is the responsibility of **Distributed Generators** to cooperate with the **Distribution Licensee** and the **Single Buyer** in the execution of all its responsibilities under this

Code.

The costs for installation and replacement of meters shall be outlined in the **Connection Agreement, ESPA or PPA.**

DC 17.4 Metering Requirements - Users

DC 17.4.1 Overall Accuracy

The overall accuracy of the electromechanically-based metering systems for revenue purposes is to be designed to give a tolerance of +/- 1% when tested in the laboratory and +/- 2% when tested in the field and shall measure the electrical energy delivered to the **User** from the **Distribution System.**

For whole current meters (single phase supply) the overall accuracy will be ± 1%.

For CT connected meters, the overall accuracy will be as follows:

a) for LV connected meters: ± 1.5%, and
b) for MV connected meters: ± 1%.

DC 17.4.2 Relevant Metering Policies, Standards and Specifications

The meters, and associated installations, used on the **Distribution Licensee's Distribution System** shall comply with the following documents:

- Meter Testing Protocol for the Electricity Sector in Mauritius – document to be developed by URA;
- Other applicable policies, engineering instructions and procedures.

The meters shall be designed, constructed and operated to comply with the latest revision of the relevant IEC 62053 or international equivalent.

DC 17.4.3 Requirement for Metering

All **Interconnection Boundaries** to the **Distribution System** shall have appropriate metering in accordance with this **Code.**

DC 17.4.4 Metering Responsibility

It is the responsibility of the **Distribution Licensee** and the **Single Buyer** to ensure that all **Point of Deliveries** are metered in accordance with this **Code.**

It is the responsibility of **Users** to cooperate with the **Single Buyer** and **Distribution Licensee** in the execution of all its responsibilities under this **Code.**

The costs for installation and replacement of meters shall be outlined in the **IA, ESPA, CA or PPA.**

DC 17.5 Metering Equipment - Users

The metering Equipment shall consist of:

a. Revenue Meters;
b. Current and Voltage Transformers where applicable;
c. All interconnecting cables, wires and associated devices, seals and protection; and
d. All Equipment associated with Advanced Metering Infrastructure.

DC 17.5.1 Revenue Meters

The revenue meter shall have the appropriate rating for the interconnection requirements to be supplied and shall conform to the terms of the **IA, ESPA, CA or PPA** between the **Distribution Licensee** and the **User.**

User revenue meters shall have an accuracy class 2 or better.

At the **System Operator's or Distribution Licensee's,** discretion **Advanced Metering Infrastructure** may be installed at some **Customers** sites. This metering infrastructure enables two-way communication with the **Metering Systems**.

The relevant metered parameters, as required by the **Distribution Licensee** for billing purposes, shall be stored cumulatively on the meter

Where required these parameters may include any or all of the following depending on the interconnection and the tariff schedule:

a. kW Hours (delivered and received);

b. kVAR Hours (delivered and received);

c. kVA Hours (delivered and received);

d. Maximum Demand (30-minute period or otherwise mentioned in the **ESPA, IA, CA** or **PPA**)

e. Power Factor

The above parameters shall be measurable over intervals from 1 minute to 60 minutes.

DC 17.5.2 Voltage and Current Transformers

For **MV** connections, all **Voltage** and **Current Transformers** shall comply with IEC Standards or their equivalents and shall have an accuracy class 0.5 or better as the case may be.

For **LV** connections, all Voltage and Current Transformers shall comply with IEC Standards or their equivalents and shall have an accuracy class 1.0 or better as the case may be.

The burden in each phase of **Voltage** and **Current Transformers** shall not exceed the specified burden of the said Transformers.

DC 17.6 Point of Delivery (metering points)

DC 17.6.1 Whole Current Metering

For whole current meters (meters where the electrical current passes through the meter itself), the **Point of Delivery** should be as close as possible to the **Interconnection Boundary.**

DC 17.6.2 CT Metering

The **Point of Delivery** shall be at the position of the **Current Transformers** (CT) used for the metering System. This should be designed to be as close as possible to the **Interconnection Boundary.**

Current Transformers should be installed in a separate chamber and must be before the main switch (on the line side). They shall be housed in suitable concrete enclosures unless otherwise agreed with the **Distribution Licensee**, and be able to be secured.

Where the **Interconnection Boundary** is declared on the outgoing side of a high voltage circuit breaker the metering transformers may be accommodated in that circuit breaker unit.

Where appropriate the **Metering Point** should be at the same voltage as the **Interconnection Boundary.**

Where the **Point of Delivery** is at a lower voltage than the **Interconnection Boundary** then appropriate loss factors should be calculated to ensure any additional loss is appropriately accounted for.

DC 17.7 Meter Reading and Collection Systems

DC 17.7.1 Meter Reading and Recording Responsibility

It is the responsibility of the **Single buyer** to ensure that meters are read in accordance with the requirements of overall standard set out in its **License.**

Meter reading and recording shall be undertaken by a suitable authorized representative of the **Single Buyer.**

It is the responsibility of **Users** and **Distributed Generators** to cooperate with the **Single Buyer** in the execution of its responsibilities under this **Code.**

The **User** shall be provided with electronic access to its billing and consumption records on request as per the policy of the **Single Buyer.**

DC 17.7.2 Approval of Meters

Only meters that have received pattern approval from the Mauritius Bureau of Standards (MSB) in accordance with "Electricity Meter Testing in Mauritius - Protocol on Administrative and Testing Procedures", may be used on the **Distribution System**, unless indicated otherwise by the **Authority.**

DC 17.8 Calibration and Sealing

DC 17.8.1 Calibration

All meters should be calibrated at the factory to ensure they comply with published accuracy specifications.

The **Meter Laboratory** will only perform calibration of electro-mechanical meters and accuracy test for electronic meters. Calibration of electronic meters (if required) will be done only at the factory.

Electronic meters should be certified by the manufacturer for a guaranteed calibration period over the operational life of the meter. However, in case that a meter experiences an accuracy drift over time due to environmental or other unknown factors, it shall be sent back to the factory for re-calibration and certification.

In case a meter has exceeded the guaranteed calibration period given by the manufacturer, it should be sent for accuracy test as soon as practical. In case the accuracy test is not within standard limits, the meter shall be sent for calibration.

All laboratory calibration shall be undertaken in laboratories accredited by the Mauritius Accreditation Service (MAURITAS), unless indicated otherwise by the Authority,

DC 17.8.2 Traceability

The kilowatt hour standard used to calibrate electricity meters shall be traceable to a recognized national or international standard.

DC 17.8.3 Sealing

All meters shall be constructed to enable the meter unit to be sealed to prevent unauthorized access or interference with the Operation of the meter or the input terminals of the meter.

Seals applied on a meter after calibration shall be marked with the date of recalibration and serial number.

DC 17.9 Metering Disputes

DC 17.9.1 Meter Inaccuracy

If the **Metering System** is found to be inaccurate by more than the allowable error (as indicated in DC 17.3.1 and DC 17.4.1) and the **Single Buyer** and the **Distributed Generator/User** fail to agree upon an estimate for the correct reading within a reasonable time (as specified in the relevant **IA**, **ESPA, CA, PPA**) of the dispute being raised, then the matter may be referred for arbitration by either party in accordance with the relevant specified agreements.

DC 17.9.2 Meter Accuracy Check

A **User/Distributed Generator** has a right to request a meter accuracy check when they consider that the meter may be reading incorrectly in accordance with the "Meter Testing Protocol for the Electricity Sector in Mauritius"

User/Distributed has to request for an installation of a check meter when they consider that the meter may be reading incorrectly in accordance with the "Meter Testing Protocol for the Electricity Sector in Mauritius"

If after adequate period, there is any discrepancy noted between the check meter reading and meter reading, then a **User/Distributed Generator** has a right to request a meter accuracy check.

Should a **User/Distributed Generator** requests more than one accuracy check in a single calendar year, then the **Single Buyer** may charge for these additional checks should the accuracy be within ± 2%

DC 17.10 Inspection and Testing

DC 17.10.1 Maintenance Policy

The **Distribution Licensee** shall put in place and implement a policy for the inspection and testing and recalibration of all metering Equipment. This policy shall be in accordance with the procedures set out in sections DC 17.3.2 and DC 17.4.2.

DC 17.10.2 Maintenance Records

The **Distribution Licensee** shall keep all test results, maintenance program records and sealing records for a period of at least 5 years.

DC 17.10.3 Generator Metering

The **Distribution Licensee** and the **Distributed Generator** shall abide by the conditions of the **Distribution Code** that details the maintenance procedures to be applied in the case of **Distributed Generator** meters. The **Distribution Code** includes provisions on the use of back-up meters when metering inaccuracies are suspected and on the resolution of metering disputes.

DC 18 REQUIREMENTS FOR THE DISTRIBUTION SYSTEM OF RODRIGUES

This section establishes the minimum requirements to ensure an efficient, coordinated and economic development system for electricity distribution in Rodrigues.

The **Distribution Licensee** and the **Users** of the **Distribution System** of Rodrigues, including **Distributed Generators** and **Customers** shall comply with the requirements laid down in the **Distribution Code**, except for the sections specified in

DC 18.1 Exemptions from the Distribution Code

a. DC 3.2.2 (Planning Criteria)
b. SOC 9.4a (methods of Demand Control – System Operations Code)

DC 18.2 Rodrigues Distribution System Planning

DC 18.2.1 Planning criteria

The electric system of the outer island of Rodrigues is a small system comprising a few generators (combustion engines and also renewable energy). Electricity is distributed to the users of the island using a 22 kV system of feeders.

In general, the system of Rodrigues shall comply with the requirements of the **Distribution Code**, however due to its small size and its isolation with the main system in the island of Mauritius, a few exceptions are identified in this section of the Distribution Code for its application to the Rodrigues' system.

DC 18.2.2 Planning criteria

The **Distribution Licensee** shall adopt the following criteria to perform the **Distribution System** planning in Rodrigues:

a) Ensure feeders' and power transformers' loading under **Normal Conditions** is limited to 100% nominal rating.
b) A margin of at least 10 % of the **System Demand** shall be maintained for the **Spinning Reserve**.
c) In the event of a **Generating Unit Outage**, the remaining available **Generating Units** shall be able to satisfy the **System Demand**.

DC 18.2.3 Frequency Criteria

The **System Operator** shall maintain the **System** frequency in Rodrigues under **Normal Conditions** within the limit of 50 Hz ± 0.75 Hz.

In case of **Generation Outage**, the **System Operator** in Rodrigues may resort to the **Demand** control methods to contain the **Frequency** outlined in SOC 9.4 and DC 18.4.

DC 18.3 Security of Supply

The **System Operator** shall use reasonable endeavours to supply from the **System** all Customers connected to it. This cannot be ensured at all times, since faults, planned Maintenance and new works outages and other circumstances outside **System Operator** control can cause interruptions. On such occasions, the **System Operator** shall use reasonable endeavours to restore the supply or connection as soon as practicable but shall be under no liability for any direct or indirect damage or associated loss incurred by the **User**.

DC 18.4 Demand Control

DC 18.4.1 Shedding of Demand by Automatic Under-Frequency Relays

The **System Operator** shall use automatic **Demand** shedding by **Under Frequency Relays** to address short-term imbalances between the **Total System Generation** and **Demand**, following the tripping of **Generation** beyond the **Spinning Reserve** value.

The **Demand** of the **System** which is subject to automatic disconnection by **Under Frequency Relays** shall be split into discrete **MW** blocks. The number, location, size and the associated low frequency settings of these blocks shall be determined by the **System Operator** through dedicated electrical studies to be approved by the **Authority**.

A load shedding table specifying the pre-selected feeders to disconnect at each level shall be computed considering the most stringent conditions, including the tripping of a large **Generating Unit** at peak time and at minimum load conditions. After 2 activations of the **Under-Frequency Relays**, if feasible, the feeders on the first 2 levels shall be swapped with the feeders on the lower levels so as not to penalize the same **Customers** each time.

DC 18.5 Frequency response requirement for MSDG 2 and MSDG 3

MSDG 2 and **MSDG 3** in Rodrigues shall comply with the following frequency response requirements:

a) Each **Generating Station**, including **Synchronous** and **Power Park Stations**, must be capable of contributing to frequency control by continuous regulation of the **Active Power** supplied to the **System**.
b) Each **Generating Unit** or **Power Park Station** must be fitted with a fast-acting proportional frequency control device (or **Governor Control System**) and **Generating Unit** load controller or equivalent control device to provide frequency response under Normal and **Contingency** Conditions. In the case of a **Power Park Station** the frequency or speed control device(s) may be on the **Power Park Station** or on each individual **Power Park Generating Unit** or be a combination of both.
c) The frequency control device (or **Governor Control System**) in co-ordination with other control devices must control the **Generating Unit** or **Power Park Station Active Power** output with stability over the entire operating range of the **Generating Unit** or **Power Park Station**.
d) The frequency control device (or **Governor Control System**) must meet the following minimum requirements:
    i. Where a **Generating Unit** or **Power Park Station** becomes isolated from the rest of the **Total System** but is still supplying **Customers**, the frequency control device (or **Governor Control System**) must also be able to control **System** frequency below 52 Hz unless this causes the **Generating Unit** or **Power Park Station** to operate below its **Designed Minimum Operating Level** when it is possible that it may trip after a time. For the avoidance of doubt the **Generating Unit,** or **Power Park Station** is only required to operate within the **System** frequency range 47 - 52 Hz.
    ii. The frequency control device (or **Governor Control System**) must be capable of being set so that it operates with an overall **Governor Droop** between 4% and 8% for other units.
    For the avoidance of doubt, in the case of a **Power Park Station** the **Governor Droop** shall be applied to each **Power Park Generating Unit** in service.
    iii. In the case of all **Generating Units** or **Power Park Station** the frequency control device (or **Governor Control System**) **Dead Band** should be no greater than 0.05 Hz (for the avoidance of doubt, ±0.025 Hz).

DC 19 DISTRIBUTION DATA REGISTRATION

DC 19.1 Objective

The objective DC 19 is to:

a. List all the data to be provided by the Users to the **System Operator** and **Single Buyer** under the **Distribution Code**;

b. List all data to be provided by the **System Operator** and/or **Single Buyer** to the **Users** under the **Distribution Code**; and

c. List all data to be provided by **Distributed Generators** to the **System Operator** and **Single Buyer** and by the **System Operator** and/or **Single Buyer** to **Distributed Generators** under the terms of the **Distribution Code**.

DC 19.2 Scope

The **Parties** to which the provisions of DC 19 apply are:

a. **Distributed Generators**;
b. **Distribution Licensee** and
c. **Users** connected directly to the **Distribution System.**

DC 19.3 Data Categories and Stages in Registration

DC 19.3.1 General

Within the Data Registration Requirements each item of data is allocated to three categories.

a. System Planning Data as required by the Planning and Interconnection section of the Distribution Code;

b. Generation Planning Data as required by the **Generation Code**;

c. Operational Data as required by the **System Operator** and including the data required from Generators in accordance with the **System Operations Code** and the Scheduling and Dispatch provisions of the **Generation Code.**

DC 19.4 Procedures and Responsibilities

DC 19.4.1 Responsibility for Submission and Updating of Data

In accordance with the provisions of the **Distribution Code**, each **User** must submit the data summarized in the DC 20. For the purpose of this section, the **User** refers both to **Customers** and **Distributed Generators**, unless otherwise specified.

DC 19.4.2 Methods of Submitting Data

The data must be submitted to the **Distribution Licensee,** which shall thereafter be shared with **the Single Buyer** and **System Operator**. The name of the person at the **User** who is submitting each schedule of data must be included. The data may be submitted via a computer link if such a data link exists between a **User** and the **Distribution Licensee** or utilizing a data transfer media, such as USB drive, CD ROM, cloud technology, etc. after obtaining the prior written consent from the **Distribution Licensee.**

DC 19.4.3 Changes to Users Data

The **User** must notify the **Distribution Licensee** of any change to data which is already submitted and registered with the **Distribution Licensee** in accordance with each section of the **Distribution Code.**

The **Single Buyer** and the **System Operator** shall be informed of any change in **User**'s data.

DC 19.4.4 Data not supplied

If a **User** fails to supply data when required by any section of the **Distribution Code**, the **Distribution Licensee** shall estimate in collaboration with the **System Operator** and/or **Single Buyer**, if required, such data if and when, in the view of the **Distribution Licensee**, it is necessary to do so.

If the **Distribution Licensee** fails to supply data when required by any section of the **Distribution Code**, the **User** to whom that data ought to have been supplied, shall estimate such data if and when, in the view of that **User**, it is necessary to do so.

Such estimates shall, in each case be based upon data supplied previously for the same **Electrical Facilities** or upon corresponding data for similar **Electrical Facilities** or upon such other information as the **Distribution Licensee** or **Single Buyer** or

System Operator or that **User**, as the case may be, deems appropriate.

The **Distribution Licensee** shall advise a **User** in writing of any estimated data it intends to use relating directly to that **User Electrical Facilities** in the event of data not being supplied.

The **User** shall advise the **Distribution Licensee** in writing of any estimated data it intends to use in the event of data not being supplied.

DC 20 DATA SCHEDULES

DC 20.1 User System Data Schedule

Users of the **MV Distribution System**, including **Customers** and **Distributed Generators**, shall submit to the **Distribution Licensee** the information in the table below.

Data	Unit	Value
Operation Line Diagram		
Single Line Diagram showing all existing and proposed equipment and Apparatus and Interconnections together with equipment rating	Drawing	
Site Responsibility Schedules	Schedule	
Safety Coordinators	Text	
Reactive Compensation Equipment: For all reactive compensation equipment connected to the User System at 22kV and above, other than Power Factor correction equipment associated directly with a Customer Plant, the following details		
Type of equipment (e.g. fixed or variable)	Text	
Capacitive rating	MVAR	
Inductive rating	MVAR	
Operating range		
Details of any automatic control logic to enable operating characteristics to be determined	Test/Drawing	
Interconnection Boundary to the User System in terms of electrical location and System voltage	Text	
Switchgear: For all switchgear (i.e. circuit breakers, switch disconnectors and isolators) on all circuits Directly Connected to the Interconnection Boundary including those at production facilities		
Rated short-circuit breaking current		
Single-phase	kA	
Three-phase	kA	
Rated load breaking current		
Single-phase	kA	
Three-phase	kA	
MV Motor Drives		
Rated Active Power	MW	

Full Load Current	kA	
Means of starting	Text	
Starting Current	kA	
Motor torque/speed characteristics	Chart	
Drive torque/speed characteristics	Chart	
Motor plus drive inertia constant	kg.m2	
User Protection Data: Following details relates only to protection equipment which can trip, inter-trip or close any Interconnection Boundary circuit breaker or any System Operator circuit breaker		
A full description including estimated settings, for all relays and Protection systems installed or to be installed on the User System	Text	
A full description of any auto-reclose facilities installed on the User System, including type and time delays	Text/Drawing	
The most probable fault clearance time for electrical faults on any part of the User System Directly Connected to the Distribution System	s	
Transient Over-Voltage Assessment Data: When requested by the Distribution Licensee, each User is required to submit data with respect to the Interconnection Site as follows (undertaking insulation co-ordination studies)		
Bus bar layout, including dimensions and geometry together with electrical parameters of any associated current transformers, voltage transformers, wall bushings, and support insulators	Drawing	
Physical and electrical parameters of lines, cables, transformers, reactors and shunt compensator equipment Connected at that bus bar or by lines or cables to the bus bar (for the purpose of calculating surge impedances)	Table	
Specification details of connected directly or by lines and cables to the bus bar including basic insulation levels	Text	
Characteristics of over-voltage protection at the bus bar and at the termination of lines and cables connected at the bus bar	Text/Tables	
User Connecting System data: Circuit Parameters for all circuits for all Systems at 22 kV connecting the User System to the Distribution System, the following details are required relating to that Interconnection Boundary		
Rated voltage	kV	
Operating voltage	kV	
Positive phase sequence		
Resistance	ohm	
Reactance	ohm	
Susceptance	ohm	

Zero phase sequence		
Resistance	ohm	
Reactance	ohm	
Susceptance	ohm	

DC 20.2 Fault Infeed Data Schedule

The following information is required from each User who is connected to the **Distribution System** via an **Interconnection Boundary** where the **User System** contains **Distributed Generating Unit(s)** and/or motor loads.

Data	Unit	Value
Name of **Interconnection Boundary**	Text	
Symmetrical three-phase short circuit current infeed:		
At instant of fault	(kA)	
After sub-transient fault current contribution has substantially decayed	(kA)	
Positive sequence X/R ratio at instant of fault	(pu)	
Zero sequence source impedance values as seen from the Interconnection Boundary consistent with the maximum infeed above:		
Resistance (R)	(ohm)	
Reactance (X)	(ohm)	

DC 21 APPENDICES

DC 21.1 DC Appendix A: Site Responsibility Schedules

For the purpose of this section, the term **User** refers to both **Distributed Generators** and **Customers** connected to the **MV Grid**.

At all **Interconnection Sites** the following Site Responsibility Schedules shall be drawn up using the pro-forma attached or with such variations as may be agreed between the **Distribution Licensee** and **Users**, and in the absence of agreement the pro-forma attached shall be used:

i) Schedule of **MV Apparatus**

ii) Schedule of **Plant**, **LV Apparatus**, services and supplies;

iii) Schedule of telecommunications and measurements **Apparatus**.

Other than at **Generating Unit** and **Generating Station** locations, the schedules referred to in (ii) and (iii) above may be combined.

Each Site Responsibility Schedule for an **Interconnection Site** shall be prepared by the **Distribution Licensee** in consultation with other **Users** at least 2 weeks prior to the **Completion Date** for that **Interconnection Site**. Each **User** shall, in a timely manner, provide information to the **Distribution Licensee** to enable it to prepare the Site Responsibility Schedule.

Each Site Responsibility Schedule shall provide the following information for each item of **Plant** and **Apparatus**;

i. Item of **Equipment** using the agreed Numbering and Nomenclature in accordance with section DC 15.

ii. Equipment Owner - This identifies the party that owns the **Equipment** under common law;

iii. Safety Rules - This identifies whether the **Distribution Licensee**'s or **User's Safety Rules** shall be applied to the **Equipment**. The **Safety Rules** shall comply with relevant electricity regulations.

iv. Operational Procedures - This identifies whether **Distribution Licensee** or **Users** personnel shall be responsible for Operations on the **Equipment.** Note that if this is **Distribution Licensee**, it does not preclude the **Distribution Licensee** from authorizing **Users** personnel from acting on its behalf and vice versa.

v. Control responsibility - This field indicates whether the control of such item of **Plant** and **Apparatus** shall be the **Distribution Licensee** or the **User's** responsibility.

vi. Maintenance responsibility - This identifies whether the **Distribution Licensee** or the **User** is responsible for the inspection and maintenance of the **Equipment.**

vii. Access and security. This identifies whether the **Distribution Licensee** or the **User** shall be responsible for the establishment and maintenance of perimeter fencing and any manned access security for the protection of the public and to prevent malicious entry. Access to operational areas of the site shall be restricted to persons duly authorized in accordance with the prevailing **Safety Rules** and relevant electricity regulations.

The **MV Apparatus** Site Responsibility Schedule for each **Interconnection Site** must include lines and cables emanating from the **Interconnection Site**.

Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

When a Site Responsibility Schedule is prepared it shall be sent by the **Distribution Licensee** to the **Users** involved for confirmation of its accuracy.

The Site Responsibility Schedule shall then be signed on behalf of **Distribution Licensee** by the Manager or designated representative responsible for the area in which the **Interconnection Site** is situated and on behalf of each **User** involved by its Responsible Manager or designated representative, by way of written confirmation of its accuracy. Once signed, two copies shall be distributed by **Distribution Licensee**, not less than two weeks prior to its implementation date, to each **User** which is a party on the Site Responsibility Schedule, accompanied by a note indicating the issue number and the date of implementation.

DC 21.1.1 ATTACHMENT TO APPENDIX A: PRO FORMA FOR SITE RESPONSIBILITY SCHEDULE

COMPANY:

INTERCONNECTION SITE:

Item of Equipment	Equipment Owner	Safety Rules	Operational Procedures	Control responsible engineer	Maintenance Responsibility	Access and Security	Comments

Signed on behalf of the System Operator Date ...

Signed on behalf of the User.

DC 21.2 DC APPENDIX B: PROCEDURES RELATING TO OPERATION DIAGRAMS

DC 21.2.1 Basic Principles

Where practicable, all the **MV Apparatus** on any **Interconnection Site** shall be shown on one **Operation Diagram**. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the **Interconnection Site**.

1. Where more than one **Operation Diagram** is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.
2. The **Operation Diagram** must show accurately the current status of the Apparatus, e.g. whether commissioned or decommissioned. Where decommissioned, the associated switch bay shall be labelled "spare bay".
3. Provision shall be made on the **Operation Diagram** for signifying approvals, together with provision for details of revisions and dates.

Apparatus to be shown on **Operation Diagrams**

1. Bus bars
2. **Circuit Breakers**
3. Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)
4. Disconnectors (Isolators) - Automatic Facilities
5. Bypass Facilities
6. **Earthing** Switches
7. Maintenance Earths
8. Overhead Line Entries
9. Overhead Line Traps
10. Cable and Cable Sealing Ends
11. **Distributed Generating Unit**
12. **Distributed Generator** Transformers
13. **Distributed Generating** Unit Step Up Transformers, Station Transformers, including the lower voltage circuit-breakers
14. Synchronous Compensators
15. Static VAR Compensators
16. Capacitors (including Harmonic Filters)
17. Series or Shunt Reactors
18. System Transformers
19. Tertiary Windings
20. **Earthing** and Auxiliary Transformers
21. Three Phase VTs
22. Single Phase VT & Phase Identity
23. High Accuracy VT and Phase Identity
24. Surge Arrestors/Diverters

25. Neutral Earthing Arrangements on MV Plant
26. Arc Suppression Coils
27. Current Transformers (where separate Plant items)
28. Wall Bushings
29. Standby Generators and Automatic Change-over Switch

DC 21.2.2 Use of Approved Graphical Symbols

All graphical symbols to be used in **Operation Diagrams** shall be approved by the **System Operator**.

DC 21.3 DC APPENDIX C: SCADA INTERFACING

This appendix sets out the technical requirements for connections to the **Distribution Licensee**'s **SCADA** outstation in terms of electrical characteristics.

DC 21.3.1 General requirements

In all cases signals shall be arranged such that the level of electrical interference does not exceed those defined in IEC 60870-2-1: "*Telecontrol Equipment and Systems - Operating Conditions – Power Supply and Electromagnetic Compatibility*" and IEC60870-3: "*Telecontrol Equipment and Systems - Specification for Interfaces (Electrical Characteristics)*".

DC 21.3.1.1 Digital Inputs

Digital inputs cover both single and double points for connection to digital input modules on the **Distribution Licensee's** outstation **Equipment**. The **Equipment** contacts shall be free of potential, whereas the input circuitry of the outstation is common to the negative 48-volt potential.

DC 21.3.1.2 Single Points

Single point inputs must be used for alarms and where single contact indications are available. The off (contact open or 0) state is considered to be the normal state and the on (contact closed or 1) state the alarm condition.

DC 21.3.1.3 Double Points

Double points are used to indicate primary Plant states by the use of complementary inputs for each Plant item. Only the "10" and "01" states are considered valid with the "00" and "11" states considered invalid. The "10" state is considered to be the normal or closed state.

DC 21.3.1.4 Energy Meter Inputs

Energy meter input pulses for connection to pulse counting input modules on the **System Operator**'s outstation **Equipment** must operate for a minimum of 100ms to indicate a predetermined flow of MWh or MVARh. The contact must open again for a minimum of 100ms. The normal state of the input must be open.

DC 21.3.1.5 Analogue Inputs

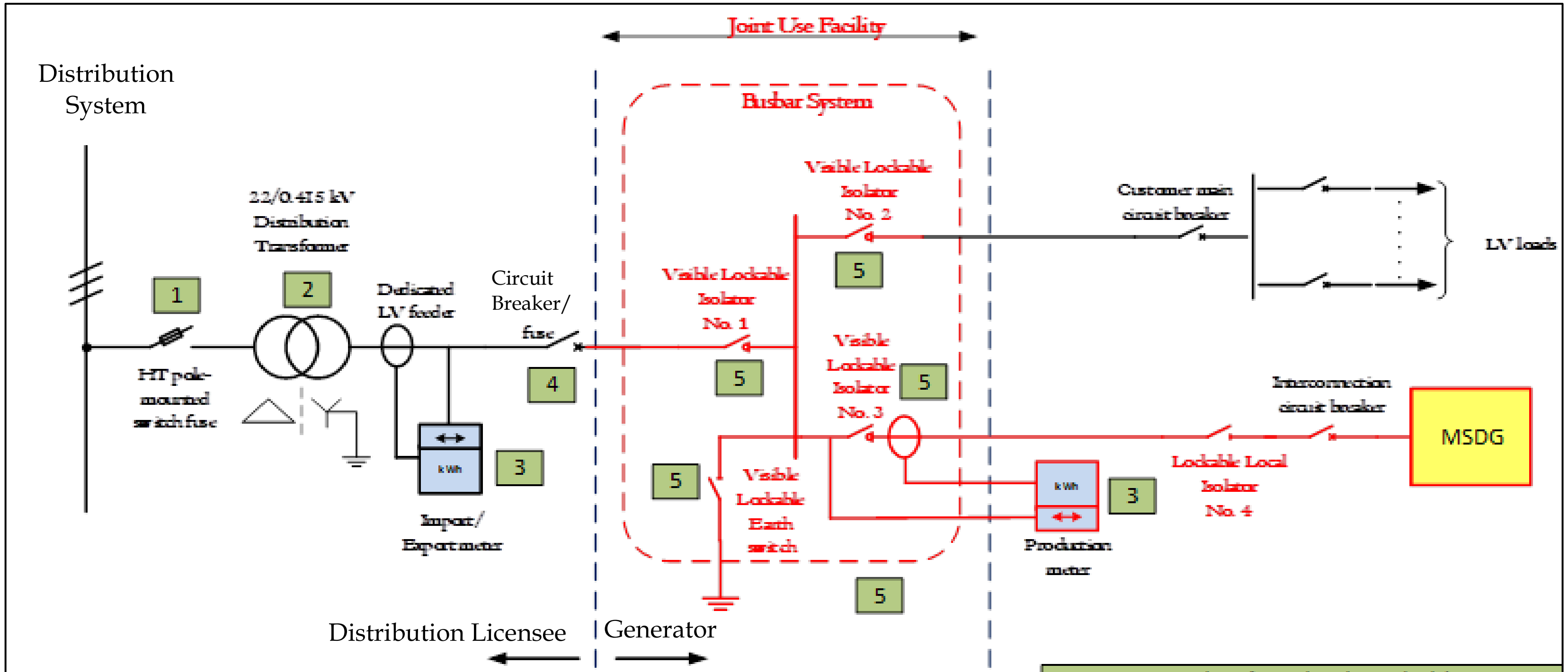
Analogue inputs for connection to analogue input modules on the **Distribution Licensee's** outstation **Equipment** must all be electrically isolated with a two-wire connection required. Signals shall be in the form of 4-20mA (or other range to be agreed between the **User** and the **Distribution Licensee**) for both unidirectional and bi-directional measured values. Signal converters shall be provided as necessary to produce the correct input signals.

DC 21.3.1.6 Command Outputs

All command outputs for connection to command output modules on the **Distribution Licensee**'s outstation **Equipment** switch both the 0 volts and 48 volts for a period of 2.5 seconds at a maximum current of 1 amp. All outputs shall electrically isolated with a two-wire connection to control interposing relays on the **Plant** to be operated.

DC 21.4 DC Appendix E: Typical interconnection diagrams

DC 21.4.1 Typical MSDG 1 interconnection layout



Notes

a) New busbar system shall be accessible to the Distribution Licensee on a 24 hours basis
b) Visible lockable isolator switches 2 and 3 shall be replaced by a lockable Circuit Breaker if the Distributed Generator Electrical Facilities are located far from the joint use facilities
c) All visible and lockable isolators shall be able to be operated on load
d) Interconnection Boundary refers to the terminals of the Distribution Licensee Circuit Breaker/fuse
e) The visible lockable isolator switch shall ensure absolute cut.

Location of Warning Sign and Stickers	
1	HT Pole on which the switch fuses are installed
2	Transformer Cabin Door
3	Meter Cabin and Box
4	Distribution Licensee Circuit Breaker or Fuse
5	Visible Lockable Isolator 1, 2,3 & Earth switch and o Joint Use Facility Cabin Door

Figure 4: Typical layout for MSDG 1.

DC 21.4.2 Typical Medium Voltage Switchgear Panel and Protection Guideline for MSDG 2 and MSDG3

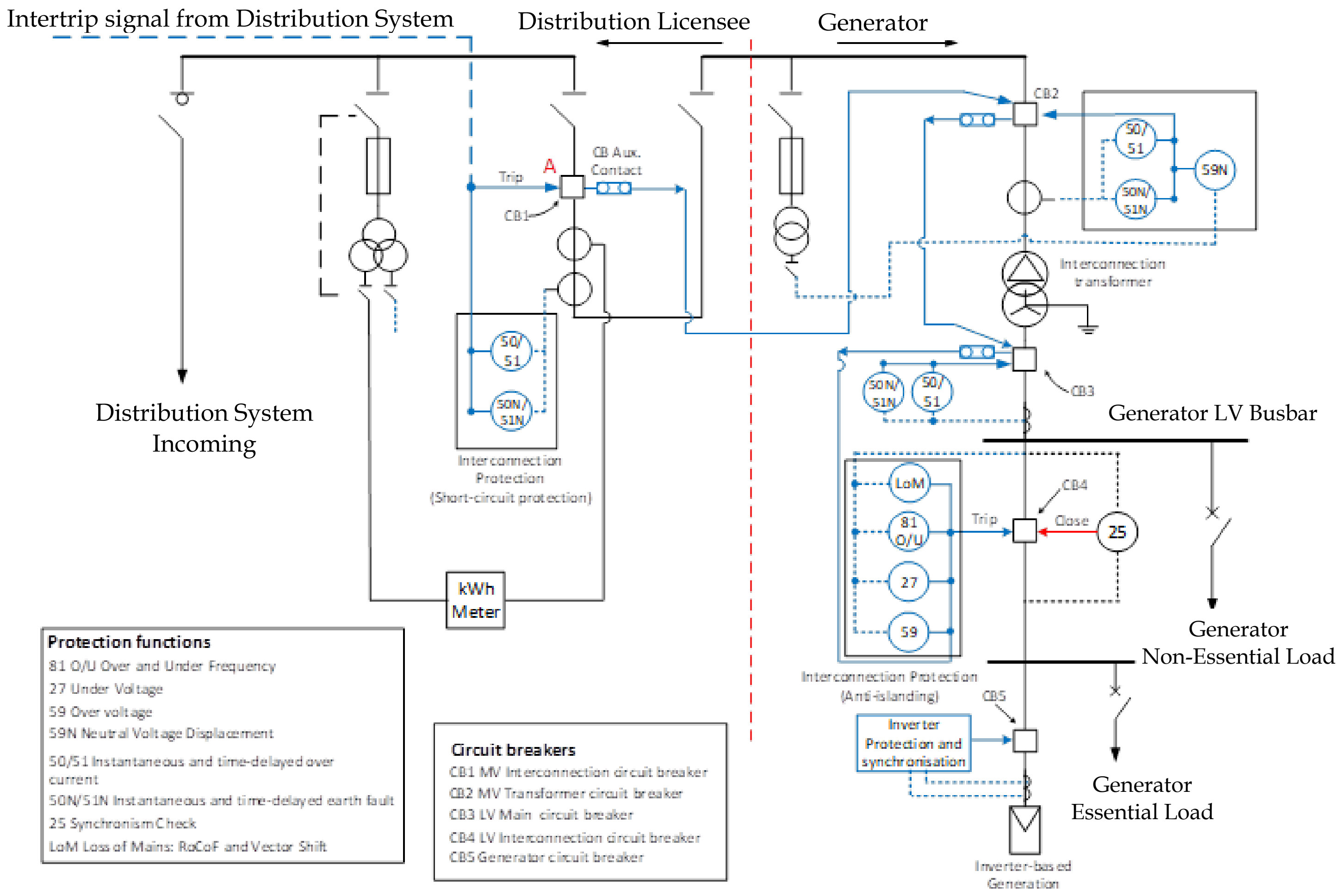


Figure 5: Typical layout for inverter-based MSDG 2 and MSDG 3.

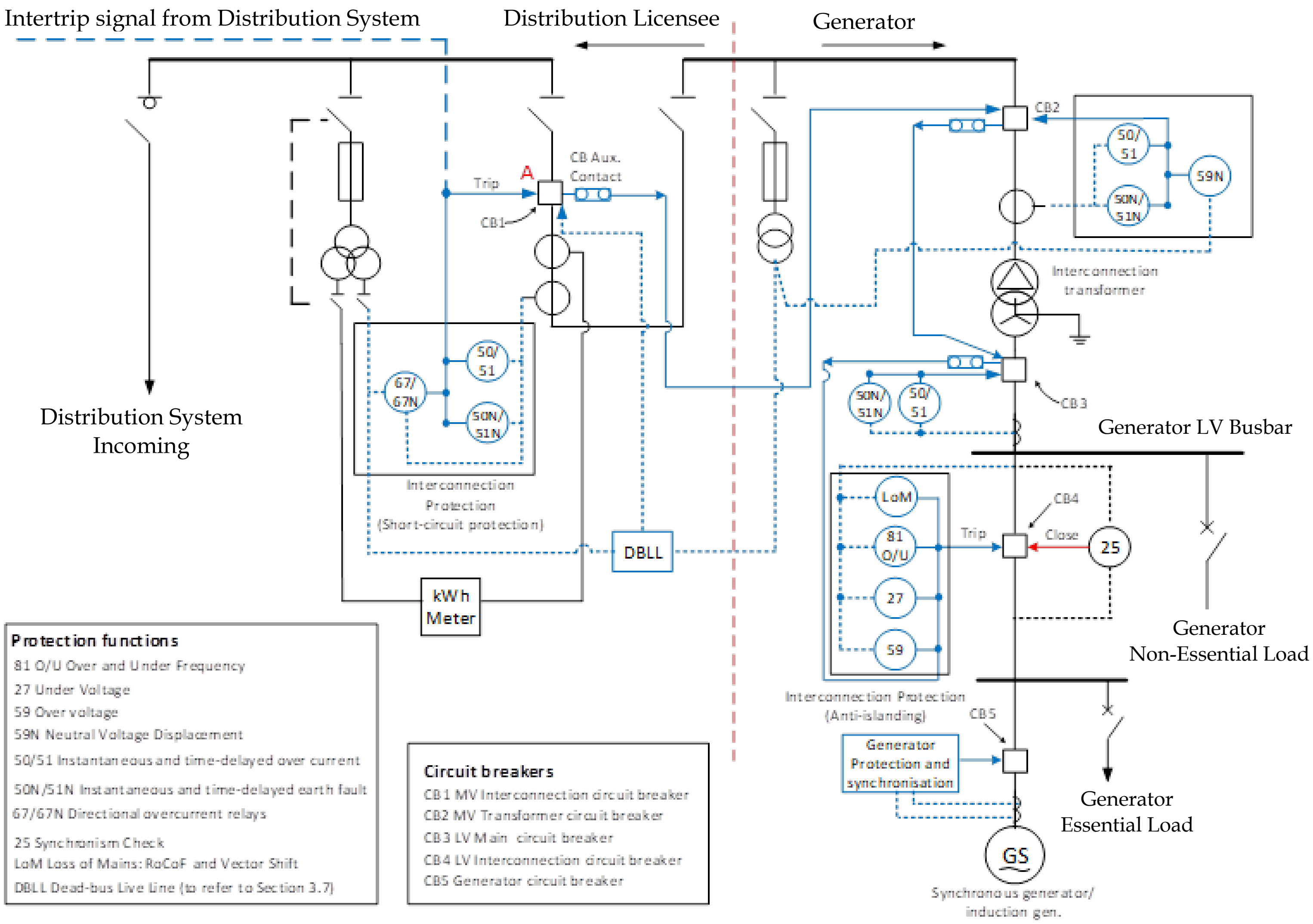


Figure 6: Typical layout for synchronous and induction machine based MSDG 2 and MSDG 3

Notes:

1. The above schematic diagrams refer to typical installations. The actual **Protection** and inter-tripping requirements may vary depending on the particular setup of the **Generating Station** under consideration.

2. The **Distributed Generator** is responsible for providing the appropriate **Protection** for its transformer and internal loads.

3. The inter-trip between **Distribution System** substation and the **Distributed Generating Station** is required for **Generating Stations** of **Registered Capacity** greater than 1 MW.

4. In case of synchronous and induction machine-based **Generating Units**:

    a. A Dead Bus Live Line (DBLL) relay is required to prevent electrical and remote closure of CB1 on an energised busbar.

    b. A key **Interlock** shall be provided between CB1 and all the **Generating Station** outgoing 22 kV **Circuit Breakers**. This **Interlock** shall prevent mechanical closure of CB1 as long as any of the **Generating Station** outgoing 22 kV **Circuit Breakers** is closed.

    c. The onus lies on the **Distributed Generator** to provide the required **Synchronism-Check Relay** on **Circuit Breakers** where there exists the possibility of closing the **Generating Unit** live on the **Distribution System.**

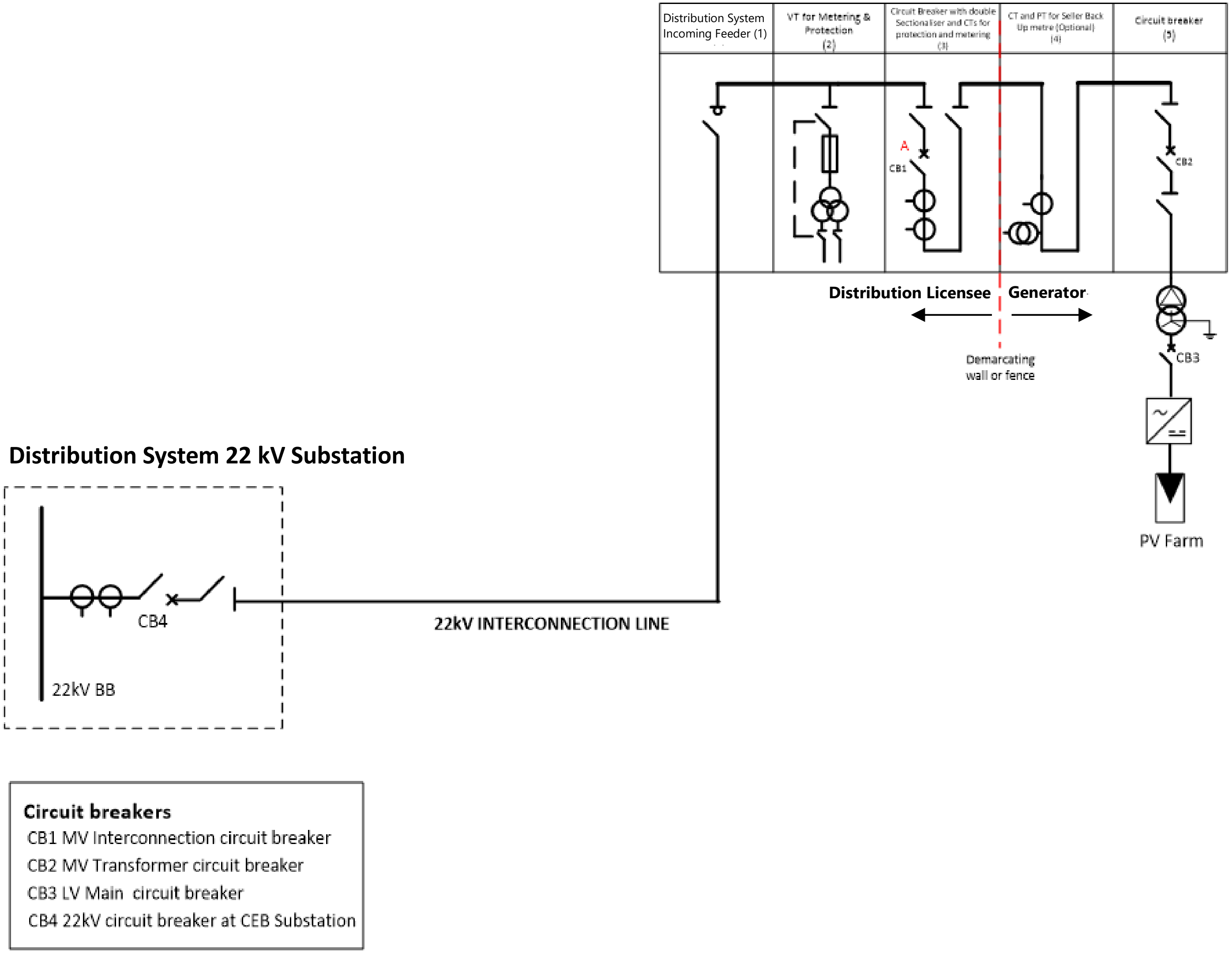


Figure 7: Typical layout for interconnection via dedicated line to a 22kV feeder panel (MSDG 3: above 4MW and up to 10MW)