ENERGY COMMISSION

NATIONAL ELECTRICITY DISTRIBUTION CODE

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Contents

PREFACE

The National Electricity Distribution Code is issued by the Commission in accordance with the regulations governing Electricity Supply and Distribution (Standard and Performance). This is in line with sections 56(1)(a)(iii) and (c)(ii) of the Commission Act, 1997 (Act 541), and is consistent with subsection (a) of section 49 of the Renewable Energy Act, 2011 (Act 832).

The primary purpose of the Distribution Code is to outline the responsibilities and obligations of Distribution Utilities, establishing the conditions they must adhere to in the discharge of their duties related to the distribution or sale of electricity under their respective licenses. The key objectives are to ensure a fair, transparent, non-discriminatory, safe, reliable, secure, and cost-efficient delivery of electrical energy.

Furthermore, the Distribution Code outlines the specific responsibilities of various stakeholders, including electricity retailers, bulk customers, customers, customer-generators, embedded generators, and variable Renewable Power Plants.

This maiden edition is designed to promote accountability, facilitate collaboration among stakeholders, and uphold the principles of a resilient, equitable, and sustainable electricity distribution system. Through adherence to the provisions outlined herein, Distribution Utilities can contribute to the achievement of broader societal goals, including energy security, economic development, and environmental stewardship.

Finally, users of the Distribution Code are highly encouraged to make submissions on any part that they consider needs improvement and refinement to assist in the establishment of a comprehensive framework that fosters accountability, reliability, and efficiency within the electricity distribution sector. Submission of any relevant comments and ideas in this regard should be forwarded to:

The Executive Secretary,
Energy Commission,
PMB, Ministries Post Office, Accra, Ghana
Email: info@energycom.gov.gh and
Telephones: (233-302) 813763, 813762 or 813756.

PART A: GENERAL PROVISIONS

SECTION 1: ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

Art. 1.01 ABBREVIATIONS

CA…………………..Connection Agreement

CAIDI………………Customer Average Interruption Duration Index

CDPR………………Consolidated Distribution Planning Report

DNPR………………Distribution Network Planning Report

DS…………………..Distribution System

DU…………………Distribution Utility

EMS………………...Energy Management System

EPA ....Environmental Protection Agency

ERP…………………Emergency Response Plan

ESP…………………Electricity Supply Plan

ERSL……………….Electricity Retail Sale License

ETC…………………Electricity Technical Committee

ETU…………………Electricity Transmission Utility

GMT………………..Greenwich Meridian Time

GPS ....Global Positioning System

GWh ....Gigawatt-hour or one billion (10^9) watt-hours of energy

ICC…………………Installation Completion Certificate

IEC ....International Electro-technical Committee

IPSMP………………Integrated Power Sector Master Plan

kVA…………………One thousand volt-amperes

kVar…………......... Kilovar, or one thousand volt-amperes of reactive power

kW................ ....Kilowatt or one thousand watts of active electric power

kWh ....Kilowatt-hour or one thousand watt-hours of electrical energy

MV………………….Medium Voltage

MVA………………..One million volt-amperes

MVar ....Megavar, one million volt-amperes of reactive electric power

MW ……………….. Megawatt, one million watts of active electric power

NITS…………………National Interconnected Transmission System

OEM…………………Original Equipment Manufacturer

OMP…………………Operation and Maintenance Plan

PCC………………….Point of Common Coupling

PPTC………………...Power Planning Technical Committee

PURC ....Public Utilities Regulatory Commission

P_{st}.................................Short-term Flicker severity

P_{lt}…………………….Long-term Flicker sensitivity

PV……………………Photovoltaic

RTU………………….Remote Terminal Unit

SAIDI………………..System Average Interruption Duration Index

SAIFI…………………System Average Interruption Frequency Index

SCADA…………..... ..Supervisory Control And Data Acquisition

SM……………………Safety Manual

SOM………………….Systems Operational Manual

STMP………………...Safety and Technical Management Plan

TCS…………………..Technical Conditions of Service

TDD………………….Total Demand Distortion

VAR ....Volt Amperes Reactive

VRPP………………..Variable Renewable Power Plant

DEFINITIONS

Art. 1.02 **DEFINITIONS**

Act means the Energy Commission Act, 1997 (Act 541),

Active energy means the electrical energy produced, flowing or supplied by an electric circuit during a time interval, being integral with respect to the time of the instantaneous active power measured in units of watthours or standard multiplies thereof

Active power means the rate at which active energy is supplied.

Apparent power means the square root of the sum of the squares of the active power and the reactive power

Asset Owner means a person who owns the whole or part of the Distribution system or any facility connected to the Distribution system.

Bi-directional meter means a meter that measures the active energy (Wh) flow in both directions (import and export) and displays both imported and exported energy in separate registers.

Bulk Customer means an entity authorised by the Commission to negotiate for the purchase of power from a wholesale supplier of power in the deregulated electricity market.

Customer Average Interruption Duration Index (CAIDI) means the average time taken for supply to be restored to a customer when an unplanned interruption has occurred and is calculated as the sum of the duration of each customer interruption, in hours, divided by the total number of customer interruptions (SAIDI divided by SAIFI). Unless otherwise stated, CAIDI excludes momentary interruptions.

Calendar year means the period from 1st January to 31st December of the same year

Commission means the Energy Commission

Connection Agreement means an agreement between a Distribution Utility and an entity that seeks connection of its facility to the Distribution system and sets out the rights, obligations and liabilities of both parties;

Customer Charter means a code of practice instituted by a Distribution Utility to improve access to its services and to promote quality by telling the customer the standards of service to expect and what to do if something goes wrong

Customer means a person or an entity that contracts to purchase electricity from a retailer

Customer-generator means any Customer of a Distribution Utility that generates electricity from a renewable energy source on the Customer's side of the billing meter that is primarily intended to offset part or all of the Customer's electricity consumption and may use a net metering system

Demand means the maximum amount of electrical power that is being consumed at a given time by a system or part of the system and is calculated as the square root of the sum of the squares of both active and reactive power unless otherwise stated;

Disconnection switching unit means a unit used to isolate an electrical circuit.

Distribution area means the area in which a Distribution Utility is licensed to distribute and supply electricity,

Distribution Code means National Electricity Distribution Code issued by the Commission in accordance with the regulations on Electricity Supply and Distribution (Standard and Performance), and furtherance to section 56(1)(a)(iii) and (c)(ii) of the Commission Act, 1997(Act 541) and in accordance with subsection (a) of section 49 of the Renewable Energy Act, 2011 (Act 832)

Distribution Utility means a person licensed under the Act to distribute electricity generally at nominal voltage levels of 36 kV or below without discrimination to customers in an area or zone designated by the Board of the Commission

Distribution licence means a licence granted under the Act to a person to distribute and supply electricity

Distribution losses mean electrical energy losses incurred in distributing electricity over a distribution system.

Distribution system means a system consisting of a network of electric feeders, transformers, service lines meters and other distribution switchgear generally at nominal voltage levels of 36 kV or below.

Electricity Retailer means a person licensed by the Commission to sell or offer electricity to a customer.

Embedded generator means an entity licensed by the Commission whose generating units (whether conventional or Renewable Energy) are directly connected to a distribution system and for which the total output of the facility is distributed and utilized locally without any requirements for the use of the NITS.

Emergency Response Plan (ERP) means a comprehensive document that plans for probable emergencies that involve the Distribution Utility employees, contractors, properties, equipment, and plants and prescribes appropriate responses or actions to the emergency situations.

Feeder means an electric line and associated equipment at a nominal voltage level of 36 kV and below, which a Distribution Utility uses to distribute electricity,

Force majeure means any event or circumstance which affects a Distribution Utility or a Customer and which is not within the reasonable control of the Distribution Utility or the customer, acting in accordance with Prudent Utility Practice, and which results in or causes the Distribution Utility or the customer to fail to perform any of its obligations.

Governor system means the automatic control system that regulates energy input into the turbine of an embedded generating unit.

Main Actors: The categories of main actors in this Distribution Code are:

(a) Distribution Utilities,

(b) Electricity Retailers,

(c) Embedded Generators (Dispatchable),

(d) Variable Renewable Power Plant (VRPP),

(e) Customer-generator,

(f) Bulk Customers, and

(g) Customers of Distribution Utility and Electricity Retailer.

Major Fault means a fault that requires capital equipment to fix or remedy, such as substation blasts, cable blasts, damaged transformers, damaged switchgear etc.

Minor Fault means a fault that requires minimal capital equipment, such as a blown substation LV fuse, jumper cut, blown aerial fuse etc.

Metering Code means National Electricity Distribution Metering Code developed by the Commission which sets out the minimum acceptable standards and technical and operational rules for persons involved in the procurement, installation, operation and maintenance of metering systems for the electricity distribution sector in Ghana.

Momentary interruption means any forced interruption to a delivery point lasting less than 1 minute

Net Metering means a methodology under which electrical energy is generated by a Customer-generator and delivered to a Distribution Utility's facility as measured by an appropriate device to offset electric energy supply by the Distribution Utility's facility to the Customer-generator during the applicable billing period.

Net-Metering Code means a document developed in accordance with the provisions of the Renewable Energy Act 2011, (Act 832) to provide guidelines and technical connection conditions for the interconnection of renewable energy generating facilities to the low voltage distribution network.

Net-metered generator means a Customer-generator to whom net metering has been made available by a Distribution Utility

Outage means a scheduled or unexpected period in a power system, during which a facility or component ceases to provide its full functioned capability and in relation to a generation unit, a total or partial reduction in availability such that the generation unit is unavailable to achieve its full registered megawatts capacity in accordance with its registered operating characteristics.

Person means a body corporate, whether corporation aggregate or corporation sole and an unincorporated body of persons as well as an individual.

Point of common coupling means the nearest point in a Distribution Utility's distribution system that connection is made between:

(a) the Distribution Utility's distribution system and another Distribution Utility's distribution system; or
(b) two or more customers' electrical installations, or
(c) the Distribution Utility's distribution system and a Customer's electrical installation or
(d) the Distribution Utility's distribution system and an Embedded Generator's network.

Power factor means the ratio of **active power** to **apparent power**.

Reactive energy means the integral with respect to the time of the instantaneous reactive power produced, flowing or supplied by an electric circuit during a time interval measured in units of Varh or standard multiples thereof;

Reactive power means the rate at which **reactive energy** is **supplied.**

Renewable energy generating facility means an electrical energy generation system that uses renewable energy resources as defined in the Renewable Energy Act, 2011 (Act 832), with an inverter facility that is electrically connected directly to a low voltage distribution system and for which the total output of the facility is distributed and utilised locally

Retail Sale licence means a licence granted under the Act to authorise the procurement of electricity from a wholesale supplier and sale to a consumer without discrimination in an area or concession designated in the license

Rural means an operational district with a customer population of under Five thousand (5000) and a demand below Fifty (50) MW

System Average Interruption Duration Index (SAIDI) means the total duration, on average, that a **customer** could expect to be without electricity over a specific period of time, and is calculated as the sum of the duration of each customer interruption**,** in hours, divided by the total number of connected customers averaged over the year.

System Average Interruption Frequency Index (SAIFI) means the number of times per year when each **customer** could, on average, expect to experience an unplanned interruption, calculated as the total number of customer interruptions divided by the total number of connected customers averaged over the year. Unless otherwise stated, SAIFI excludes momentary interruptions.

System Operational Manual means a document that guides the employees of a Distribution Utility to perform their functions correctly according to stipulated standards.

Safety Manual means a document that guides the employees of a Distribution Utility to comply with the industry-accepted safety standards.

Significant incident means any occurrence of a non-routine event which is inconsistent with standards and practice and has or has the potential to jeopardise the distribution network such as force majeure situations, bulk supply and primary substation faults, transformer failures and sub-transmission network failures.

Urban means an operational district with a customer population of more than Five thousand (5000) and a demand above Fifty (50) MW

Variable Renewable Power Plant means a renewable power plant with continuously varying power output following the availability of primary energy without any storage.

Voltage means (except in the case of impulse voltage) the root mean square (RMS) of the phase-to-phase voltage.

Wholesale Supplier means a person licensed under the Commission Act, 1997 (Act 541) to install and operate a facility to procure or produce electricity for sale to a bulk customer or a Distribution Utility for distribution and sale to consumers

SECTION 2: PURPOSE AND SCOPE

PURPOSE AND SCOPE

Art. 2.01 This National Electricity Distribution Code, hereafter referred to as the Distribution Code, is issued by the Commission in accordance with the regulations on Electricity Supply and Distribution (Standard and Performance), and in furtherance to sections 56(1)(a)(iii) and (c)(ii) of the Commission Act, 1997(Act 541) and in accordance with subsection (a) of section 49 of the Renewable Energy Act, 2011 (Act 832).

Art. 2.02 The Distribution Code defines the responsibilities and obligations of Distribution Utilities and sets out the conditions that they must meet in carrying out their obligations to distribute or sell electricity under its licence for fair, transparent, non-discriminatory, safe, reliable, secure and cost-efficient delivery of electrical energy.

Art. 2.03 The Distribution Code also provides for the responsibilities of:

(a) Electricity retailers,
(b) Bulk customers and customers,
(c) Customers-generators,
(d) Embedded generators, and
(e) Variable Renewable Power Plants.

STRUCTURE OF THE DISTRIBUTION CODE

Art. 2.04 The Distribution Code is divided into four parts as follows:

a. Part A covers the General Provisions that contain the purpose and scope of the Distribution Code, a definition of roles, responsibilities, and arrangements for the management and governance of the Distribution Code.

b. Part B defines the Conditions of the Distribution Licence. In addition, this Part contains connection arrangements, rights, and the requirements for transparency and non-discrimination.

c. Part C states the Responsibilities of Distribution Utilities and the responsibilities of the distributor, which include planning requirements, system operations, scheduling, and safety.

d. Part D states the responsibilities of the various actors under the Distribution Code.

Art. 2.05 Nothing in this Distribution Code precludes the application of evolving technologies and processes as they become available.

SECTION 3: APPLICATION OF THE DISTRIBUTION CODE

MAIN ACTORS

Art. 3.01 Unless otherwise stated in a licence or a Distribution Code issued under the Commission Act, 1997 (Act 541) or the Renewable Energy Act, 2011 (Act 832) this Distribution Code applies to all transactions and interactions between all the main actors.

Art. 3.02 All main actors shall comply with this Distribution Code and all the requirements of relevant laws, codes, and Prudent Utility Practices.

Art. 3.03 This Distribution Code and all other relevant laws and codes shall be fairly and uniformly applied to all classes within a category of main actors.

SECTION 4: ADMINISTRATION OF THE DISTRIBUTION CODE

PURPOSE AND SCOPE

Art. 4.01 This section deals with the implementation of this Distribution Code and the arrangement for the management and governance of a distribution system.

ROLE OF THE ELECTRICITY TECHNICAL COMMITTEE (ETC) OF THE COMMISSION

Art. 4.02 The authority for the implementation of this Distribution Code and the arrangement for the management and governance of a distribution system shall lie with the Electricity Technical Committee (ETC) of the Commission

Art. 4.03 The role of the ETC with regard to the operation of a distribution system shall be to ensure compliance with this Distribution Code by all main actors in the distribution system. To perform this role, the ETC shall have the power to oversee all technical functions, operations, activities, and transactions of the main actors and supervise their performance towards ensuring the fulfilment of their roles as required under this Distribution Code.

Art. 4.04 In fulfilment of Art. 4.02 and Art. 4.03, the ETC shall perform the following functions:

(a) Supervise the Distribution Utilities in the implementation of all their technical functions, operations, activities, and transactions and oversee all operations and activities on their distribution systems to ascertain compliance with this Distribution Code;

(b) Review and assess regularly the following:

(i) the performance of the Distribution Utilities and their distribution systems,

(ii) the extent of compliance with rules and regulations by main actors,

(iii) fairness and non-discrimination in all operational activities in the distribution systems and on the part of main actors;

(c) Consider, investigate, assess, and advise the Distribution Utilities and the Commission as appropriate on the following issues:

(i) the non-compliance of the main actors to this Distribution Code,

(ii) proposals for the revision of the Distribution Code, and the procedures, practices, rules or regulations covering the distribution systems,
(iii) distribution system development strategies and plans,
(iv) distribution system Standards of Performance and penalties, and
(v) any distribution system-related complaints;

(d) Establish procedures for the resolution of disputes concerning the provisions of this Distribution Code among main actors; and

(e) Perform any other functions conferred on it by this Distribution Code

REVISION OF DISTRIBUTION CODE

Art. 4.05 A main actor may make a proposal for the revision of any provision of this Distribution Code.

Art. 4.06 A proposal for the revision of this Distribution Code shall be in writing and sent to the Commission with a copy to the Distribution Utilities.

Art. 4.07 The Commission shall receive, register, and acknowledge every submission for revision of this Distribution Code

Art. 4.08 The Commission shall notify the main actors and the Distribution Utility of every proposal received and make copies accessible to them either over the Internet or through other appropriate means.

Art. 4.09 A main actor shall, within sixty days of the receipt of a revision proposal sent to it by the Commission, provide the Commission and the Main Actor making the proposal with its views.

Art. 4.10 The Commission shall, in consultation with the ETC, consider every proposal and the comments of all main actors and inform all the respective main actors within thirty days of its decision with written justifications.

CONDUCT OF A DISTRIBUTION UTILITY

Art. 4.11 A Distribution Utility, which has the exclusive mandate to operate its distribution system, shall be responsible for the good governance and management of its distribution system in accordance with this Distribution Code and guided at all times by generally accepted best practices.

Art. 4.12 The Distribution Utility shall not accept any directions or instructions that may have the effect of subverting the fundamental principles of fairness, transparency, non-discrimination and open access in the governance and management of its distribution system.

Art. 4.13 The Distribution Utility shall prepare a quarterly report of its activities and make it available for the information of all Main Actors and other stakeholders.

Art. 4.14 The Distribution Utility shall be accountable to the Commission for the performance of its distribution system and compliance with the letter, spirit, and intent of this Distribution Code.

REPORTS, COMPLAINTS AND DISPUTE RESOLUTION PROCEDURES

Art. 4.15 A main actor may submit a report in writing to the Commission where it believes that the rules, regulations or procedures of this Distribution Code are not being administered fairly.

Art. 4.16 A main actor may also report in writing to the Commission, where it believes that a Distribution Utility or another main actor is not acting in accordance with this Distribution Code.

Art. 4.17 The Commission shall receive, register, and acknowledge in writing all such reports.

Art. 4.18 The Commission shall promptly notify the relevant parties to the report and the Distribution Utility of the receipt of such a report and make copies of the reports accessible to them either over the Internet or through other appropriate means.

Art. 4.19 An affected party shall, within one month of the receipt of a report, provide the reporting entity, the Distribution Utility, and the Commission with its views, comments, and responses to the report.

Art. 4.20 The Commission shall forward all complaints received from a customer of a Distribution Utility, reporting of not receiving value for money from the Distribution Utility, to the PURC for resolution.

Art. 4.21 A dispute that arises under this Distribution Code shall be settled at the first instance by negotiation between the parties.

Art. 4.22 Where the dispute cannot be resolved by negotiation, the parties shall refer the matter to the ETC for mediation.

Art. 4.23 Where the mediation fails, the matter shall be referred to the Board of the Commission which shall set up an arbitration panel under the Alternative Dispute Resolution Act, 2010 (ACT 798) to settle the dispute.

Art. 4.24 Where a Main Actor is dissatisfied with the decision of the arbitration panel, the Main Actor may pursue the matter in Court.

PART B:
CONDITIONS OF A DISTRIBUTION LICENCE

SECTION 5: TRANSPARENCY AND NON-DISCRIMINATION REQUIREMENTS

PUBLICATION OF PROCEDURES

Art. 5.01 A Distribution Utility shall develop and publish in detail all technical requirements and administrative procedures to be fulfilled or followed by those seeking to be provided with service by the Distribution Utility.

Art. 5.02 The technical requirements shall include all technical standards for connection equipment, communication, operating parameters, and performance benchmarks for service provision.

Art. 5.03 The administrative procedures shall include all legal, financial, and any other relevant processes to be followed prior to the commissioning of the connection and the obligations of a main actor for the continued provision of the service.

Art. 5.04 The Commission shall publish this Distribution Code on its website and make readily available to the public copies of this Distribution Code and all related publications upon the payment of a published fee.

EXERCISE OF DISCRETION BY DISTRIBUTION UTILITIES AND OTHER OFFICIALS

Art. 5.05 A Distribution Utility or any other main actor shall not decide that, is inconsistent with this Distribution Code in respect of the usage or provision of services from the distribution system.

Art. 5.06 A Distribution Utility shall use its discretion and good judgment in making decisions on any matter in which this Distribution Code does not contain complete or adequate stipulations.

Art. 5.07 The exercise of discretionary power shall, however, be justified in writing to both the Commission and the affected party that such a decision has been taken.

Art. 5.08 The principles and rationale for any discretion exercised or decision taken by the Distribution Utility shall be published on its website and made available to any person upon request.

Art. 5.09 A person aggrieved by a discretionary decision taken by a Distribution Utility may request a review by the Commission or PURC as necessary

FEES AND CHARGES FOR DISTRIBUTION SERVICE

Art. 5.10 Fees and charges for the use of a distribution system or the services of a Distribution Utility service shall comply with those approved by the PURC and as published in the Gazette or national dailies.

PROVISION OF INFORMATION

Art. 5.11 A Distribution Utility shall communicate general market and educational information to its main actors connected to its distribution system as required by the Commission.

Art. 5.12 A Distribution Utility shall, in addition to informing all other main actors about their obligations to the Distribution Utility, monitor and require compliance to ensure that every main actor is meeting its obligations.

Art. 5.13 A Distribution Utility shall inform all other main actors about the Distribution Utility's rights to disconnect service.

Art. 5.14 At the request of a customer, a Distribution Utility shall provide a list of Electricity Retailers who have service agreements in effect with the Distribution Utility.

Art. 5.15 Upon receiving an inquiry from a customer connected to its distribution system, the Distribution Utility shall either respond to the inquiry if the customer deals with the Distribution Utility's distribution service or provide the customer with contact information for the entity responsible for the item of inquiry.

SECTION 6: LIABILITY

Art. 6.01 A Distribution Utility shall only be liable to a customer for any damages which arise directly out of the wilful misconduct or negligence of the:

(a) Distribution Utility in providing distribution service to the customer; or

(b) Distribution Utility in meeting its respective obligations under this Distribution Code, their licences and any other applicable law.

Art. 6.02 A customer shall only be liable to a Distribution Utility for any damages which arise directly out of the wilful misconduct or negligence of

(a) An action of the customer in being connected to the Distribution Utility’s network; or

(b) The customer in meeting its respective obligations under this Distribution Code, their licences and any other applicable law.

Art. 6.03 A Distribution Utility shall educate its customers on the use of appropriate equipment or arrangement in the circumstance to control loss or damage, which may result from poor quality or reliability of electricity supply within its distribution system.

Art. 6.04 A customer shall be liable to the Distribution Utility for any loss or damage resulting from the use of electricity in a manner that will make the Distribution Utility’s system unsafe.

SECTION 7: FORCE MAJEURE

Art. 7.01 If a force majeure event prevents a main actor from performing any of its obligations under this Distribution Code, the main actor shall:

(a) Immediately notify the main actor affected by the force majeure of the force majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing without delay.

(b) Not be entitled to suspend the performance of any of its obligations under this Distribution Code to any greater extent or for any longer time than the force majeure event and its effect requires it to do;

(c) Use its best efforts to mitigate the effects of the force majeure event, remedy its inability to perform and resume full performance of its obligations as soon as possible;

(d) Keep the other main actor continually informed of the efforts to mitigate the effects of the force majeure event;

(e) Notify the other main actor when it resumes the performance of any of its obligations affected by the force majeure event.

Art. 7.02 Neither party shall be held to have breached any obligation under this Distribution Code if prevented from performing that obligation, in whole or in part, because of a force majeure event.

SECTION 8: TECHNICAL CONDITIONS OF SERVICE

ESTABLISHMENT OF TECHNICAL CONDITIONS OF SERVICE (TCS)

Art. 8.01 A Distribution Utilities shall develop Technical Conditions of Service (TCS) that shall be consistent with the provisions of this Distribution Code and all other applicable codes and legislations approved by the Commission.

Art. 8.02 The Technical Conditions of Service shall describe the operating practices and connection policies of the Distribution Utility.

Art. 8.03 Subject to this Distribution Code and other applicable laws, a Distribution Utility shall comply with its Technical Conditions of Service but may waive a provision of its Technical Conditions of Service in favour of a customer or a potential customer with the approval of the Commission.

Art. 8.04 A Distribution Utility's Technical Conditions of Service shall include, at minimum, a description of the following:

(a) The types of connection service performed by the Distribution Utility for each customer class, and the conditions under which these connection services would be performed;
(b) The Distribution Utility's basic connection service;
(c) The Distribution Utility's capital contribution policy by customer class for an offer to connect, including procedures for the payment of capital contribution;
(d) The demarcation point at which the Distribution Utility's ownership of distribution equipment ends at the customer's premises;
(e) The design requirements for connection to the distribution system;
(f) The voltages at which the Distribution Utility provides electricity and corresponding load thresholds;
(g) The type of meters provided by the Distribution Utility;
(h) The quality of service standards to which the distribution system is designed and operated;
(i) The conditions under which supply may be unreliable or intermittent;
(j) The conditions under which service may be interrupted;

(k) The conditions under which the Distribution Utility may disconnect a customer;
(l) The policies for planned interruptions;
(m) The Distribution Utility's rights and obligations with respect to a customer;
(n) The rights and obligations a customer or embedded generator has with respect to the Distribution Utility;
(o) The Distribution Utility's limitations in accordance with this Distribution Code;
(p) The Distribution Utility's dispute resolution procedure; and
(q) The terms and conditions under which the Distribution Utility provides other services in its capacity as a Distribution Utility.

Art. 8.05 A Distribution Utility shall:

(a) file a copy of its Technical Conditions of Service with the Commission and the PURC;
(b) publish its Technical Conditions of Service as part of its application procedures and other forms of communication where applicable; and
(c) make copies of its Technical Condition of Service available on its website.

Art. 8.06 A Distribution Utility's Technical Conditions of Service shall be deemed to meet the standards set out in this Distribution Code for a period of one year following the coming into force of this Distribution Code, after which date the Distribution Utility shall revise the existing Technical Conditions of Service to fully comply with this Distribution Code.

Art. 8.07 A Distribution Utility shall enter into a Connection Agreement (CA) with a customer connected to the Distribution Utility's distribution system and shall be deemed to be a Wholesale Electricity Market participant.

Art. 8.08 A Distribution Utility shall make every reasonable effort to respond promptly to a person's request for connection in accordance with the relevant rules and regulations established by the Commission.

Art. 8.09 A Distribution Utility shall be deemed to have a contract with any person that is connected to the Distribution Utility's distribution system and receives distribution services from the Distribution Utility.

Art. 8.10 The terms of the implied contract in Art. 8.09 shall be as embedded in the Distribution Utility's Technical Conditions of Service, the Distribution

Utility's rate schedules, the Distribution Utility's licence, and this Distribution Code.

Art. 8.11 The responsibilities to the person in Art 8.09 do not apply to the connection or operation of the person's emergency backup generation facility.

Art. 8.12 A Distribution Utility shall enter into a Connection Agreement with all existing generators that have a generation facility connected to the Distribution Utility's distribution system prior to connecting a new generation facility.

Art. 8.13 Where a Distribution Utility does not have a Connection Agreement with an existing generator that has a generation facility connected to the Distribution Utility's distribution system, the Distribution Utility shall be deemed to have a contract with the generator. The contract that is deemed to exist shall be formalized with a Connection Agreement (CA) within ninety days.

Art. 8.14 A Distribution Utility shall ensure that all embedded generators provide relevant communication and data acquisition systems linked to the Distribution Utility's Supervisory Control and Data Acquisition (SCADA) system.

PART C:
ROLES AND RESPONSIBILITIES OF DISTRIBUTION UTILITIES

SECTION 9: ROLES OF THE DISTRIBUTION UTILITY

GENERAL ROLES OF THE DISTRIBUTION UTILITIES

Art. 9.01 The roles of a Distribution Utility shall include the following:

(a) The operation of all its distribution system equipment, installations, and facilities in accordance with the operational instructions for the respective equipment or in accordance with this Distribution Code and Prudent Utility Practices;

(b) The provision of open, fair and non-discriminatory access and connection to the distribution system for all licensed or permitted main actors in accordance with the regulations and provisions of this Distribution Code

(c) The performance of all the planning functions related to the distribution system;

(d) Making the necessary recommendations for transmission or distribution system expansion projects to adequately meet the forecast requirements for demand growth and customer reliability standards;

(e) Undertaking outage planning and coordinating maintenance activities of all equipment and facilities that will or are likely to impact the reliability of the distribution system;

(f) The planning, development, supply, installation, commissioning, and maintenance of adequate central SCADA/EMS systems together with any necessary associated backup systems, telecommunication systems and the coordination of their expansion and upgrade;

(g) The planning, development, installation, and maintenance of remote terminal units at substations and the coordination of their upgrade;

(h) Investigation and review of each major power system fault and the issuance of the relevant reports;

(i) Provision, installation, operation and maintenance of the revenue meters of the distribution system;

(j) Administering power supply and power purchase agreements;

(k) The real-time monitoring and recording of electric power and energy balance and the performance of the accounting and billing function for the distribution system supply and services;

(l) The development of a System Operational Manual (SOM) and a Safety Manual (SM) for the coordinated and safe operation of the distribution system;

(m) The development, planning, and implementation of demand-side management (DSM) or demand-side response (DSR) programs, including the modification of consumer demand for energy through various methods such as financial incentives and behavioural change through education,

(n) supervising and ensuring adherence to the Safety Manual by the main actors,

(o) Collation of information and statistics, publication of reports, and dissemination of information relating to its distribution system's performance to stakeholders; and

(p) Maintaining a register of all generators and customers connected to its networks. As a minimum, the register shall contain the name of the original owner or the person who has a relevant connection agreement with the Distribution Utility.

SECTION 10: PLANNING REQUIREMENTS

REQUEST FOR INFORMATION

Art. 10.01 A Customer, Embedded Generator, or Retailer shall, on request from a Distribution Utility, provide details of loads connected or loads to be connected to the distribution system of the Distribution Utility, which is required by the Distribution Utility to plan the distribution system.

Art. 10.02 A Distribution Utility shall, on request from another Distribution Utility, provide information concerning a Point of Common Coupling (PCC) as the other Distribution Utility may reasonably require for the integrated planning of the system.

DISTRIBUTION NETWORK PLANNING REPORT (DNPR)

Art. 10.03 A Distribution Utility shall submit to the Commission an annual report called the Distribution Network Planning Report (DNPR) detailing how it plans to:

(a) Meet the predicted demand for electricity supplied through its sub-transmission lines, primary substations and high-voltage lines;

(b) Improve reliability to its customers; and

(c) Implement any security of supply upgrade plans over the following five (5) calendars.

Art. 10.04 In meeting the requirements of Art 10.03 (a), the report shall include the following information:

(a) The historical (five years) and forecast (five years) demand from, and capacity of, each primary substation;

(b) An assessment of the magnitude, probability, and impact of the loss of load for each sub-transmission line and primary substation;

(c) The Distribution Utility’s planning standards;

(d) A description of feasible options for meeting forecast demand, including opportunities for embedded generation and demand management;

(e) Where a preferred option for meeting forecast demand has been identified, a reasonably detailed description of that option, including estimated costs; and

(f) The availability of contributions from embedded generators or customer-generators to the Distribution Utility to reduce forecast demand and defer or avoid expansion of the Distribution Utility's distribution network.

Art. 10.05 In meeting the requirements of Art. 10.03(b), the report shall include the following information:

(a) A description of the nature, timing, cost and expected impact on the performance of the Distribution Utility's reliability improvement programs; and

(b) An evaluation of the reliability improvement programs undertaken in the preceding year.

Art. 10.06 In meeting the requirements of Art. 10.03(c) (if applicable), the report shall include the following information:

(a) An outline of the capital and other works carried out in the preceding year in implementing the security of supply upgrade plan;

(b) An evaluation of whether the relevant security of supply objectives specified in the security of supply upgrade plan has been achieved in the preceding year; and

(c) An outline of the capital and other works connected with the security of supply objectives is proposed to be carried out in the following five years.

Art. 10.07 A Distribution Utility shall publish its DNPR on its website and provide the customer with a copy on request. The Distribution Utility may impose a charge for providing a customer with a copy of the report.

Art. 10.08 The Commission, following the submission of the DNPR from all Distribution Utilities, shall prepare a joint report called a Consolidated Distribution Planning Report (CDPR) detailing how together all Distribution Utilities plan to meet the predicted demand for electricity supplied into their distribution networks from the Bulk Supply Points (BSP) and Primary Substations over the following five (5) calendar years.

Art. 10.09 The report shall include the following information:

(a) The historical and forecast demand from, and capacity of, each BSP and Primary Substation;

(b) An assessment of the magnitude, probability, and impact of the loss of load for each BSP and Primary Substation;

(c) Each Distribution Utility's planning standards;

(d) A description of feasible options for meeting forecast demand at each BSP and Primary Substation, including information on a land acquisition where the possible options are constrained by land access or use issues;

(e) The opportunity for embedded generation, customer self-generation or demand management to be used to defer or avoid modification of each BSP and Primary Substation, including, where possible, an estimate of the generation capacity allowable at each distribution transformer; and

(f) Where a preferred option for meeting forecast demand has been identified, a description of that option, and a reasonably detailed estimate of its cost.

Art. 10.10 A Distribution Utility shall carry out demand forecasting within its regions of operation to determine customers' spot loads as well as increases in the demand of their customers due to economic growth. The Distribution Utilities shall make significant inputs into the development of the annual Electricity Supply Plan (ESP) and the IPSMP through the Power Planning Technical Committee (PPTC).

Art. 10.11 The Commission shall publish the ESP and the IPSMP on its website and provide the customer with a copy on request. The Commission may impose a charge for providing a customer with a copy of the report.

SECTION 11: CONNECTIONS

GENERAL CONDITIONS

Art. 11.01 A Distribution Utility shall establish a connection policy as specified in its Technical Conditions of Service and in compliance with all relevant regulations connections to VRPP and dispatchable units.

Art. 11.02 A Distribution Utility shall ensure that all electrical connections to its distribution system meet its design requirements and may refuse an application for a connection if an electrical connection or a facility for which connection is being requested does not meet its design requirement or the provisions of the Electrical Wiring Regulations 2011 (LI 2008).

Art. 11.03 If a Distribution Utility refuses to connect a person who applies for connection, the Distribution Utility shall inform the person requesting the connection of the reason(s) for not connecting and, where the Distribution Utility is able to provide a remedy, make an offer to connect. If the Distribution Utility is unable to provide a remedy to resolve the issue, it is the responsibility of the applicant person requesting the connection to provide a remedy before a connection may be made.

Art. 11.04 A Distribution Utility may deny access to the service where a consumer or a person requesting the connection fails to comply with the PURC's Consumer Service Regulations 2020, (LI 2413).

Art. 11.05 Where there are valid grounds for the Distribution Utility to refuse an application for connection, the Distribution Utility shall comply with its obligation to connect as soon as practicable after removing or eliminating the reason for which the connection was refused.

Art. 11.06 A Distribution Utility may connect and serve a Bulk Customer who has negotiated with a Wholesale Supplier, subject to the Bulk Customer paying the associated PURC's distribution wheeling charges.

PROCEDURE FOR CONNECTION OF AN APPLICANT

Art. 11.07 A Distribution Utility is obliged to connect an applicant for electricity supply for electricity consumption, subject to:

(a) An adequate supply of electricity available at the required voltage at the boundary of the new supply address;

(b) An Installation Completion Certificate (ICC) issued by a certified wiring professional provided to the Distribution Utility in respect of the electrical installation at the customer's supply address;

(c) The applicant complying with Art. 11.04 to Art. 11.06; and

(d) The applicant provides valid identification.

Art. 11.08 An applicant requiring a connection to the distribution network of a Distribution Utility for electricity consumption shall submit a request for connection in the form of a completed application form to the Distribution Utility accompanied by the payment of the approved fee.

Art. 11.09 On receipt of the applicant's application form and payment of the approved fee in Art. 11.08, the Distribution Utility shall

(a) Connect the applicant at the location address in accordance with rules and regulations established by the Commission;

(b) Connect the applicant in accordance with the following benchmarks or as may be periodically determined by the Commission in consultation with the PURC:

(c) that supplier fails to provide the applicant with an estimate and charges for the connection service within;

1) five working days, if the connection is to be made from an existing supply line; or
2) two weeks, if the connection requires a line extension,

(d) that supplier fails to provide the connection service to a customer after that customer has paid the required charges for the connection service within;

1) five working days if the connection is to be made from an existing supply line; or
2) one month if the connection requires a line extension.

PROCESS FOR CONNECTION OF CUSTOMER-GENERATOR (BI-DIRECTIONAL/NET-METERED CONNECTIONS)

Art. 11.10 An applicant for a bi-directional connection to a distribution system shall enter into a Connection Agreement with a Distribution Utility that is consistent with this Distribution Code and the Net Metering Code.

Art. 11.11 The applicant shall be subject to all applicable laws and bound by the terms and conditions of the Distribution Utility's Technical Conditions of Service as amended.

Art. 11.12 The applicant shall provide a suitable location at the applicant's premises for the installation of and easy access to the Distribution Utility's bi-directional meter.

Art. 11.13 The maximum capacity of a renewable energy generating facility that a Customer-generator can install shall be determined by the Energy Commission in consultation with the PURC and the Distribution Utilities Utility.

Art. 11.14 The bi-directional supply shall be connected through an appropriate service connection and protective device that is in accordance with the applicable standards.

Art. 11.15 The applicant shall:

(a) Ensure that the electrical installation is safe for the bi-directional supply of electricity;
(b) Provide safe and reasonable access to its premises for the Distribution Utility to undertake work related to the bi-directional flow of electricity; and
(c) Keep vegetation and other objects at the premises clear from the Distribution Utility's network.

Art. 11.16 The applicant requiring a connection for a bi-directional connection to the distribution system of the Distribution Utility shall submit a request for connection in the form of a completed application form to the Distribution Utility.

Art. 11.17 On receipt of the application form, the Distribution Utility shall provide an estimate of materials and charges for the connection within five (5) working days, provided the applicant meets all the requirements after the Distribution Utility has carried out all the necessary inspections.

Art. 11.18 Where the applicant pays the required cost of materials and charges, the Distribution Utility shall install the bi-directional meter within five (5) working days after payment of the required cost.

Art. 11.19 A Customer-generator shall have the right to terminate the Connection Agreement (CA) with the Distribution Utility in line with the provisions of the CA, and in such an event, the Customer-generator shall be required to disconnect its generating facility and notify the Distribution Utility of such action.

Art. 11.20 The Distribution Utility may terminate the Connection Agreement with a Customer-generator at any time if the Customer-generator fails to comply with the terms of this Distribution Code and the CA.

Art. 11.21 The inverter of the Net-Metered-Generating Unit shall be a product certified to comply with applicable legislative instruments, codes and standards.

Art. 11.22 The Person responsible for the installation of a Net-Metered Generating Unit shall ensure that the installation of the system complies with all requirements according to IEC 60364-7-712 and this document.

PROCESS FOR CONNECTION OF AN EMBEDDED GENERATING FACILITY:

Art. 11.23 A Distribution Utility shall require a Person who applies for the connection of an embedded generation facility to the Distribution Utility's distribution system to, upon making the application, pay for the cost of conducting an impact assessment.

Art. 11.24 The Distribution Utility shall promptly make available a generation connection information package (the "package") to the Person making the request. The package shall contain:

(a) The process for having a generation facility connected to the Distribution Utility's distribution system, including any form necessary for applying to the Distribution Utility;

(b) Information regarding any approvals from the Commission or EPA that are required before the Distribution Utility can connect a generation facility to its distribution system;

(c) The technical requirements to be met before connection to the Distribution Utility's distribution system can be carried out., including the protection and metering requirements; and

(d) The standard contractual terms and conditions for being connected to the Distribution Utility's distribution system.

Art. 11.25 Subject to all applicable laws, the Distribution Utility shall make all reasonable efforts to connect a generation facility that is the subject of an application for connection.

Art. 11.26 The applicant for connection of an embedded generating facility to the distribution system shall:

(a) Ensure that the design and installation of the generating facility are in accordance with the specifications of the Distribution Utility to guarantee the safety and security of both the embedded generating facility and the distribution system;

(b) Provide the Distribution Utility with details of the capacity and type of the embedded generating facility to be installed, including the fuel to be used or in use, estimated load and expected energy consumption at the applicant's premises;

(c) Agree to pay the requisite fee, including the capital contribution where necessary and an advance deposit for connection and net metering equipment;

(d) Agree to allow the Distribution Utility's staff access to observe the operation of the protective devices required for the maintenance of the distribution system; and

(e) Permit access at reasonable times and adequate protection for the Distribution Utility's agent during meter readings, fault rectification, disconnection and other lawful activities connected with the supply at the applicant's premises.

Art. 11.27 The Distribution Utility shall provide the applicant proposing to connect its embedded generation facility with the Distribution Utility's assessment of the impact of the proposed generation facility, a detailed cost estimate of the proposed connection and an offer to connect within:

(a) Sixty (60) calendar days of the receipt of the application and requisite connection fee where no distribution system reinforcement or expansion is required; and

(b) Ninety (90) calendar days of the receipt of the application and requisite connection fee where a distribution system reinforcement expansion is required.

Art. 11.28 The Distribution Utility's impact assessment in Art. 11.27 shall set out the impact of the proposed generation facility on the Distribution Utility's distribution system and any customers of the Distribution Utility, including:

(a) Any voltage impacts, impacts on current loading settings and impacts on fault currents;

(b) The connection feasibility;

(c) The need for any line or equipment upgrades;

(d) The need for sub-transmission or distribution system protection and control modifications;

(e) Any metering requirements; and

(f) Current and voltage harmonic impacts (for solar PV and wind farm systems).

Art. 11.29 Any material revisions to the design, planned equipment, or plans for the proposed embedded generation facility and connection shall be filed with the Distribution Utility, and the Distribution Utility shall prepare a new impact assessment

Art. 11.30 The Distribution Utility shall notify the Transmission Utility whose network is directly connected to the Distribution Utility's distribution system before an embedded generator is connected to the Distribution Utility's distribution system.

Art. 11.31 The results of the impact assessment shall be provided to the applicant and shall provide the basis for negotiation between the applicant and the Distribution Utility on the scope of the connection project and the determination of the cost of the connection.

Art. 11.32 The Distribution Utility shall take all necessary steps, to ensure that the equipment to be used by the embedded generator is safe and of the required standard.

Art. 11.33 Once the Distribution Utility and the applicant have agreed on the scope of the project, the applicant shall pay the Distribution Utility for the cost of preparing a detailed cost estimate of the proposed connection. The Distribution Utility shall then provide the applicant with a detailed cost estimate and an offer to connect not later than 90 days after the receipt of payment.

Art. 11.34 The applicant and the Distribution Utility shall negotiate in good faith on the connection offer and sign the Connection Agreement that will govern the connection of the embedded generation facility to the distribution system.

Art. 11.35 The Distribution Utility shall have the right to witness the commissioning and testing of the connection of the embedded generation facility to the Distribution Utility's distribution system.

Art. 11.36 Once the applicant informs the Distribution Utility that it has received all necessary approvals from the Commission, the applicant may commence construction of the facility.

Art. 11.37 On completion of construction, in accordance with the terms of the CA and subject to proof of receipt of all regulatory approvals, the Distribution Utility shall connect the embedded generation facility to the distribution system.

Art. 11.38 The Technical requirements for connecting the embedded generation facility to the distribution system shall be established by the Distribution Utility and shall include but not limited to the list in Technical Schedule C.

Art. 11.39 The applicant shall ensure that a means of isolation complies with the standards established by the Distribution Utility, and the Distribution Utility's practice may require its own additional means of disconnection on the Distribution Utility's side of the point of common coupling.

Art. 11.40 Adequate voltage regulation shall be maintained under a variety of operating conditions. During normal operation, and whenever possible, the embedded generation facility shall be loaded and unloaded gradually as specified by the equipment manufacturer, to allow adequate time for regulating devices to respond.

Art. 11.41 During commissioning, the Distribution Utility shall ensure that its distribution system can receive a supply of electricity from an embedded generating unit connected to its distribution system in accordance with an agreement with the embedded generator on the terms and conditions of dispatch, connection, and disconnection.

Art. 11.42 During commissioning and normal operation, the embedded generator shall not significantly impact the power quality of the distribution system. The embedded generator shall be required to disconnect any unit if there are negative impacts as a result of the embedded generation facility being in service

Art. 11.43 The embedded generation facility shall be required to remain disconnected until appropriate measures have been taken to prevent continued negative impacts on the distribution system and the customers it serves.

Art. 11.44 Where the distribution system supplies single-phase loads, some unbalances are inevitable, and the generation facility shall be expected to operate under those conditions and shall not cause further deterioration of existing unbalanced conditions.

Art. 11.45 For the avoidance of doubt, a Distribution Utility is not liable for any loss of income by an embedded generator for being unable to receive a supply of electricity from an embedded generating unit connected to the distribution system of the Distribution Utility because of any supply interruption.

ILLEGAL CONNECTIONS

Art. 11.46 A Distribution Utility may disconnect supply to a customer's supply address immediately if:

(a) The supply of electricity to a customer's electrical installation is used other than at the customer’s premises, except in accordance with the Act;

(b) A customer takes at the customer’s supply address electricity supplied to another supply address;

(c) A customer tampers with or permits tampering with, the meter or associated equipment; or

(d) A customer allows electricity supplied to the customer’s supply address to bypass the meter.

Art. 11.47 In addition to Art. 11.46, an electricity supply to any premises made contrary to LI 1816 and any other relevant LIs or codes is illegal.

DISCONNECTION OF SUPPLY OF ELECTRICITY

Art. 11.48 Without prejudice to any provision of this Distribution Code, which provides for the disconnection of electricity, the Distribution Utility shall disconnect the electricity supply to a Customer or Customer-generator only in accordance with the PURC’s Consumer Service Regulations, 2020 (LI 2413).

Art. 11.49 In the event that the Distribution Utility determines that a generating facility causes damage that adversely affects other distribution system Customers or the Distribution Utility's assets, the facility shall be disconnected immediately from the distribution system upon direction from the Distribution Utility, and the Customer-generator shall correct the problem at its expense

Art. 11.50 A Distribution Utility may disconnect supply to a customer's location address if supply otherwise would potentially endanger or threaten to endanger the health or safety of any person or the environment or an element of the environment or if there is otherwise an emergency.

Art. 11.51 Except in the case of an emergency, or where there is a need to reduce the risk of fire or where relevant regulations require otherwise, a Distribution Utility shall not disconnect a customer, a customer-generator or an embedded generator, unless the Distribution Utility has:

(a) Given written notice of disconnection stating the reason for the disconnection;

(b) Allowed the customer, the Customer-generator or the embedded generator five days from the date of receipt of the notice to eliminate the cause of the potential danger; and

(c) At the expiration of those five days, must have given the customer, the customer-generator, or the embedded generator by way of a written disconnection warning another five days' notice of its intention to disconnect the customer, the customer-generator, or the embedded generator (the five days is to be counted from the date of receipt of the notice).

Art. 11.52 A Distribution Utility shall, upon a request for disconnection by a customer, customer-generator or embedded generator, use best efforts to effect the disconnection as requested.

SECTION 12: ASSETS MANAGEMENT

GOOD ASSET MANAGEMENT

Art. 12.01 A Distribution Utility shall use its best effort to:

(a) Assess and record the nature, location, condition, and performance of its distribution system assets in order to deliver on its regulatory and institutional targets;

(b) Develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair, and disposal of its distribution system assets to;

(i) comply with the laws and other performance obligations that apply to the provision of distribution services, including those contained in this Distribution Code;

(ii) minimise the risks associated with the failure or reduced performance of assets; and

(iii) minimise costs to customers considering distribution losses;

(c) Develop, test, or simulate and implement contingency plans, including where relevant plans to strengthen the security of supply, to deal with events that have a low probability of occurring but are realistic and would have a substantial impact on customers should they occur.

CUSTOMER'S ELECTRICAL INSTALLATION AND EQUIPMENT

Art. 12.02 A customer's electrical installation shall at all times comply with the requirements of the Distribution Utility.

Art. 12.03 A customer shall ensure that the distribution system and the reliability and quality of supply to other customers are not adversely affected by the customer's actions or equipment

Art. 12.04 A Customer shall not increase the initially approved load at the time of application for service without prior permission from the Distribution Utility.

DISTRIBUTION UTILITY'S EQUIPMENT ON CUSTOMER PREMISES

Art. 12.05 A customer shall:

(a) Not interfere, and shall use best effort not to allow interference with the Distribution Utility's distribution system, including any of the Distribution Utility's equipment installed in or on the customer's premises; and

(b) Provide and maintain on the customer's premises any reasonable or agreed facility required to protect any equipment of the Distribution Utility.

Art. 12.06 Provided official identification is produced by the Distribution Utility's representatives on request, a customer shall provide to the Distribution Utility representatives at all times convenient and unhindered access to

(a) the Distribution Utility's equipment for any purposes associated with the supply, metering or billing of electricity; and

(b) the customer's electrical installation for the purposes of:

(i) the inspection or testing of the customer's electrical installation in order to assess whether the customer is complying with this Distribution Code; and

(ii) connecting, disconnecting or reconnecting supply and safe access to and within the customer's premises to comply with this Distribution Code.

Art. 12.07 In cases other than emergencies, a Distribution Utility shall use its best effort to access a customer's premises at a time that is reasonably convenient to both the customer and the Distribution Utility.

SECTION 13: MODIFICATION OF DISTRIBUTION SYSTEM

Art. 13.01 If a Distribution Utility intends to modify its existing distribution system to be able to connect a specific customer or group of customers, the Distribution Utility shall perform an economic and financial evaluation of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance cost of the expansion project.

Art. 13.02 If a modification of the Distribution Utility's distribution system is needed for the Distribution Utility to connect a customer, the Distribution Utility shall be required to make an offer to the customer to connect the customer.

Art. 13.03 A Distribution Utility shall be responsible for the preliminary planning, design, and engineering specifications of the work required for the distribution system expansion and connection. Specifications shall be made according to the Distribution Utility's standards for design, material, and construction as specified in Technical Schedules G:

Art. 13.04 In providing the estimates for the amount to be charged to the customer(s) to construct the distribution system referenced in Art. 13.01**.** A Distribution Utility shall delineate estimated costs specifying those costs attributed to engineering design, materials, labour, equipment, and administrative activities.

Art. 13.05 Where with the approval of a Distribution Utility, a customer finances the development of the Distribution Utility's system, the customer shall be entitled to a 60 percent refund of the investment from the Distribution Utility when the Distribution Utility subsequently connects other customers to the newly developed part of the distribution system.

Art. 13.06 The amount a Distribution Utility may offer to charge a customer other than a Generator or another Distribution Utility to construct the expansion to the Distribution Utility's distribution system shall be in accordance with procedures approved by the PURC.

Art. 13.07 A Distribution Utility shall continue to plan and build the distribution system to meet reasonable forecast load growth.

Art. 13.08 A Distribution Utility may perform modifications to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints.

Art. 13.09 In determining system modifications to be performed on its distribution system, a Distribution Utility shall consider the following:

(a) Good utility practice;

(b) Improvement of the system to either meet or maintain required performance-based indices;

(c) Current levels of customer service and reliability and potential improvement from the enhancement; and

(d) Costs to customers associated with current levels of distribution reliability and potential improvement from the enhancement.

RELOCATION OF DISTRIBUTION SYSTEM

Art. 13.10 Where the Commission, the PURC or a Main Actor, requests a Distribution Utility to relocate its distribution system or an existing agreement requires the relocation of its distribution system, the Distribution Utility shall exercise its rights and discharge its obligations in accordance with existing legislation, regulations, formal agreements, easements, and common law.

SECTION 14: HEALTH AND SAFETY

Art. 14.01 A Distribution Utility shall prepare and submit for approval by the Commission a Safety and Technical Management Plan (STMP) in respect of matters prescribed under the Licence.

Art. 14.02 The Distribution Utility shall review the STMP annually and submit a report to the Commission within three months after the end of a Licence Year indicating the degree of compliance with the Plan.

Art. 14.03 Notwithstanding Art. 14.02, the Distribution Utility shall follow good utility practices in operating and maintaining the distribution system and shall abide by safety rules and regulations that apply to routine utility work.

Art. 14.04 A Distribution Utility shall show good utility practice in operating and maintaining its distribution system and shall abide by the safety rules and regulations that apply to routine work.

Art. 14.05 A Distribution Utility shall implement an industry-recognised safety program that includes training and regularly conducted audits. This program also will include Public Education and Public safety initiatives.

Art. 14.06 Any problems that a Distribution Utility identifies as part of the audit shall be remedied as soon as possible or in accordance with the Distribution Utility's health and safety procedures.

Art. 14.07 A Distribution Utility shall have a corporate policy that addresses environmental stewardship that applies to all of the Distribution Utility's operations.

Art. 14.08 A documented program with supporting procedures and appropriate training should be in place to ensure compliance with environmental regulations and indicate a proactive approach to the avoidance of environmental damage

Art. 14.09 A Distribution Utility shall ensure that when it becomes aware of any unsafe conditions, it shall respond to eliminate the unsafe condition in accordance with the benchmarks below or as may be periodically determined by the ETC on behalf of the Commission in consultation with the PURC

(a) 2 hours, where the location of the fault is within a 30-kilometre radius;

(b) 4 hours, where the location of the fault is within a 60-kilometre radius; or

(c) 5 hours where the location of the fault is within a radius of 60 kilometres and above, from the district or regional office of the supplier where the information was received.

SECTION 15: OPERATIONS

QUALITY OF SUPPLY

Art. 15.01 A Distribution Utility shall prepare and submit to the Commission by the thirtieth day of November each year, an Operation and Maintenance Plan (OMP) for the following year of the distribution system in accordance with the requirements and standards established under the relevant laws and regulations.

Art. 15.02 The Distribution Utility shall operate and maintain the electricity distribution and supply equipment, installations and facilities in accordance with the operating instructions and maintenance guidelines established by the respective Original Equipment Manufacturer (OEM) of the equipment and in accordance with prudent utility practice.

Art. 15.03 Notwithstanding Art. 15.02, a Distribution Utility shall follow good utility practices in managing the power quality of the Distribution Utility's distribution system as defined in its Technical Conditions of Service, the quality of service standards to which the distribution system is designated and operated.

Art. 15.04 A Distribution Utility shall maintain a voltage variance standard in accordance with existing regulations.

Art. 15.05 A Distribution Utility shall practice reasonable diligence in maintaining voltage levels but is not responsible for variations in voltage from external sources, such as operating contingencies, exceptionally high loads and low voltage supply from the Transmission Utility.

Art. 15.06 A Distribution Utility shall respond to and take reasonable steps to investigate all customer power quality complaints and report to the customer, where necessary, the results of the investigations within 14 days.

Art. 15.07 If the source of a power quality problem is established to have been caused by the customer making the complaint, the Distribution Utility may seek reimbursement for the time and cost spent to investigate the complaint.

Art. 15.08 A Distribution Utility shall take appropriate actions to control harmonic distortions found to be detrimental to other parties connected to its distribution system within limits specified in Table 1 of Technical Schedule A.

Art. 15.09 A Distribution Utility shall ensure that the customer's equipment contribution to the harmonic distortion levels in the distribution system at the point of common coupling is within limits specified in Table 1 of Technical Schedule A.

Art. 15.10 Pursuant to Art 14.09 in deciding which actions to take, a Distribution Utility shall ensure that appropriate industry standards and good utility practices are adhered to.

Art. 15.11 A Distribution Utility shall require a customer that owns or operates an equipment connected to its distribution system to take reasonable steps to ensure that the operation or failure of the equipment does not cause a distribution system outage or disturbance.

Art. 15.12 A Distribution Utility may require that a customer connection, equipment or environment that adversely affects its distribution system be corrected immediately at the customer's cost.

Art. 15.13 A Distribution Utility may direct a customer connected to its distribution system to take corrective or preventive action on the customer's equipment when there is a direct hazard to the public or the customer is causing or could cause adverse effects on the reliability of the Distribution Utility's distribution system.

Art. 15.14 If the situation is not corrected, the Distribution Utility may disconnect the customer in accordance with its disconnection policy.

TARGETS FOR SUPPLY RELIABILITY

Art. 15.15 The ETC shall prescribe performance benchmarks using international standards and indices that shall be used to evaluate the performance of a distribution system, and the historical data for the past three years may be used as a guide to set annual performance benchmarks for the reliability indices.

Art. 15.16 The following indices shall, at the minimum, be monitored and calculated for the purposes of assessing the performance of the distribution system;

(a) *System Average Interruption Duration Index (SAIDI)*;
(b) System Average Interruption Frequency Index (SAIFI) ;
(c) Availability - Percentage of time the entire distribution system is available for the distribution of electricity, and it shall be

calculated as the sum of planned, unplanned, and disturbance outage durations divided by the total hours that the system or the relevant circuit should have been available in a given period;

(d) Sub-Transmission Line Faults - Number of faults on the circuit lines.

Art. 15.17 Before 31 December each year, targets for the reliability of supply for the ensuing year of a Distribution Utility shall be published on the websites of the Distribution Utility and the Commission.

Art. 15.18 A Distribution Utility shall use its best effort to meet targets required by existing regulations and this Distribution Code or otherwise meet reasonable customer expectations of reliability of supply.

INTERRUPTIONS

Art. 15.19 In the case of interruption (whether planned or unplanned), a Distribution Utility shall ensure to provide information to all affected persons of the nature of the interruption and an estimate of the time when supply shall be restored or when reliable information on the restoration of supply shall be available, and as a minimum;

(a) Make this information available by way of a 24-hour telephone service, social media, radio and television announcement and by way of frequently updated entries on a prominent part of its website within 30 minutes of being advised of the unplanned interruption or emergency or at least 24 hours before a planned interruption;

(b) Use other means of communication to send customers a summary of this information; and

(c) Provide options for customers to call a Service/Call Centre.

Art. 15.20 A Distribution Utility shall ensure that the cumulative electricity interruption for each customer within an operational year does not exceed

(a) forty-eight hours, in a metropolitan or municipal area, or industrial estate;

(b) seventy-two hours, in a district capital; and

(c) one hundred and forty-four hours, in a rural area.

Art. 15.21 Despite Art. 15.20 the Distribution Utility shall ensure that the electricity interruption to a customer's premises within an operational year does not exceed six periods.

Art. 15.22 Despite Art. 15.20 and Art. 15.21 the duration of each outage shall not exceed;

(i) eight hours in a metropolitan or municipal area or industrial estate;
(ii) twelve hours in a district capital; and
(iii) twenty-four hours in rural areas.

Art. 15.23 For the purposes of Art. 15.20, Art. 15.21 and Art. 15.22 the period of an interruption shall be consistent and commence from the time the Distribution Utility is initially informed by

(i) a customer that the supply to the customer's premises has been interrupted; or

(ii) a person other than the customer or is otherwise made aware by the operation of any automatic system operated by the Distribution Utility in circumstances in which the supply to the customer's premises has been interrupted or may reasonably be expected to have been interrupted.

Art. 15.24 An interruption of supply to a customer shall not be treated as wrongful where;

(i) the interruption was as a result of a major fault or damage to indispensable equipment in the Distribution Utility's distribution system;

(ii) the interruption was as a result of a failure of, fault in or damage to either the transmission system to which the Distribution Utility's distribution system was connected or a generating station connected to that transmission system;

(iii) the interruption was as a result of a failure of, fault in or damage to a generating station connected to the Distribution Utility's distribution system;

(iv) the customer informed the supplier that the customer did not wish the supplier to take any action; or

(v) the interruption was one for;

a. planned maintenance,

b. emergency,

c. supply disconnection,

d. load shedding, or

e. safety.

Art. 15.25 Where a major outage was due to the negligence of the Distribution Utility, paragraph (i) of Art. 15.24 shall not apply.

Art. 15.26 The Commission in consultation with the PURC may periodically review the benchmarks for interruption of supply.

RESTORATION OF SUPPLY

Art. 15.27 Where a Distribution Utility is informed of an interruption in the customer's supply due to a fault in or damage to the Distribution Utility's distribution system either by the customer or a person other than the customer, the Distribution Utility shall, unless the fault was caused by a natural disaster, restore supply to the customer's premises

(i) in the case of a minor fault, within

a. eight hours, in the case of a metropolitan or municipal area or industrial estate,

b. twelve hours, in the case of a district capital, and

c. twenty-four hours, in the case of a rural area; or

(ii) in the case of a major fault that would require capital-intensive equipment replacement, within

a. eighty hours, in the case of a metropolitan or municipal area or industrial estate,

b. one hundred and twenty hours, in the case of a district capital, and

c. two hundred and forty hours, in the case of a rural area.

Art. 15.28 Where the electricity supply to a customer's premises is interrupted by a natural disaster supply shall be restored by the Distribution Utility within the period specified Art. 15.27 after the situation returns to normalcy.

Art. 15.29 The Commission in consultation with the PURC may periodically review the benchmarks for the restoration of supply.

SCHEDULED ELECTIVE MAINTENANCE

Art. 15.30 In the case of planned maintenance, a Distribution Utility shall provide each affected customer with at least three days' notice of an interruption. The notice must:

(a) Specify the expected date, time, and duration of the interruption; and

(b) Include a 24-hour telephone number for enquiries.

Art. 15.31 The Distribution Utility shall use its best effort to restore the customer's supply as quickly as possible or in accordance with existing regulations.

DISCONNECTION AND RECONNECTION

Art. 15.32 A Distribution Utility shall establish a process for disconnection and reconnection that specifies timing and means of notification consistent with existing regulations.

Art. 15.33 In developing physical and business processes for disconnection and reconnection, the Distribution Utility shall document its business process for disconnection and reconnection in the Distribution Utility's Technical Conditions of Service.

Art. 15.34 Without limiting the generality of the foregoing, prior to disconnection of a property, the Distribution Utility shall provide to any person that, according to the Distribution Utility's Technical Conditions of Service, receives notice of disconnection:

(a) The Fire Safety Notice of the Ghana National Fire Service GNFS; or

(b) Any other public safety notices or bulletins issued by public safety authorities and provided to the Distribution Utility, provide information to consumers respecting dangers associated with the disconnection of electricity service.

Art. 15.35 The Distribution Utility shall include a copy of the notices or bulletins referred to in Art. 15.34(b) along with any notice of disconnection that is left at the property at the time of actual disconnection.

UNAUTHORISED ENERGY USE

Art. 15.36 A Distribution Utility may take action to mitigate unauthorized energy use. Upon notification or identification of possible unauthorized energy use, the Distribution Utility shall disconnect and investigate the unauthorized energy use.

Art. 15.37 The Distribution Utility may recover from the customer responsible for the unauthorized energy use all reasonable costs incurred by the Distribution Utility arising from unauthorized energy use.

Art. 15.38 A Distribution Utility shall monitor losses and unaccounted energy use monthly to detect any upward trends that may indicate the need for management policies to mitigate unauthorized energy use.

SYSTEM INSPECTION REQUIREMENTS AND MAINTENANCE

Art. 15.39 A Distribution Utility shall maintain its distribution system in accordance with good utility practices and performance standards to ensure reliability and quality of electricity service on both a short-term and long-term basis.

Art. 15.40 A Distribution Utility shall develop an Inspection Manual using but not limited to the guide in Technical Schedule B for the conduct of inspection of the distribution infrastructure for approval by the Commission.

Art. 15.41 A Distribution Utility shall perform inspection activities of its distribution system in accordance with the Inspection manual developed in Art. 15.40.

Art. 15.42 A Distribution Utility shall perform inspection activities using persons qualified to identify the types of defects that could be discovered during such inspection activities.

Art. 15.43 Persons performing inspection activities shall be trained on operational and safety issues to protect both themselves and the public and to respond to emergencies that may arise as a result of inspection activities.

Art. 15.44 A Distribution Utility shall determine the methodology by which inspection cycles shall be structured and how defects identified during inspection activities shall be repaired in accordance with good utility practice.

Art. 15.45 A Distribution Utility shall address a defect by planning repair activities or by performing any other action that is an affirmative response to the discovery of the defect.

Art. 15.46 A Distribution Utility shall have internal monitoring mechanisms to ensure that the identified defects and follow-up activities are addressed appropriately.

Art. 15.47 A Distribution Utility shall make all reasonable efforts to minimize the duration and frequency of planned outages.

Art. 15.48 A Distribution Utility's policies and procedures with respect to planned outages shall be described in the Technical Conditions of Service and published on the Distribution Utility's website.

UNPLANNED OUTAGES AND EMERGENCY CONDITIONS

Art. 15.49 A Distribution Utility may require other main actors to a joint use agreement to comply with reasonable and appropriate instructions from the Distribution Utility during an unplanned outage or emergency situation.

Art. 15.50 To assist with distribution system outages or emergency response, a Distribution Utility may require a customer to provide the Distribution Utility emergency access to customer-owned distribution equipment that normally is operated by the Distribution Utility or Distribution Utility-owned equipment on the customer's property.

Art. 15.51 During an emergency, a Distribution Utility may interrupt supply to a consumer in response to

(a) A shortage of supply,

(b) To effect repairs on the distribution system, or

(c) While repairs are being made to customer-owned equipment.

Art. 15.52 A Distribution Utility shall require a customer with a portable or permanently connected emergency backup generation facility to notify the Distribution Utility regarding the presence of such equipment.

Art. 15.53 A Distribution Utility shall require that the customer's portable or permanently connected emergency backup generation facility complies with all applicable criteria of the Electrical Wiring Regulations 2011 (L I 2008) and does not adversely affect the Distribution Utility's distribution system.

Art. 15.54 A Distribution Utility shall develop and maintain appropriate emergency response plans in accordance with existing regulations.

Art. 15.55 A Distribution Utility's emergency plan shall include, at a minimum, mutual assistance plans with neighbouring Distribution Utilities or other measures to respond to a widespread emergency.

Art. 15.56 A Distribution Utility shall establish outage management policies that include the following:

(a) Arrangements for on-call personnel in accordance with good utility practices,

(b) Establishment and operation of a Call/Service Centre or equivalent telephone service to provide customers with available information regarding an outage

(c) Identification of the location of distribution circuits for emergency services and critical customers such as hospitals, water supply, health care facilities, and designated emergency shelters for coordination with other agencies.

UNDERGROUND CABLE NETWORK

PRELIMINARY WORKS

Art. 15.57 Before any cable works are undertaken, due notice in writing shall be given to all utility services that may conflict with the proposed cable route, e.g. telephone, water, sewage, road, railway, etc. The Distribution Utility shall contact the responsible agency for assistance.

Art. 15.58 Where cables are to be installed in roads, footpaths or streets, it shall be mandatory to liaise closely with the road's authority and police to ensure that all necessary measures are taken to minimize the hazards and disruptive effects of installation works.

SAFETY SIGNAGE DURING UNDERGROUND WORK

Art. 15.59 Working signs, bollards, danger tapes, lights and watchmen shall be provided where necessary to ensure ample advance warning of and restrict public access to, the works area. Warning lights and signs shall be displayed along pits and trenches on both sides. Steel plate or wooden planks shall be provided across the trench at entrances to residences.

USE OF LINE MARKERS FOR BURIED UNDERGROUND CABLES

Art. 15.60 A Distribution Utility shall ensure that a line marker is placed and maintained as close as practical over each buried underground cable:

(a) At each crossing of a public road and railway; and

(b) Whenever necessary identify the location of the buried underground cable to reduce the possibility of damage or interference.

CAPTION FOR LINE MARKERS

Art. 15.61 A Distribution Utility shall ensure that the following is written legibly on a background of a sharply contrasting colour on each line marker:

(a) The words “Warning,” “Caution,” or “Danger” followed by the words “HT Cable” or “LV Cable”; and

(b) The name of the Distribution Utility and telephone number on which the Distribution Utility can be reached at all times.

SECTION 16: METERING

METERING REQUIREMENTS

Art. 16.01 A Distribution Utility shall ensure that all meters installed on its system are in accordance with the Metering Code.

Art. 16.02 A Distribution Utility shall require that an embedded generator that sells energy and settles through the Distribution Utility's retail settlement process shall install an appropriate meter.

Art. 16.03 A Distribution Utility shall procure and install meters for all embedded generation facilities connected to its distribution system.

Art. 16.04 Where practical, metering for an embedded generation facility shall be installed at the point of common coupling.

SECTION 17: EMERGENCY RESPONSE PLANS

PURPOSE

Art. 17.01 A Distribution Utility shall develop an Emergency Response Plan (ERP) to ensure that the main actors in the electricity distribution system, adequately identify, plan for, and are able to respond effectively to emergencies that might present adverse effects to personnel, facilities, or the environment.

SCOPE

Art. 17.02 This Emergency Response Plan applies to electricity distribution system construction, operations, and maintenance, including embedded generator facilities, Electricity Retailers, and areas where third-party activities are ongoing. It addresses all aspects of emergency preparedness and response systems, including identification of potential emergencies, response personnel, preparedness measures, training, equipment, and inspections, as well as detailed testing of the Emergency Response Plan.

PROCEDURE

Art. 17.03 It shall be the responsibility of all officials and personnel of the main actors to ensure that persons in their area of control comply with the procedures below.

IDENTIFICATION OF POTENTIAL INCIDENTS AND EMERGENCIES

Art. 17.04 The Emergency Response Plan of a Distribution Utility shall be consistent with the requirements of the distribution licence issued to the Distribution Utility by the Commission

Art. 17.05 All facilities and areas of operations of the Distribution Utility shall be audited annually in accordance with relevant hazard identification procedures to systematically identify situations or events that would require an emergency response, including but not limited to:

(a) Electrical leaks or faults;
(b) Fires (structural, equipment, etc.);
(c) Medical emergencies, injuries;
(d) Major chemical or hydrocarbon spills or gas;
(e) Explosions;
(f) Civil disturbances; and
(g) Natural disasters.

Art. 17.06 Consideration shall be given to extreme risks, geographic location of potential events, proximity to populated areas, concerned stakeholders, available external emergency services, as well as internal and external communication channels.

Art. 17.07 Remediation procedures shall be included in the Emergency Response Plan, in particular for materials that pose a significant risk to human health and safety, the environment or the community.

Art. 17.08 As a minimum, each Main Actor organization will conduct an annual review; and testing of the Emergency Response Plan, such as drills and desktop situations, shall be conducted annually to maximize the operation or facility's preparedness for emergencies.

AVAILABILITY OF EMERGENCY RESPONSE PLANS (ERP)

Art. 17.09 A copy of the Emergency Response Plan shall be available to appropriate personnel and at key locations and must be linked to the safety systems of the main actors.

Art. 17.10 An Emergency Response Plan shall be communicated to relevant organizations such as the Fire Service, Police, and healthcare facilities to ensure a systematic approach is applied to identify and manage these situations or events.

SECTION 18: INFORMATION AND DATA EXCHANGE DISCLOSURE

BACKGROUND, PURPOSE, AND SCOPE

Art. 18.01 A Distribution Utility shall ensure that its distribution system is operated in a reliable and secure manner using regular power system information exchange with the main actors.

Art. 18.02 Information and data exchange protocols shall be developed by the Distribution Utility based on the requirements of this Distribution Code and other statutory requirements. The protocols would define the reciprocal obligations of the main actors with regard to the provision of information and exchange of data for the implementation of this Distribution Code.

Art. 18.03 The requirements of this Distribution Code are complementary to any information and data exchange requirements defined in other sections of the National Electricity Grid Code.

INFORMATION EXCHANGE INTERFACE

Art. 18.04 A Distribution Utility and a main actor shall designate an office, each as its contact office, for the exchange of information pertaining to the real-time operation of the distribution system.

Art. 18.05 The main actors shall agree on appropriate procedures for the transfer of information.

GENERAL PRINCIPLES FOR IMPLEMENTATION OF INFORMATION AND DATA EXCHANGE

Art. 18.06 The information exchanged between a Distribution Utility and a main actor may be either confidential (bilateral) information or public information intended for all parties. The provider of the information shall indicate whether the information being provided should be considered confidential or public.

Art. 18.07 The Distribution Utility shall make available critical data to allow a main actor to make rational and informed decisions regarding the operations of its distribution system.

Art. 18.08 In the case of electronic data sharing, access to the distribution system information shall be provided on a read-only basis.

Art. 18.09 The Distribution Utility shall be responsible for the procurement and maintenance of the required communication systems as well as the data communication costs of its systems used for the purpose of Information and Data Exchange.

INFORMATION EXCHANGE BETWEEN MAIN ACTORS

PROVISION OF INFORMATION TO A DISTRIBUTION UTILITY

Art. 18.10 A Distribution Utility may require information of a technical nature, to the extent not supplied under any other provisions of this Distribution Code, to be supplied by a main actor to enable the Distribution Utility to undertake the following:

(a) Analysis and evaluation of equipment and service performance of the distribution system as well as the preparation of the distribution system performance reports;

(b) Survey of distribution system conditions;

(c) Assessment of risks to distribution system operations;

(d) Analysis of distribution system equipment performance; and

(e) Analysis and validation of policies of the Distribution Code.

Art. 18.11 The Distribution Utility shall send a written request to the main actor, setting out the information it reasonably requires, the preferred medium and format for the submission and the time by which it reasonably requires a response to the request.

Art. 18.12 The main actor shall use all reasonable effort to provide the required information in the required format and within the time stated.

Art. 18.13 Unless specifically provided in other sections of this Distribution Code, communications with the Distribution Utility on all other matters shall be with the Head Office of the Distribution Utility.

PLANNING INFORMATION

Art. 18.14 A main actor shall provide regular planning information as a Distribution Utility may reasonably request to plan and develop the distribution system and to enable the Distribution Utility to fulfil its statutory or regulatory obligations. The main actor shall submit the information to the Distribution Utility without justifiable cause for delay.

Art. 18.15 The Distribution Utility shall provide regular planning information as the Commission or a Main Actor may reasonably request to plan and fulfil its statutory or regulatory obligations. The Distribution Utility shall submit the information to the Commission or a Main Actor without justifiable cause for delay.

Art. 18.16 A distribution system Asset Owner shall provide a main actor with information about equipment and systems installed at the Asset Owner's distribution facilities.

Art. 18.17 A Distribution Utility shall keep an updated technical database of its distribution system for purposes of modelling and studies on the distribution system.

Art. 18.18 A Distribution Utility shall provide a main actor with any relevant information that may be reasonably required by the main actor to properly plan and design its network in accordance with prudent utility practice.

NETWORK INFORMATION EXCHANGE

Art. 18.19 A main actor shall promptly provide to the Distribution Utility, on request, network information that is considered reasonable for the security and integrity of the distribution system.

Art. 18.20 The Distribution Utility shall communicate network information as required for safe and reliable operation to the contact points designated by each main actor.

Art. 18.21 The network information exchange shall be in a medium and in a time frame agreed upon between the main actors.

OPERATIONAL COMMUNICATION AND DATA RETENTION REQUIREMENTS

Art. 18.22 Adequate communication facilities and procedures shall be established between a Distribution Utility and each main actor to allow the timely transfer of information.

Art. 18.23 The communication facilities for voice and data that are to be installed and maintained between the Distribution Utility and the main actors shall comply with the applicable standards for SCADA and communication equipment.

Art. 18.24 The communication facilities shall support data acquisition from Remote Terminal Units (RTU). The Distribution Utility shall be capable of monitoring the state of the distribution system via telemetry from the Remote Terminal Unit connected to the plant or facility of a main actor plant or substation.

Art. 18.25 The Distribution Utility and the main actors may, in place of the above systems, adopt the use of new technologies and methodologies for the communication of information where there is a recognizable benefit in quality, reliability, and features, and to do so would be reasonable in the circumstances.

SCADA INFRASTRUCTURE

Art. 18.26 Each distribution system shall be accessible to the SCADA system, which shall be used for the storage, display, and processing of operational data.

Art. 18.27 All main actors shall make available outputs of their respective operational equipment to the SCADA system.

Art. 18.28 SCADA Remote Terminal Units shall be installed for the transmission of signals and indications to and from the Distribution Utility. The signals and indications that shall be provided by main actors for transmission by SCADA equipment are those specified in this Distribution Code, together with such other data or information as the Distribution Utility may reasonably request, from time to time, by notice to main actors.

Art. 18.29 All SCADA, metering, computer, and communications equipment, and the data or information carried by the distribution system shall be secure from unauthorized access.

Art. 18.30 Procedures governing security and access shall be agreed upon with all main actors but shall allow for adequate access to the equipment and information by the relevant main actor and the Distribution Utility for maintenance, repair, testing and recording of measurements.

TIME STANDARD

Art. 18.31 The time standard used shall be the Greenwich Meridian Time (GMT) standard and all-time information shall be referenced to it. To maintain synchronization, each distribution system code shall be provided with a connection to GPS satellite receivers that enable all relevant devices to maintain time synchronization.

DATA RETENTION AND ARCHIVING

Art. 18.32 A Distribution Utility and every main actor shall maintain sufficient records to support audit and verification requirements and to support monitoring of compliance with the provisions of the Grid Code. They shall also maintain adequate data and records, in sufficient detail, to support event diagnostics and troubleshooting.

Art. 18.33 The Distribution Utility shall maintain a complete and accurate record of all operational data supplied or maintained under this Distribution Code.

Art. 18.34 All operational data shall be maintained for a period of not less than five (5) years, commencing from the date the operational data was first supplied or first created, if earlier.

Art. 18.35 The Distribution Utility shall allow a main actor access to its records of relevant operational data.

Art. 18.36 The obligations for data retention and archiving shall be the responsibility of the information owner.

Art. 18.37 The systems for the storage of data and information to be used by the parties shall be of their own choice and installed at their own cost.

Art. 18.38 The Commission may at any time audit the data retention and archiving systems of any Distribution Utility.

Art. 18.39 A Distribution Utility shall store operational information that is kept electronically for a period of at least five (5) years or the life of the plant or equipment concerned, whichever is longer.

Art. 18.40 A Distribution Utility shall ensure reasonable security against unauthorized access, use, and loss of information. To this end, the Distribution Utility shall, among other things, develop and implement a backup strategy for the information system equipment.

DISTRIBUTION SYSTEM PERFORMANCE DATA

Art. 18.41 The following distribution system performance indicators and operational information shall be made available by a Distribution Utility to the Commission and a main actor upon request:

(a) Daily-

(i) power and energy generation by each generating facility registered with the Distribution Utility; and

(ii) hourly actual demand of the previous day in MW.

(b) Monthly -

(i) energy balance indicating internal generation, imports, exports, energy available for sale and transmission losses;

(ii) generating plant Availability;

(iii) number and total duration of frequency excursions outside statutory limits on the sub-transmission network;

(iv) number and total duration of voltage excursions outside statutory limits on the sub-transmission network;

(c) Annually -

(i) annual energy balance for the year;

(ii) annual peak demand in MW, date and time;

(iii) annual minimum demand in MW, date and time;

(iv) outage time at each sub-transmission network node.

Art. 18.42 A distribution system Asset Owner shall also make available all information collected via recorders installed at substations to the Distribution Utility for analysis. The Distribution Utility shall make this information available to affected Main actors on request.

Art. 18.43 The Distribution Utility shall publish quarterly, a report on the power system performance for the previous quarter, including a report on major faults and operating conditions relevant to the operation of the distribution system.

EVENTS REPORTING

Art. 18.44 In the case of a Significant Incident, which has been notified by a main actor to a Distribution Utility, the main actor shall provide a written report to the Distribution Utility.

Art. 18.45 In the case of a Significant Incident that has been notified by a Distribution Utility to a main actor, the Distribution Utility shall provide a written report to the main actor.

Art. 18.46 The reports referred to in Art. 18.44 and Art. 18.45 shall, where applicable, include at least the following:

(a) Time and date of Significant Incident;

(b) Location;

(c) Plant and equipment involved;

(d) Brief description of the Significant Incident;

(e) Estimated time and date of return to service;

(f) Supplies/generation interrupted and duration of interruption;

(g) Generating unit–frequency response achieved;

(h) Generating unit – MVar performance achieved;

(i) Any other information that the Distribution Utility or main actor reasonably considers may be required in relation to the Significant Incident

CONFIDENTIALITY OBLIGATIONS

Art. 18.47 A Distribution Utility shall use all reasonable effort to keep as confidential any information classified as such and which comes into the possession or control of the Distribution Utility or of which the Distribution Utility becomes aware.

Art. 18.48 The information owner may request the recipient of the information to enter into a confidentiality agreement before information established to be confidential is provided.

Art. 18.49 A Distribution Utility shall not:

(a) Disclose confidential information to any third party without the written consent of the owner or provider of the information.

(b) Use or reproduce confidential information for any purpose other than that for which it was disclosed or for purposes contemplated by this Distribution Code, and

(c) Permit unauthorized persons to have access to confidential information.

Art. 18.50 A Distribution Utility shall use all reasonable efforts to prevent unauthorized access to confidential information that is in the possession or control of the Distribution Utility.

Art. 18.51 A Distribution Utility shall reasonably ensure that any person to whom it discloses confidential information observes the provisions for confidentiality in relation to that information.

Art. 18.52 A Distribution Utility shall report to the information owner or provider any unauthorised disclosure of information that is governed by a confidentiality agreement as soon as practicable after it has become aware of the unauthorised disclosure and shall provide all reasonable assistance to ensure recovery or destruction of that confidential information as may be deemed appropriate by the information owner or provider.

EXCEPTIONS

Art. 18.53 The confidentiality provisions in this section of this Distribution Code do not prevent the disclosure, use or reproduction of information,

(a) If the relevant information is at the time generally and publicly available other than as a result of a breach of confidentiality by a Distribution Utility or any person to whom the Distribution Utility has disclosed the information;

(b) By a Distribution Utility for the use of an employee or officer of a main actor or a related body corporate of the Distribution Utility; or a legal or another professional adviser, auditor or another consultant which requires the information for this Distribution Code, or for the purpose of advising the Distribution Utility;

(c) With the consent of the person who provided the relevant information under this Distribution Code;

(d) To the extent required by law or by a lawful requirement of any government or governmental body, authority or agency having jurisdiction over a Distribution Utility or its related corporate bodies;

(e) If required in connection with legal proceedings, arbitration, expert determination or other dispute resolution mechanisms relating to this Distribution Code;

(f) If required to protect the safety of personnel or equipment; or

(g) Of a historical nature in connection with the preparation and submission of reports under this Distribution Code.

DISCLOSURE OF CONFIDENTIAL INFORMATION

Art. 18.54 A Distribution Utility that needs to disclose confidential information shall consult with the provider of the information prior to its release and inform those affected by the information disclosure.

SECTION 19: BREACH OF THE DISTRIBUTION CODE

DISTRIBUTION UTILITY'S OBLIGATION TO REMEDY

Art. 19.01 If a Distribution Utility breaches this Distribution Code, it shall remedy that breach without delay.

NOTIFICATION TO OTHER MAIN CUSTOMERS

Art. 19.02 If a Distribution Utility becomes aware of its failure to comply with any obligation under this Distribution Code, which can reasonably be expected to have a material, adverse impact on other main actors, it shall:

(a) Notify each customer likely to be adversely affected by the non-compliance within five (5) days;

(b) Investigate the non-compliance as soon as practicable but in any event within 20 days; and

(c) Advise the other main actors of the steps it is taking to comply.

Art. 19.03 If a Distribution Utility becomes aware of a breach of this Distribution Code by a main actor, the Distribution Utility shall notify the main actor, in writing of:

(a) Details of the non-compliance and its implications, including any impact on the Distribution Utility and other main actors;

(b) Actions that other main actors can take to remedy the non-compliance;

(c) A reasonable period in which compliance shall be demonstrated; and

(d) Any consequences of non-compliance;

Art. 19.04 A main actor shall use best effort to remedy any non-compliance with this Distribution Code within the period specified in any notice of non-compliance sent by a Distribution Utility.

SECTION 20: RESPONSIBILITIES OF ELECTRICITY RETAILERS

GENERAL RESPONSIBILITIES OF AN ELECTRICITY RETAILER

Art. 20.01 An Electricity Retailer shall not engage in electricity generation.

Art. 20.02 An Electricity Retailer shall carry out its operations in accordance with the Electricity Retail Sale License (ERSL) and any other relevant codes of practice and performance standards stipulated specifically for electricity supply.

Art. 20.03 An Electricity Retailer shall take reasonable steps to ensure that in procuring electricity for sale to all of its customers, it shall consider the network capacity to ensure the sale of electricity without discrimination.

Art. 20.04 An Electricity Retailer shall enter into a relevant agreement with a licensed Distribution Utility to wheel power for retail sale to its customers.

INFORMATION PROVISION

Art. 20.05 An Electricity Retailer shall, on request from a Distribution Utility, provide details of loads connected or planned to be connected to the distribution system, which is required for the Distribution Utility planning its distribution system. The details shall include:

(a) The location of the load in the distribution system;

(b) Existing loads;

(c) Existing load profile;

(d) Changes in load scheduling;

(e) Forecasts of load growth;

(f) Anticipated new loads; and

(g) Anticipated redundant loads.

SECTION 21: RESPONSIBILITIES OF BULK CUSTOMERS AND OTHER CUSTOMERS

Art. 21.0 (a) A Bulk Customer or Customer installing any new or replacing generating or associated equipment to form part of or to be connected to a distribution system shall inspect and test the equipment to demonstrate that it complies with relevant standards, the provisions of this Distribution Code and any relevant Connection Agreement prior to or within an agreed time after being connected to the distribution system, and the Distribution Utility are entitled to witness such inspections and tests.

(b) The Distribution Utility may, at its sole discretion, witness commissioning tests relating to new or replacement generating or associated equipment that could reasonably be expected to alter the performance of the distribution system or the accurate metering of energy.

(c) The Distribution Utility shall, within a reasonable period of receiving advice of commissioning tests, notify the person whose new or replacement generating, or associated equipment is to be tested whether or not the person wishes to witness or observe the commissioning tests and finds the proposed commissioning times to be suitable.

Art. 21.01 On request from a Distribution Utility, a bulk customer or other customers shall provide details of loads connected (or planned to be connected) to the distribution system that is required for planning purposes by the Distribution Utility. The details shall include:

(a) The location of load in the distribution system;

(b) Existing loads;

(c) Existing load profile;

(d) Changes in load scheduling;

(e) Planned outages;

(f) Forecasts of load growth;

(g) Anticipated new loads; and

(h) Anticipated redundant loads.

Art. 21.02 A Bulk Customer or Customer installing any new or replacing generating or associated equipment to form part of or to be connected to the distribution system shall notify with the Commission.

SECTION 22: RESPONSIBILITIES OF CUSTOMER-GENERATORS

GENERAL RESPONSIBILITIES

Art. 22.01 A customer-generator shall be responsible for;

(a) The operation of its facilities connected to the distribution system to ensure safe and reliable operation in accordance with the requisite performance and reliability standards;

(b) The execution of the operating instructions and directives of the Distribution Utilities in a manner that is consistent with the reliable operation of the distribution system;

(c) The facility and its operation in a manner that does not degrade the performance of the distribution system and for the execution of the necessary measures to promptly remedy any degradation that may occur; and

(d) The provision of the means for averting any damage to the installation by atmospheric electricity as may be determined by the Distribution Utility.

Art. 22.02 The Customer-generator is responsible for protecting its equipment in such a manner that faults or other disturbances in the distribution system do not cause damage to the Customer-generator's equipment.

Art. 22.03 The Customer-generator shall ensure the automatic disconnection of the renewable energy generating facility from the distribution system in the event of a power outage in the distribution system or any abnormal operation of the distribution system as specified in Technical Schedule D.

Art. 22.04 The Customer-generator accepts that its generating facility shall be disconnected immediately from the distribution system upon direction from the Distribution Utility in the event the Distribution Utility determines that the generating facility is producing adverse effects or causing damage to other distribution system customers or the Distribution Utility's assets.

Art. 22.05 A Customer-generator shall meet the requirements of this Distribution Code relating to power quality parameters at the Point of common coupling unless otherwise specified by the Distribution Utility.

Art. 22.06 The design, installation, operation, and maintenance of the customer-generators facility shall be conducted in a manner that ensures the safety and security of both the generating facility and the distribution system.

SECTION 23: RESPONSIBILITIES OF EMBEDDED GENERATORS (DISPATCHABLE AND CONVENTIONAL PLANTS)

GENERAL RESPONSIBILITIES

Art. 23.01 An Embedded Generator (dispatchable and conventional) such as thermal plants or hydro plants shall be responsible for:

(a) The design, installation, commissioning, operation and maintenance of its plant and equipment to meet the requirements of this Distribution Code and other relevant regulations;

(b) Compliance at all times with applicable requirements and conditions of connection for generating units in accordance with the Connection Agreement with the Distribution Utility;

(c) Providing the Distribution Utility with information on variable capacities and operating constraints of its generating units to facilitate dispatch under all power system operating states;

(d) The development of maintenance plans for its equipment and the provision of necessary information to the Distribution Utility; and

(e) The provision of accurate and timely data, information and reports to the Distribution Utility

SUPPLY FREQUENCY

Art. 23.02 An embedded generator (dispatchable and conventional) shall ensure that the embedded generating unit is capable of continuous, uninterrupted operation at the system frequency of 50 Hz and permitted variations in accordance with existing regulations.

CO-ORDINATION AND COMPLIANCE OF EMBEDDED GENERATING UNITS

Art. 23.03 An embedded generator (dispatchable and conventional) shall ensure that:

(a) The embedded generating unit, and any equipment within it that is connected to a distribution system;

(i) complies with this Technical Schedule C;
(ii) this Distribution Code; and
(iii) complies with all relevant Distribution Utility Standards and Specifications;

(b) Protection equipment is at all times effectively coordinated with the protection system of the distribution system.

Art. 23.04 A Distribution Utility may disconnect or request an embedded generator to disconnect its embedded generating unit from the distribution system if the embedded generating unit breaches any safety regulations or is not in compliance with the Distribution Utility's standards.

Art. 23.05 If requested under Art. 23.04, the embedded generator shall disconnect the embedded generating unit from the distribution system.

Art. 23.06 The embedded generator shall ensure that the power it injects into the distribution system is within the limits prescribed in this Distribution Code.

Art. 23.07 The embedded generator shall continuously monitor the power quality in accordance with this Distribution Code and submit annual reports to the Commission.

Art. 23.08 All power quality parameters shall be monitored at the point of common coupling and shall comply with the limits presented in this Distribution Code.

Art. 23.09 An embedded generator shall design, implement, coordinate, and maintain its protection system to ensure the desired speed, sensitivity, and selectivity in clearing faults on the embedded generator's side of the point of common coupling.

Art. 23.10 An embedded generator shall ensure fault levels in the distribution system do not exceed the levels specified in Table A -3 of Technical Schedule A.

Art. 23.11 An embedded generator shall have relays/trip settings for over/under voltage, over/under frequency, and earth fault. The embedded generator shall have overcurrent protection, surge protection, and lightning arrestors.

Art. 23.12 Protection functions required for protecting the National Interconnected Transmission System (NITS) or distribution system from getting out of normal operating ranges shall be specified by the Distribution Utility in consultation with the Electricity Transmission Utility (ETU), including trip settings and response times.

Art. 23.13 An embedded generator shall be equipped with effective detection of islanded operation in all system configurations and shall have the capability to shut down the generation of power in such conditions within 2 seconds.

Art. 23.14 Operation in an island mode with part of the distribution system shall not be permitted unless specifically agreed with the ETU and the Distribution Utility.

Art. 23.15 The coordination among protections at the connection point shall be agreed between the ETU, the Distribution Utility, and the embedded generator.

Art. 23.16 The circuit breaker used for connection switching in the distribution system connected generators shall be equipped with a disconnection system to ensure safe operation during re-connection and re-synchronization to the distribution system.

Art. 23.17 The embedded generator shall have lightning arrestors installed to protect all the equipment of the Solar PV system as well as the interconnection equipment.

Art. 23.18 The Distribution Utility may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the distribution system except that, such a change shall not result in an embedded generator being exposed to negative impacts from the distribution system lying outside of the design requirements.

Art. 23.19 The Distribution Utility shall inform the embedded generator of the highest and lowest short-circuit current that shall be expected at the point of common coupling as well as any other information about the distribution system as may be necessary to define the embedded generator's protection functions.

Art. 23.20 Where the embedded generator’s protection equipment is required to communicate with the Distribution Utility’s protection equipment, it must meet the communications interface requirements specified by the Distribution Utility and this Distribution Code.

SECTION 24: RESPONSIBILITIES OF A VARIABLE RENEWABLE POWER PLANT (VRPP) OPERATOR

GENERAL RESPONSIBILITIES

Art. 24.01 A Variable Renewable Power Plant (VRPP) operator shall be responsible for:

(a) Ensuring that the interconnection of a VRPP with a distribution system shall not deteriorate system security;

(b) Ensuring that VRPP meets the requirements of Technical Schedule F at the point of common coupling.

(c) The design, installation, commissioning, operation, and maintenance of the generation facility must be conducted in a manner that ensures the safety and security of a VRPP and distribution system;

(d) Ensuring that the VRPP is maintained and operated in accordance with the instructions of the Distribution Utility to supply electricity through the distribution system to customers;

(e) Ensuring that the VRPP connected to the distribution system is equipped with adequate protection in such a manner that faults or other disturbances in the distribution system do not cause damage to their equipment;

(f) Complying with applicable requirements and conditions of connection for generating units and in accordance with any Connection Agreement with the Distribution Utility; and

(g) Ensuring that the Distribution Utility shall be permitted to participate in the inspection, testing, or commissioning of facilities and equipment to be connected to the distribution system.

Art. 24.02 A VRPP shall demonstrate compliance with all applicable requirements specified in this Distribution Code and any other applicable code or standard approved by a Distribution Utility in consultation with the ETU, as applicable, before being allowed to connect to the distribution system.

Art. 24.03 A VRPP operator shall conduct tests or studies to demonstrate that the VRPP complies with each of the requirements of this Distribution Code and submit such test reports to the Distribution Utility.

Art. 24.04 The Distribution Utility may issue an instruction requiring the VRPP operator to carry out a test to demonstrate that the relevant VRPP complies with the Distribution Code requirements, and the VRPP operator shall not refuse such an instruction, provided it is issued without delay and there are reasonable grounds for suspecting non-compliance.

Art. 24.05 A VRPP operator shall keep records relating to the compliance of the VRPP with each section of this Distribution Code or any other code applicable to the VRPP, setting out such information that the Distribution Utility reasonably requires for assessing power system performance, including actual VRPP performance during abnormal/continuous operating conditions. Records shall be kept for a minimum of five (5) years (unless otherwise specified in this Distribution Code) commencing from the date the information was created.

TECHNICAL SCHEDULES

TECHNICAL SCHEDULES A: BENCHMARKS AND INDICES FOR STANDARDS OF SUPPLY: RELIABILITY AND QUALITY

Table A - 1

VOLTAGE HARMONIC DISTORTION LIMITS			
Voltage at point of common coupling	**Total harmonic distortion**	**Individual voltage harmonics**	
		Odd	**Even**
< 1 kV	5%	4%	2%
> 1 kV and < 36 kV	3%	2%	1%

Table A - 2

CURRENT HARMONIC DISTORTION LIMITS						
	Maximum Harmonic Current Distortion in Percent of IL					
	Individual Harmonic Order "h" (Odd Harmonics)					**Total Harmonic Distortion**
ISC/L	**<11**	**11 ≤ h <17**	**17 ≤ h < 23**	**23 ≤ h < 35**	**35 ≤ h**	
<20*	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
<100	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

<u>Notes:</u>

1. Even harmonics are limited to 25% of the odd harmonics listed above.

2. Current distortions that result in a DC offset, e.g., half-wave converters, are not allowed.

*3. *All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L.*

*4. Isc = maximum short-circuit current at the **point of common coupling**.*

*5. I_L = maximum **demand** load current (fundamental frequency component) at the **point of common coupling**.*

Table A - 3

DISTRIBUTION SYSTEM FAULT LEVELS (IEC 60909)		
Voltage Level kV (V_n)	**System Fault Level MVA (F_l)**	**Short Circuit level Level kA Circuit(kA) (I_f)**
36	2500	40.1
11	500	25.
6.6	250	21.9
<1	36	50.0
$I_f = F_l / \sqrt{3} * V_n$		

Table A – 4

Frequency Ranges of Operation (Must remain connected conditions)

Frequency (Hz)	Operation
47.5 ≤ F < 48.75	90 Minutes
48.75 ≤ F < 51.25	Unlimited (Continuous Range)
51.25 < F ≤ 51.5	90 Minutes
51.5 < F ≤ 52	15 Minutes

Table A - 5

Over/under voltage protection relay response time

Voltage Range (at Point of common coupling)	Maximum clearing time (s)
V < 50 %	0.16
50% <=V < 85 %	11
85% < V < 90%	61
110 % < V < 115%	61
115 % < V	0.16

Table A - 6

Over/under frequency relay response times

Frequency	Protection relay setting values
F<48.75Hz	0.2 s
F>51.25Hz	0.2 s

Table A – 7

Flicker limits are to be applied in the absence of apportioned limits

Planning level	Emission Limit (MV)
P_{st}	0.4
P_{lt}	0.4

Table A – 8

STANDARD NOMINAL VOLTAGE VARIATIONS

Voltage Level in kV	Voltage Range for Time Period		
	Steady State	Transient State	
		Less than I minute	Less than 10 seconds
<1.0	±10%	±15%	Phase to Earth +50% - 100% Phase to Phase +20% - 100%
11	±10%	±15%	Phase to Earth +80% - 100% Phase to Phase +20% - 100%
33	±10%	±15%	Phase to Earth +80% - 100% Phase to Phase +20% - 100%
34.5	±10%	±15%	Phase to Earth +80% - 100% Phase to Phase +20% - 100%

Table A – 9

POWER FACTOR LIMITS

Supply Voltage in kV	Power Factor Range for Customer Maximum Demand and Voltage					
	Up to 100 kVA		Between 100kVA – 2MVA		Over 2 MVA	
	Minimum		Maximum		Minimum	
	Lagging	Leading	Lagging	Leading	Lagging	Leading
<1.0	0.95	0.95	-	-	-	-
11	0.95	0.95	0.95	0.95	0.96	0.96
33	0.95	0.95	0.95	0.95	0.96	0.96
34.5	0.95	0.95	0.95	0.95	0.96	0.96

TECHNICAL SCHEDULE B: MINIMUM INSPECTION REQUIREMENTS

B.1 GUIDE FOR DEVELOPMENT OF DISTRIBUTION INSPECTION MANUAL

Inspection Cycles

A Distribution Utility shall ensure that only qualified persons are involved in inspection activities. Since some inspections can expose inspectors to energized lines or high-voltage circuits and equipment and may include inspection repair, a qualified person should be assigned to this work. This assumes that they are both properly trained to protect both themselves and the public and to respond to those emergencies, which may arise during inspections.

In developing the standards for facilities inspections, the patrol inspection is defined as follows:

- Patrol or simple visual inspections consist of walking, driving, or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism.

- In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, individual pieces of equipment carefully observed, and their condition noted and recorded, and a summary document prepared in the Distribution Utility's annual reports.

In all cases, a Distribution Utility is responsible for ensuring that appropriate follow-up and corrective action is taken regarding problems identified during a patrol.

The Commission reserves the right to conduct random audits of inspection reports to ensure that appropriate follow-up and corrective action is taken regarding problems identified during a patrol.

It is expected that Distribution Utilities will file both annual summary reports of detailed patrol inspection activities that have taken place during the previous year as well as an outline of inspection plans ("compliance plan") for the forthcoming year.

The following description provides a list of the requirements to be expected from a typical distribution line patrol inspection in terms of the types of defects that may be detected visually. Clearly, the list will vary depending on the equipment specifics and locations, thus this should be viewed as a ‘generic’ patrol expectation.

1. Substation- May consist of one or all types of the following equipment listed

    - Transformers and Switchgears
    - Distribution Pillars
    - Paint condition and corrosion
    - Transformer platform (pad or pole mounted)
    - Check for lock and holding/anchor bolt in place
    - Grading changes
    - Access changes (Shrubs, trees, etc.)
    - Phase indicators and unit numbers match operating map (where used)
    - Leaking oil
    - Flashed or cracked insulators
    - Pad-mounted – lid damage, missing bolts, cabinet damage, public security lock damage

1. **Switching/Protective Devices**

2. **Uniform Nomenclature** for identifying substation

3. **Feeder Identification**

4. **Overhead pole mounted**
    - Bent, broken bushings and cut-outs,
    - Damaging lightning arresters, control boxes, current, and potential transformers
    - Pad-mounted substations
    - Security condition of enclosure

5. **Voltage Regulators**
    - Condition of bushings
    - Tank corrosion/leaks
    - Damaged disconnect switches or lightning arresters

6. Capacitors

- Condition of bushings
- Tank corrosion/leaks
- Damaged switches, disconnects or control cabinet

7. Conductors and Cables

- Low conductor clearance
- Broken /frayed conductors or tie wires
- Tree conditions, exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag.
- Insulations fraying on secondary especially open wire

8. Poles/Supports:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications or burning

9. Hardware and attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated/cracked (difficult to see)
- Tie wire unravelled
- Ground wire broken or removed
- Ground wire guards removed or broken

10. Equipment Installations (includes transformers and Ring Main Units)

- Contamination/discoloration of bushing
- Oil leaks
- Rust
- Ground lead attachment
- Ground wires on arrestors unattached
- Bird or animal nests
- Vines or brush growth interference

- Evidence of bushing flashover
- Accessibility compromised

11. Vegetation and Right of Way

- Leaning or broken “danger” trees
- Growth into the line of “climbing “trees
- Unapproved/unsafe occupation or secondary use

12. Civil Infrastructure

For example, buildings that house the equipment may need attention (cracking, fire hazards, etc.). In addition, cable chambers, and tunnels crossing the rail track or water are also included in this category.

13. Underground systems:

With respect to underground systems, riser poles should be checked as with an overhead patrol, with a visual check of cable, cable guards, terminators, and arrestors. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. The cable route for an underground system should be documented.

Underground Cables are hard to check, but the system can be checked for exposed cable or grading changes that may have brought cable or wire too close to the surface.

TABLE B - 1
Electric Utility system inspection cycles
(Minimum number of inspections/patrols in a year)

Major or Substantial Distribution Facility*	**Patrol/Inspection**	**Patrol/Inspection**	**Patrol/Inspection**
	Urban	**District Capital**	**Rural**
Bulk Supply Point			
Enclosed/Indoor Switchgear	4	5	6

Cables, terminations and lugs	4	5	6
Protection and Control Equipment	4	5	6
Outdoor Circuit breakers	4	5	6
Metering	4	5	6
Station service transformer	4	5	6
Voltage quality Monitoring	6	6	6
Power factor	6	6	6
Load factor	6	6	6
Primary Distribution Substation			
Power Transformers	4	5	6
Earth Reactor	4	5	6
Switchgear	4	5	6
Voltage Regulators and surge Arrestors	4	5	6
Cables, terminations and lugs	4	5	6
Protection and Control Equipment	4	5	6
Outdoor Circuit breakers	4	5	6
Secondary Distribution Substation			

Indoor distribution transformers	4	5	6
Indoor Distribution Pillars	4	5	6
Outdoor Pad mounted transformers	4	5	6
Outdoor Pole mounted transformers	4	5	6
Package transformers substation	4	5	6
Standalone transformer substation	4	5	6
Customer specific substation	4	5	6
Transformer load monitoring of all distribution transformers	4	4	4
Overhead Lines and Associated Equipment			
Conductors, cables, terminations, and lugs	4	5	6
Switchgear (Ring main units, circuit breakers, etc.)	4	5	6
Capacitor banks	4	5	6
Voltage Regulators	4	5	6
Wood Poles	2	3	4
Line vegetation/undergrowth	2	3	4
Civil works/infrastructure/Gantry	2	3	4

Notes to Table B-1

1. The above distribution system patrol cycles form part of the regulatory framework and are minimum inspection requirements for each major or substantial distribution component and related hardware.

2. The method by which inspection cycles are structured, and the work carried out is at the discretion of the Distribution Utility. The above table is organized according to the major classification of equipment.

TECHNICAL SCHEDULE C: TECHNICAL REQUIREMENTS FOR CONNECTING EMBEDDED GENERATION FACILITIES

Technical Requirements for Generator Connection

General Requirements

A. An embedded generating unit over 1 MW shall have:

   (a) an excitation control system including a voltage regulator;
   (b) a governor system responsive to system frequency changes; and
   (c) real-time systems events log

B. An embedded generator shall ensure that each of its embedded generating units with a nameplate rating over 10 MW complies with the relevant codes, standards and regulatory requirements for generating units with a nameplate rating over 30 MW with regards to:

   (a) response to disturbances;

   (b) safe shutdown without an external electricity supply;

   (c) restart following loss of external electricity supply; and

   (d) frequency responsiveness and governor stability.

1. Point of common coupling

The point of common coupling will be identified in the design and on the single-line diagram. The Distribution Utility will coordinate the design, construction, maintenance, and operation of the facilities on its side of the point of common coupling. The applicant is responsible for the design, construction, maintenance, and operation of the facilities on its side of the point of common coupling unless described otherwise in an interconnection agreement.

TABLE C - 1

Requirement for Point of Common Coupling

Item	**Subject**	**Requirement**	**Details of requirement**
	Grounding at point of common coupling	IEEE std 80: Guide for safety in AC substation grounding IEEE 81 Guide for measuring resistivity ground impedance, and earth surface potentials of grounding systems	IEEE 80 for substation grounding has values of ½ to 1 ohm for generating plants and large substations
	Voltage at point of common	Voltage Regulation, IEEE 1547	
	Synchronization	Synchronization, IEEE 1547	
	Voltage Unbalance	Voltage Unbalance, IEEE 1547	
	Power Factor during operation	preferred range of 0.9 lag to 0.95 lead	
	Grounding at point of connection	IEEE 142-2007: Recommended practice for grounding of industrial and commercial power systems	IEEE 142,IEEE" recommends an earth resistance in the range of ½ to 5 ohms .

2. Interconnecting Grounding

Generation facilities and the associated interconnection systems must be grounded as per the manufacturer’s recommendations, as well as taking into account the normal practices of the Distribution Utility.

Interconnection of three-phase transformers and transformer grounding systems on three-phase distribution systems shall be co-coordinated with the Distribution Utility and shall not cause voltage disturbances or disrupt the co-ordination of distribution system ground fault protection.

3.1 Steady-State Voltage,

Customers connected to the feeder must be supplied with voltage levels established by the Commission for the following situations:

- with and without the generation facility
- generating power for minimum and maximum feeder loading conditions.

3.2 Voltage Regulation, IEEE 1547 (equivalent to IEC 61727),

The generation facility must operate satisfactorily within the extreme voltage level variation limits shown in these standards. Voltage regulation is the responsibility of the Distribution Utility.

An embedded generator shall ensure that an embedded generating unit’s contribution to the negative sequence voltage at the point of common coupling between the embedded generating unit and the distribution system is less than 1%.

3.3 Synchronization, IEEE 1547

The generator shall parallel with the distribution system without causing a voltage fluctuation of flicker greater than those specified by the above standards at the point of common coupling.

3.4 Voltage Unbalance

Where the distribution system supplies single-phase loads, some unbalances are inevitable. The generation facility should be capable of operating under these conditions and shall not cause further deterioration of existing unbalanced conditions.

4. Power Factor, IEEE 1547,

The generator's system is not required to be capable of adjusting the power factor but shall operate in the preferred range of 0.9 lag to 0.95 lead. If the generation facility disturbs the distribution system voltage levels at the point of common coupling, then the generator may be required to operate its facility within a smaller range or take other compensatory measures. Field settable fixed and dynamic power factor correction techniques may be used if consultation with the Distribution Utility reveals no adverse effect on the distribution system. For generators that are inactive, the reactive power compensation at the generating units should be sufficient so as not to cause any material increase in the reactive power requirements at the transmission system transformer station due to operation of the NITS at any distribution feeder load conditions.

5. **Equipment Ratings and Requiremen**t

The generation facility interface equipment must be compatible with DU equipment ratings at the connection voltage (maximum voltage, basic impulse limit, short circuit ratings, capacity, etc.) and the incorporation of the added generation facility must not result in any distribution system equipment operating beyond the distribution system operational rating. A Distribution Utility shall review the equipment ratings for the purpose of assessing the integration of the generation facility with the distribution system. The equipment ratings that shall be reviewed include but not limited to, the following:

5.1 Equipment Thermal Loading

All existing Distribution Utility's equipment in distribution and transmission stations shall not be overloaded beyond acceptable limits under all operating conditions of the generation facility. This equipment includes feeder conductor, line voltage regulators, regulating stations, recloses, circuit breakers, and transformers.

Assuming that under existing operating conditions, there is no overloaded equipment, the study will be conducted for minimum load conditions and maximum generation, including all generation facilities already existing on the feeder. The load flow study will identify the potential overload of the existing equipment.

5.2 Impact of Generation Facility Fault Contribution on Equipment Rating

The generation facility will contribute to the total fault current. The distribution system's interrupting devices shall be able to interrupt the maximum fault current that will flow through the devices. All the distribution system's electrical equipment has to be able to withstand the fault current passing through it for the required time for the protection to clear the fault.

The fault interrupting rating of the existing interrupting devices and the fault withstanding rating of the electrical equipment shall be higher than the maximum fault current possible to flow through the equipment.

Where the generator causes these limits to be exceeded, distribution system equipment replacement or fault current limiting devices may be required.

5.3 Voltage Regulating and Metering Devices

The Distribution Utility's system has been designed for unidirectional flow of power from a source (i.e., station) to the customer. Therefore, the voltage regulating and metering devices are designed to correctly operate in these conditions. The connection of generating facilities to the distribution feeder could cause the power flow to be reversed through the power equipment, which will create difficulties to properly regulate the voltage or to measure the energy, respectively.

Where it is possible for power to flow in reverse through the existing voltage regulating devices or the metering points, the regulating devices and metering devices shall be suitable for such bi-directional flow.

The study will be conducted for minimum load and maximum generation conditions. The direction of the power flow through voltage regulating devices connected between the generation facility and the transformer station will be verified, including line voltage regulators, regulating stations, and transformers under load tap changers, at the substation and transformer station. Also, all metering devices, either for billing purposes or monitoring reasons, will be verified.

6. Cease to Energize

The Distribution Utility will review the generator's design to ensure that the facility will cease to energize automatically from the distribution system's supply under the conditions identified in this section.

Important considerations in this design review are

I. As per IEEE 1547- 2018- to maintain the reliability of the distribution system, the Distribution Utility may use automatic re-closing. The applicant needs to be aware of line re-closing when designing the system protection schemes to ensure that it de-energizes the distribution system prior to the automatic re-close of the distribution system's breakers or line reclosers. The Distribution Utility must review to ensure that the generator's design will de-energize the generation facility prior to the auto-reclose operation of feeder tripping devices

II. After a disturbance on the distribution system, no reconnection shall take place until the distribution system voltages and frequency are within the limits specified by the Energy Commission.

III. The generator's interconnection system shall include an adjustable delay (or a fixed delay of 5 minutes) that may delay reconnection for up to 5 minutes after the distribution system's steady-state voltage and frequency are restored to the ranges identified above.

6.1 Loss of DU Supply, Resulting in the Formation of an Island, IEEE 1547 -2018 (loss of Supply Authority Voltage)

6.1.2 Unplanned Islanding

The applicant's system shall cease to energize the distribution system following the formation of an unintentional island.

6.1.3 Planned islanding

Where planned islanding is allowed, the generator and the Distribution Utility will jointly agree to all requirements.

6.2 Over-Current Protection Coordination Due to Generation Facilities Fault Contribution IEEE 1547

Any element of the interconnection system external to the generation facility, but ahead of the point of common coupling, should be installed in a fail-safe manner with self-checking features or redundant protection functions for large generators.

Equipment and conductors shall be provided with over-current protection from each source of supply. The generation facilities protection system shall be capable of automatically isolating the generator from the distribution system for the following:

- Internal faults within the facility; or
- External faults within the distribution system.

The protective device selectivity and sensitivity have to be maintained over the range of minimum to maximum fault currents with infeed from the generator.

Where the primary connection of the generation facility transformer is Wye- (Y) grounded, the sensitivity of the ground fault protections could become deficient, as zero-sequence current will have an additional ground path through the transformer to the distribution system. The ground fault occurring within the protected zone has to be seen by the ground fault protections with and without a transformer connected.

6.5 System Voltage Changes Beyond the Over or Under Voltage Range, IEEE 1547

Over and under voltage and over and under frequency protection is required at the generation facilities interconnection point.

The set points and clearing times for over or under voltages and over or under frequencies are dependent upon the magnitude of voltage and frequency variations and generator size, for details, see the relevant clause of IEEE 1547.

Note: The Electricity distribution rules established by the Commission state that each parallel power generation facility installation shall be provided with such additional devices that are required for system stability and equipment protection.

7. Feeder Relay Directioning

The existing over-current protections in the distribution system are typically designed to clear line and ground faults occurring downstream from their location, as the source feeding the fault is only the transformer station. Connecting a generation facility provides another source supplying the fault, and the fault contribution from the facility might cause protection to operate non-selectively for reverse faults, out of the protected zone.

If the maximum reverse fault current through a non-directional fault-interrupting device exceeds the setting of the device, the fault-interrupting device shall be provided with a directional feature to prevent tripping for reverse fault current flow. The phase protection could be replaced with an impedance relay (21) if required.

The main concern is the infeed from the generation facility with a Wye-(Y) grounded connection on the HV of the interface transformer for faults on the adjacent feeders. The generator may consider adding a reactor <5 ohms in the neutral of the generator’s transformer, within the constraints of the over-voltages.

8. Monitoring, IEEE 1547, Distribution Utility Requirements for Facilities of 10 MW and Higher

A generation facility connected to the point of common coupling, rated at greater than 250 kVA, shall have provision for monitoring connection status, real power output, reactive power output, and voltage either at the point of common coupling or aggregate connection, as required by the Distribution Utility. The monitoring equipment shall either be installed, or there shall be an adequate provision in the design to allow future installation of such equipment if not required at the time of interconnection. When the implementation of data telemetry is required, the Distribution Utility and the generator will mutually agree upon communication media options.

9.1 Flicker, IEEE 1547, IEC 61000-3-11

The generation facility does not cause objectionable flicker on the distribution system. It is recognized that flicker is a site-dependent condition. Loss of synchronism protection may be required to be incorporated by the generator, if necessary, to limit flicker.

9.3 Limits of DC Injection, IEEE 1547

The generation facility shall not inject a d.c. current greater than 0.5% of the unit rated output current after a period of six cycles following the energizing of the distribution system.

10.4 Protection from Electromagnetic Interference (EMI), IEEE 1547,

The influence of EMI should not interfere with the operation of the generation facility's interconnection system.

10.5 Surge Withstand Performance, IEEE 1547(equivalent to IEC 61727),

The interconnection system shall have the capability to withstand voltage and current surges

10.6 Paralleling Device, IEEE 1547(equivalent to IEC 61727)

The interconnection system paralleling device shall be capable of withstanding 220% of the interconnection system rated voltage.

11. Harmonics

1. An embedded generator shall ensure that an embedded generating unit's contribution to the harmonic distortion levels in the supply voltage at the point of common coupling between the embedded generating unit and the distribution system is within the limits specified in Table 1 of Technical Schedule A.
2. An embedded generator shall comply with IEEE Standard 519-2014 'Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems' and the current harmonic limits in Table 2 of Technical Schedule A.

12. Reactive power control requirements

1. An embedded generator shall be equipped with control functions to control reactive power at the point of common coupling following instructions from the DU using set-points and gradients, and the parameter settings agreed between the DU and an embedded generator shall be as documented in the relevant System Operational Manual.

2. An embedded generator shall support each of the following control functions:

   (a). Reactive Power control
   (b). Power Factor Control

3. The choice of control mode and the definition of target values shall be within the responsibility of the DU, and it must be possible for the DU to change control mode and target values at any time during the lifetime of an embedded generator.

4. An embedded generator shall be capable of controlling reactive power at the point of common coupling either to a constant reactive power target (Q-target) or an active power-dependent reactive power target (Q(P)).

13. Power Factor Control Requirements

An embedded generator shall be capable of controlling the power factor at the point of common coupling either to a constant power factor target (cosφ -target) or an active power-dependent power factor target (cosφ (P)).

14. Active power control

1. For system security reasons, it may be necessary for the ETU or DU to curtail an embedded generator's active power output.

2. An embedded generator shall be capable of operating at a reduced power level if active power has been curtailed by ETU or DU, for network or system security reasons;

3. The accuracy of the control performed and of the set point shall not deviate more than ±1 % of the rated power.

4. The type of communication between a DU and an embedded generator must be agreed upon between the parties and specified as part of the bilateral connection agreement.

5. The relationship between the ETU and an embedded generator shall be specified as part of the bilateral connection agreement between the DU and an embedded generator.

TECHNICAL SCHEDULE D- REQUIREMENTS FOR CONNECTION OF A CUSTOMER-GENERATOR

1.0 Compatibility with the distribution system

1. The generating facility's AC voltage, current, and frequency shall be compatible with the Supplier's distribution system.

2. Inverters of generating units larger than 13.8 kVA shall be of balanced three-phase type, and inverters up to 13.8 kVA can be of single-phase type.

3. A customer with a multiphase connection shall endeavour to split the Net-Metered Generating Unit in a balanced manner over all phases. Where the Net-Metered Generating Unit is larger than 4.6 kVA, the customer generator shall be required to balance the generation over all phases.

4. In the case of long feeder spurs, the maximum desired capacity of the Net-Metered Generating Unit shall be subject to the approval of the Distribution Utility, and the Distribution Utility may require the use of a three-phase connection.

2.0 Safety and protection

The Customer-generator shall be responsible for providing adequate protection for its facility under all operating conditions regardless of whether or not the renewable energy generating facility is in operation. Conditions include but are not limited to single phasing of supply, system faults, equipment failures, abnormal voltage or frequency, lightning and switching surges, excessive harmonic voltages, excessive negative sequence voltages, and islanding.

3.0 Synchronization

The utility voltage and frequency shall be within the steady-state range for at least 5 minutes before synchronizing the generating facility to the distribution system, i.e., voltage between 90% and 110% of rated voltage and frequency between 49.8 Hz and 50.2 Hz.

During synchronisation, the controller of the renewable energy inverter must ensure that no transient currents or voltages occur that would adversely impact the distribution system.

4.0 Protection and control devices

The Customer-generator's protection system shall coordinate with the Supplier's protection system.

5.0 Disconnect Device

The disconnect device should be located at the PGC, where the renewable energy generating facility and the building's electrical system interconnect, or at the distribution board. The disconnection device also referred to as the main switch, inverter supply shall be visible, easily accessible to service personnel, and should allow manual operation.

Protective relays

1. Protective relays shall be installed to trip the corresponding circuit breaker, or relays internal to the inverter shall trip the inverter, during inadmissible network conditions.

2. The admissible tolerance value between the setting value and trip value of the voltage shall be a maximum ± 1% and the admissible tolerance for the frequency at the maximum ± 0.1%.

Reclosing

3. For a distribution system with automatic reclosing, the Net-Metered Generating Unit shall wait for at least 5 minutes until the re-closer has normalized the portion of the system to which the facility is connected before synchronizing back to the system.

Loss of utility voltage (islanding)

4. To prevent islanding, a Net-Metered Generating Unit shall cease to energize an otherwise de-energized utility system, irrespective of connected loads or other generators within two seconds, according to IEC 61727.

Earthing

5. The customer-generators renewable energy generating facilities and the associated interconnection systems must be grounded in accordance with existing regulations.

6. The grounding scheme of the customer-generator renewable energy generating facility shall not cause voltage disturbances or disrupt the coordination of the ground fault protection on the local distribution system.

Safety and protection

7. The Customer-generator and the Distribution Utility shall ensure the safe operation of the customer-generator renewable energy generating facility and the utility network. The safe operation also includes the safety of the following persons:

   i. Owner (including personnel and inhabitants of the property) of the generator facility;

   ii. General public safety;

   iii. Distribution Utility personnel;

   iv. General emergency response personnel, e.g., fire brigade, should a fire arise at the small renewable energy generating facility.

   v. Any other applicable safety standards for electric installations, as they may be defined by the Electrical Wiring Regulation, shall be considered.

Labelling

8. Appropriate signage shall be displayed on the distribution board where the Net-Metered Generating Unit is connected, warning any personnel to completely disconnect the renewable energy generating facility and isolate it from the distribution lines before working with equipment therein.

Emergency Shutdown

9. All generating facilities shall have emergency shutdown capability. During an emergency, all fuel inputs (e.g., d.c. input to inverter, etc.) and a.c. voltages shall be shut off regardless of the operating mode of the equipment.

10. D.C connection of solar PV panels and other storage mediums shall be open-circuited.

Testing and commissioning

11. The Customer-generator shall provide a minimum of ten (10) working days' notice to the Distribution Utility for a pre-commissioning test of the Net

metered Generating Unit, and schedule a suitable time for the commissioning.

12. The commissioning test shall be conducted after the interconnection system is installed and is ready for operation.

13. The commissioning test shall include the following:

(a) Verification and inspections

(b) Production test

(c) Response to abnormal voltage

(d) Response to abnormal frequency

(e) Synchronization

(f) Unintentional islanding functionality test

(g) Cease-to-energize functionality test

14. The commissioning test shall not be limited to the above.

15. The Distribution Utility shall not be responsible for verifying any control or signal wiring not directly related to the interconnection protection.

16. Prior to final approval by the Distribution Utility or anytime thereafter, the Distribution Utility reserves the right to test the relaying and control related to the protection of the distribution system.

17. If the Distribution Utility personnel is not present to witness the commissioning tests, the Distribution Utility shall still consider approving the commissioning of the renewable energy generating facility if the inverter of the generating facility is certified and upon receiving a copy of the test data.

TECHNICAL SCHEDULE E - REQUIREMENTS FOR CONNECTION OF A VARIABLE RENEWABLE POWER PLANTS (VRPP)

This Schedule provides for the standardization of connection processes, size categories, and time frames for connecting embedded load displacement generation facilities to the distribution system. These categories are described below.

1. Categories of VRPP

TABLE E - 1
Categories of VRPP

Generator Classification	Rating
Micro	≤ 10 kW, for customer's own use
Small/Mini	(a) ≤ 500 k W connected on distribution system voltage < 15 kV, (b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV.
Mid-sized	(a) >500 kW connected on distribution system voltage < 15 k V, (b) > 1 MW < 10 MW connected on distributions system voltage > 15 kV.
Large	> 10 MW

2.0 Frequency Range of Operation

TABLE E - 2

Frequency Ranges of Operation (Must remain connected conditions)

Frequency (Hz)	Operation
47.5 ≤ F < 48.75	90 Minutes
48.75 ≤ F < 51.25	Unlimited (Continuous Range)
51.25 < F ≤ 51.5	90 Minutes
51.5 < F ≤ 52	15 Minutes

(1). A VRPP shall be capable of staying connected within the frequency ranges and times specified in TABLE E **- 2**

(2).[1].

(3). In case of frequencies outside the frequency and time ranges specified in TABLE E **- 2**

(4)., VRPPs are allowed to disconnect.

[1] Continuous frequency range of operation is in-line with Art. 12.24 of the Grid Code. Other frequency limits are required because actual frequency can get out of the described limits. Frequency range down to 47,5Hz has been chosen for ensuring that there will be no disconnection of any VRPP, even in case of AFLS stage 4 and 5.

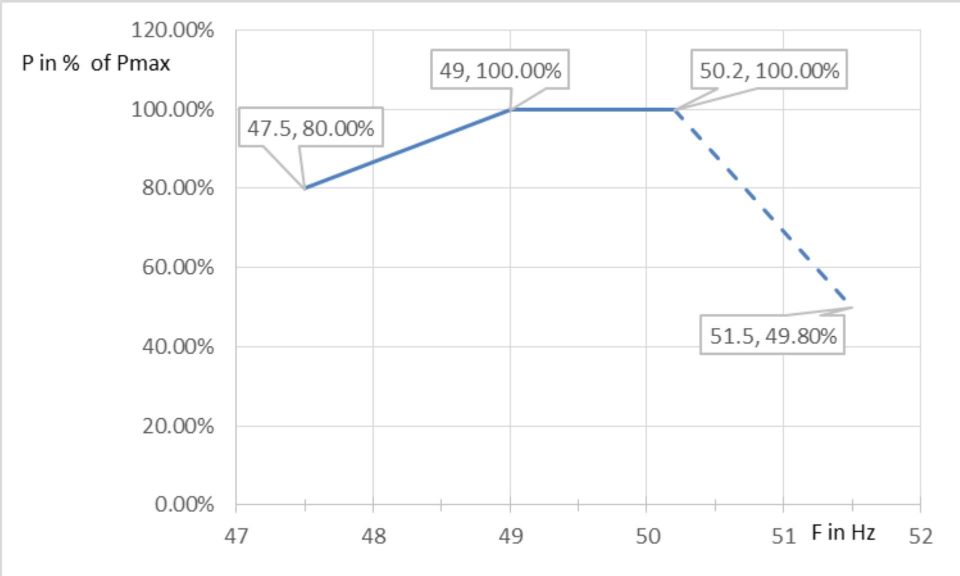

Figure 1: Maximum Active Power Capability in Function of Frequency

(5). A VRPPs shall be capable of Unrestricted Operation within the system frequency range of 49 Hz to 51 Hz[2], meaning that there is no technical restriction with regard to the delivery of active power or reactive power permitted within this frequency range.

(6). Outside the frequency range of Unrestricted Operation, technical restrictions with regard to the delivery of active power are permitted. The minimum active power output that a VRPP must be capable of delivering is depicted in Figure 1.

Note 1: The frequency dependent power limits according to Figure 1 relate to the technical capability under the condition that sufficient primary energy is available (e.g. wind speed, solar irradiation). Additional limits due to limited primary energy may apply but these limits are not frequency dependent.

Note 2: The dashed line displayed for frequencies >50,2Hz results from the high-frequency response according to Figure 1.

2.1 High-Frequency Response

[2] Based on of the Grid Code Articles 9.51 and 9.217, covering Normal State and Alert State.

1. During high-frequency operating conditions in NITS and distribution systems, each distribution system connected to VRPP shall be required to operate at reduced active power output in order to stabilize grid frequency.

2. When the frequency on the NITS and distribution system exceeds 50.2 Hz, each VRPP shall be required to reduce active power as a function of change in frequency, as illustrated in Figure 6.

3. High frequency response must operate with a minimum gradient of 100% of rated power per minute as provided by the primary frequency control time scales.

2.2 Primary and Secondary Frequency Control

4. Unless otherwise required by the ETU/DU, a VRPP shall be exempted from primary or secondary frequency control capabilities except from high frequency response.

3.0 Power Quality

All power quality parameters (voltage, flicker and harmonics) and the impact of VRPP on voltage quality shall be monitored at the point of common coupling. The power quality parameters shall comply with the limits presented in this section.

3.1 Voltage Range of Operation

(1). For all VRPPs, no disconnection of any unit within a power park is permitted as long as the voltage at the point of common coupling remains within +/-10% of nominal voltage or within IEC-voltage limits for continuous operation, whatever is the narrower voltage range (Continues Voltage Range).

(2). For voltages at the point of common coupling between +/-5% of nominal voltage, no restrictions with regard to the provision of active or reactive power are permitted (Unrestricted Voltage Range).

3.1.1 Rapid voltage changes

(1). During regular switching operations within a VRPP (for example, switching operation on a wind turbine within a wind farm or switching of a shunt reactor/capacitor), the resulting voltage change at point of common coupling shall not deviate more than 2 % of the Nominal Voltage.

(2). The maximum permitted voltage change at any point in the network resulting from switching of several units within a VRPP or connection/disconnection of a complete VRPP is limited to 5 % of Nominal Voltage.

3.1.2 Voltage unbalance

VRPPs' contribution to negative sequence voltage shall not exceed 1 % at the point of common coupling.

Note: Voltage unbalance is measured in terms of negative sequence voltage in per cent of nominal voltage.

3.1.3 Behaviour During Abnormal Voltage Conditions

1. Low Voltage Ride Through (LVRT) / High Voltage Ride Through (HVRT) Capability for VRPPs. A VRPP shall be designed to operate for up to one minute within a voltage range of +/-15% of nominal voltage.

2. An embedded generator shall be designed to have LVRT and HVRT capability as illustrated in Figure 7.

3. For all voltages at the point of common coupling, which are between the HVRT (red) and the LVRT (blue) lines according to Figure 7, no disconnection of an embedded generator or (individual units) shall be permitted.

4. The voltage at point of common coupling is defined to be the lowest of the three line-line or line-earth voltages.

5. If the voltage reverts to the Continuous Voltage Range (between Vcmin and Vcmax) during a fault sequence resulting from reclosing, subsequent voltage drops or voltage spikes shall be regarded as new LVRT or HVRT condition.

3.2 Flicker

(1). For each VRPP, ETU shall apportion flicker emission limits based on flicker planning levels according to IEC61000-3-11, existing background flicker levels, possible future installations and the total size of VRPP to be connected. The methodology for apportioning VRPP-specific flicker limits shall be in line with IEC61000-3-11.

(2). In the absence of any project-specific flicker limits apportioned by the DU, flicker caused by VRPPs shall not exceed the flicker limits as shown in **Error! Reference source not found.** at the point of common coupling.

TABLE E – 3

Flicker limits to be applied in the absence of apportioned limits

Planning level	Emission Limit (MV)
P_{st}	0.4
P_{lt}	0.4

3.3 Harmonics

(1). For each VRPP, DU shall apportion individual harmonic voltage distortion limits based on the planning level for individual harmonic distortions (HD) and total harmonic distortion (THD), existing background harmonics, possible future installations and the total size of VRPPs to be connected, according to methodology described in IEEE std 519-1992[3].

(2). In the absence of any apportioned limits, individual harmonic voltage distortion limits for odd harmonics shall not exceed 2 % and for even harmonics 1 %. Total harmonic voltage distortion shall not exceed 3 % at the point of common coupling.

(3). In addition to (3), generators shall not exceed harmonic current distortion limits specified in **Error! Reference source not found.** at the point of common c oupling.

[3] Reference to IEEE 519-1992 only made because draft Distribution Code refers to IEEE 519. Generally IEC61000-3-6 would be the preferred standard.

TABLE E – 4

Current distortion limits for distribution system-connected VRPPs

Current Harmonic Distortion limits						
I_{sc}/I_L	Maximum Harmonic Current Distortion in Percent (%)of I_L					
	Individual Harmonic Order "h" (Odd Harmonics)					
	<11	$11\leq h<17$	$17\leq h<23$	$23\leq h<35$	$35\leq h$	TDD
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

* All power generation equipment is limited to these values of current distortion, regardless of actual I_{sc}/I_L.

1. Even harmonics are limited to 25% of the odd harmonic limits above.
2. Current distortions that result in a DC offset, e.g. half-wave converters, are not allowed.
3. I_{sc} = maximum short-circuit current at the point of common coupling
4. I_L = maximum demand load current (fundamental frequency component of generation current) at the point of common coupling.
5. TDD (Total Demand Distortion) = harmonic current distortion in % of maximum demand load (or generation) current (15 or 30 min demand).

4.0 Reactive power capability

(1). VRPPs shall be capable of varying power factor continuously in the entire range of 0.95 under-excited to 0.95 over-excited during operation with maximum active power output [4] and voltage within the Unrestricted Range of Operation

(2). VRPPs shall be capable of varying reactive power at the point of common coupling within their reactive power capability range as defined by Figure 3 when operating within the Unrestricted Voltage Range and at an active power output level between 5% and 100% of Rated Power.

(3). If the voltage is outside the Unrestricted Voltage Range but within the Continuous Voltage Range[5] the reactive power capability limits of VRPPs according to Figure 3 can be adjusted to the voltage-dependent limits according to Figure 2.

Note: P_n in MW corresponds to the rated installed capacity of the VRPP minus the sum of the installed capacity of all units being temporarily out of service.

(4). In the case of operation with active power below 5% of P_n, there is no reactive power capability requirement. In this range, reactive power must be within the tolerance range of +/-5% of P_n.

[4] Clause 4 of the draft Distribution Code requires DS connected generators be able to vary power factor in the range 0.95 under-excited and 0.9 over-excited which is very demanding and expensive for VRPPs, hence limits suggested according to international practice.

[5] (Vmax and Vcmin in Figure 2 represent max. and min. limits of the Continuous Voltage Range)

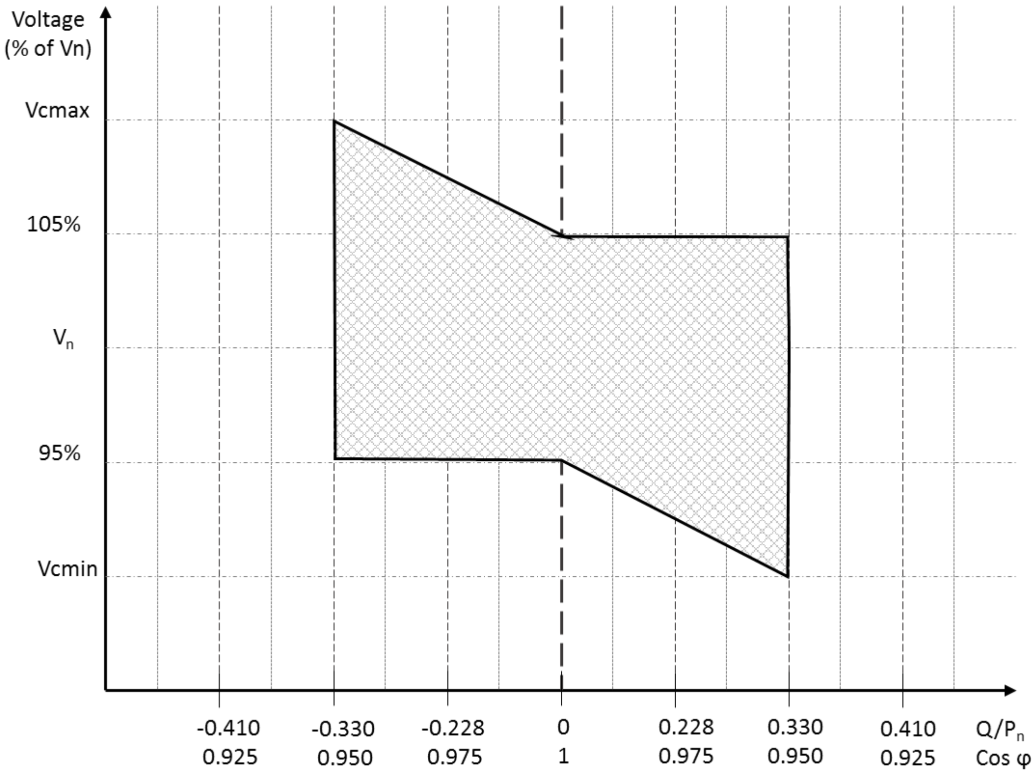

Figure 2: Reactive power requirements for distribution system connected VRPPs (corresponding to voltage)

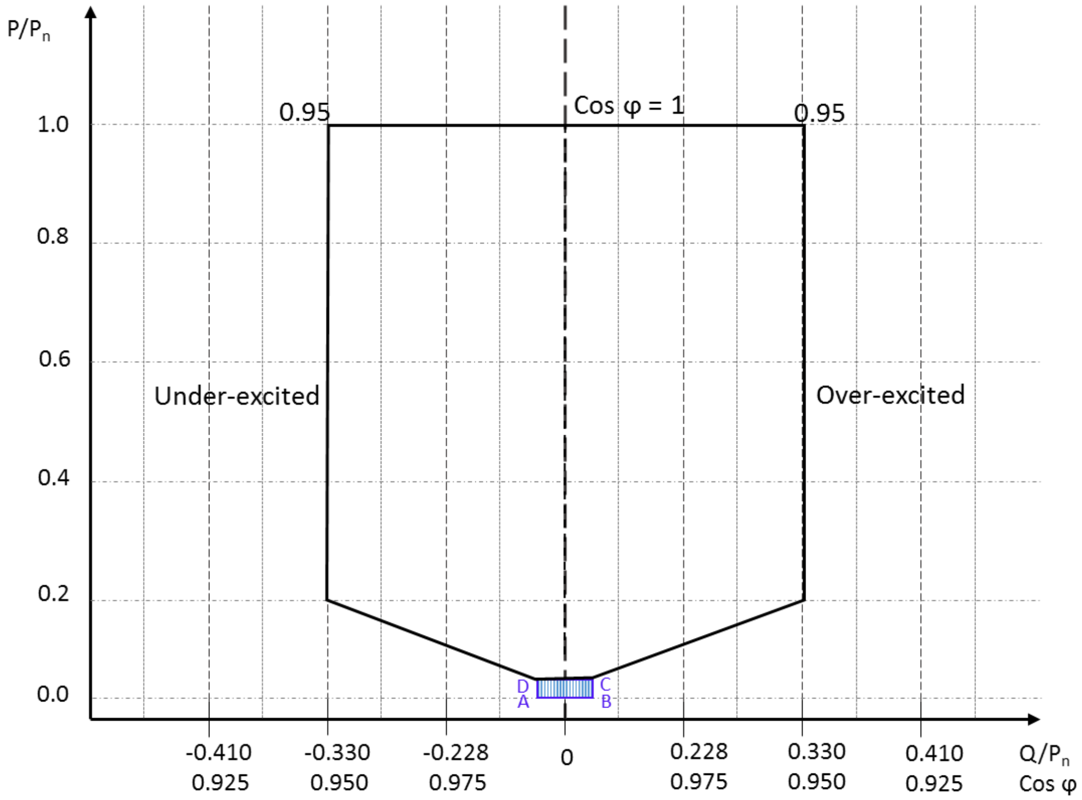

Figure 3: Reactive power requirements for distribution system connected VRPPs at full and partial active power output conditions

4.1 Reactive power control requirements

4.1.1 General

(1). All VRPPs shall be equipped with control functions to control reactive power at the point of common coupling via orders using set-points and gradients. The parameter settings shall be agreed between the DU and the VRPP operator or shall be as documented in the relevant System Operational Manual.

(2). Each VRPP shall support each of the following control functions:

(a). Q control (details in 0)

(b). Power Factor Control

(3). The choice of control mode and the definition of target values is within the responsibility of the DU. It must be possible for the DU to change control mode and target values at any time during the lifetime of a VRPP.

4.1.2 Reactive power control (Q control)

(1). VRPPs shall be capable of controlling reactive power at the point of common coupling either to a constant reactive power target (Q-target) or an active power dependent reactive power target (Q(P)).

(2). The DU shall define the actual settings of the Q/ Q(P) control characteristic (shape of Q(P)-characteristic, target values).

(3). If the control target is changed by DU, such change shall be completed no later than 2 minutes after the receipt of the new target value.

(4). The maximum permitted deviation of actual reactive power from the Q-target shall be no greater than 2% of rated power (0,02 p.u., 2 minutes after change of Q-target during steady system conditions).

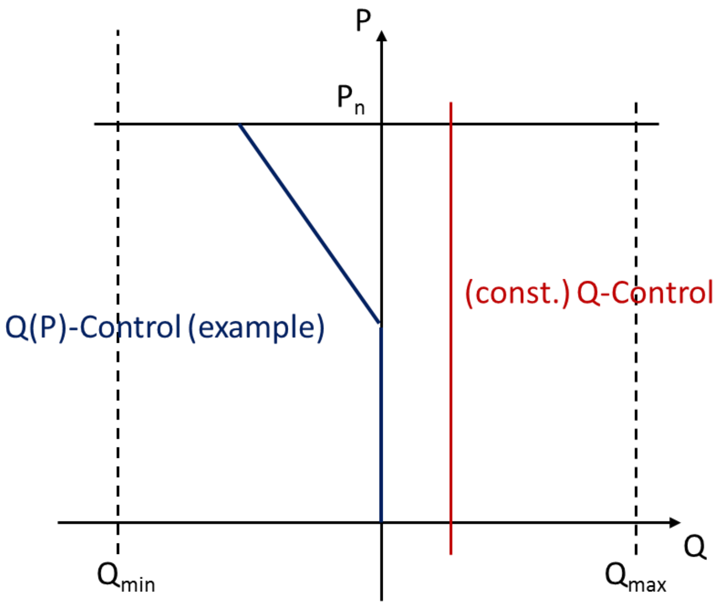

Figure 4: Reactive power control function of distribution system connected VRPP (const Q-control and Q(P)-control)

5.0 Power Factor control (cosphi-control)

(1). VRPPs shall be capable of controlling power factor at the point of common coupling either to a constant power factor target (cosphi-target) or an active power dependent power factor target (cosphi(P)).

(2). The Distribution Utility shall define the actual settings of the cosphi/ cosphi(P) control characteristic (shape of cosphi(P)-characteristic, cosphi-target).

(3). If the control target is changed by Distribution Utility, such change shall be completed no later than 2 minutes after the receipt of the new target value.

(4). The maximum permitted deviation of actual power factor from the cosphi-target shall be no greater than Δcosphi=0,005 (2 minutes after change of cosphi-target during steady system conditions).

5.1 Active power control

(1). For system security reasons it may be necessary for the ETU to curtail the VRPP active power output.

(2). VRPPs shall be capable of operating at a reduced power level if active power has been curtailed by ETU, for network or system security reasons;

(3). The accuracy of the control performed and of the set-point shall not deviate by more than ±1 % of the rated power.

(4). The type of communication between ETU and VRP operator must be agreed between the parties and specified as part of the bilateral connection agreement.

6.0 Frequency response

6.1 High Frequency Response For VRPPS

(1). During high frequency operating conditions in NITS and Distribution system, all distribution system connected VRPPs shall be capable of operating at reduced active power output in order to stabilize grid frequency.

(2). When the frequency on the NITS and Distribution system exceeds 50.2 Hz[6], all VRPPs shall be capable of reducing active power as a function of change in frequency as illustrated in figure below.

(3). High frequency response must operate with a minimum gradient of 100% of rated power per minute (primary frequency control time scales).

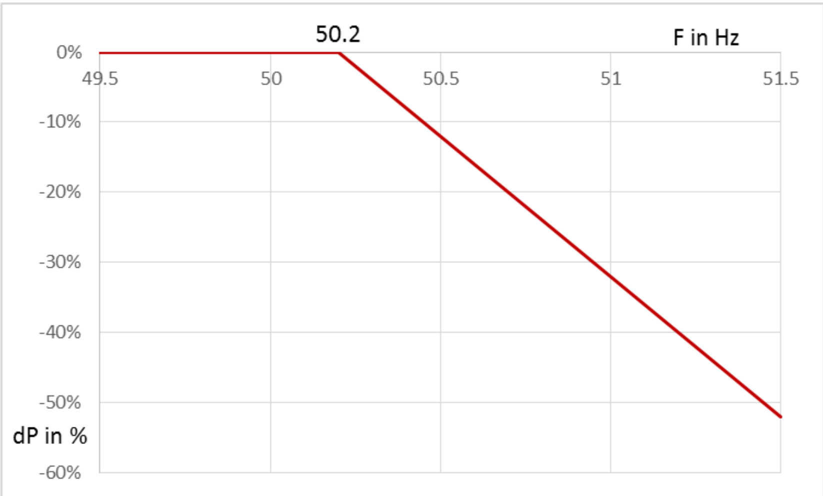

Figure 5: Mandatory high frequency response for all distribution system connected VRPPs

Note: ‘dP’ in the figure represents percentage of active power by which the output has to be decreased in case of increasing system frequency.

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[6] According to Grid Code normal operating frequency range in NITS is between 49.8 Hz to 50.2 Hz

6.2 Primary and Secondary Frequency Control

Unless otherwise required by the ETU/DU, VRPPs are exempted from primary or secondary frequency control capabilities (except high-frequency response according to section 6.1).

7.0 Behaviour during abnormal voltage conditions (LVRT/HVRT situations)

7.1 Low Voltage Ride Through (Lvrt)/High Voltage Ride Through (Hvrt) Capability For VRPPS

(1). VRPPs shall be designed to operate for up to one minute within a voltage range of +/-15% of nominal voltage[7].

(2). VRPPs shall be designed to have low voltage ride through (LVRT) and high voltage ride through (HVRT) capability as illustrated in Figure 6.

(3). For all voltages at the point of common coupling, which are between the red and the blue line according to Figure 6, no disconnection of a VRPP or of individual units within a VRPP is permitted.

(4). The voltage at the point of common coupling is defined to be the lowest of the three line-line or line-earth voltages.

(5). If the voltage reverts to the Continuous Voltage Range (between Vcmin and Vcmax) during a fault sequence (e.g. resulting from reclosing), subsequent voltage drops or voltage spikes shall be regarded as new LVRT or HVRT conditions.

[7] This is in-line with „Transient State“ according to the draft Distribution Code.

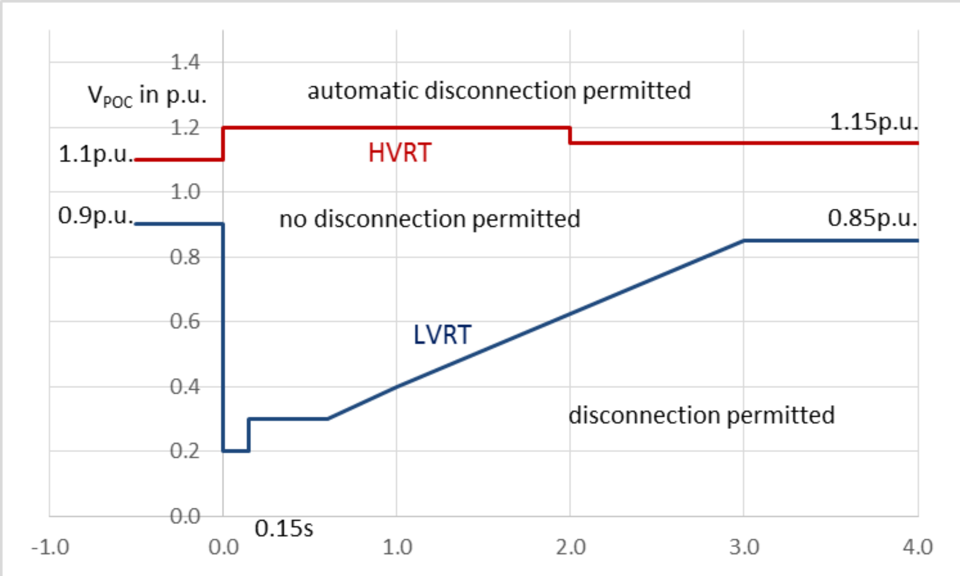

Figure 6: LVRT and HVRT capability for distribution system connected VRPPs[8]

7.2 Reactive Current Support During Lvrt/Hvrt Situations

During a LVRT or HVRT situation, VRPPs having a direct connection to the secondary side of a substation shall support the grid voltage by injecting (or absorbing) reactive current as follows:

(1). During LVRT and HVRT situations, both symmetrical and asymmetrical, all units within a VRPP shall support the voltage by injecting or absorbing additional reactive current ΔI_Q at the generator terminals proportional to the change of the unit's terminal voltage ΔV_t, as depicted in Figure 7.

(2). The factor of proportionality between additional reactive current and voltage deviation is named K ($\Delta I_Q = K \Delta V_t$). The factor K must be settable in the range of $0 <= K <= 10$.

[8] Table 6 of the draft Distribution Code also considers transient states with voltages between 20% and 80% for up to 10 s. Ideally, LVRT should cover this range. However, such long LVRT situations would be technically very challenging to realize, would deviate from international practice and would therefore be very expensive.

(3). The absolute value I of current in each of the three phases of the unit's terminals may be limited to rated current (1 p.u.).

Notes:

- Voltages and currents in this section are defined to be positive sequence components of the fundamental frequency value of voltages and currents respectively. This applies to pre-fault and post-fault voltages and currents.
- The additional reactive current ΔI_Q shall be injected in addition to the pre-fault voltage. The positive sign of ΔI_Q in Figure 7 is voltage supporting (injection of reactive power).
- The voltage deviation ΔV_t is defined by the difference between the pre-fault and the post-fault voltage.
- Both pre-fault current and pre-fault voltage are defined by the 1-minute average of current and voltage respectively.

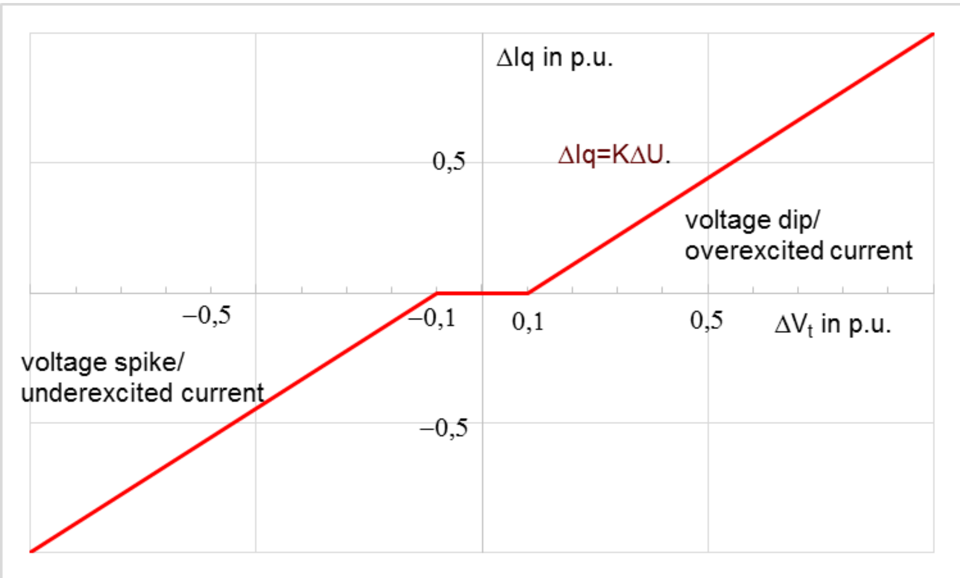

Figure 7: Reactive current support ΔI_Q during LVRT and HVRT situations at the unit's terminals

(4). Dynamic performance: After 60ms, the additional current must have been settled, meaning that it shall remain within a tolerance band of ±20% around the value according to Figure 7.

(5). Reactive Current Priority: During LVRT and HVRT conditions, the active current I_P shall be reduced in proportion to the voltage change ΔV_t (reactive current prioritisation).

During an LVRT situation, VRPPs having a connection on a distribution feeder (“embedded generators) shall behave as follows:

(1). During a LVRT situation, VRPPs shall control active and reactive power according to a “zero current” strategy, meaning that both, active and reactive current shall be reduced to zero.

During an HVRT situation, VRPPs having a connection on a distribution feeder (“embedded generators) shall maintain normal active and reactive power control modes.

7.3 Active And Reactive Power Behaviour During Voltage Recovery

(1). After voltage at the point of common coupling has returned into the range of +/-15% of nominal voltage, the VRPP shall restore its active power output to at least 90% of its pre-fault value within 1 second.

(2). During voltage recovery, the VRPP shall not absorb more reactive power than prior to the LVRT situation.

8.0 Automatic Resynchronization

(1). Automatic synchronization device/ automatic close equipment shall be installed to allow a VRPP to connect to the system automatically, with a delay of 5 minutes, if the following system conditions are fulfilled:

- The voltage at the point of common coupling is within the Steady State Range of +/-10% of nominal voltage, as specified in section 20 of [1]
- Frequency is within the range of $49.8 \text{ Hz} \leq F \leq 50.2 \text{ Hz}$.

(2). During automatic connection/synchronisation, VRPPs must ensure compliance with “rapid voltage change” requirements according to section 3.1.1.

9.0 Protection and fault levels

(1). VRPP operators shall design, implement, coordinate and maintain their protection system to ensure the desired speed, sensitivity and selectivity in clearing faults on VRPP's side of the point of common coupling

(2). Protection functions required for protecting the NITS/distribution system from getting out of normal operating ranges will be specified by the DU in consultation with the ETU, including trip settings, response times etc. (e.g. overvoltage and undervoltage protection, over-/underfrequency protection etc.)

(3). VRPPs shall be equipped with effective detection of islanded operation in all system configurations and shall have the capability to shut down the generation of power in such conditions within 2 seconds. Islanded operation with part of the distribution system is not permitted unless specifically agreed with the ETU/DU.

(4). The coordination among protections at connection point must be agreed between ETU, the Distribution Utility, and the VRPP operator.

(5). The circuit breaker used for connection switching in distribution system-connected generators shall be equipped with a disconnection system to ensure safe operation during re-connection/re-synchronization to the grid.

(6). The Distribution Utility may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the TS and distribution system. However, such change shall not result in the VRPP being exposed to negative impacts from the TS and distribution system lying outside of the design requirements.

(7). The Distribution Utility shall inform the VRPP operator of the highest and lowest short-circuit current that can be expected at the point of common coupling as well as any other information about the TS and distribution system as may be necessary to define the VRPP's protection functions.

(8). Where VRPP's protection equipment is required to communicate with the DU's protection equipment it must meet the communications interface requirements specified by the Distribution Utility and this document.

10.0 Communication and Control

(1). VRPPs shall be equipped to receive target values for control purposes from the ETU (voltage/reactive power control according to section 5.1, active power curtailment according to 0 and other control functions as it may be applicable).

(2). All further requirements with regard to the exchange of information will be agreed on between VRPP and ETU within the bilateral connection agreement.

TECHNICAL SCHEDULE G: DESIGN STANDARDS FOR CONSTRUCTION OF DISTRIBUTION LINES

1. Design Standards for Construction covering:

- Minimum Conductor Vertical Clearance for 33 kV, 11 kV and LV lines.

Item	System Voltage	Minimum Conductor Vertical Clearance (m)
1	33kV	1.4
2	11kV	1.2
3	LV	0.3

- Minimum vertical depth of cables for 33 kV, 11 kV and LV lines.

Item	System Voltage	Minimum Vertical Depth (m)
1	33kV	1.1
2	11kV	0.9
3	LV	0.6

2. Minimum Climbing space for pole infrastructure.

Item	Description of Pole	Minimum Value (m)
1	8m	6.7
2	9m	7.5
3	10m	8.3
4	11m	9.2
5	12m	10.0

3. Minimum working space for substation infrastructure, i.e., transformers, RVP main units etc. **At least radius**

4. Minimum clearance of exposed sections of cable risers

Item	Description of Pole	Minimum Value (m)
1	8m	3.7
2	9m	4.5
3	10m	5.3
4	11m	6.2
5	12m	7.0

5. Maximum span length of 33 kV, 11 kV and LV under normal conditions

Item	Network System	Maximum Span (m)
1	High Voltage (33 kV)	120
2	Medium Voltage (11 kV)	120
3	Low Voltage (LV)	50

6. Standard earthing systems for pole networks for 33 kV, 11kV and LV

Item	Network System	Earthing Resistance value (Ω)
1	High Voltage (33 kV)	5
2	Medium Voltage (11 kV)	5
3	Low Voltage (LV)	<1

Earthing Resistance Value reference IEC 60479-1:2018 and IEEE Std 80-2000

7. Minimum spacing for phases in three-phase pole construction for 33 kV, 11 kV and LV lines

Item	Network System	Minimum Spacing for phases (m)
1	High Voltage (33 kV)	1.4
2	Medium Voltage (11 kV)	1.2
3	Low Voltage (LV)	0.3

HEAD OFFICE - GREATER ACCRA
P. M. B. Ministries, Accra Ghana
GA-037-3212
info@energycom.gov.gh
+233 (0)302 813 756/7

TAKORADI OFFICE
SSNIT House, Close to
Central Police Station
+233 (0)312 035401

Takoradi Port
+233 (0)312 291804

TAMALE OFFICE
SSNIT Road, Beside Fire Service Office
+233 (0)372 001572

KUMASI OFFICE
Opposite the Main Baba Yara
Sports Stadium and adjacent
the Eno Donkor Hotel

Energy Commission of Ghana
Energy Commission Ghana
Energy Commission
Energy Commission