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THE ELECTRICITY ACT,
(CAP.131)

RULES

(Made under section 45 (b)(v) and (iv))

THE ELECTRICITY (GRID AND DISTRIBUTION CODES) RULES, 2017

Citation

1. These rules may be cited as the Electricity (Grid and Distribution Codes) Rules, 2017.

Application

2. These rules shall govern the operation and management of the electicity transmission and distribution systems in Tanzania Mainland.

Grid Code

3. The Grid Code for the operation and management of the electricity transmission system shall be as specified in the First Schedule to these Rules.

Distribution Code

4. The Distribution Code for the operation and management of the electricity distribution system shall be specified in the Second Schedule to these Rules.

Compliance with the Grid and Distribution Codes

5. Any person who is participating in the electricity supply industry shall comply with the provisions of the Grid and Distribution Codes.

First Schedule

(Made under Rule 3)

The Grid Code

Second Schedule

(Made under Rule 4)

The Distribution Code

Dar es Salaam,
10th November, 2017

GODWIN SAMWEL,
Director General

FIRST SCHEDULE - THE GRID CODE

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

1 of 8 Code Documents - Preamble

Version 2

1st March 2017

Table of Contents

1 Introduction

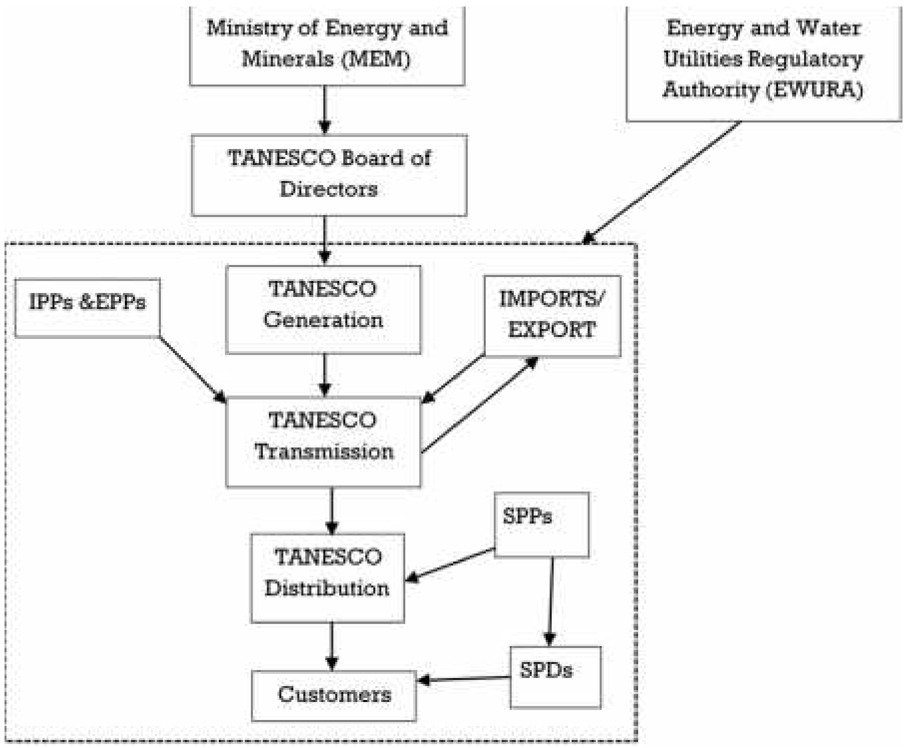
(1) The preamble provides the context for the Grid Code and its various sub-sections. It also contains detailed definitions and acronyms of the terms used in the Grid Code documents.

2 Policy

2.1 Electricity Industry Structure

(1) The current structure of the power sector in Tanzania is illustrated in Figure 1 below.

FIGURE 1: TANZANIA POWER SECTOR STRUCTURE



(2) The Ministry of Energy and Minerals (MEM) oversees the power sector direction, and appoints TANESCO's Board of Directors. The Energy and Water Utilities Regulatory Authority (*EWURA* or the *Authority*) is an autonomous multi-sectoral regulatory authority. It is responsible for technical and economic regulation of, among others, the electricity sector.

(3) The Tanzania Electric Supply Company Limited (TANESCO) is a state owned, vertically integrated company carrying out *generation*, *transmission* and *distribution*. Under the current market structure, the *System Operator* is part of TANESCO Transmission.

(4) Independent Power Producers (IPPs) are licensed to operate in the generation segment. In addition, interconnections with Zambia and Uganda enable imports of electricity. TANESCO Transmission acts as the single buyer for the purchases of this power.

(5) Tanzania electricity market is vertically integrated; TANESCO generates, imports and buys power in bulk from IPPs under a single buyer model and transports it over the transmission and distribution networks for resale to its customers.

2.2 Electricity Industry Reform

(1) Tanzania will continue to pursue its ongoing reform programme for the power sector.

(2) In the medium-term, reform plans for unbundling of TANESCO into separate generation, transmission, and distribution companies encompass the ring-fencing of separate business areas (internal restructuring) while retaining state-ownership.

(3) In the long term, the plan ultimately envisages the evolution from a single buyer market structure, with long-term PPAs with TANESCO, to a wholesale power market, in which the producers sell directly (or through a pool or voluntary electricity exchange) to distribution companies. Under this future market structure, it is likely that the roles and relationships associated with Transmission and the *System Operator* may change and that the *Grid Code* will need to be updated to reflect this.

(4) In order to ensure that the goals of the reform process are achieved, it is imperative that various arrangements are put in place that outline how the various parties in the electricity supply industry are expected to interact. The Tanzanian *Grid Code* represents one such arrangement with the aims of facilitating and governing open and non-discriminatory access to the transmission system, setting standards for reliable and stable operation of the interconnected system, technically and commercially. The *Grid Code* thus addresses the needs of the current market structure while taking cognisance of anticipated market reforms.

3 Authority

3.1 Legislation

(1) The *Grid Code* derives its legal authority from the Electricity Act and from the Energy and Water Utilities Regulatory Authority (EWURA) Act.

(2) In terms of Section 5 of the Electricity Act, the Authority shall have powers to:

(a) award *licenses* to entities undertaking or seeking to undertake a *licensed activity*;

(b) approve an enforce tariffs and fees charged by *licensees*;

(c) approve *licensees* terms and conditions of electricity supply; and

(d) approve initiations of the procurement of new electricity supply installations.

(3) Sections 8(1) and (2) of the Electricity Act specify the following activities as requiring a license, unless the person or activity is exempted by the Authority:

(a) *Generation*;

(b) *Transmission*;

(c) *Distribution*;

(d) *Supply*;

(e) *System Operation;*

(f) *Cross-border electricity trade*

(g) Physical and financial trade in electricity; and

(h) Electrical installation.

(4) Furthermore, Section of the 45(b) (v) of the EWURA Act states that the *Authority* may make Rules with respect to the operation and management of the transmission system to be known as the Grid Code.

3.2 Multiple Licenses

(1) Several of the *licenses* identified above may be held by a single entity. The decision to grant multiple *licenses* to a single entity depends on the functions that the company must fulfil.

(2) A transmission company may, for example, hold licenses for *transmission*, *supply*, *system operation, cross-border electricity trade*, physical and financial trade in electricity; and electrical installation.

3.3 Applicability

(1) All *licensees* are required to comply with the provisions of the Act and approved codes and Regulations. Any breach could result in the suspension or withdrawal of the license or fine.

(2) More specifically:

(a) Section 17(2)(a) of the Electricity Act stipulates that a *transmission licensee* shall be required to comply with the *Grid Code*.

(b) Section 20(3) of the Electricity Act stipulates that the *System Operator* shall abide by the *Grid Code*.

(c) Section 21(2) of the Electricity Act stipulates that a *distribution licensee* shall, subject to conditions of licence and rules issued by the Authority comply with the applicable requirements of the *Grid Code*.

(3) In terms of Section 18(1) of the Electricity Act, the Authority may grant exemptions to the licence conditions and code requirements.

(4) Transmission-Connected Customers are required to comply with certain provisions of the *Grid Code* in order to give full effect to its objectives.

(5) The *Grid Code* is applicable to all *Grid Code* Participants registered in accordance with the *Grid Code* Governance Code.

4 Grid Code

4.1 Definition

(1) The term *Grid Code* is widely used to refer to a document (or set of documents) that legally establishes technical and other requirements for the connection to and use of an electrical system by parties other than the owning electric utility in a manner that ensures reliable, efficient, and safe operation.

(2) The Electricity Act defines the *Grid Code* as the technical and procedural rules and standards issued by the Authority on transmission and system operation.

4.2 Objectives

(1) The fundamental function of a *Grid Code* is to establish the rules and procedures that allow independent parties to use the power system and to permit the power system to be planned and operated:

(a) Safely,

(b) Reliably,

(c) Efficiently, and

(d) Economically.

(2) In order to achieve this goal, the *Grid Code* must:

(a) Be objective,

(b) Be transparent,

(c) Be non-discriminatory,

(d) Be consistent with Government policy,

(e) Define the obligations and accountabilities of all the parties

(f) Specify minimum technical requirements for the Transmission system

(g) That the relevant Grid Code is made available

(3) The *Grid Code* provides the following assurances:

(a) To the Authority, the assurance that the *licensees* operate according to the respective license conditions.

(b) To *customers*, the assurance that *licensees* operate transparently and provide non-discriminatory access to their defined services.

(c) To *licensees*, the assurance that *customers* will honour their mutual *Grid Code* obligations and that there is industry agreement on these.

4.3 Grid Code Overview

(1) The *Grid Code* covers a range of technical, operational, commercial and governance issues. In order to address these comprehensively in a structured way, the *Grid Code* is broken down into a number of "sub-codes". These are:

(a) The Grid Code Preamble;

(b) The Network Code;

(c) The System Operation Code;

(d) The Scheduling and Dispatch Code

(e) The Metering Code;

(f) The Information Exchange Code;

(g) The Transmission Tariff Code; and

(h) The Governance Code.

(2) The key aspects of each of these are set out briefly below.

(3) The **Grid Code Preamble** provides the context for the *Grid Code* and its various sub-sections. It also contains detailed definitions and acronyms of the terms used in the *Grid Code* documents.

(4) The **Network Code** focuses on the technical requirements and standards of the high voltage network. It is broken down into sections defining:

(a) Connection conditions (for generators, distributors and end-use customers),

(b) Technical design requirements applicable to the *Grid Code Participants*,

(c) Electrical protection requirements,

(d) Investment planning, process and methodology, and

(e) Network Maintenance requirements.

(5) The **System Operation Code** sets out the responsibilities and roles of the *Grid Code Participants* as far as the operation of the *Interconnected Power System* (IPS) is concerned. It addresses, amongst other things:

(a) Reliability, Security and safety;

(b) *Ancillary Services*;

(c) Market operation actions required by the *System Operator*;

(d) Independent actions required and allowed by *customers*;

(e) Operation of the IPS under abnormal conditions; and

(f) Field operation, maintenance and maintenance co-ordination / outage planning.

(6) The **Scheduling and Dispatch Code** sets out the responsibilities and roles of the *Grid Code Participants* as far as the *Scheduling and Dispatch* of the *Interconnected Power System (IPS)* is concerned and more specifically issues related to: -

(a) Generation Scheduling;

(b) Generation Dispatch;

(c) *System Operator* roles and responsibilities.

(7) The **Metering Code**: This code ensures a Metering standard for all current and future *Grid Code Participants*. It specifies Metering requirements to be adhered to, and addresses levels of responsibility. The code sets out provisions relating to:

(a) Main Metering Installations and check Metering Installations used for the measurement of active and reactive energy;

(b) The collection of Metering data;

(c) The provision, installation and maintenance of equipment;

(d) The accuracy of all equipment used in the process of electricity Metering;

(e) Testing procedures to be adhered to;

(f) Storage requirements for Metering data;

(g) Competencies and standards of performance; and

(h) The relationship of entities involved in the electricity Metering industry.

(8) The **Information Exchange Code** defines the obligations of parties with regard to the provision of Information for the implementation of the *Grid Code*. The Information requirements as defined for the *Grid Code Participants* are necessary to ensure the non-discriminatory access to the *Transmission System* and the safe, reliable provision of *Transmission* services. The Information requirements are divided into:

(a) Planning Information,

(b) Operational Information, and

(c) Post-dispatch Information.

(9) The **Transmission Tariff Code** sets out the objectives and principles of *Transmission* service pricing, application of charges and fees and the procedure to be followed in applications by *licensees* to change revenue requirements, tariff levels or tariff structure. It covers the:

(a) Authority of EWURA to regulate tariffs/charges

(b) Applicability and objectives of the Transmission Tariff Code

(c) Principles for the regulation of income

(d) Approach to the determination of tariff structures and levels

(e) Procedure for the Authority Approval and Tariff Change Notifications

(10) The **Governance Code** sets out how the *Grid Code* will be maintained. It describes the process that will be followed to update the *Grid Code* to improve safety, reliability and operational standards. It sets out how *Grid Code Participants* can influence the amendment process and defines who has the authority to recommend and ultimately approve and enforce the changes. In addition the document also explains oversight and compliance requirements that need to be observed by all *Grid Code Participants*.

5 Definitions and Acronyms

(1) The glossary of definitions and acronyms is set out taking cognisance of the international and regional context, recognising that some terms are, however, only used in the Tanzanian market.

5.1 Definitions

(1) **Ancillary Services** - Services supplied to the *Transmission* company by *generators*, *distributors* or *end-use customers* necessary for the reliable and secure transport of power from *generators* to *distributors* and

customers, i.e. to maintain the short-term reliability of the IPS. They include the various types of reserves, Black Start, reactive power etc.

(2) **Area Control Error** - The mismatch between the instantaneous demand and supply of a *Control Area*. It combines the frequency error and the tie line schedule error.

(3) **Authorised Area** – means an area in which a *Distribution licensee* has a non-exclusive right to sell or provide services to consumers.

(4) **Authority –** means the Energy and Water Utilities Regulatory Authority established under EWURA Act.

(5) **Automatic Generation Control** - The automatic centralised closed loop control of generating units by means of the computerised EMS of the *System Operator*. Unit output is controlled by changing the set point on the governor.

(6) **Auxiliary Supply** - Supply of electricity to auxiliary systems of a *Unit* or substation equipment.

(7) **Black Start** - The provision of generating equipment that, following a total system collapse (black out), is able to:

   (a) Start without an outside electrical supply and

   (b) Energise a defined portion of the *Transmission System* so that it can act as a start-up supply for other capacity to be synchronised as part of a process of re-energising the *Transmission System.*

(8) **Busbar** - An electrical conduit at a substation where lines, transformers and other equipment are connected.

(9) **Co-generator** - A generating unit that is part of a specific industrial or production process and is not connected to the *Transmission System*.

(10) **Constrained generation** - The difference between the energy scheduled at the *Point of Connection* of the generator under the unconstrained schedule, and the energy scheduled at the *Point of Connection* under the constrained schedule derived to accommodate *Transmission System* constraints.

(11) **Control Area** - A subset of *IPS* that adheres to the minimum requirements for a control area as defined in the Power Pool Operating Guidelines. Control area services such as AGC are under their control.

(12) **Control Centre** - means a place from where controlling and / or directing the safe operation of the generation, transmission and distribution of electric power to customers is carried out.

(13) **Cross-border electricity trade** – means trading in electricity between two states sharing a common border through an interconnector power line, but linked through a power pool which involves export or export of energy between the states.

(14) **Customer Service Charter** – means a document which sets out terms and conditions of provision of service, rights and duties of a *licensee* and *customers*.

(15) **Customer –** means a person who purchases or receives electricity for own use or sale.

(16) **Data** - See *Information*.

(17) **Day** - A period of 24 consecutive hours commencing at 00:00 and ending at 24:00 Tanzanian Standard Time.

(18) **Distribution** - Means the transportation of electric energy and power by means of medium to low voltage lines, facilities and associated meters, including the construction, operation, management and maintenance of such lines, facilities and meters.

(19) **Distribution Code** – means the technical and procedural rules and standards issued by the *Authority* governing matters pertaining to the distribution of electricity.

(20) **Distribution Licensee** – means a *licensee* authorised to undertake distribution activities.

(21) **Distribution System** - An electricity network consisting of assets (including: substations, transformers, cables, lines and associated equipment) which are operated at *Medium Voltage* and *Low Voltage*.

(22) **Distributor** - A licensed entity that owns operates and maintains a *Distribution system*.

(23) **Economic regulation** – means an intervention to modify, as and when deemed appropriate, the economic behaviour of a regulated supplier aimed at narrowing choices in certain areas including prices, rate of return and methods of procurement.

(24) **Electricity supply industry** – electricity *generation*, electric power *transmission*, electricity *distribution* and electricity *supply*.

(25) **Eligible Customer** – means any person who is authorised by the *Authority* to enter into contract for the supply of electricity directly with any person licensed to generate electricity.

(26) **Embedded generator** - A Unit, other than a co-generator, that is not directly connected to the *Transmission System*.

(27) **Emergency** - A situation where *Transmission* or *Distribution licensees* have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their system demand.

(28) **Emergency outage** - An outage when plant has to be taken out of service so that repairs can immediately be affected to prevent further damage or loss.

(29) **End-use customer** - Users of electricity of different classes such as Domestic, Commercial and Industrial.

(30) **Energy Management System** - means usually a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. The monitor and control functions are known as SCADA; the optimization packages are often referred to as "advanced applications”.

(31) **EWURA Act –** The Energy and Water Utilities Regulatory Authorities Act, 2008.

(32) **Fair Competition Commission –** the Commission established by the Fair Competition Act.

(33) **Franchise area –** means the area within which a *distribution licensee* has the exclusive right to provide service to any customer who is not an eligible customer in that area.

(34) **Firm supply** - is defined such that if any parallel circuit is out for maintenance or on an unplanned outage, the supply can still be supplied via the remaining parallel circuit within its transfer capability.

(35) **Forced outage** - An outage that is not a *Planned Outage*.

(36) **Frequency** - The number of oscillations per second on the AC waveform.

(37) **Generation licensee** – means a *licensee* authorised to undertake electricity *generation* services.

(38) **Generation** – means the production of electric energy and power from any primary source of energy.

(39) **Generating Unit** - A device used to produce electrical energy.

(40) **Generator** - A legal entity operating a licensed *Generating Unit* or *Power Station*.

(41) **Governing** - A mode of operation where any change in system frequency beyond the allowable frequency dead band will have an immediate effect on the *Generating Unit* output according to the *governor droop characteristic*.

(42) **Governor droop Characteristic** - means the ratio of the per unit steady state change in speed, or in Frequency to the per unit steady state change in power output.

(43) **Grid Code –** means the technical and procedural rules and standards issued by the *Authority* on *transmission* and *system operation*.

(44) **Grid Code Participant** - Any legal entity that falls under the mandate of the *Grid Code* and registered as set out in the *Grid Code Governance Code*.

(45) **High Voltage –** means ac or dc voltage whose nominal r.m.s. value lies in the range 33kV < Un ≤ 220kV plus or minus ten per cent.

(46) **Information** - Any type of knowledge that can be exchanged, always expressed (i.e. represented) by some type of data. Information is made into data to be stored and processed either electronically or otherwise.

(47) **Information Owner** - The party to whose system or installation the Information pertains

(48) **Instruction** – means any command, given by the network operator either orally (via telephone), written or via remote control, to a generator in order to perform an action, enable/disable or block functionalities of a power station.

(49) **Interconnected Power System -** The *transmission system* and any other connected system elements including *Customers*, *Power Stations* and International Interconnections.

(50) **Interruptible Load** - *Customer* load or a combination of customer loads that can be contractually interrupted or reduced by remote control or on instruction from the *System Operator*. Individual contracts place limitations on usage.

(51) **Interruption of Supply -** An interruption of the flow of power to a *Point of Supply* not requested by the *customer*.

(52) **Licence –** means a *licence* issued by the *Authority* pursuant to the EWURA Act, relating to the electricity supply industry.

(53) **Licensed activity –** means the activities specified as requiring a *licence* grant as set out in Sections 8(1) of the Electricity Act.

(54) **Licensee –** means any person licensed to provide electricity market administration services.

(55) **Low Voltage –** ac or dc voltage voltage whose upper limit of nominal r.m.s. value is 1 kV plus or minus five percent.

(56) **Losses -** The technical or resistive energy losses incurred on the t*ransmission system*.

(57) **Manual load shedding -** The load reduction obtained by manually shedding load at convenient points on the distribution system within 10 minutes of the instruction being issued by the *System Operator*.

(58) **Marketing Business Unit** – Business unit in TANESCO.

(59) **Medium Voltage –** ac or dc voltage whose nominal r.m.s value lies in the range 1kV < Un ≤ 33kV plus or minus ten percent.

(60) **Maximum Continuous Rating -** The capacity that a *generating unit* is rated to produce continuously under normal conditions.

(61) **Metering -** All the equipment employed in measuring the supply together with the apparatus directly associated with it.

(62) **Metering Installation -** An installation that comprises an electronic meter that is remotely interrogated has an electronic communication link and is connected to the TMA's Metering database.

(63) **Minister –** means the Minister responsible for electricity matters.

(64) **Month -** A calendar month comprising a period commencing at 00:00 hours on the first day of that month and ending at 24:00 on the last day of that month.

(65) **Net Capacity -** Is defined as the maximum capacity that can be supplied, measured at the point of outlet to the network, excluding the power taken by the station's auxiliaries and the losses in the transformers that are considered integral parts of the station.

(66) **Non-dispatchable generation -** A generator can be non-dispatchable because of two reasons:

1. The generation technology does not allow a dispatch. This is mainly the case for fluctuating primary resources, like wind power or solar power. Such non-dispatchable power stations can be of any size in terms or MW. Depending on its size the point of connection might be at high, medium or low voltage, i.e. in transmission or distribution network.

2. The power generating installation is too small for individual consideration in the scheduling and dispatch process. This is the case for distributed generation in the low-voltage networks.

(67) **Off-grid** – means an electricity supply system that is not electrically connected, directly or indirectly to any part of the *transmission system*.

(68) **Operating Reserves -** are required to secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of operating reserves: *Spinning Reserve*, *Regulating Reserve* and *Non-Spinning Reserve*.

(69) **Participant -** See *Grid Code Participant*.

(70) **Performance Agreement –** means an agreement between a *licensee* and the *Authority* which establishes incentives and penalties related to the measurable performance of the *licensee*, and which is designed to improve the efficiency and effectiveness of the *licensee*.

(71) **Planned Interruption -** A *Planned Outage* that will interrupt customer supply.

(72) **Planned Outage -** An outage of equipment that is requested, negotiated, scheduled and confirmed a minimum of 14 days prior to the outage taking place.

(73) **Point of Common Coupling -** The electrical node, normally a *busbar*, in a *transmission substation* where different feeds to customers are connected together for the first time.

(74) **Point of Connection -** The electrical node in a *transmission substation* where a *customer's* assets are physically connected to the *transmission* company assets.

(75) **Point of Delivery -** See *Point of Supply*.

(76) **Point of Supply -** A *transmission substation* where energy can be supplied to customers.

(77) **Power Pool** - Interconnection to SAPP or EAPP and the rules associated with each Power Pool.

(78) **Power Station -** One or more *Generating Units* at the same physical location.

(79) **Power System Expansion Plan –** means a planning document prepared by the *Minister* and updated on an annual basis by the *System Operator*, dealing with indicative medium and long-term plans for the expansion of the *transmission system* to cater for expected generation and demand developments.

(80) **Primary Substation Equipment -** *High voltage* equipment installed at *substations*

(81) **Priority customers –** means *customers* of a *distribution licensee* who, due to the essential nature of their activities, are prioritised by the *Authority* to receive supply when *the* licensee suspends electricity supply services.

(82) **Protection -** The process of clearing a fault on the IPS in order to protect plant and people.

(83) **Quick Reserve -** *Interruptible Load* or capacity readily available which can be started and loaded within ten (10) minutes to meet the system demand. This includes hydro plant, gas turbines, pumped storage and Interruptible Load.

(84) **Regulating Reserve -** Generation capacity (or customer loads) available to respond within 10 seconds and be fully responsive in 10 minutes. The purpose of this is to allow for enough capacity on AGC to control the frequency and *Control Area* tie-lines power within acceptable limits in real time.

(85) **Related business –** means any business or company which directly or indirectly, in whole or in part, is owned by the licensee; or is owned by a company which owns or is owned by the *licensee*.

(86) **Scheduling -** A process to determine which unit or equipment will be in operation and at what loading.

(87) **Security -** The probability of not having an unwanted operation.

(88) **Service Provider -** Any licensed entity that provides services to *Grid Code Participants* pursuant to the *Grid Code* including.

(a) Network Operator

(b) *System Operator*;

(c) Metering Administrator;

(d) Market Operator (if/when appointed).

(89) **Spinning Reserve -** the additional output from generating plant that must be automatically fully realisable within 10 - 30 seconds to arrest a drop of frequency due to a loss of generation or a loss of external inter-

connector or mismatch between generation and demand. Spinning reserve can also be provided by demand side participants who can automatically reduce their output through under frequency load shedding relays.

(90) **Stakeholders -** The entities affected by or having a material interest in the *Grid Code*. This includes customers and other industry participants.

(91) **Standardized Small Power Purchase Agreement –** means the agreement between a utility entity and a developer entered for purposes of selling power to the grid not exceeding 10MW but not less than a 100kW.

(92) **Standardized Small Power Purchase Tariff –** means the tariff agreed on in the Standardized Power Purchase Agreement.

(93) **Substation -** A site at which switching and/or transformation equipment is installed.

(94) **Supply –** means the sale of electricity to customers.

(95) **System Frequency -** The frequency of the fundamental AC voltage as measured at selected points by the *System Operator*. The scheduled (target) system frequency for the interconnected networks in the Southern African region is 50 Hz.

(96) **System Minutes -** The normalised performance indicator for interruptions, defined as energy interrupted (MWh) * 60 / system peak demand (MW).

(97) **System Operator –** means a person licensed to provide *system operation* services.

(98) **Transmission –** means the transportation of electrical energy and power by means of *high voltage* lines, facilities and associated meters, including the construction, operation, management and maintenance of such lines, facilities and meters.

(99) **Transmission-Connected Customer** – A *Customer* connected directly to the *Transmission system*.

(100) **Transmission Equipment -** Equipment that is needed for the purpose of *Transmission*.

(101) **Transmission licensee –** means a licensee authorised to undertake *transmission* activities

(102) **Transmission Metering Administrator -** A party that is responsible for all t*ransmission* tariff metering Installation, maintenance and operations.

(103) **Transmission system -** An electricity network consisting of assets (including: substations, transformers, cables, lines and associated equipment) which are operated wholly or mainly at a *High Voltage*.

(104) **Type 1 generating unit –** A generating units is of Type 1, if it uses a synchronous generators, which is synchronously connected to the grid (directly or via a machine transformer). A Type 1 generating unit is for example the synchronous generator of a steam power plant, a hydro power plant or a conventional combustion engine unit. In this paragraph, the term “generator” refers to the electric device (not to the entity).

(105) **Type 2 generating unit –** A generating unit is of Type 2, if it uses any generator technology which is different from a synchronously grid-connected synchronous generator. A Type 2 generating unit is for example a photovoltaic inverter, a wind turbine with fully rated converter, a wind turbine with doubly-fed induction generator, etc. or a simple induction generator. In this paragraph, the term “generator” refers to the electric device (not to the entity).

(106) **Unit Islanding -** The capability of *generating units* to settle down at nominal speed, supplying own auxiliary load after separation from the grid, at up to full load pre-trip conditions.

5.2 Acronyms

(1) Note: Standard SI symbols and abbreviations are used throughout the *Grid Code* without re-definition here.

AC:	Alternating Current
ACE:	Area Control Error
AGC:	Automatic Generation Control
ARC:	Automatic Re-Closing
AVR:	Automatic Voltage Regulator
CT:	Current Transformer
DC:	Direct Current
DLC:	Dead Line Charge
DPI:	Dip Proofing Inverter
DTE:	Data Terminal Equipment
EAPP:	East Africa Power Pool
EENS:	Expected Energy Not Served
E/F:	Earth Fault
EMS:	Energy Management System
EPP:	Emergency Power Producer
EWURA:	Energy and Water Utilities Regulatory Authority
FACTS:	Flexible AC Transmission system
FSM:	Frequency Sensitive Mode
GCAC:	Grid Code Advisory Committee
GCS:	Grid Code Secretariat
GCR:	Grid Code Requirement
HV:	High Voltage
HVDC:	High Voltage Direct Current
Hz:	Hertz
IDMT:	Inverse Definite Minimum Time
IEC:	International Electro-technical Commission

IPP:	Independent Power Producer
IPS:	Interconnected Power System
LFSM-O:	Limited Frequency Sensitive Mode – Over-frequency
MBU:	Marketing Business Unit
MCR:	Maximum Continuous Rating
MUT:	Multiple-Unit Tripping
MV:	Medium Voltage
MVA:	Megavolt-Ampere
MW:	Megawatt
NGCC	National Grid Control Centre
OEM:	Original Equipment Manufacturer
O/C:	Over-Current
OVRT:	Over-Voltage-Ride-Through
PCC:	Point Of Common Coupling
PCLF:	Plant Capability Loss Factor
POD:	Point Of Delivery
pu:	Per Unit
QOS:	Quality of Supply
RTU:	Remote Terminal Unit
SAPP:	Southern African Power Pool
SCADA:	Supervisory Control and Data Acquisition
SSR:	Sub-Synchronous Resonance
SVC:	Static VAR Compensator
TMA:	Transmission Metering Administrator
TRFR:	Transformer
TRANSMISSION SYSTEM:	Transmission system
UAGS:	Unplanned Automatic Grid Separations
UCLF:	Unit Capability Loss Factor

Um, Umax:	Maximum Rated Voltage
Un:	Nominal Voltage
UVRT:	Under-Voltage-Ride-Through
VT:	Voltage Transformer

6 Notices and domicile

(1) Communication with the *Grid Code* Secretariat in respect of the normal operations of this *Grid Code* shall be sent to the following chosen address:

Manager (System Operations)

Tanzania Electric Supply Company Limited

Umeme Park, Ubungo

Morogoro Road

P.O. Box 9024,

Dar es Salaam, Tanzania

(2) Communication with the *Authority* in respect of the normal operations of this *Grid Code* shall be sent to the following chosen address:

The Director General

Energy and Water Utilities Regulatory Authority

P.O. Box 72175

6th Floor, Harbour View Towers

Samora Avenue

Dar es Salaam, Tanzania

(3) Communication with TANESCO Transmission in respect of the normal operations of this *Grid Code* shall be sent to the following chosen address:

Deputy Managing Director (Transmission)

Tanzania Electric Supply Company Limited

Umeme Park, Ubungo

Morogoro Road

P.O. Box 9024,

Dar es Salaam, Tanzania

(4) Any notice given in terms of this *Grid Code* shall be in writing and shall -

(e) if delivered by hand, be deemed to have been duly received by the addressee on the date of delivery and a receipt will have to be produced as proof of delivery;

(f) if posted by pre-paid registered post, be deemed to have been received by the addressee 14 days after the date of such posting;

(g) if successfully transmitted by facsimile, be deemed to have been received by the addressee one day after dispatch.

(5) Notwithstanding anything to the contrary contained in this *Grid Code*, a written notice or communication actually received by one of the parties from another, including by way of facsimile transmission, shall be adequate written notice or communication to such party.

7 Acknowledgement

(1) This *Grid Code*, although uniquely Tanzanian, has drawn on regionally and internationally available grid codes and other documents where applicable. In particular the grid codes of Kenya, Namibia, South Africa, Uganda, United Kingdom and Zambia were consulted.

8 References

[1] Tanzania Bureau of Standards (TBS): Tanzania Standard – Power quality – Quality of supply

[2] IEC 61000-4-7, International Standard: Electromagnetic compatibility (EMC) – Part 4-7: Testing and measurement techniques – General guide on harmonics and interharmonics measurements and instrumentation, for power supply systems and equipment connected thereto

[3] IEC 61400-21, International Standard: Wind turbines – Part 21: Measurement and assessment of power quality characteristics of grid connected wind turbines

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

2 of 8 Code Documents – The Network Code

Version 2

1st March 2017

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1 Introduction

(1) This code contains a set of connection conditions for *generators*, *distributor*s and *end-use customers*, and the standards used to plan and develop the *Transmission System (TS)*.

2 Applications for *Grid System* connections

(1) The *(Transmission) System Operator (TSO*) shall provide *Quote*s for new connections (or for upgrading existing connections) according to an approved Energy and Water Utilities Regulatory Authority *(*EWURA) tariff methodology and within time frames agreed with prospective customers.

(2) The agreed time period for connecting customers or upgrading connections shall be negotiated between the *(Transmission) System Operator (TSO*) and the *customer* in every instance.

(3) Applications for new or revised connections shall be lodged with the *(Transmission) System Operator (TSO*) at the address specified in the Preamble.

3 Connection conditions

(1) This section on connection conditions specifies both the acceptable technical, design and operational criteria which must be complied with by any *customer connected to* or seeking *connection to the TS* or by *embedded* or co-*generators*, and the minimum technical, design and operational criteria with which *Transmission* and the *System Operator* shall comply in relation to the part of the TS where the connection will take place.

(2) The objective of the connection conditions is to ensure that by specifying minimum technical, design and operational criteria, the basic rules for *connection to the TS* are similar for all *customers* of an equivalent category and will enable *Transmission* and the *System Operator* to comply with its statutory and licence obligations. Since quality of supply and grid integrity are shared responsibilities between *Transmission* and the *System Operator* and their *customers*, these conditions furthermore ensure adherence to sound engineering practice and codes by all the *Participants.*

3.1 Generator connection conditions

(1) This section defines acceptable requirements for *generator* connections. Note that some of the sections below refer to a *Grid Code* requirement (*GCR*) for brevity and later reference.

(2) Compliance with the *GCR* shall be read in conjunction with the *Generating Unit* characteristics and sizes as specified in Table 1(a) and (b) in Appendix 1.

(3) Transmission shall offer to connect and, subject to the signing of the necessary agreements as specified in section 2, make available a *Point of Connection* to any requesting *generator* licensed to generate electricity.

(4) For new units special consideration shall be given to the impact of the risks on future operating costs, e.g. for *ancillary services*. The *System Operator* is to quantify these expected costs. The special consideration may include obtaining the Authority approval for including these costs in the tariff base or obliging the *generator* to purchase reserves.

3.1.1 *Protection*

(1) A *Generating Unit*'s, *unit* step-up transformer, *unit* auxiliary transformer, associated *Busbar* ducts and switchgear shall be equipped with well maintained *Protection* functions, in line with international best practices, to rapidly disconnect appropriate plant sections should a fault occur within the relevant *Protection* zones which fault may reflect into the TS.

(2) The following *Protection* functions shall be provided as defined to protect the TS:

3.1.1.1 Backup Impedance

(1) An impedance facility with a large reach shall be used. This shall operate for phase faults in the *unit*, in the *HV* yard or in the adjacent TS lines, with a suitable delay, for cases when the corresponding main *Protection* fails to operate. The impedance facility shall have fuse fail interlocking.

3.1.1.2 Loss of Field

(1) All Type 1 generating *units* shall be fitted with a loss of field facility that matches the system requirements. The type of facility to be implemented shall be agreed with *Transmission*.

3.1.1.3 Pole Slipping Facility

(1) Type 1 generating *units* shall be fitted with a pole slipping facility that matches the system requirements, where the *System Operator* determines that it is required.

3.1.1.4 Trip to House load

(1) This *Protection* shall operate in the event of a complete loss of load. For example if all the feeder breakers open at a *Power Station*, power flow into the system is cut off and the *generators* will accelerate. At 51.5 *Hz* the over-*frequency* facility shall pick up to start the house loading process. At this stage the *HV* breakers will still be closed. There will be power swings between the *units* and as soon as a *unit* has a reverse power condition the *Protection* shall open the *HV* breaker. The *units* shall *island* feeding their own auxiliaries. When system conditions have been restored then the *islanded units* can be resynchronised to the system

(2) Paragraph (1) of Section 3.1.1.4 (Trip to House load) does not apply to power stations / power generating facilities, which have only Type 2 generating units (but no Type 1 generating units).

3.1.1.5 Unit Transformer *HV* back-up Earth Fault *Protection*

(1) This is an *IDMT* facility that shall monitor the current in the *unit* transformer neutral. It can detect faults in the transformer *HV* side or in the adjacent network. The back-up earth fault facility shall trip the *HV* circuit-breaker.

3.1.1.6 *HV* Breaker Fail *Protection*

(1) The “breaker fail” *Protection* shall monitor the *HV* circuit breaker's operation for *Protection* trip signals, i.e. fault conditions. If a circuit breaker fails to open and the fault is still present after a specific time delay (nominally 120 ms), it shall trip the necessary adjacent circuit breakers.

3.1.1.7 *HV* Pole disagreement *Protection*

(1) The pole disagreement *Protection* shall cover the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal.

3.1.1.8 Unit Switch onto Standstill *Protection*

(1) This *Protection* shall be installed in the *HV* yard *Substation* or in the *unit Protection* panels. If this *Protection* is installed in the *unit Protection* panels then the *DC* supply for this *Protection* and that used for the circuit-breaker closing circuit shall be the same. This *Protection* safeguards the *generator* against an unintended connection to the TS (back energisation) when at standstill or at low speed.

(2) This section (Section 3.1.1.8, Unit Switch onto Standstill *Protection*) applies to Type 1 generating units or power stations with Type 1 generating units only. It does not apply to Type 2 generating units.

3.1.1.9 Overcurrent Protection of Power Station with Type 2 Generating Units

(1) For short-circuit protection at least over-current protection shall be provided as minimum requirement.

(2) The connection of a power station to the HV network is usually implemented by means of circuit breakers.

(3) A power station shall be equipped at least with overcurrent time protection as short-circuit protection.

(4) The short-circuit protection devices of the power station must be integrated into the overall protection concept of the network operator. For this reason, the protection scheme shall be agreed with the network operator at the stage of planning. The protection equipment settings are specified by the network operator as far as they have an impact on his network.

3.1.1.10 Protective disconnection devices for Power Stations with Type 2 Generating Units

(1) The function of protective disconnection devices described here is to disconnect the power station or the individual generating units from the network in the event of disturbed operating conditions. Examples are network faults, islanding, or a slow build-up of the network voltage after a fault in the transmission system. The reason for disconnection can be either to avoid unstable or unsecure operation of the power system, or to protect the installations and other customer facilities connected to the network. The generator is responsible for a reliable protection of his power station.

(2) The following functions of the protective disconnection equipment shall be realized:

- Over-frequency protection f>
- Under-frequency protection f<
- Over-voltage protection U> and U>>
- Under-voltage protection U< and U<<

(3) The settings of the protective disconnection devices are not allowed to counteract other requirements.

(4) The parameter settings have to be agreed with the responsible transmission system operator.

(5) The settings for the under-frequency protection shall allow to ride through typical under-frequency fault cases which might happen in the system and which shall be withstand by the system, for example the temporary frequency drop subsequent to the loss of a power station in the system.

(6) If a power station consist of more than one generating unit, the settings must be chosen in a way to disconnect the individual generating units at slightly different thresholds or time settings in order to minimize the power change to the system at one instant in time. The transmission system operator may provide accordingly different settings to different power stations in the network to minimize the power change to the system at one instant in time.

(7) Protective disconnection shall be realized within a self-sufficient device. The loss of the auxiliary voltage of the protection equipment must lead to an instantaneous tripping of the switch.

(8) Protective disconnection devices are installed at the Point of Connection and/or at the terminals of the power generating units.

3.1.1.11 Additional Protection

(1) In addition, should system conditions dictate, other *Protection* requirements shall be determined by the *System Operator* in consultation with the *generator* and these should be provided and maintained by the relevant *generator* at its own cost.

3.1.1.12 Fault Clearance Times

(1) Required *HV* breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by *Transmission*. Guidelines for operating times are:

(a) 80 ms where the *Point of Connection* is 330kV or above

(b) 80 ms where the *Point of Connection* is 220 kV

(c) 100 ms where the *Point of Connection* is 132 kV and below

(2) Further downstream breaker tripping (away from the system), fault clearing times, including breaker operating time, shall not exceed the following:

(3) 120 ms plus additional 30 ms for *DC* offset decay or

(4) 100 ms plus additional 40 ms for *DC* offset decay.

(5) Where system conditions dictate, these times may be reduced. Where so designed, earth fault clearing times for high resistance earthed systems may exceed the above tripping times.

3.1.1.13 Protection Co-ordination, Configuration, Testing and Commissioning

(1) All *Protection* interfaces with *Transmission* shall be co-ordinated between the *Participants*.

(2) The settings of all the *Protection* tripping functions on the *unit Protection* system of a *unit*, relevant to TS performance and as agreed with each *generator* in writing, shall be co-ordinated with the *Transmission Protection* settings. These settings shall be agreed between *Transmission* and each *generator*, and shall be documented and maintained by the *generator*, with the reference copy, which reflects the actual plant status at all time, held by *Transmission*. The *generator* shall control all other copies.

(3) For system abnormal conditions, a *unit* is to be disconnected from the TS in response to conditions at the *Point of Connection*, only when the system conditions are outside the plant capability where damage will occur. *Protection* setting documents shall illustrate plant capabilities and the relevant *Protection* operations.

(4) Competent persons shall carry out testing, commissioning and configuration of *Protection* systems. Prototype and routine testing shall be carried out as defined Appendix 2, Section 10.5.1

(5) Any work on the *Protection* circuits interfacing with *Transmission Protection* systems (e.g. bus zone) must be communicated to the *System Operator* before commencing with the works. This includes work done during a *unit* outage.

3.1.2 Ability of *units* to *island*

(1) Every *unit* that does not have *black start* capabilities of less than one hour without power from the TS shall be capable of *unit Islanding*.

(2) *Islanding* testing shall be contracted as an *ancillary service*. The procedure for testing is given in Appendix 2, Section 10.5.2.

(3) Section 3.1.2 (Ability of *units* to *island*) does not apply to non-dispatchable generation.

3.1.3 Excitation system requirements

(1) A continuously-acting automatic excitation control system (*AVR*) shall be installed to provide constant terminal voltage control of the *unit*, without instability, over the entire operating range of the *unit*. (Note

that this does not include the possible influence of a power system stabiliser.) Excitation systems shall comply with the requirements specified in *IEC* 60034.

(2) The excitation control system shall be equipped with an under-excitation limiter, load angle limiter and flux limiter as described in IEC60034-16-1.

(3) The excitation system shall have a minimum excitation ceiling limit of 1.6 pu rotor current, where 1 pu is the rotor current required to operate the unit at rated load and at rated power factor.

(4) The settings of the excitation system shall be agreed between the *System Operator* and each *generator*, and shall be documented, with the master copy held by the *System Operator*. The generators shall control all other copies. The procedure for this is shown Appendix 2, Section 10.5.3.

(5) In addition, the unit shall be capable of operating in the full range as indicated in the capability diagram supplied as part of the Information Exchange Code. Test procedures are shown in Appendix 2, Section 10.5.4.

(6) The active power output under steady state conditions of any unit shall not be affected by voltage changes in the normal operating range. Units with water-cooled stator windings shall be capable of delivering rated Megavolt-Ampere (*MVA)* at terminal voltages between 95 and 105% of rated voltage. Units with gas-cooled stator windings are specified to be capable of delivering rated *MVA* at terminal voltages between 100 and 105% of rated voltage, and rated stator current at voltages below 100%.

(7) Power system stabilisers as described in IEC60034-16-1 are a requirement for all new units, and for existing units retrofitting may be required depending on *IPS* requirements. The requirements for other excitation control facilities and *AVR* refurbishment shall be determined in conjunction with the *System Operator*.

(8) Routine and prototype response tests shall be carried out on excitation systems as indicated in Appendix 2, Section 10.5.3 and in accordance to IEC60034-16-3.

(9) Section 3.1.3 (Excitation system requirements) does not apply to Type 2 generating units.

3.1.4 Voltage control, reactive power control

(1) For power stations with Type 2 generating units which have the point of connection (PoC) of the power station at high voltage, the following requirements apply:

(a) A power station with Type 2 generating units shall provide the capability of the following control modes effective at the point of connection (PoC) of the power station:

- reactive power (constant Q)
- power factor (constant cos phi)
- power factor with active power characteristic (cos phi (P))
- voltage with voltage/reactive power droop

(b) For power stations with Type 2 generating units, the network operator selects the control mode which has to be activated for operation and specifies the parameter settings, depending on the location of the PoC in the network.

(c) A power station with Type 2 generating units shall be able to operate in any operating point of the reactive power capability diagram specified in Section 3.1.5, for the active power range which is possible to operate with respect to the primary power source of the power station.

(d) For an adjusted control mode and parameter set, the power station with Type 2 generating units shall be able to settle each accessible operating point with respect to the control mode within 30 seconds.

(e) If the share of the sum of the nominal power of all Type 2 generation units with PoC at HV becomes larger than 15% of the installed capacity in the system, newly commissioned generators must have voltage control capability, in addition to the reactive power / power factor control capabilities described in Paragraph a.

(f) In order to run stable with neighbouring power stations, the voltage control has to be equipped with a voltage/reactive power droop functionality.

3.1.5 Reactive power capabilities

(1) All new Type 1 generating *units* shall be capable of supplying rated power output Megawatt (*MW*) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the *unit* terminals. Reactive output shall be fully variable between these limits under *AVR*, manual or other control.

(2) Routine and prototype response tests shall be carried out to demonstrate reactive capabilities as indicated in Appendix 2, Section 10.5.4.

(3) For power stations with Type 2 generating units, the following requirements apply:

(a) If the generating units run with nominal active power, the reactive power flow at the point of connection (PoC) of the installation shall be sufficient to provide a power factor at the PoC of at least 0.95 overexcited to 0.95 underexcited, i.e. 0.95 or lower for voltage increasing operation and 0.95 or lower for voltage decreasing operation, if the voltage at the PoC is within 0.95 through 1.05 p.u.

(b) In partial load operation, the power station shall have the capability to inject/absorb the same amount of reactive power as at nominal active power of the generating units, down to 20% of the nominal active power of the power station, as depicted in Figure 3.1.

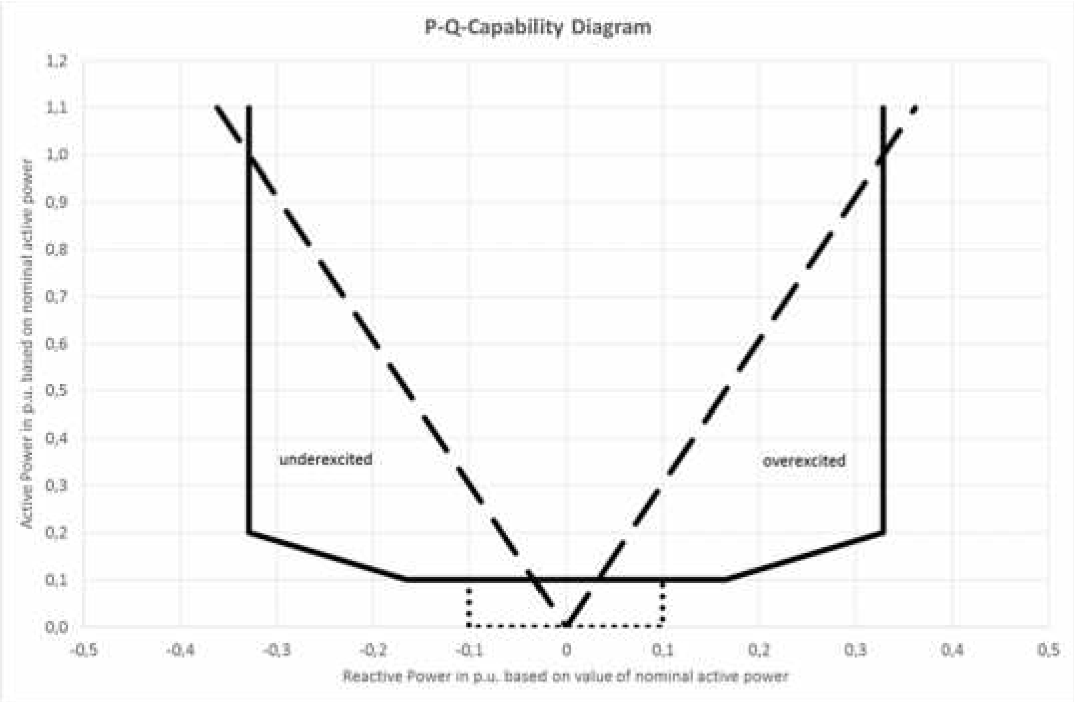


Figure 3.1: P-Q-Capability Diagram (generation oriented),
solid curve: requirement,
dashed curve: power factor = 0.95
dotted curve: area of 10% reactive power below 10% active power

(c) Between 10% and 20% of the nominal active power of the power station, the reactive power requirement is as depicted Figure 3.1.

(d) Below 10% of the nominal active power of the power station, the reactive power injection/absorption shall not be larger than 10% based on the value of the nominal active power of the installation (i.e. inside the dotted line of Figure 3.1). This requirement does not apply, if an operation in synchronous condenser or STATCOM mode has been agreed with the network operator.

(e) With respect to voltage-dependency of the reactive power capability,

(i) above 1.02 p.u. voltage at the PoC, the same underexcited reactive power (absorption of reactive power) is required as at 1.00 p.u. voltage, but less overexcited reactive power (injection of reactive power), as depicted in Figure 3.2,

(ii) below 0.98 p.u. voltage at the PoC, the same overerexcited reactive power (injection of reactive power) is required as at 1.00 p.u. voltage, but less underexcited reactive power (absorption of reactive power), as depicted in Figure 3.2.

(iii) Above 1.05 p.u. and up to 1.10 p.u. voltage at the PoC, only underexcited reactive power absorption of reactive power) is required), as depicted in Figure 3.2.

(iv) Below 0.95 p.u. and down to 0.90 p.u. voltage at the PoC, only overexcited reactive power absorption of reactive power) is required), as depicted in Figure 3.2.

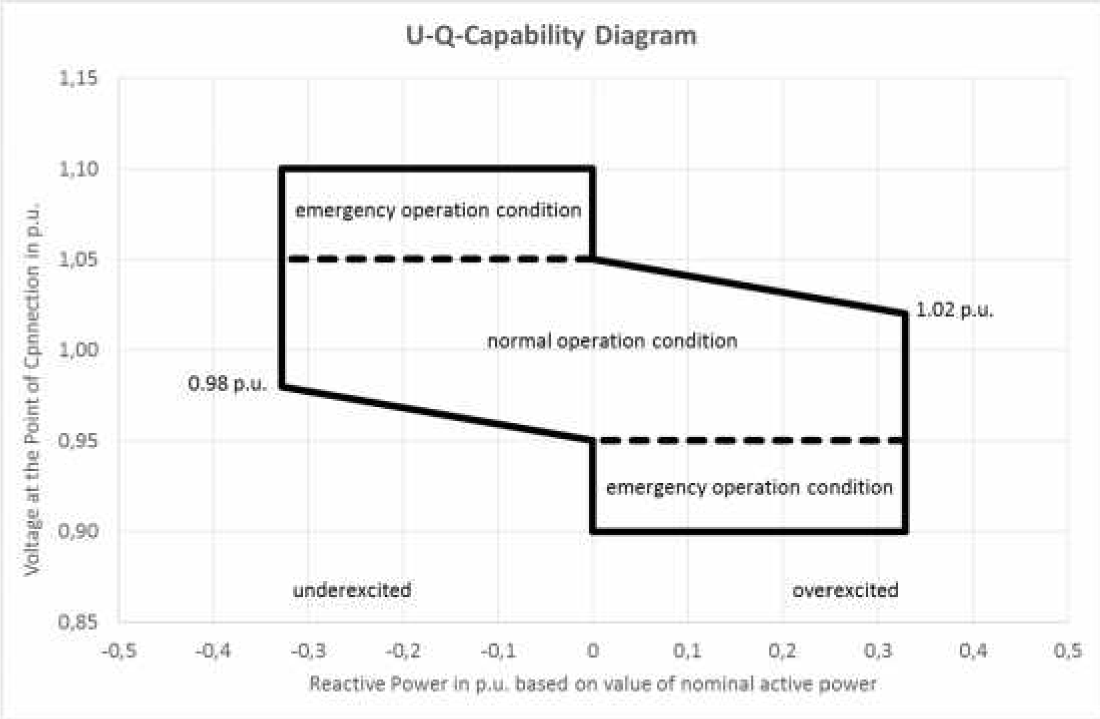


Figure 3.2: U-Q-Capability Diagram solid line = requirement for 20% to 100% nominal active power

(f) The generator shall document the maximum possible reactive power capability in terms of five P-Q-Capability Diagrams of the power station as follows, and a U-Q/Pmax-Profile of the power station and provide the information to the network operator. The reactive power capability can be examined by means of network calculations, taking the voltage-dependent reactive power capability curves of the generating units into account. Voltage drop and voltage rise within the power station and loading of the equipment within the power station (e.g. cables, transformers) has to be considered.

(i) P-Q-Capability Diagram of the installation for 0.90 p.u. voltage at the PoC

(ii) P-Q-Capability Diagram of the installation for 0.95 p.u. voltage at the PoC

(iii) P-Q-Capability Diagram of the installation for 0.98 p.u. voltage at the PoC

(iv) P-Q-Capability Diagram of the installation for 1.02 p.u. voltage at the PoC

(v) P-Q-Capability Diagram of the installation for 1.05 p.u. voltage at the PoC

(vi) P-Q-Capability Diagram of the installation for 1.10 p.u. voltage at the PoC

(vii) U-Q/Pmax-Profile of the installation

(g) In order to achieve the requirement at the PoC, usually the generating units have to provide a larger reactive power capability at their terminals. If the generating units cannot provide sufficient reactive power to fulfil the requirement of the installation at the PoC, additional devices such as capacitor banks, shunt reactors, STATCOMs or synchronous condensers can be installed within the power station.

3.1.6 Multiple Unit Tripping (*MUT*) risks

(1) A *Power Station* and its *units* shall be designed, maintained and operated to minimise the risk of more than one *unit* being tripped from one common cause within a short time.

(2) Routine and prototype response tests shall be carried out to demonstrate *MUT* withstand capabilities as indicated in Appendix 2, Section 10.5.5.

3.1.7 *Governing*

3.1.7.1 Design requirements

(1) All *units* above 2.5 *MVA* shall have an operational governor that shall be capable of responding according to the minimum requirements set out in this document.

3.1.7.2 System *Frequency* Variations

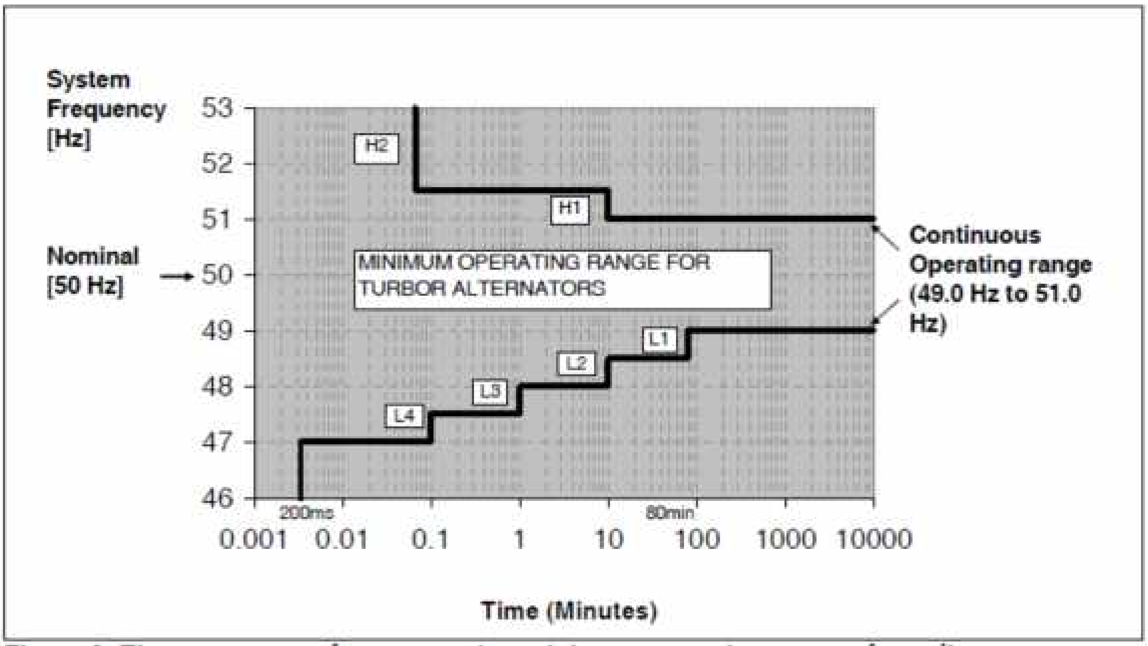
(1) Because of the uncertain dynamic behaviour of the Tanzanian system, *frequency* variations cannot be specified in this document. New Generators will need to do comprehensive system studies to ascertain the dynamic behaviour of the system as applicable to their position on the network. The *frequency* tolerances apply to voltage tolerances as specified in section 3.1.9.

(2) The design of turbo-alternator *units* must enable continuous operation, at up to 100% active power output, within the range as defined in Figure 3.3.

(3) Type 2 generating units must be able to operate in steady-state in a frequency band of +/- 2.5% around the nominal frequency of 50 Hz, i.e. 48.75 Hz through 51.25 Hz.

(4) Tripping times for *units* in the range of 47.5Hz to 48.5Hz shall be as agreed with the *system operator*. Sections 3.1.6.3 to 3.1.6.5 shall be used as guidelines for these tripping times.

Figure 3.3: Time vs. *system frequency* plot, minimum operating range of a turbo-alternator *unit*.



3.1.7.3 High *Frequency* Requirements for Turbo-alternators

(1) All synchronised *units* shall respond by reducing active power to frequencies above 50 *Hz* plus allowable dead band described in section 3.1.6.7. Speed governors shall be set to give a 4 % *governor droop characteristic* (or as otherwise agreed by the *System Operator*). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the *frequency* excursion. The *unit* shall respond to the full designed minimum operational capability of the *unit* at the time of the occurrence.

3.1.7.3.1 High *Frequency* Conditions in the Range 51.0 to 51.5 *Hz* (Stage H1)

(1) When the *frequency* goes above 51.0 *Hz* but less than 51.5 *Hz* the requirement is that the unit shall be designed to run for at least 10 minutes over the life of the plant. The turbo-alternator units shall be able to operate for at least 5 minutes continuously without tripping in this range.

(2) Exceeding this limit shall prompt the *generator* to take all reasonable efforts to reduce the system *frequency* below 51.0 *Hz*. Such actions can include manual tripping of the running unit. Tripping shall be staggered in time and be initiated once the *frequency* has been greater than 51.0 *Hz* for 5 minutes. The *generator* will trip a unit, and if the system *frequency* does not fall below 51.0 *Hz*, the other units shall be tripped in staggered format over the next five minutes or until the system *frequency* is below 51.0 *Hz*. The *System Operator* shall approve this tripping philosophy and the settings.

3.1.7.3.2 High *Frequency* Conditions in the above 51.5 *Hz* (Stage H2)

(1) When the *frequency* goes above 51.5 *Hz* the requirement is that the *unit* shall be designed to run for at least 1 minute over the life of the plant. The turbo-alternator *units* shall be able to operate at least 30 seconds continuously without tripping in this range.

(2) When the system *frequency* exceeds 51.5 *Hz*, the *generator* can start tripping *units* sequentially. Tripping shall be spread over a 30-second window. If a *generator* chooses to implement automatic tripping, the tripping shall be staggered. The *System Operator* shall approve this tripping philosophy and the settings. As an example, the first *unit* will trip in 5 seconds, the second *unit* trip in 10 seconds, etc.

3.1.7.4 High *Frequency* Requirements for Hydro Alternators

(1) All synchronised hydro *units* shall respond by reducing active power to frequencies above 50 *Hz* plus allowable dead band described in section 3.1.6.7. Speed governors shall be set to give a 4 % *governor droop characteristic* (or as otherwise agreed by the *System Operator*). The response shall be fully achieved within 30 seconds and must be sustained for the duration of the *frequency* excursion. The *unit* shall respond to the full load capability range of the *unit*.

(2) As the Tanzanian system is not designed for n-1 contingencies high over-*frequency* withstand capabilities are required. When the *frequency* goes above 54 *Hz* the requirement is that the *unit* shall be designed to run for at least 120 seconds over the life of the plant. It is expected that there will be less than 30 events of this nature for the lifetime of the *unit* (50 years). Hence the hydro-alternator *units* shall be able to operate at least 4 seconds in this range.

(3) When the system *frequency* increases to 54 *Hz* for longer than 4 seconds, the *generator* shall start staggered tripping of *units* as per the procedure for turbo-alternators. Settings shall be agreed with the *System Operator*.

3.1.7.5 Low *Frequency* Requirements for Turbo-alternator *Units*

(1) Low *frequency* response is defined as an *ancillary service* as *Spinning Reserve*. However all *units* shall be designed to be capable of having a 4 % *governor droop characteristic* (or as otherwise agreed by the *System Operator*) with a minimum response of 3% of Maximum Continues Rating (*MCR)* within 10 seconds of a *frequency* incident. The response must be sustained for at least 10 minutes.

3.1.7.5.1 Low *frequency* in the Range 48.5 to 48.0 *Hz* (StageL1)

(1) When the *frequency* goes below 48.5 *Hz* but greater than 48.0 *Hz* the requirement is that the *unit* shall be designed to run for at least 10 minutes over the life of the plant. The *unit* shall be able to operate at least 5 minutes continuously without tripping while the *frequency* is in this range.

(2) If the system *frequency* is in this range for more than 5 minutes, independent action may be taken by a *generator* to protect the *unit*.

3.1.7.5.2 Low *frequency* in the Range 48.0 to 47.5 *Hz* (Stage L2)

(1) When the *frequency* goes below 48.0 *Hz* but greater than 47.5 *Hz* the requirement is that the *unit* be designed to run for at least 1 minute over the life of the plant. The *unit* shall be able to operate at least 30 seconds continuously without tripping while the *frequency* is below 48.0 *Hz* but greater than 47.5 *Hz*.

(2) If the system *frequency* is in this range for more than 30 seconds, independent action may be taken by a *generator* to protect the *unit*.

3.1.7.5.3 Low *frequency* below 47.5 *Hz* (Stage L3)

(1) If the system *frequency* falls below 47.5 *Hz* for longer than 6 seconds, independent action may be taken by a *generator* to protect the *unit*.

(2) If the system *frequency* falls below 47.0 *Hz* for longer than 200 milliseconds, independent action may be taken by a *generator* to protect the *unit*.

3.1.7.6 Low *Frequency* Requirements for Hydro-alternator *Units*

(1) All reasonable efforts shall be made by the *generator* to avoid tripping of the hydro-alternator for under *frequency* conditions provided that the system *frequency* is above 46 *Hz*.

(2) If the system *frequency* falls below 46 *Hz* for more than 1 second, independent action may be taken by a *generator* to protect the *unit*. Such action includes automatic tripping.

3.1.7.7 Droop

(1) The speed governor of a Type 1 generating unit must be capable of being set so that it operates with an overall speed droop of between 2% and 10%.

3.1.7.8 Dead band

(1) The maximum allowable dead band shall be 0.15 *Hz* for *governing*. This means that no response is required from the *unit* while the *frequency* is greater than 49.85 to and less than 50.15 *Hz*.

(2) Routine and prototype response tests shall be carried out on the *governing* systems as indicated in Appendix 2, Section 10.5.6.

3.1.7.9 Frequency Sensitive Mode of Type 2 Generating Units

Type 2 generating units must be able to run in a limited frequency sensitive mode in cases of over-frequencies:

(a) In cases of frequency above 50.5 Hz (which is the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System), power stations shall reduce active power output with a droop of between 2% and 10% (default value 4%), starting from 50.5 Hz. This refers to as Limited Frequency Sensitive Mode – Over-Frequency (LFSM-OF). The droop s of the LFSM-OF is defined as given in the equation below with the momentary value of the active power output of the installation at the instant of time when exceeding the 50.5 Hz threshold as P_{ref}.

$$s[\%] = 100 \cdot \frac{f - 50.5\,\text{Hz}}{50.0\,\text{Hz}} \cdot \frac{P_{ref}}{|\Delta P|}$$

The value for the setting has to be specified by the responsible TSO, if no value is provided, the default value of 4% shall be used. The responsible TSO can specify other values for the droop and the activation threshold for LFSM-OF, is technically justified. At 52.0 Hz and above it is allowed to reduce active power output to zero, if agreed with the responsible network operator.

Hint: In other African Grid Codes the LFSM-OF may refer to as “power curtailment during over-frequency”.

(b) The following equation defines the required power change for cases in which the frequency f is higher than 50.5 Hz.

$$\Delta P = \frac{100}{s[\%]} \cdot \frac{-(f - 50.5\,Hz)}{50.0\,Hz} \cdot P_{ref}$$

A droop of 4% results in a power change ΔP of 50% of P_{ref} per Hz.

(c) The power station shall be capable of activating active power frequency response as fast as technically feasible with an initial delay that shall be as short as possible (usually within 2 seconds).

(d) The power station shall be capable of continuing operation at its minimum regulating level when reaching it.

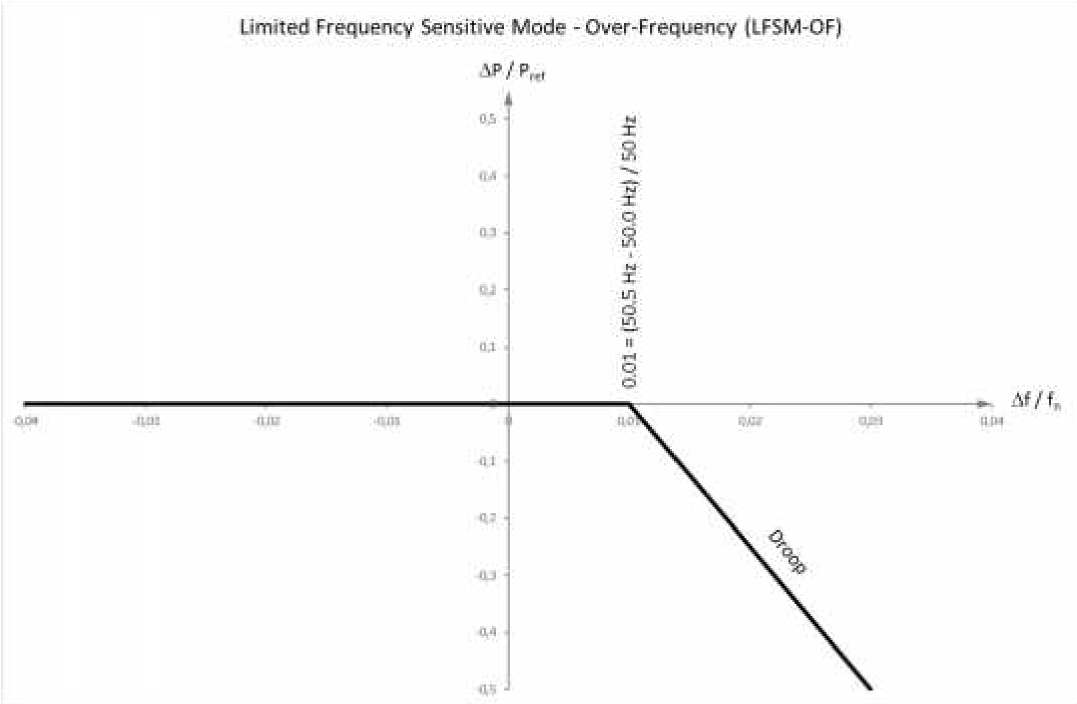


Figure 3.4: Limited Frequency Sensitive Mode – Over-Frequency (LFSM-OF)

(e) If the share of the sum of the nominal power of all Type 2 generation units with PoC at LV becomes larger than 30% of the installed capacity in the system, newly commissioned generators must be able to run in full frequency sensitive mode, i.e. they must be able to participate in frequency control of the system.

(i) In case of over-frequency, the active power frequency response is limited by the minimum regulating level.

(ii) In case of under-frequency, the active power frequency response is limited by maximum capacity, which depend on environment conditions in cases of wind and solar for example.

(iii) The initial activation of active power frequency response required shall be provided within 2 seconds.

(iv) Activation of a minimum response of 3% of maximum continues rating shall be provided within 10 seconds.

(v) The power station shall be capable of providing full active power frequency response for a period of 10 minutes.

(vi) Deviant settings may be provided by the network operator.

(vii) Deviant settings must be agreed with the network operator.

(viii) During operation of the power station, the responsible network operator can ask to activate or deactivate the frequency sensitive mode via instruction. The generator has to follow the instruction. The network operator and the generator have to mutually agree on the way how the instruction is transferred and received.

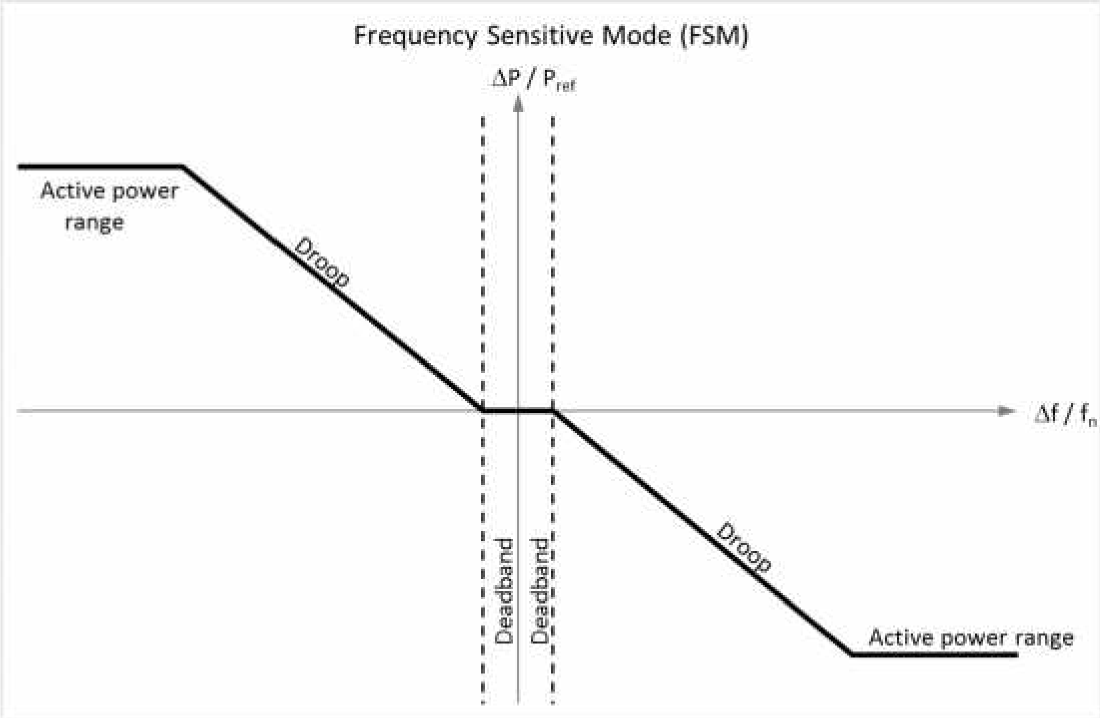


Figure 3.5: Frequency Sensitive Mode (FSM)

$$s[\%] = 100 \cdot \frac{|\Delta f|}{50.0\,\mathrm{Hz}} \cdot \frac{P_{ref}}{|\Delta P|}$$

$$\Delta P = \frac{100}{s[\%]} \cdot \frac{-(\Delta f \mp deadband)}{50.0\,\mathrm{Hz}} \cdot P_{ref}$$

3.1.8 Restart after *Power Station* black-out

3.1.8.1 Thermal *Power Station*s

(1) A *Power Station* and a *unit* is to be capable of being restarted and synchronised to the *IPS* following restoration of external *auxiliary AC supply* without unreasonable delay resulting directly from the loss of external *auxiliary AC supply*.

(2) For the purposes of this code, examples of unreasonable delay in the restart of a *Power Station* are:

(3) Restart of the first *unit* that takes longer than 1 hour after restart initiation

(4) Restart of the second *unit* that takes longer than 1 hour after the synchronising of the first *unit*.

(5) Restarting of all other *units* that take longer than 30 minutes each after the synchronising of the second *unit*.

(6) Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant *generator* and

(7) The start up facilities for a new *unit* not being designed to minimise start up time delays for the *unit* following loss of external auxiliary *AC* supplies for two hours or less.

(8) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix 2, Section 10.5.7

3.1.8.2 Hydro, Diesel and Gas engines and Gas turbines

(1) A *Power Station* and a *unit* is to be capable of being restarted and synchronised to the *IPS* following restoration of external *auxiliary AC supply* without unreasonable delay resulting directly from the loss of external *auxiliary AC supply*.

(2) For the purposes of this code, examples of unreasonable delay in the restart of a *Power Station* are:

(3) Restart of the first *unit* that takes longer than 30 minutes after restart initiation

(4) Restarting of all other *units* that take longer than 30 minutes each after the synchronising of the first *unit*.

(5) Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant *generator* and

(6) The start up facilities for a new *unit* not being designed to minimise start up time delays for the *unit* following loss of external auxiliary *AC* supplies for 30 minutes or less.

(7) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix 2, Section 10.5.7

3.1.9 Black starting

(1) *Power Stations* that have declared that they have a station *black start* capability shall demonstrate this facility by test as described in Appendix 2, Section 10.5.8.

(2) *Back start* capable *Power Stations* may be called from time to time not to carry out a full station *black start* but a *unit black start* as described in Appendix 2, Section 10.5.8.

3.1.10 External supply disturbance withstand capability

(1) Any *unit* and any *Power Station* equipment shall be designed with anticipation of the following voltage conditions at the *Point of Connection*:

(a) A voltage deviation in the range of 90% to 110% for protracted periods

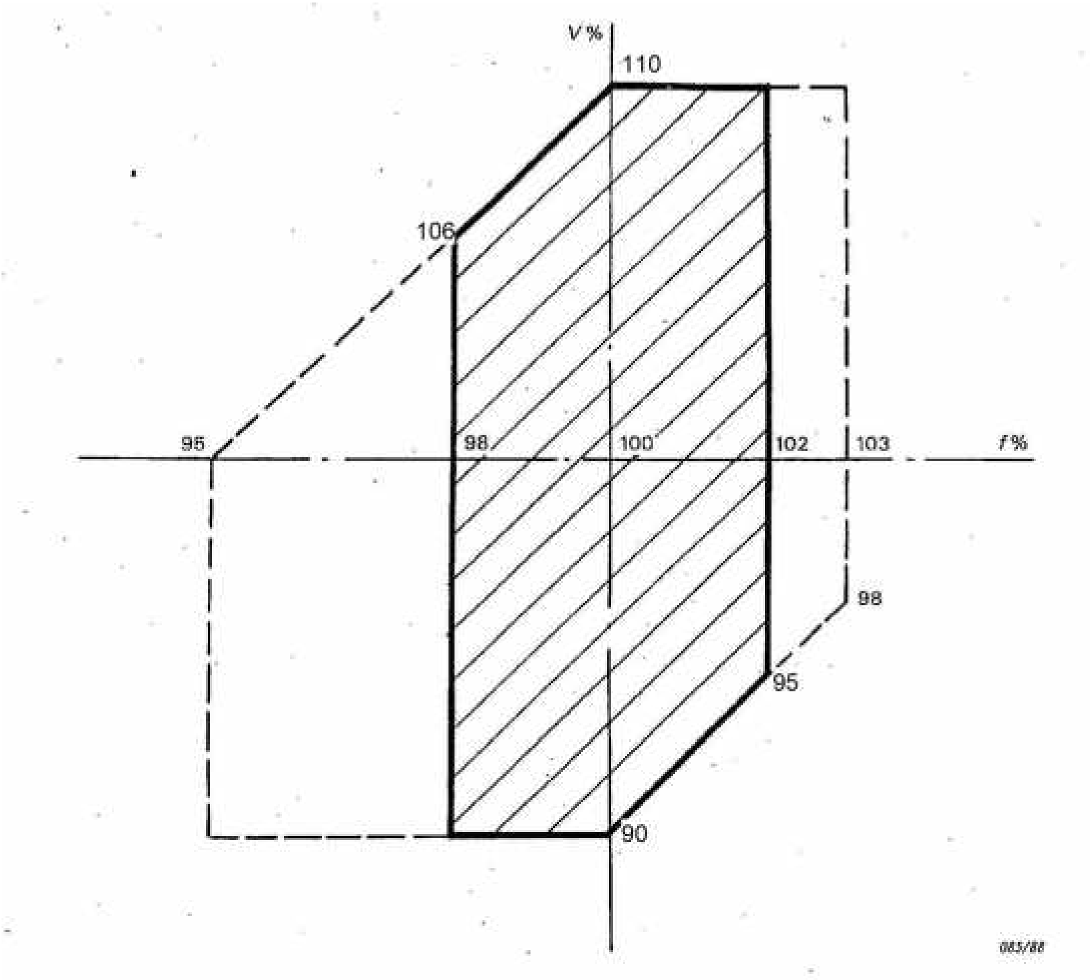
(b) A voltage drop to zero for up to 0.2s, to 75% for 2s, or to 85% for 60 s provided that during the 3 minute period immediately following the end of that 0.2s, 2s, or 60s periods the actual voltage remains in the range 90-110% of the nominal voltage. This requirement is referred to as “Under-Voltage-Ride-Through” (UVRT).

(c) Unbalance between phase voltages of not more than 3 % negative phase sequence and or the magnitude of one phase not lower than 5 % than any of the other two for 6 hours.

(d) A requirement to withstand the ARC cycle for faults on the transmission lines connected to the power station, being three single phase faults, each of 150 ms duration, within 31 seconds.

(2) The voltage tolerances apply to frequency tolerances as specified in **Figure 3.6**.

Figure 3.6: Voltage tolerances for various frequency ranges



(3) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix 2, Section 10.5.10.

(4) Power stations with Type 2 generating units shall be designed to withstand and ride through a voltage rise to 120% for 2 s, or to 115% for 60 s provided that during the 3 minute period immediately following the end of that 2 s, or 60 s periods the actual voltage remains in the range 90-110% of the nominal voltage. This requirement is named "Over-Voltage-Ride-Through" (OVRT).

(5) For power stations with Type 2 generating units, for Paragraph 1.a, 1.b and 4 of Section 3.1.10 (External supply disturbance withstand capability) the voltage to be considered is:

(a) the lowest of the three line-to-line voltages in cases of voltages below 100% of the nominal voltage, and

(b) the highest of the three line-to-line voltages in cases of voltages above 100% of the nominal voltage.

(6) Type 2 generating units shall inject additional reactive power to support the voltage during the above specified Under-Voltage-Ride-Through (UVRT) and Over-Voltage-Ride-Though (OVRT).

(a) Generating units of Type 2 shall start to inject an additional reactive current ΔI_Q at their terminals in proportion to the deviation of the voltage U from the pre-fault voltage U_0, following the equation given below, if the voltage at the unit's terminal is 10% (percentage based on nominal voltage) below the pre-fault voltage U_0, as depicted in Figure 3.7.

$$\Delta I_Q / I_n = K \cdot (-\Delta U) / U_n = -K \cdot (U - U_0) / U_n$$

(b) The equation is written generation oriented, i.e. the additional current is an overexcited reactive current (supporting voltage) in case of a voltage dip.

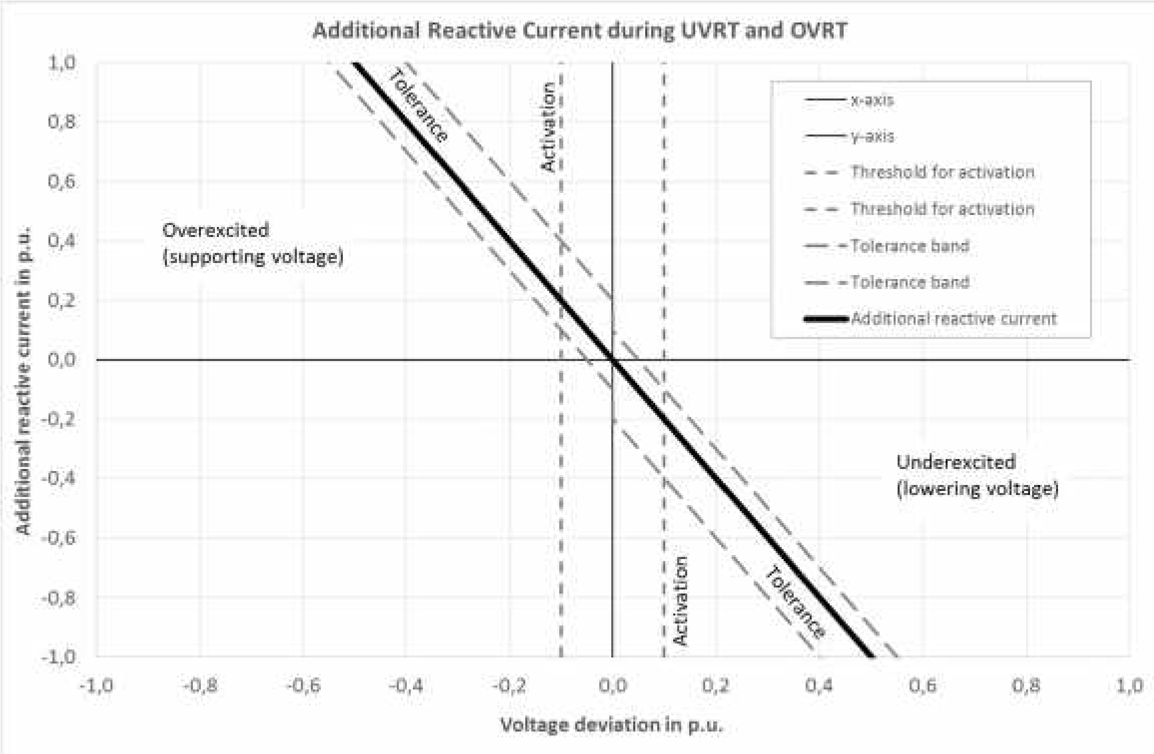


Figure 3.7: Requirement for additional reactive current
Note: The diagram is drawn in a generation-oriented way, i.e. positive additional reactive current is overexcited operation, increasing the voltage.

(c) The factor K is an integer number and has to be adjustable in the range from 0 to 8. The default setting is 2. The network operator may require a different value within the range from 0 to 8, if needed.

(d) The voltage U in the equation given in Paragraph a is the positive sequence value of the fundamental frequency at the generating unit terminals.

(e) The pre-fault voltage is the 1-minute mean value of the RMS value of the voltage at the generating unit terminals.

(f) It is allowed to adjust the threshold for activating the additional reactive current injection (10% below the pre-fault voltage U_0) to a value closer to the pre-fault voltage U_0, i.e. 0%-10% below U_0 (0% means a permanent voltage control).

(g) With the pre-fault reactive current I_{Q0}, the total injected reactive current I_Q is:

$$I_Q = I_{Q0} + \Delta I_Q$$

(h) The tolerance band for accuracy of the magnitude $|\Delta I_Q|$ of the additional reactive current is -10% and +20% of the nominal current of the generating unit, as depicted in Figure 3.7.

(i) In case of a three-phase fault, the generating unit must be able to inject a reactive current I_Q of at least 100% of the generating unit's nominal current.

(j) In case of a single-phase fault or a two-phase fault, the generating unit must be able to inject a reactive current I_Q of at least 40% of the generating unit's nominal current.

(k) The additional reactive current has to be settled within 60 ms after beginning of the fault, i.e. 60 ms after beginning of the fault the additional reactive current has to be and stay within the tolerance band.

(l) The additional reactive current has to reach the tolerance band for the first time within 30 ms after beginning of the fault.

(m) Note: There is no deadband for the additional reactive current. Once the voltage is below the activation band of 10% below the pre-fault voltage, the additional current has to be injected according to equation given in Paragraph a.

(n) During UVRT or OVRT generating units of Type 2 shall give priority to reactive current injection, it is allowed to reduce active current. It is recommended (but not mandatory) to reduce active current I_P in proportion to the deviation of the voltage, as indicated by the following equation or similar:

$$I_P/I_n = (I_{P0} - \Delta I_P)/I_n = (I_{P0}/I_n) - |(-\Delta U/U_n)| = (I_{P0}/I_n) - |(U - U_0)/U_n|$$

(o) The responsible TSO has to announce if this functionality of dynamic voltage support (additional reactive current during UVRT and OVRT) shall be activated and which value shall be used for the K factor (default value is 2). The TSO has the right at any time in the future to require the activation of this functionality.

3.1.11 On load tap changing for generating *unit* step-up transformers

(1) All new generating *unit* step-up transformers shall have on-load tap changing which can be remotely controlled. The range shall be agreed between *Transmission* and the *generator*.

3.1.12 *Emergency unit* capabilities

(1) All *generators* shall specify their *units'* capabilities for providing real power above rated capability.

3.1.13 Facility for independent *generator* action

(1) *Frequency* control under system island conditions shall revert to the *Power Stations* as the last resort, and *units* and associated plant shall be equipped to handle such situations. The required control range is from 49 to 51 *Hz*.

3.1.14 Automatic under-*frequency* starting

(1) It may be agreed with the *System Operator* that a *unit* that is capable of automatically starting within 10 minutes shall have automatic under-*frequency* starting. This starting shall be initiated by *frequency*-level facilities with settings in the range 49Hz to 50Hz as specified by the *System Operator*.

3.1.15 Connection and Reconnection Requirements for Type 2 Generating Units

(1) A connection of a commissioned Type 2 generating unit shall be admissible only if the network voltage at the PoC is inside its normal operating voltage band (0.90 p.u. – 1.10 p.u.) and the frequency is between 47.5 Hz and 50.5 Hz (which are the lower frequency band limit under extreme system operation of fault conditions and the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System).

(2) If the voltage at the PoC is outside of the above mentioned voltage band (0.90 p.u. – 1.10 p.u.), connection shall be blocked.

(3) If the frequency is is below 47.5 Hz or above 50.5 Hz, connection shall be blocked. A different value for the setting may be applied in agreement with the responsible TSO.

(4) The reconnection of a power generating unit after being disconnected for protection is only allowed:

(a) if the voltage at the PoC is within a band of 0.80 p.u. – 1.10 p.u.,

(b) if the frequency is below 47.5 Hz or above 50.5 Hz (a different value for the setting may be applied in agreement with the responsible TSO,

(c) if there is no Instruction from the network operator for disconnection or for power limit of 0%, compare Section 3.1.16.

(5) If the power station consists of several generating units, the responsible DNO can specify a minimum delay time interval between the connection/reconnection of the individual units in order to limit impact on voltage and ensure desired power quality (e.g. flicker).

3.1.16 Power Reduction on Demand

(1) Power stations with Type 2 generating units must have a remote control connection to reduce power injection to zero (i.e. stop of power injection) by the responsible TSO. To run the customer's facility in an isolated mode, disconnected from the network of public supply, is allowed.

(2) Power stations with Type 2 generating units must have a remote control connection to reduce the power by the responsible TSO in pre-defined steps. The responsible TSO shall defines the required power steps (e.g. steps of 25% of the nominal power of the power station).

(3) The technical requirements for the remote control connection have to be specified by the responsible TSO.

3.1.17 Harmonics

(1) A power station with Type 2 generating units shall withstand and function correctly in the presence of harmonic voltages up to the compatibility levels for HV or EHV networks specified in the TBS Standard "Power Quality – Quality of Supply" [1] (long-term and short-term).

(2) The power station with Type 2 generating units is not allowed to inject harmonic currents into the network which lead to harmonic voltages or a THD at the PCC which are higher than the compatibility levels for HV or EHV networks specified in TBS Standard "Power Quality – Quality of Supply" [1]. The responsible TSO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

(3) If the compatibility levels for harmonic voltages or THD at the PCC are exceeded in operation, the responsible TSO has to carry out measurements in accordance to [1] in combination with IEC 61000-4-7 [2] or if applicable in combination with IEC 61400-21 [3] in order to find the most disturbing device. If this device belongs to the power station, the generator has to do countermeasures to lower the harmonic disturbance.

3.1.18 Testing and compliance monitoring

(1) A *generator* shall keep records relating to the compliance by each of its *units* with each section of this code applicable to that *unit*, setting out such *Information* that the *System Operator* reasonably requires for assessing power system performance (including actual *unit* performance during abnormal conditions).

(2) Within one *Month* after the end of June and December, a *generator* shall review, and confirm to the *System Operator*, compliance by each of that *generator's units* with every *GCR* during the past 6 *Month* period.

(3) A *generator* shall conduct tests or studies to demonstrate that each *Power Station* and each generating *unit* complies with each of the requirements of this code. Tests shall be carried out on new *units*, after every outage where the integrity of any *GCR* may have been compromised, to demonstrate the compliance of the *unit* with the relevant *GCR*(s). The *generator* shall continuously monitor its compliance with all the connection conditions of the *Grid Code*. The Authority may waive this requirement parties to the PPA have testing obligations agreed under their PPAs.

(4) Each *generator* shall submit to the *System Operator* a detailed test procedure, emphasising system impact, for each relevant part of this code prior to every test.

(5) If a *generator* determines, from tests or otherwise, that one of its *units* or *Power Station*s is not complying with one or more sections of this code, then the *generator* shall:

(6) promptly notify the *System Operator* of that fact;

(7) promptly advise the *System Operator* of the remedial steps it proposes to take to ensure that the relevant *unit* or *Power Station* (as applicable) can comply with this code and the proposed timetable for implementing those steps;

(8) Diligently take such remedial action as will ensure that the relevant *unit* or *Power Station* (as applicable) can comply with this code. The *generator* shall regularly report in writing to the *System Operator* on its progress in implementing the remedial action;

(9) And after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *System Operator* that the relevant *unit* or *Power Station* (as applicable) is then complying with this code.

(10) Power stations with Type 2 generating units shall install a power quality monitoring device and a fault recorder within their facility at the connection to the PoC.

(a) Minimum requirements for the power quality monitoring are:

(i) Parameter settings shall be configurable

(ii) recording of the line-earth voltages U_{L1-E}, U_{L2-E}, U_{L2-E}

(iii) recording of the line-line voltages U_{L1-L2}, U_{L2-L3}, U_{L3-L1}

(iv) recording of the currents I_{L1}, I_{L2}, I_{L3}, I_0; current measurement capability shall include 4 × I_n continuously

(v) recording of the active power, reactive power, apparent power and power factor

(vi) recording of the harmonic voltages at least to the 40th order

(vii) recording of the interharmonic voltages at least to the 40th order

(viii) recording of the harmonic currents at least to the 40th order

(ix) recording of the interharmonic currents at least to the 40th order

(x) recording of the frequency

(xi) recording of all 10 minute mean values for at least 50 days

(xii) FIFO buffer

(xiii) configurable recording period

(b) Minimum requirements for the fault recording are:

(i) adjustable time parameter for pre-fault and post-fault recording

(ii) Capability to export in COMTRADE format

(iii) Trigger:

- U_{max}, U_{min}, dU/dt
- f_{max}, f_{min}, df/dt
- I_{max}, I_{min}, dI/dt
- P_{max}, Q_{max}
- binary input signals
- individual for all analogue and binary input signals which are used for triggering
- high, low, positive slope and negative slope

(c) The generator has to provide recordings of the power quality monitoring and fault recording to the TSO upon request.

3.1.19 Non-compliance suspected by the *System Operator*

(1) If at any time the *System Operator* believes that a *unit* or *Power Station* is not complying with this code, and then the *System Operator* must notify the relevant *generator* of such non-compliance specifying the code section concerned and the basis for the *System Operator's* belief.

(2) If the relevant *generator* believes that the *unit* or *Power Station* (as applicable) is complying with the code, then the *System Operator* and the *generator* must promptly meet to resolve their difference.

3.1.20 Unit modifications

3.1.20.1 Modification proposals

(1) If a *generator* proposes to change or modify any of its *units* in a manner that could reasonably be expected to either adversely affect that *unit's* ability to comply with this code, or changes the performance, *Information* supplied, settings, etc, then that *generator* shall submit a proposal notice to the *System Operator* which shall:

(2) contain detailed plans of the proposed change or modification;

(3) state when the *generator* intends to make the proposed change or modification; and

(4) Set out the proposed tests to confirm that the relevant *unit* as changed or modified operates in the manner contemplated in the proposal, can comply with this code.

(5) If the *System Operator* disagrees with the proposal submitted, it may notify the relevant *generator*, and the *System Operator* and the relevant *generator* shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement.

3.1.20.2 Implementing modifications

(1) The *generator* shall ensure that an approved change or modification to a *unit* or to a subsystem of a *unit* is implemented in accordance with the relevant proposal approved by the *System Operator*.

(2) The *generator* shall notify the *System Operator* promptly after an approved change or modification to a *unit* has been implemented.

3.1.20.3 Testing of modifications

(1) The *generator* shall confirm that a change or modification to any of its *units* as described above conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions, promptly after the proposal has been implemented.

(2) Within 20 business days after any such test has been conducted, the relevant *generator* shall provide the *System Operator* with a report in relation to that test (including test results of that test, where appropriate).

3.1.21 Equipment requirements

(1) Where the *generator* needs to install equipment that connects directly with *Transmission* equipment, for example in the high voltage yard of *Transmission*, such equipment shall adhere to *Transmission* design requirements as set out in this code.

(2) *Transmission* may require *customers* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

3.2 Distributors and end-use customers

(1) This section describes connection conditions for *distributors* and *end-use customers*.

(2) Transmission shall offer to connect and, subsequent to the signing of the relevant agreements, make available a *Point of Connection* to any requesting *distributor* or *end-use customer*.

(3) A *customer* may request additional reinforcements to the TS over and above that which could be economically justified as described in the section on TS Planning and Development. *Transmission* shall provide such reinforcements if the *customer* agrees to bear the costs, which shall be priced according to the Tariff Code provisions.

3.2.1 Power factor

(1) *Distributors* and *end-use customers* shall take all reasonable steps to ensure that the power factors at the *Point of Supply* is at all times 0,90 lagging or better, unless otherwise agreed to in existing contracts between the *Participants*. This requirement applies to each *Point of Supply* individually for *customers* with more than one *Point of Supply*. A leading power factor shall not be acceptable, unless specifically agreed to in writing.

(2) Should the power factor be less than the said limit during any 10 (ten) demand-integrated half hours in a single calendar *Month*, the *Participants* shall co-operate in determining the plans of action to rectify the situation. Overall lowest cost solutions shall be sought.

3.2.2 *Protection*

(1) Each *Participant* shall take all reasonable steps to protect its own plant.

(2) The *System Operator Protection* requirements, with which the *customers* shall interface, are described in section 5. The detailed *Protection* applications, insofar as the equipment of one *Participant* may have an impact on the other, shall be agreed to in writing by the relevant *Participants*. *Distributors* who have

customers connected directly to the *Transmission substations* are responsible for ensuring that such *customers* comply with the relevant *Protection* standards.

(3) The *Participants* shall co-ordinate *Protection* to ensure proper grading and *Protection* coordination.

3.2.3 Fault levels

(1) Minimum fault levels at each *Point of Supply* shall be maintained by *Transmission* under normal operating conditions to ensure compliance with the relevant Quality of Supply standards and to ensure correct operation of the *Protection* systems.

(2) *Transmission* shall liaise with *customers* as per the process defined in the section on Network planning and development, on how fault levels are planned to change and on the best overall solutions when equipment ratings become inadequate. Overall lowest cost solutions shall be sought and a joint impact assessment shall be done covering all aspects. *Transmission* shall communicate the potential impact on safety of people when equipment ratings are exceeded.

(3) The *System Operator* shall annually, or when substantial deviations have taken place, publish updated minimum and maximum normal operating fault levels for each *Point of Supply*. The *customer* shall ensure his equipment is capable of operating at the specified fault level ranges.

(4) If equipment fault level ratings are or will be exceeded, the *customer* shall promptly notify *Transmission*. *Transmission* shall seek overall lowest cost solutions to address fault level problems. Corrective action shall be at the cost of the relevant asset owner.

3.2.4 ***Distributor* or *end-use customer* network performance**

(1) If the *distributor* or *end-use customer* network performance falls below acceptable levels and affects the quality of supply to other *customers* or causes damage (direct or indirect) to *Transmission* equipment, the process for dispute resolution, as described in the Governance Code, shall be followed.

(2) Acceptable network performance shall be:

(a) Performance comparable to benchmarks for similar networks, and

(b) Performance that complies with *Transmission* operating and maintenance procedures at that *Substation*, and

(c) Performance that complies with the minimum agreed standards of Quality of Supply *QOS*, see 3.2.5 below.

(3) If *distributors* or *end-use customers* are aware that their network performance could be unacceptable as described above, they shall take reasonable steps at their own cost to overcome the shortcomings, for example by improving line maintenance practices, improving *Protection* and breaker operating times, if necessary by replacing the said equipment, installing additional network breakers, changing operating procedures, by installing fault-limiting devices if the number of faults cannot be reduced, etc. These changes should be effected in consultation with *Transmission* on both the technical scope and the time frame.

(4) Where *QOS* standards are transgressed, the parties shall co-operate and agree in determining the root causes and plans of action.

3.2.5 ***Transmission*'s delivered *QOS***

(1) Quality of supply is a shared responsibility between *Transmission* and its *customers*, and based on Tanzanian *QOS* standards [1] as agreed with all *Stakeholders*.

(2) *Transmission* shall agree in writing with its *customers*, for every *Point of Supply*, at least on the following *QOS* parameters, taking local circumstances, historical performance and the relevant standards into account:

(a) Interruption performance

(b) Voltage regulation performance

(c) Dip performance

(d) Total harmonic distortion performance

(e) *Flicker* performance

(f) Unbalance performance

(g) *Customer* responsibilities in terms of harmonic current injection, unbalanced currents and addition of voltage dips to the network could also be included in the agreement.

(3) A reasonable time period for monitoring performance shall be allowed before performance is agreed to for the first time in terms of interruptions and dips. This time period shall be three years unless otherwise agreed. For harmonic voltages and voltage unbalance, performance can be monitored after one week of measurements is done.

(4) Where *Transmission* fails to meet the agreed *QOS* parameters, they shall take reasonable steps at own cost to overcome the shortcomings, for example by improving line maintenance practices, improving *Protection* and breaker operating times, if necessary by replacing the said equipment, installing additional network breakers, changing operating procedures, by installing fault-limiting devices if the number of faults cannot be reduced, etc. These changes should be effected in consultation with the *customer* on both the technical scope and the time frame.

3.2.6 Equipment requirements

(1) Where the *distributor* or *end-use customer* need to install equipment that connects directly with *Transmission* equipment in *Transmission substations*, such equipment shall adhere to *Transmission* design requirements as set out below in 4. (These can be at any voltage level.)

(2) *Transmission* may require *customers* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

(3) Any *distributor* or *end-use customer* wishing to install a new series capacitor, shall at his expense and according to *Transmission's* requirements, arrange for sub synchronous resonance, harmonic and *Protection* coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any *generator*.

4 *Transmission* technical design requirements

(1) The purpose of this section is to document the design and other technical standards that *Transmission* shall adhere to.

4.1 Equipment design standards

(1) *Primary Substation Equipment* shall comply with *IEC* specifications. Application shall cater for local conditions, e.g. increased pollution levels and should be determined by or in consultation with the *customer*.

(2) *Transmission* shall design, install and maintain equipment in accordance with the standards.

(3) *Customers* may require *Transmission* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

4.2 Clearances

(1) Clearances shall at least comply with the The Electricity Rules, Section 84, requirements.

4.3 CT and VT ratios and cores

(1) *CT* and *VT* ratios and cores shall be determined by or in consultation with *Transmission*.

4.4 Standard busbar arrangements and Security criteria

(1) *Substation*s on the *Grid System (GS)* shall be configured according to the principles described in this section.

4.4.1 *Transmission Substation* standard *Busbar* arrangements

(1) The reliability and availability of the *Grid System* is not dependent only on TS lines, transformers, and other primary and secondary plant; the *busbar* layout also plays a part. It is important that the *busbar* layout and what it can do for the reliability and availability of the *customer's* supply be prudently assessed when planning the TS.

(2) The standard arrangement shall be based on providing one *busbar* zone for every main transformer/line normally supplying that *busbar*. *Transmission* shall however consider local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required *busbar* redundancy. System reliability criteria as described in the TS Planning and Development Section should also be adhered to.

4.4.2 Use of bypasses

(1) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability

(2) The bypass with single *busbar* selection shall be used at 132 *kV* on single line radial feeds to provide continuity of supply when maintaining the line breakers

(3) The bypass with double *busbar* selection shall be used on new 220 *kV* and above lines where justified.

4.5 Motorised isolators

(1) The provision of motorised isolators at new *substations* is to be based on the following:

(a) All 220 *kV* and above isolators shall be motorised at new *substations*.

(b) Isolators of 132 *kV* and below shall be specified on individual merit (importance ranking vs. cost vs. remoteness)

4.6 Earthing isolators

(1) Earthing isolators shall be provided at new *substations* where the fault level is designed for 15 *kA* and above.

4.7 Busbar Protection CT's

(1) For *busbar Protection* schemes, single sets of *CT's* shall be used on bus couplers and bus section breakers (i.e. 3 *CT's* instead of 6 *CT's*) to reduce the probability of a double bus zone outage for a *CT* fault on a bus coupler or bus section breaker (i.e. non-overlapped zones will apply).

(2) At *Power Station*, overlapped bus zones shall be retained to ensure fastest possible clearance of *busbar* faults.

4.8 Telecontrol

(1) Either *Participant* may be permitted to have telecontrol equipment in the *substations* / yards / buildings of the other *Party*, to perform agreed monitoring and control. Access shall be provided to such equipment.

(2) *Distributors* shall have reliable *SCADA* facilities (including telecommunications, computers and *RTUs*) for the *distribution system* connected directly to the TS, to provide the necessary response where system conditions require.

4.9 Transformer tap change

(1) *Transmission* shall install automatic tap changing facilities on all new transformers.

(2) Transformers used in the TS at 220kV and above are normally not on automatic tap change. Transformers supplying a *customer* are usually on automatic tap change. Voltage levels, sensitivity and time settings and on/off auto tap changing shall be determined by the *System Operator* in consultation with the *customer*, and *Transmission*.

4.10 Substation drawings

(1) The following set of drawings shall be made available by the respective asset owners for all *points of supply*, if required by the other *Party* for the purposes of connection:

(a) Station Electric Diagram

(b) Key Plan

(c) Bay Layout Schedules

(d) Foundation, Earthmat and Trench Layout

(e) Steelwork Marking Plan

(f) *Security* Fence Layout

(g) Terrace, Road and Drainage Layout

(h) Transformer Plinth

(i) General Arrangement

(j) Sections

(k) Slack Span Schedule

(l) Barrier Fence Layout

(m) *Security* Lighting

(n) Floodlighting Parameter Sketch

(o) *Protection* details

(p) Contour Plan

5 *Protection* requirements

(1) This section specifies the minimum *Protection* requirements for *Transmission*'s as well as typical settings, to ensure adequate performance of the TS as experienced by the *customers*.

(2) *Transmission* shall at all times install and maintain *Protection* installations that comply with the provisions of this section.

(3) *Transmission* shall conduct periodic testing of equipment and systems to ensure and demonstrate that these are performing to the design specifications. Tests procedures shall be according to the manufacturers' specifications.

(4) *Transmission* shall make available to *customers* all results of test performed on equipment for reasonable requests.

(5) *Protection* schemes are generally divided into:

(a) equipment *Protection* and

(b) System *Protection*.

5.1 Equipment Protection requirements

5.1.1 Feeder *Protection*: 220kV and above

5.1.1.1 *Protection* Design Standards

(1) New feeders shall be protected by two equivalent *Protection* systems – Main 1 and Main 2.

(2) The Main 1 and Main 2 *Protection* systems shall be fully segregated in secondary circuits.

(3) An additional earth fault function shall be incorporated in the main *Protection* relays or installed separately to alleviate possible deficiencies of distance relays in detection of high resistance faults.

5.1.1.2 *Protection* Settings

(1) The *Protection* relays shall provide reliable *Protection* against all possible short circuits, provide remote and/or local back up for not cleared *busbar* faults and are set to provide overload tripping.

(2) Where specifically required, the feeder *Protection* may be set, if possible, to provide remote back up for other faults as agreed upon with other *Participants*.

5.1.1.3 Automatic Re-closing

(1) Automatic re-closing (*ARC*) facilities shall be provided on all feeders.

(2) The *System Operator* shall decide on *ARC* selection based on real time system, environmental constraints and consultation with *customers*, with regard to equipment capabilities and in accordance with the *ARC* philosophy below. All *ARC* settings and methodology shall be implemented by *Transmission* and be made available to *customers* on request.

5.1.1.4 *ARC* cycles

(1) Either of the following two *ARC* cycles for single phase faults shall be used:

(a) Double attempt *ARC* cycle for persistent fault:1ph fault – 1ph trip – 1ph *ARC* – 3ph trip – 3ph *ARC* – 3ph trip – lockout

(b) Single attempt *ARC* cycle for persistent fault: 1ph fault – 1ph trip – 1ph *ARC* – 3ph trip – lockout

(c) The *ARC* cycle for a multiphase (mph) fault shall be: mph fault – 3ph trip – 3ph *ARC* – 3ph trip – lockout

(2) On some lines the *ARC* is being switched off according to the following operational needs:

(a) Sporadically, when high risk of line fault is recognised, for live line work or to reduce breaker duty cycle where breaker's condition is questionable.

(b) Periodically, during season of high fault *frequency*,

(c) Permanently, on lines with the highest fault *frequency* throughout the year or on *customers*' request.

(d) Whenever an *ARC* could initiate a severe power swing or an Out-Of-Step condition in weakly interconnected systems.

5.1.1.5 Single Phase *ARC*

(1) In most applications the dead time of Single Phase *ARC* is selected to 1 second but may differ for different system requirements. The closing of the breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the whole incident.

5.1.1.6 Three Phase *ARC*

5.1.1.6.1 Fast *ARC*

(1) Fast *ARC* i.e. fast closing of the breaker without checking synchronism is not used on the TS to avoid stress to the rotating machines at the *Power Station*s and at the *customers*' plant. This option is available on *Protection* panels and can be selected in case of *emergency* i.e. when as a result of outages or disturbance load/generation islands are interconnected via a single line. The operating practice, however, is to use only single phase *ARC* (fast by its nature) in such situations as a compromise between supply reliability and stress to the equipment.

5.1.1.6.2 Slow *ARC*

(1) The Dead Line Charging (*DLC*) end is selected in line with the Table 5.1 below based on fault level (FL) at the connected *substations* A and B.

Table 5.1: Selection of Dead Line charging end of the line.

End A / End B	*Substation* FL<10kA	*Substation* FL>10kA	*Power Station*
Substation FL<10kA	*Substation* with higher FL	*Substation* A	*Substation* B
Substation FL>10kA	*Substation* B	*Substation* with lower FL	*Substation* B
Power Station	*Substation* A	*Substation* A	*Power Station* with lower FL

(2) In most applications the dead time of slow *ARC* is selected to 3 seconds at *DLC* end of the line. At the synchronising end of the line the *ARC* dead time is usually selected to 4 seconds. The close command will be issued only after synch-check is completed. This may take up to 2 seconds if synchronising relays are not equipped with direct slip *frequency* measurement. The breaker may take longer to close

if its mechanism is not ready to close after initial operation at the time when the close command is issued.

(3) On the line between two *Power Station*s the dead time at the *DLC* end should be extended to 25 seconds to allow *generators'* rotors oscillations to stabilise. The dead time on the synchronising end is then extended accordingly to 30 seconds.

(4) The synchronising relays are installed at both ends of the line to enable flexibility in *ARC* cycles and during restoration.

5.1.1.7 Power Swing Blocking

(1) New distance relays on the TS shall be equipped with power swing blocking facility. All unwanted operations of distance relays during power swing conditions shall be blocked on the TS.

5.1.2 Feeder *Protection*: 132kV and below, at *Transmission* substations

5.1.2.1 Design Standard

(1) These feeders shall be protected by a single *Protection* system, incorporating either distance or differential *Protection* relays, unless otherwise agreed. Back up shall be provided by definite time and inverse definite minimum time (*IDMT*) over-current and earth fault relays.

(2) The *Protection* shall be equipped with automatic re-closing. Synchronising relays shall be provided on feeders that operate in "ring supplies" and are equipped with line voltage transformers.

5.1.2.2 *Protection* Settings

(1) *Protection* relays shall provide reliable *Protection* against all possible short circuits, provide remote and/or local back up for *Un*-cleared *busbar* faults and should not be set to provide overload tripping where measurements and alarms are provided on *SCADA* system. In isolated applications where *SCADA* system is not available, overload tripping will be provided. Where overload conditions are alarmed at *control centres*, it is the *control centre* responsibility to reduce load to an acceptable level as quickly as possible.

5.1.2.3 Automatic Re-closing

(1) The *customer* shall determine *ARC* requirements. The *System Operator* may specify additional *ARC* requirements for system *Security* reasons, which could extend beyond *Transmission substations*.

5.1.3 Tele-*Protection* requirements

(1) New distance *Protection* systems shall be equipped with tele-*Protection* facilities to enhance the *Speed of Operation*.

5.1.4 Transformer and reactor *Protection*

(1) The standard schemes for transformer *Protection* comprise a number of systems, each designed to provide the requisite degree of *Protection* for the following fault conditions:

(a) Faults within the tank

(b) Faults on transformer connections

(c) Overheating

(d) Faults external to the transformer

(2) *Transmission* shall consider the application of the following relays in the design of the *Protection* system:

5.1.4.1 Transformer *IDMT E/F*

(1) The *MV E/F Protection* is to discriminate with the feeder back-up *E/F Protection* for feeder faults

5.1.4.2 Transformer *HV/MV IDMT O/C*

(1) The *System Operator* requires that the *IDMT O/C* does not operate for twice transformer full load. Overloading of the transformer is catered for by the winding and oil temperature *Protection*. However, network requirements may be such that the above standard cannot be applied. In this case, a mutually agreed philosophy may be used.

5.1.4.3 Transformer *HV/MV* Instantaneous *O/C*

(1) This back-up *Protection* is to cater for flash-overs external to the Transformer (*TRFR)* on the *HV* side or *MV* side and should operate for minimum fault conditions (possibly as well for an *E/F* condition). However, the overriding requirement is not to operate for through faults or for magnetising inrush current.

5.1.4.4 Transformer LV (Tertiary) *IDMT*/Instantaneous *O/C*

(1) This *Protection* is to operate for external faults between the main delta winding of the *TRFR* and the auxiliary *TRFR*, but not for faults on the secondary side of the auxiliary *TRFR*. The auxiliary *TRFR* is protected by Buchholz and temperature *Protection*.

5.1.4.5 Transformer Current Differential *Protection*

(1) This is the main transformer *Protection* for *E/F* and phase to phase faults. Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current, with its attendant decaying offset.

5.1.4.6 Transformer High Impedance Restricted *E/F*

(1) This *Protection* is an additional *Protection* for the *TRFR* differential relay to cater for earth faults close to the star point of the *TRFR* winding, where phase to phase faults are most unlikely to occur.

5.1.4.7 Transformer Thermal Overload

(1) Winding temperature and oil temperature relays, supplied by the manufacturer are used to prevent transformer damage or life time reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

5.1.5 *Transmission System Busbar Protection*

(1) *Busbars* shall be protected by current differential *Protection* (bus-zone) set to be as sensitive as possible for the “in-zone faults” and maintain stability for any faults outside the protected zone, even with fully saturated *CT*.

5.1.6 *Transmission System* bus coupler and bus section *Protection*

(1) Bus-coupler and bus-section panels are equipped with *O/C* and *E/F Protection*.

5.1.7 *Transmission System* shunt capacitor *Protection*

(1) All the new high voltage capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors shall also be employed to limit inrush current.

(2) The following *Protection* functions shall be provided for all types of *Protection* schemes:

(a) Unbalanced *Protection* with alarm and trip stages

(b) Over-current *Protection* with instantaneous and definite time elements

(c) Earth fault *Protection* with instantaneous and definite time sensitive function

(d) Overload *Protection* with *IDMT* characteristic

(e) Over-voltage with definite time

(f) Circuit breaker close inhibit for 300 seconds after de-energisation

(3) Ancillary functions as indicated below.

5.1.8 Over-voltage *Protection*

(1) Primary *Protection* against high transient over-voltages of magnitudes above 140% (e.g. induced by lightning) shall be provided by means of surge arrestors. To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage *Protection* shall be installed on shunt capacitors and feeders.

(2) Over-voltage *Protection* on shunt capacitors is set to disconnect capacitor at 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients.

(3) Over-voltage *Protection* on the feeders is set to trip the local breaker at voltage level of 120% with a delay of 1 to 2 seconds.

5.1.9 Ancillary *Protection* functions

(1) *Protection* systems are equipped with auxiliary functions and relays that enable adequate co-ordination between *Protection* devices and with bay equipment. *Transmission* shall consider the following functions for all new *Protection* system designs:

5.1.9.1 Breaker Fail / Bustrip

(1) Each individual *Protection* scheme is equipped with breaker fail / bustrip function to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

5.1.9.2 Breaker Pole Discrepancy

(1) Breaker pole discrepancy *Protection* compares, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase. When breaker on one phase is in a different position than breakers on remaining phases a trip command is issued after time delay.

5.1.9.3 Breaker Anti-pumping

(1) To prevent repetitive closing of the breaker in case of fault in closing circuits the standard *Protection* schemes provide breaker anti pumping timer. Circuit breakers are often equipped with their own anti pumping devices. In such cases anti pumping function is duplicated.

5.1.9.4 Pantograph Isolator Discrepancy

(1) The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarm.

5.1.9.5 Master Relay

(1) Transformer and reactor *Protection* schemes are equipped with latching master relay that require manual reset before the circuit breaker is enabled to close. The master relay is operated by *unit Protection* that indicates possibility of internal failure.

5.2 System Protection requirements

5.2.1 Under-*frequency* load shedding

(1) The actions taken on the power system during an under-*frequency* condition is defined in the System Operation Code.

(2) Under-*frequency* load shedding relays shall be installed in the TS as determined by the *System Operator* in consultation with *distributors* and *end-use customers*. The respective asset owners shall pay for the installation and maintenance of these relays.

(3) Under-*frequency* relays shall be tested periodically. *Distributors* and *end-use customers* shall submit to the *System Operator* a written report of each such test, within a *Month* of the test being done, in the format specified in the Information Exchange Code. The testing shall be done by isolating all actual tripping circuits, injecting a *frequency* to simulate a *frequency* collapse and checking all related functionality.

5.2.2 Out of step tripping

(1) The purpose for the out-of-step tripping *Protection* is to separate power system in a situation where a loss of synchronous operation takes place between a *unit* or *units* and the main power system. In such a situation system separation is desirable to remedy the situation. Once the islanded system is stabilised it can be reconnected to the main system.

(2) The *System Operator* shall determine and specify the out-of-step tripping (OST) functionality to be installed at selected locations by *Transmission*.

5.2.3 Under-voltage load shedding

(1) Under-voltage load shedding *Protection* schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads is carried out to arrest the slide.

(2) The *System Operator* shall determine and specify the under-voltage load shedding functionality to be installed at selected locations by *Transmission*.

5.2.4 Sub-synchronous resonance *Protection*

(1) The sub-synchronous resonance (*SSR*) condition may arise on a power system where a *generator* is connected to the main power system through long series compensated TS lines. The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and larger thermal turbo-generators are employed. The *SSR* condition is addressed either through *Protection* or mitigation. In case of *Protection*, a suitable relay shall be deployed as part of the turbo-*generator Protection* that will lead to the *unit* disconnection on detection of the *SSR* condition. The *Protection* does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance. Mitigation, on the other hand, acts to reduce or eliminate the resonant condition. Mitigation is needed only under conditions when it is desirable or essential to continue operation when the power system is at or near a resonant condition.

(2) New *generators* shall liaise with *Transmission* regarding *SSR Protection* studies. Least-cost solutions shall be determined by *Transmission* in accordance with the TS planning and Development Section, and implemented by the relevant asset owner.

5.2.5 *Protection* against near 50 *Hz* Resonance

(1) Due to the length of the TS network in Tanzania and due to the relatively low load conditions, a near 50 *Hz* resonance may arise on the TS network. Adequate reactive compensation therefore needs to be installed on the *Transmission System* and the influence of the *System Operator* and clients on this near 50 *Hz* resonance needs to be reduced. *Transmission*'s has to ensure that the near 50 *Hz* resonance is catered for in any old or new networks.

5.2.6 *Protection* Settings impact on Network Stability (Transient Stability)

(1) Minimum clearance times for *Protection* in *Distributor* or *end-use customer* networks will be determined on a case by case basis in order to ensure Transient Stability of the TS.

5.3 Protection system performance monitoring

(1) To maintain high level of *Protection* performance and long term sustainability, *Transmission* shall monitor *Protection* performance.

(2) Each *Protection* operation shall be investigated for its correctness based on available *Information*. *Transmission* shall provide a report to *customers* affected by a *Protection* operation when requested to do so.

6 Nomenclature

(1) All safety terminology shall comply the requirements of the Employment and Labour Relations Act (2004), specifically the Regulations relating to Occupational Health and Safety Act (2003).

7 *TS* planning and development

(1) This section specifies the technical, design and economic criteria and procedures to be applied by *Transmission* in the planning and development of the TS and to be taken into account by *customers* in the planning and development of their own systems. It specifies *Information* to be supplied by *customers* to *Transmission*, and *Information* to be supplied by *Transmission* to *customers*.

(2) The development of the TS, will arise for a number of reasons including, but not limited to:

(a) a development on a *customer* system already *connected to the TS*;

(b) the introduction of a new TS *Substation* or *Point of Connection* or the modification of an existing connection between a *customer* and the TS;

(3) The cumulative effect of a number of such developments referred to in (a) and (b) by one or more *customers*.

(4) The need to reconfigure, decommission or optimise parts of the existing network.

(5) Accordingly, the development of the TS may involve work:

(a) at a *Substation* where *customer*'s plant and/or apparatus is *connected to the TS*;

(b) on TS lines or other facilities which join that *Substation* to the remainder of the TS;

(c) on TS lines, TS *substations* or other facilities at or between points remote from that *Substation*.

(6) The time required for the planning and development of the TS will depend on the type and extent of the necessary reinforcement and/or extension work, the need or otherwise for statutory planning consent, the associated possibility of the need for public participation and the degree of complexity in undertaking the new work while maintaining satisfactory *Security* and quality of supply on the existing TS.

7.1 Planning process

(1) *Transmission* shall follow a planning process divided into major activities as follows:

(a) Needs identification.

(b) Formulation of alternative options to meet this need.

(c) Studying these options to ensure compliance with agreed technical limits, and justifiable reliability and quality of supply standards.

(d) Costing these options on the basis of present-*day* capital costs and using appropriate net discount rates, establish the net present cost of each option.

(e) Determining the preferred option.

(f) Building a business case, bankable documentation for the required financing, for the preferred option using acceptable justification criteria.

(g) Requesting approval of preferred option and initiating execution.

7.2 Identification of the need for TS development

(1) *Transmission* shall source relevant *data* from relevant national planning studies, specific *customer Information*, Governmental, new IPP's and *customer* development plans to establish the needs for network strengthening.

7.3 Forecasting the demand

(1) *Transmission* is responsible for producing the TS demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years.

(2) The TS demand forecast shall be determined for each *Point of Supply*. Generation and import capacity plans shall be used to obtain the annual generation patterns.

(3) To forecast the maximum demand (*MW*) for each TS *Substation*, *Transmission* shall use *distributor* and *end-use customer* load forecasts. Final loads are reconciled with *data* from various sources.

(4) The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to line up with the higher-level *data*.

(5) All *distributors* and *end-use customers* shall annually, by end October, supply their 5-year ahead load forecast *data* and an estimate for the 10 years ahead demand as detailed in the Information Exchange Code.

7.4 Technical limits and targets for planning purposes

(1) The limits and targets against which proposed options are checked by *Transmission* shall include technical and statutory limits which must be observed, and other targets, which indicate that the system is reaching a point where problems may occur. If technical or statutory limits are not achieved, alternative options shall be evaluated. If targets are not achieved, some options may be still acceptable as per the investment criteria.

7.4.1 Voltage limits and targets

(1) Technical or statutory limits are stated in table 7.4.1.1:

Table 7.1: Technical and Statutory Voltage Limits

Nominal continuous operating voltage on any bus for which equipment is designed	U_N
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed *Um*, the highest voltage used at sending-end *busbars* in planning studies should not exceed 0.98 *Um*	U_M
Minimum voltage on Point of Common Coupling (*PCC*) during motor starting	0.85 U_N
Maximum voltage change when switching lines, capacitors, reactors, etc.: Maximum Fault Level Minimum Fault Level	0.03 U_N 0.075 U_N
Statutory voltage change on bus supplying *customer* for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	0.10 U_N U_N + OR - 10%

Table 7.2: Standard Voltage Levels

	Voltage limits in Percent of nominal.			
Voltage Class	Normal Operation Condition		Emergency Operation Condition	
Nominal Voltage (kV)	min	max	min	max
400	**95%**	**105%**	**90%**	**105%**
220	**95%**	**105%**	**90%**	**110%**
132	**95%**	**105%**	**90%**	**110%**
66	**95%**	**105%**	**90%**	**110%**
33	**95%**	**105%**	**95%**	**105%**
11	**95%**	**105%**	**95%**	**105%**
0.4	**95%**	**105%**	**95%**	**105%**

(2) Target voltages for planning purposes are as in Table 7.3:

Table 7.3: Target Voltages for Planning Purposes

Minimum steady state voltage on any bus not supplying a *customer* With multiple feeder supplies: With single feeder supplies and after contingency for multiple feeder supplies:	 0.95 U_N 0.90 U_N
Maximum harmonic voltage caused by *customer* at *PCC*:	ACCORDING TO NRS 048
Maximum negative sequence voltage caused by *customer* at *PCC*:	ACCORDING TO NRS 048
Maximum voltage change due to load varying N times per hour:	$(4.5 \log_{10} N)\%$ OF U_N
Maximum voltage decrease for a 5% load increase at receiving end of system (without adjustment):	0.05 U_N

7.4.2 Other targets for planning purposes

7.4.2.1 *Transmission System* Lines

(1) Thermal ratings of standard TS lines shall be determined and updated from time to time. The temperatures used are 90ºC for aluminium conductor steel reinforced lines providing a *firm supply* (under single contingencies), and 75ºC for lines of copper or aluminium alloy or aluminium conductor steel reinforced lines not providing a *firm supply*. The thermal ratings shall be used as an initial check of line overloading. If the limits are exceeded the situation shall be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

7.4.2.2 Transformers

(1) Standard transformer ratings shall be determined and updated from time to time using *IEC* specifications. The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors. If target loads are exceeded the specific situation shall be assessed as it may be possible to defer adding extra transformers, depending on the actual transformer and on load conditions.

7.4.2.3 Series Capacitors

(1) With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.

(2) *IEC* 143 standards call for cyclic overload capabilities as follows:

(a) 8 hours in a 12-hour period: 1.1 times rated current

(b) ½ hour in a 6 hour period: 1.35 times rated current

(c) 10 minutes in a 2 hour period: 1.5 times rated current

(3) In addition, *Transmission* may require an occasional over-current rating of:

(a) 2 hours once per year: 1.3 times rated current

(4) The particular rating to be used must match the duration of the contingency with the required overload capability. Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

(5) Any *Transmission* wishing to install a new series capacitor or modify the size of an existing series capacitor, shall at his expense and according to the *Transmission's* requirements, arrange for sub synchronous resonance, harmonic and *Protection* coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any *generator*.

7.4.2.4 Shunt Reactive Compensation

(1) Shunt capacitors shall be able to operate at 30% above their nominal rated current at *Un* to allow for harmonics and voltages up to *Um*.

(2) Reactive compensation, whether new or modified, may cause harmonic resonance problems. Any *Participant* wishing to install or modify such equipment shall at his expense arrange for harmonic resonance studies to be conducted. If such studies indicate possible harmonic resonance conditions which could impact on the TS, such *Party* shall inform the *System Operator* before proceeding with the installation or modification.[1]

7.4.2.5 Circuit Breakers

(1) Normal and fault current ratings for standard switchgear are determined and updated from time to time. These ratings, and the following limits specified for circuit breakers, shall not be exceeded:

(a) Single-phase breaking current: 1.15 times 3 phase fault current

(b) Peak making current: 2.55 times 3 phase rms fault current

7.4.2.6 Secondary *ARC* current during single-phase re-closing

(1) The secondary *ARC* current shall not exceed:

(a) 20 amps rms with recovery voltage of 0.4 pu

(b) 40 amps rms with recovery voltage of 0.25 pu

7.4.3 Reliability criteria for planning purposes

(1) A system cannot be made 100% reliable as planned and *forced outage*s of components will occur, and multiple outages are always possible, despite having a very low probability of occurrence. From an economic point of view optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific *customer* involved. The appropriate degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.

(2) *Transmission* shall formulate long-term plans for expanding or strengthening the TS on the basis of the justifiable redundancy.

7.4.4 Contingency criteria for planning purposes

(1) A system meeting the n-1 (or n-2) contingency criterion must comply with all relevant limits outlined in 7.4.1 (voltage limits) and the applicable current limits, under all credible system conditions.

(2) For contingencies under various loading conditions it shall be assumed that appropriate, normally-used, generating plant is in service to meet the load and provide *Spinning Reserve*. For the more probable n-1 network contingency the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable n-2 network contingency an average pattern shall be used. More details of load and generation assumptions for load flow studies are given in section 7.4.5.

(3) The generation assumptions for the n-1 and n-2 network contingencies do not affect the final justification to proceed with investments, but merely check that the backbone of the network is still sufficient to meet an n-1 or n-2 contingency.

7.4.5 Integration of *Power Station*s

(1) When planning the integration of *Power Station*s the following criteria shall apply:

7.4.5.1 *Power Stations* of less than 500 *MW*

(1) With all connecting lines healthy it shall be possible to transmit the total output of the *Power Station* to the system for any system load condition. If the local area depends on the *Power Station* for voltage support, connection shall be done with a minimum of two lines.

(2) Transient stability shall be maintained following a successfully cleared single phase fault where economically justifiable.

(3) If only a single line is used it shall be able to be selected to alternative *busbars* and be able to go on to bypass at each end of the line

7.4.5.2 *Power Stations* of more than 500 *MW*

(1) With one connecting line out of service (n-1) it shall be possible to transmit the total output of the *Power Station* to the system for any system load condition

(2) With the two most onerous line outages (n-2) it shall be possible to transmit 83% of the total output of the *Power Station* to the system

7.4.5.3 Transient stability

(1) Transient stability shall be retained for the following conditions:

(a) a three-phase, line or *Busbar* fault, cleared in normal *Protection* times, with the system healthy and the most onerous *Power Station* loading condition, or

(b) a single phase fault cleared in "bus strip" times, with the system healthy and the most onerous *Power Station* loading condition, or

(c) a single-phase fault, cleared in normal *Protection* times, with any one line out of service and the *Power Station* loaded to average availability.

(2) The above conditions will only apply to *Power Station*s larger than 500 *MW*. For *Power Station*s smaller than 500 *MW*, the conditions will only apply where it is economically justifiable.

(3) The cost to ensure transient stability shall be carried by the *generator* if the optimum solution, as determined by *Transmission*, results in *unit* or *Power Station* equipment to be installed. In other cases, *Transmission* shall bear the costs and recover these as per the approved tariff methodology.

7.4.5.4 *Busbar* arrangements

(1) *Busbar* layouts shall allow for selection to alternative *busbars* and the ability to go on to bypass, and not more than 300 *MW* of generation shall be connected to any bus section, even with one bus section out of service.

7.4.5.5 Information required

(1) To enable *Transmission* to successfully integrate new *Power Stations*, detailed *Information* is required per *unit* and *Power Station*, as described in the Information Exchange Code.

7.5 Criteria for network investments

(1) The planning limits, targets and criteria form the basis for evaluation of the long-term development of the TS.

(2) *Transmission* shall only invest in the TS when the required development meets the approved investment criteria specified in this section. *Transmission* shall invest if the development meets the approved criteria, however it may be mutually agreed with affected *customers* to waiver certain investments.

(3) Any one of the following investment criteria, each applicable under different circumstances, can be applied.

(4) Calculations will assume a typical project life expectancy of 25 years except where otherwise dictated by plant life or project life expectancy.

(5) The following key economic parameters shall have the Authority approved process of being established:

(a) Discount rate

(b) COUE.

7.5.1 Least economic cost criteria.

(1) When investments are made in terms of improved supply reliability and/or quality, this would be the preferred method to use. This methodology should also be used to determine and/or verify the desired level of network or equipment redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the cost of interruptions, load shedding, network constraints, poor quality of supply (*QOS*), etc. Statistical analysis of network outages is also required.

(2) The least-cost investment criterion equation to be satisfied can be expressed as follows:

(a) Value of improved *QOS* to *customers* > Cost to the *Service Provider* to provide improved *QOS*

(3) From the equation above it is evident that if the value of the improved *QOS* to the *customer* is less than the cost to the *Service Provider*, then the *Service Provider* should not invest in the proposed project(s).

(4) Equation above can be stated differently as: Annual value (TZS/kWh) x Reduction in *EENS* to Consumers (kWh) > Annual cost to the *Service Provider* to reduce *EENS* (TZS)

(5) The reduction in *EENS* (expected energy not served) is calculated on a probabilistic basis based on the improvements derived from the investments

(6) The cost of unserved energy is a function of the type of load, the duration and *frequency* of the interruptions, the time of the *day* they occur, whether notice is given of the impending interruption, the indirect damage caused, the start-up costs incurred by the consumers, the availability of *customer* back-up generation and many other factors.

(7) Figure 7.1 indicates the concept of a load profile, while Figure 7.2 indicates the energy not served. This is in the event of a load growing to 125 *MVA* whereas the firm transformer rating is 100 *MVA*.

Figure 7.1: Typical Load Profile

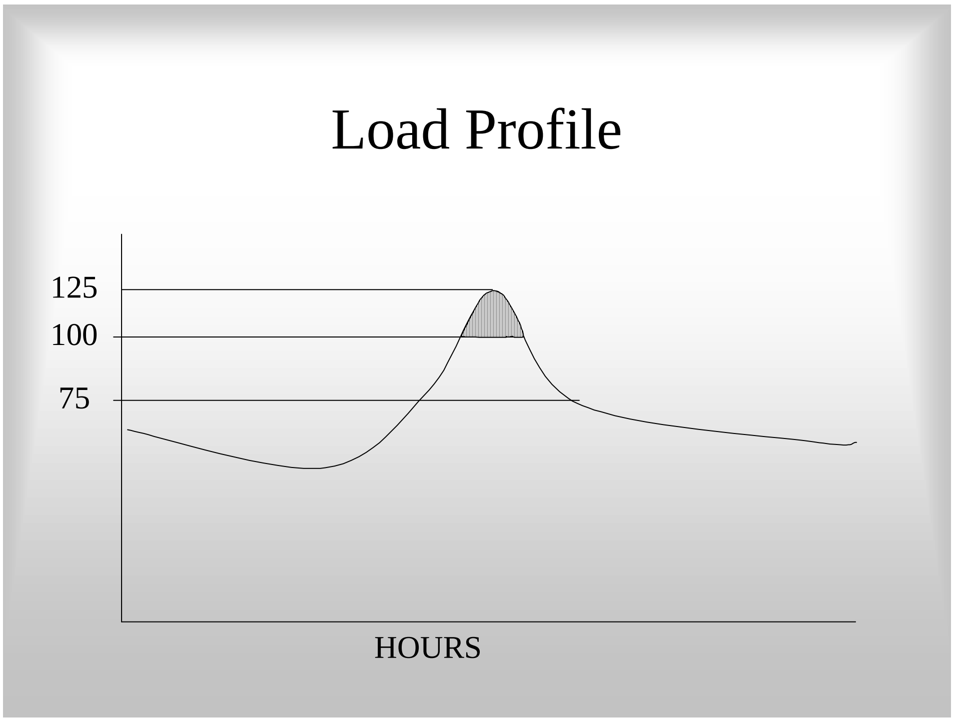
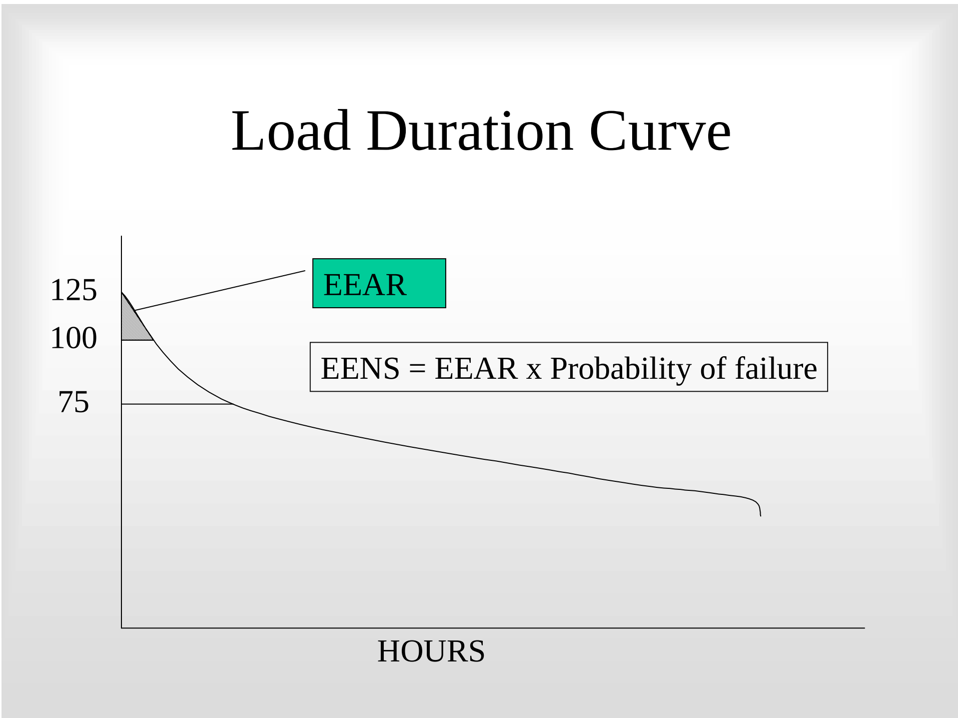


Figure 7.2: Load Duration Curve



7.5.2 Cost reduction investments

(1) Proposed expenditure which is intended to reduce *Service Providers'* costs (for example, shunt capacitor installations, telecommunication projects and equipment replacement which reduce costs, external telephone service expenses and maintenance costs respectively) or the cost of *Losses* or other *ancillary services*, should be evaluated in the following manner:

(2) Firstly, it is necessary to calculate the net present value of the proposed investment using the discounted cash flow method. This should be done by considering all cost reductions (e.g. savings in system *Losses*) as positive cash flows, off-setting the required capital expenditure. Once again, *sensitivity analysis* with respect to the amount of capital expenditure (estimated contingency amount), the annual average incremental cost of generation (when appropriate) and, future load growth scenarios is required. As before, a resulting positive net present value indicates that the investment is justified over the expected life of the proposed new asset.

7.5.3 Statutory or strategic investments

(1) It must also be stressed that Tanzania is still a developing country and certain strategic decisions would therefore need to be taken in order to encourage development in the country.

(2) This category of projects include the following:

(a) Investments formally requested by government. This includes investments that will allow Tanzania to become more self-sufficient in electricity supply and issues pertaining to the electrification of Tanzania.

(b) Increased connection with neighbouring countries and *SAPP* requirements to allow the Tanzanian Electricity Industry access to other markets.

(c) Projects necessary to meet environmental legislation, for example the construction of oil containment dams.

(d) Expenditure to satisfy the requirements of the Employment and Labour Relations Act (2004), specifically the Regulations relating to Occupational Health and Safety Act (2003). This classification is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission.

(e) Possible compulsory contractual commitments.

(f) Servitude acquisition

(g) This category shall not be used for justifying projects that are merely not of economic benefit.

7.6 Development investigation reports

(1) *Transmission* shall compile, before any development of the *TS* is approved, a detailed development investigation report. The report shall be used as the basis for making the investment decision and shall as a minimum contain the following elements:

(a) A description of the problem/request

(b) Alternatives considered (including non-transmission or capital) and an evaluation of the long-term costs/benefits of each alternative.

(c) Detailed techno-economic justification of the selected alternative according to the approved investment criteria.

7.7 Transmission System Master Plan

(1) *Transmission* shall annually publish a five year ahead network expansion plan, indicating the major capital investments planned (but not yet necessarily approved).

(2) This plan shall be based on all *customer* requests received at that time, network load forecasting, as well as *Transmission* initiated projects.

7.8 Mitigation of network constraints

(1) *Transmission* has the obligation to resolve network constraints.

(2) Network constraints shall be regularly reviewed by *Transmission*. Economically optimal plans shall be put in place around each constraint, which can involve investment, the purchase of the *constrained generation ancillary service* or other solutions.

7.9 Interfacing between Participants

(1) *Transmission* shall ensure regular interfacing with *customers* regarding network development. One objective shall be to achieve overall optimal plans, ensuring economically efficient investment.

7.10 Special customer requirements for increased reliability

(1) Should a *customer* require a more reliable connection than the one provided for by *Transmission*, and the *customer* is willing to pay the total cost of providing the increased reliability, *Transmission* shall meet the requirements at the lowest overall cost.

(2) Customers paying extra for reliability should be able to recoup some of the expenses from other customers. Details regarding recovery of direct costs should be included in connection agreement.

8 Network maintenance

(1) *Participants* shall operate and maintain the equipment owned by them. The cost of such operation and maintenance shall be borne by the respective *Participants* unless such equipment is proved to have been damaged by a negligent act or omission of a *Participant* other than the owner, its agents or employees, in which case the responsible *Participant* shall be liable for the costs of repairing such damage.

(2) *Participants* shall monitor the performance of their plant and take appropriate action where deteriorating trends are detected.

9 Appendix 1 *Generator* Connection Conditions

Figure 9.1: Summary of the requirements applicable to specific classes of *units*

***Grid Code* Requirement**		***Unit*s other than Hydro (*MVA* rating)**					
		<20	**20 to 100**	**100 to 200**	**200 to 300**	**300 - 800**	**>800**
GCR1	Plant availability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR3	***Protection***						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of Field	-	Depends on System Requirements	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes
	- Gen *TRFR* backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- *Unit* Switch-onto-standstill *Protection*		Depends on System Requirements	Yes	Yes	Yes	Yes
	- Main *Protection* only	Yes	Yes	Depends on System Requirements	-	-	-

	- Main *Protection* (monitored) or main and backup	-	-		Depends on System Requirements	-	-
	- Main and Backup *Protection* (both monitored)	-	-	-		Depends on System Requirements	Yes
GCR4	Ability To Island	-	-	Depends on System Requirements	Yes	Yes	Yes
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
	- Limiters	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR7	Multiple *Unit* tripping	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR8	*Governing*	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station

GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR11	External Supply Disturbance Withstand Capacity	Depends on System Requirements	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GRC13	*Emergency unit* capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on System Requirements	Yes	Yes	Yes

Figure 9.2: Summary of the requirements applicable to specific classes of *units*

***Grid Code* Requirement**		Hydro *Units* (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR3	***Protection***						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of Field	-	Depends on System Requirements	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on System Requirements	Depends on System Requirements	Yes	Yes
	- Gen *TRFR* backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- *Unit* Switch-onto-standstill *Protection*		Depends on System Requirements	Yes	Yes	Yes	Yes
	- Main *Protection* only	Yes	Yes	Depends on System Requirements	-	-	-

	- Main *Protection* (monitored) or main and backup	-	-		Depends on System Requirements	-	-
	- Main and Backup *Protection* (both monitored)	-	-	-		Depends on System Requirements	Yes
GCR4	Ability To *Island*	-	-	-	-	-	-
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
	- Limiters	-	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR7	Multiple *Unit* tripping	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR8	*Governing*	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on System Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed

GCR11	External Supply Disturbance Withstand Capacity	Depends on System Requirements	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on System Requirements	Yes	Yes	Yes	Yes	Yes
GRC13	*Emergency unit* capabilities	Depends on System Requirements	Depends on System Requirements	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on System Requirements	Yes	Yes	Yes

10 Appendix 2 Surveying, monitoring and testing for generators [2]

10.1 Introduction

(1) This section specifies the procedures to be followed in carrying out the surveying, monitoring or testing to confirm the:

(a) compliance by *Power Station*s with the *Grid Code*

(b) provision by *Power Station*s of *ancillary services* which they are required or have agreed to provide.

10.2 Scope

(1) This code applies to *generators*.

10.3 Request for surveying, monitoring or testing

(1) The *System Operator* may at any time (although it may not do so more than twice in any calendar year in respect of any particular *Power Station* except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test) issue an instruction requiring a *Power Station* to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, to demonstrate that the relevant *Power Station* complies with the *Grid Code* requirements.

10.4 Ongoing Monitoring of a Unit's Performance

(1) A *generator* shall monitor each of its *units* during normal service to confirm ongoing compliance with the applicable parts of this code. Any deviations detected must be reported to the *System Operator* within 5 working days.

(2) A *generator* shall keep records relating to the compliance by each of its *units* with each section of this code applicable to that *unit*, setting out such *Information* that the *System Operator* or *Transmission* reasonably requires for assessing power system performance (including actual *unit* performance during abnormal conditions).

(3) Within one *Month* after the end of June and December, a *generator* shall provide to the *System Operator* a report detailing the compliance by each of that *generator's units* with every code section during the past 6 *Month* period. The template is attached as an Appendix 2 in the Information Exchange Code.

[2] To be reviewed. Drafting still in progress

10.5 Procedures

10.5.1 Unit *Protection* System *Grid Code* Requirement *GCR* 3

Parameter	**Reference**	
Protection Function and Setting Integrity Study		**APPLICABILITY** ***Prototype study:*** All new *Power Station*s coming on line or *Power Station*s where major refurbishment or upgrades of *Protection* systems have taken place. ***Routine review:*** All *Power Station*s every 5 to 6 years. **PURPOSE** To ensure that the relevant *Protection* functions in the *Power Station* is co-ordinated and aligned with the system requirements. **PROCEDURE** ***Prototype*:** 1. Establish the System *Protection* function and associated trip level requirements from *Transmission*. 2. Derive *Protection* functions and settings that match the *Power Station* plant, *Transmission* plant and system requirements. 3. Confirm the stability of each *Protection* function for all relevant system conditions. 4. Document the details of the trip levels, stability calculations for each *Protection* function. 5. Convert *Protection* tripping levels for each *Protection* function into per unit base.

		6. Consolidate all settings in per unit base for all *Protection* functions in one document 7. Derive actual relay dial setting details and document the relay setting sheet for all *Protection* functions. 8. Document the position of each *Protection* function on one single line diagram of the generating unit and associated connections. 9. Document the tripping functions for each tripping function on one tripping logic diagram. 10. Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base *Information* the settings are based on, tripping logic diagram, *Protection* function single line diagram and relevant *Protection* relay manufacturers *Information* into one document. 11. Submit to *Transmission* for their acceptance and update. 12. Provide *Transmission* with one original reference copy and one working copy. ***Review*:** 1. Review Items 1 to 10 above. 2. Submit to *Transmission* for their acceptance and update. 3. Provide *Transmission* with one original reference copy and one working copy. **ACCEPTANCE CRITERIA** All *Protection* functions are set to meet the necessary *Protection* requirements of the TS and *Power Station* plant with minimal margin. Optimal fault clearing times and maximum plant availability. Submit a report to *Transmission* one *Month* after commissioning for prototype study or 5 to 6 yearly for routine tests.

Parameter	Reference	
Protection Integrity Tests		**APPLICABILITY** ***Prototype test***: All new *Power Station*s coming on line and all other *Power Station*s after major modifications or refurbishment of *Protection* or related plant. ***Routine test:*** All *Power Station*s 5 to 6 yearly or after major overhaul of plant. **PURPOSE** To confirm that the *Protection* has been wired and function according to the specified. **PROCEDURE** 1. Apply final settings as per agreed documentation to all *Protection* functions. 2. With the *generator* unit off load and de-energized, inject appropriate signals into every *Protection* function and confirm correct operation and correct calibration. Document all *Protection* function operations. 3. Carry out trip testing of all *Protection* functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. *HV* Breaker). Document all trip test responses. 4. Apply short circuits at all relevant *Protection* zones and with *generator* at nominal speed excite *generator* slowly, record currents at all relevant *Protection* functions, and confirm correct operation of all relevant *Protection* functions. Document all readings and responses. Remove all short circuits. 5. With the *generator* at nominal speed, excite *generator* slowly recording voltages on all relevant *Protection* functions. Confirm correct operation and correct calibration of all *Protection* functions. Document all readings and responses.

		ACCEPTANCE CRITERIA All *Protection* functions fully operational and operate to required levels within the relay Original Equipment Manufacturer (*OEM*) allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to traceable standard. Submit a report to *Transmission* one *Month* after test.

10.5.2 Unit *Islanding* Capability *Grid Code* Requirement *GCR* 4

Parameter	Reference	
Islanding		**APPLICABILITY** ***Prototype test*:** For all other fossil and Nuclear *Power Station*s ***Routine test*:** For stations that have contracted to Island under the *Ancillary Services* Agreement. 5-6 yearly or after modifications done to plant that may effect *Islanding* Capability ***Continuous monitoring:*** Where in the *day* to *day* running of the plant, a real condition arises where a Generating Unit is required to Island, and the *Islanding* takes place successfully, and the *Islanding* condition is sustained as specified under acceptance criteria below or is called to synchronize and complete synchronizing successfully it shall be considered as a successful *Islanding* test. **PURPOSE** To confirm that a Generating Units that have specified and/or contracted to provide an *Islanding* service, complies. *Islanding* is the ability of a Generating Unit to suddenly disconnect from the TS by the opening the *HV* breaker, and automatically control all the necessary critical parameters sufficiently to maintain the turbine-*generator* at speed and excited and supplying its own auxiliary load. This Islanded mode must be sustained for at least 20 minutes without tripping of the turbine, boiler, excitation system, or other systems critical to sustain an *Islanding* condition. **PROCEDURE** • Generating Unit running at steady state conditions above 60% full load conditions. • All *Protection* and control systems in normal operating conditions.

		• No special modifications to the plant for the purpose of the test, accept installation of monitoring equipment, is allowed. • The Unit supplies all its own auxiliary load during the test • No operating is allowed for the first 5 minutes following the initiation of the *Islanding*. • Equipment is connected to the Generating unit that records critical parameters. The following minimum parameters is recorded: (c) Turbine speed (d) Alternator load (e) Alternator voltage and current (f) Exciter voltage and current (g) Unit board voltage (h) Anticipatory device position (where installed) (i) System *frequency* • Initiation of the *Islanding* is done by opening the *HV* Breaker/ **ACCEPTANCE CRITERIA** The turbine must settle at or close to its nominal speed, the excitation system must remain in automatic channel, supplying all the unit's auxiliary load. The *Islanding* condition must be sustained for at least 20 minutes.

10.5.3 Excitation System *Grid Code* Requirement *GCR* 5

Parameter	Reference	
Excitation and Setting Integrity Study		**APPLICABILITY** ***Prototype study:*** All new *Power Station*s coming on line or *Power Station*s where major refurbishment or upgrade of *Protection* systems have taken place. ***Routine review:*** All *Power Station*s every 5 to 6 years. **PURPOSE** To ensure that the Excitation systems in the *Power Station* is co-ordinated and aligned with the system requirements. **PROCEDURE** ***Prototype:*** 1. Establish the System excitation system performance requirements from *Transmission*. 2. Derive a suitable model for the excitation system according to IEEE421.5 or *IEC* 60034.16.2. Where necessary, non standard models (non *IEC* or IEEE) shall be created.. This may require *frequency* response and bode plot tests on the excitation system as described in IEEE 421.2.1990. 3. Submit the model to *Transmission* for their acceptance. 4. Derive excitation system settings that match the *Power Station* plant, TS plant and system requirements. This includes the settings of all parts of the excitation system such as the chop-over limits and levels, limiters, *Protection* devices, alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions system conditions.

		6. Document the details of the trip levels, stability calculations for each setting and function. 7. Convert settings for each function into per unit base and produce a high level dynamic performance model with actual settings in *P.U.* values. 8. Derive actual card setting details and document the relay setting sheet for all setting functions. 9. Produce a single line diagram / block diagram of all the functions in the excitation system and indicate signal source. 10. Document the tripping functions for each tripping on one tripping logic diagram. 11. Consolidate detail setting calculations, model, per unit setting sheets, relay setting sheets, plant base *Information* the settings are based on, tripping logic diagram, *Protection* function single line diagram and relevant *Protection* relay manufacturers *Information* into one document. 12. Submit to *Transmission* for their acceptance and update. 13. Provide *Transmission* with one original master copy and one working copy. ***Review:*** Review Items 1 to 10 above. Submit to *Transmission* for their acceptance and update. Provide *Transmission* with one original master copy and one working copy update if applicable. **ACCEPTANCE CRITERIA** Excitation system is set to meet the necessary control requirements in an optimized manner for the performance of the TS and *Power Station* plant. Excitation system operates stable both internally and on the network.

		Submit a report to *Transmission* one *Month* after commissioning for prototype study or 5 to 6 yearly for routine tests, within one *Month* after due date expiry.

Parameter	Reference	
Excitation Response Tests		**APPLICABILITY** ***Prototype test:*** All new *Power Station*s coming on line and all other *Power Station*s after major modifications or refurbishment of *Protection* or related plant. ***Routine test:*** All *Power Station*s 5 to 6 yearly or after major overhaul of plant. ***Prototype test***: All new *Power Station*s coming on line and all other *Power Station*s after major modifications or refurbishment of *Protection* or related plant. ***Routine test:*** All *Power Station*s 5 to 6 yearly or after major overhaul of plant. **PURPOSE** On confirm that the excitation system performs as per the specified. **PROCEDURE** With the *generator* off line, carry out frequency scan / bode plot tests on all circuits in the excitation system critical to the performance of the excitation system. With the *generator* in the open circuit mode, carry out the Large signal performance testing as described in IEEE 421.2 Determine Time response, Ceiling voltage, voltage response,

		• With the *generator* connected to the network and loaded, carry out the small signal performance tests according to IEE 421.2.. Also carry out power system stabiliser tests and determine damping with and without Power System stabiliser. Document all responses. **ACCEPTANCE CRITERIA** Excitation system meets the necessary control requirements in an optimised manner for the performance of the TS and *Power Station* plant as specified. Excitation system operates stable both internally and on the network. Power System stabilisers set for optimised damping.

10.5.4 Unit Reactive Power Capability *Grid Code* Requirement *GCR* 6

Parameter	Reference	
Reactive Power Capability		**APPLICABILITY** ***Prototype test***: All new *Power Station*s coming on line and all other *Power Station*s after major modifications or refurbishment of *Protection* or related plant. **PURPOSE** To confirm that the reactive Power Capability specified are met. **PROCEDURE** The duration of the test will be for a period of up to 60 minutes during which period the System voltage at the Grid Entry Point for the relevant Generating Unit will be maintained by the *Generator* at the voltage specified by adjustment of Reactive Power on the remaining Generating Units , if necessary. **ACCEPTANCE CRITERIA** Generating Unit will pass the test if it is within ±5% of the capability registered with *Transmission* Submit a report to *Transmission* one *Month* after test.

10.5.5 *Power Station* Multiple Unit Trip *Grid Code* Requirement *GCR* 7.

Parameter	**Reference**	
Multiple Unit Tripping (*MUT*)Tests, Study and Survey		**APPLICABILITY** ***Prototype tests / study / survey:*** • New *Power Station*s coming on line, items 1 to 5 below or • *Power Station*s where major modifications or changes have been implemented on plant critical to Multiple Unit Tripping. Applicable item(s) listed 1 to 5 below. ***Routine assessment:*** All *Power Station*s. Item 5 below every 6 years. ***Routine testing***: All *Power Station*s. Review and confirm the status every 6 years, and test if required. **PURPOSE** To confirm that a *Power Station* is not subjected to unreasonable risk of *MUT* as defined in Network Code Section 3.1.5. **PROCEDURE AND ACCEPTANCE CRITERIA** ***1. Emergency supply isolation test:*** On all *emergency* supplies (e.g. *DC* supplies) common to more than one generating unit, isolate supply for at least one second, with the unit running at full load under normal operating conditions. Tests are carried out on one unit at the time. Where two supplies feed one common load, isolation of one supply at a time would be sufficient. Confirm that that the unit or part of the

		unit plant does not trip. No change in the unit output shall take place. Document results. This test does not apply to nuclear plant. ***2. Disturbance on DC supply survey:*** On all *DC* supplies common to more than one unit, carry out a survey of the immunity of all devices that are part of tripping circuits, to supply voltage according to *IEC* specifications. All devices on *DC* supplies common to more than one unit that form part of tripping circuits or that can cause tripping or Load Reduction on a unit must comply to *IEC* specification. Document findings. ***3. Uninterruptible power supplies (UPS) integrity testing:*** On all UPS's supplying critical loads that can cause tripping of more than one generating unit within the time zones specified in 3.1.5, isolate the *AC* supply to the UPS for a period of at least 1 minute. Where two UPS's supply one common load, one UPS at a time can be isolated. Load equipment must resume normal operation. Document results. This test does not apply to nuclear plant. **4. Earth mat integrity inspection and testing:** Carry out an inspection and tests on all parts of the *Power Station* earth mat that is exposed to lighting surge entry and in close proximity to circuits vulnerable to damage that will result in tripping of more than one unit within the time zones specified in 3.1.5 (e.g. Chimney on fossil *Power Station*s or penstock on hydro *Power Station*s) Confirm that all the earthing and bonding are in place, and measure resistances to earth at bonding points. Document findings and results. **5. *MUT* risk assessment:** Identify all power supplies, air supplies, water supplies, and other supplies / systems common to more than one unit than are likely to cause the tripping of more than one unit within a short time.. Calculate the probability of all the *MUT* risk areas for the *Power Station*. Document all findings listing all risks and probabilities.

		No unreasonable *MUT* items shall be present. . Report to be submitted to *the System Operator* one *Month* after testing. Routine studies, and survey reports to be submitted one moth after expiry of due date.

10.5.6 *Governing* System *Grid Code* Requirements *GCR* 8

Parameter	***Grid Code*** **Reference**	
Governing Response Tests		**APPLICABILITY** ***Prototype test***: All new *Power Station*s coming on line and all other *Power Station*s after major modifications or refurbishment of *Protection* or related plant. ***Routine test:*** All Units to be monitored continuously, additional tests may be requested by the *System Operator* **PURPOSE** Prove the unit is capable of the minimum requirements required for *Governing* **PROCEDURE** 1. *Frequency* or speed deviation to be injected on the Unit for 10 minutes. 2. Real Power Output of the Unit is to be measured and recorded. **ACCEPTANCE CRITERIA** Minimum requirements of the *Grid Code* are met

10.5.7 Unit Restart after Station Blackout Capability *Grid Code* Requirement *GCR* 9

Parameter	Reference	
Restart after Station Blackout Survey.		**APPLICABILITY** ***Prototype survey:*** Item 1 for new *Power Station*s or *Power Station*s where modifications have been carried out on plant critical to multiple unit restarting. ***Routine survey:*** All *Power Station*s. Item 2 very 3 *Months*. **PURPOSE** To confirm that a *Power Station* can restart unit simultaneously to the criteria outlined in section 2.2.1.7 after a station blackout condition. **PROCEDURE** ***1. Plant capacity survey:*** • Identify all supply systems common to two or more systems (e.g. Power supplies, crude oil, air, demin water) • Determine the quantity and supply rate required to simultaneously restart the number of units specified in section 2.2.1.7 • Document list of critical systems, required stock, study details and findings. ***2.*** **Survey of available stock:** • For each of the applicable critical systems identified, document the average stock for the year, minimum stock and duration below critical stock levels.

		ACCEPTANCE CRITERIA More than 95% of the time of the year, all stocks above critical levels. Report to be submitted to *Transmission* one *Month* after commissioning. Routine survey reports to be submitted one moth after expiry of due date.

10.5.8 *Power Station Black Start* Capability *Grid Code* Requirement *GCR* 10

Parameter	**Reference**	
Unit Black Starting		**APPLICABILITY** ***Routine Test:*** *Power Station*s that have contracted under the ancillary services to supply Unit *Black Start* services. When called for by *Transmission* but not more than once every 2 years **PURPOSE** Demonstrate that a *Black Start* Unit has a *Black Start* Capability **PROCEDURE** • The relevant Generating Unit shall be Synchronised and Loaded; • All the Auxiliary Gas Turbines and/or Auxiliary Diesel Engines in the *Black Start* Station in which that Generating Unit is situated, shall be Shutdown. • The Generating Unit shall be De-Loaded and De-Synchronised and all alternating current electrical supplies to its Auxiliaries shall be disconnected. • The Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) to the relevant Generating Unit shall be started, and shall re-energise the Unit Board of the relevant Generating Unit. • The Auxiliaries of the relevant Generating Unit shall be fed by the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s), via the Unit Board, to enable the relevant Generating Unit to return to Synchronous Speed. • The relevant Generating Unit shall be Synchronised to the System but not Loaded, unless the appropriate instruction has been given by *Transmission*.

		All *Black Start* Tests shall be carried out at the time specified by *Transmission* in the notice given under 2.2.1.8 and shall be undertaken in the presence of a reasonable number of representatives appointed and authorised by *Transmission*, who shall be given access to all *Information* relevant to the *Black Start* Test. **ACCEPTANCE CRITERIA** A *Black Start* Station shall fail a *Black Start* Test if the *Black Start* Test shows That it does not have a *Black Start* Capability (i.e. if the relevant Generating Unit Fails to be Synchronised to the System within two hours of the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) being required to start). Submit a report to *Transmission* one *Month* after test.
Parameter	**Reference**	
Station Black Starting		**APPLICABILITY** ***Routine test***: All Stations contracted under *Ancillary Services* to provide a Station *Black Start* service. When called for by *Transmission* but not more than once every 2 years **PURPOSE** Demonstrate that a *Black Start* Station has a *Black Start* Capability **PROCEDURE** • All Generating Units at the *Black Start* Station, other than the Generating Unit on which the *Black Start* Test is to be carried out, and all the Auxiliary Gas Turbines and/or Auxiliary Diesel Engines at the *Black Start* Station, shall be Shutdown.

		• The relevant Generating Unit shall be Synchronised and Loaded. • The relevant Generating Unit shall be De-Loaded and De-Synchronised. • All external alternating current electrical supplies to the Unit Board of the relevant Generating Unit, and to the Station Board of the relevant *Black Start* Station, shall be disconnected. • An Auxiliary Gas Turbine or Auxiliary Diesel Engine at the *Black Start* Station shall be started, and shall re-energise either directly, or via the Station Board, the Unit Board of the relevant Generating Unit. • The Auxiliaries of the relevant Generating Unit shall be fed by the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s), via the Unit Board, to enable the relevant Generating Unit to return to Synchronous Speed. • The relevant Generating Unit shall be Synchronised to the System but not Loaded, unless the appropriate instruction has been given by *Transmission*. All *Black Start* Tests shall be carried out at the time specified by *Transmission* in the notice given under 2.2.1.8 and shall be undertaken in the presence of a reasonable number of representatives appointed and authorised by *Transmission*, who shall be given access to all *Information* relevant to the *Black Start* Test. **ACCEPTANCE CRITERIA** A *Black Start* Station shall fail a *Black Start* Test if the *Black Start* Test shows that it does not have a *Black Start* Capability (i.e. if the relevant Generating Unit fails to be Synchronised to the System within two hours of the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) being required to start). Submit a report to *Transmission* one *Month* after test.

10.5.9 Unit Intermediate Load Capability *Grid Code* Requirement *GCR* 11

Parameter	***Grid Code*** **Reference**	
Intermediate Load Capability		**APPLICABILITY** ***Prototype study:*** All new *Power Station*s coming on line or *Power Station*s where major refurbishment or upgrade of the Unit have taken place. ***Routine test:*** All Units to be monitored continuously, additional tests may be requested by the *System Operator* **PURPOSE** Prove Unit can meet the minimum requirements of the *Grid Code* **PROCEDURE** 1. A section of the Unit is to be tripped that will cause a 15% of *MCR* reduction of the output of the Unit. Should nothing be found to induce this reduction a sudden reduction of the Unit output shall be done manually. 2. The plant is to be monitored and recorded to ensure the plant continues to operate in a stable and controlled mode after the reduction. **ACCEPTANCE CRITERIA** The Unit shall be in a stable and controlled mode after the trip or reduction in the Unit output.

10.5.10 External Supply Disturbance Withstand Capability *Grid Code* Requirement *GCR* 12

Parameter	**Reference**	
Voltage and *Frequency* Deviation		**APPLICABILITY** ***Prototype survey / test:*** New *Power Station*s coming on line or *Power Station*s where major modifications to plant that may be critical to system supply *frequency* or voltage magnitude deviations. Items 1 to 3 and 4 for plants using Dip Proofing Inverters (*DPI*) ***Routine testing and survey:*** All *Power Station*s. Review items 1 to 3 every 5 to 6 years. Carry out item 5 every 5 to 6 years. **PURPOSE** To confirm that the *Power Station* and its *Auxiliary Supply* loads conforms to the requirements of supply *frequency* and voltage magnitude deviations as specified (to be determined). **SCOPE OF PLANT OR SYSTEMS** ***Critical plant:*** Equipment or systems that is likely to cause tripping of a unit, parts of a unit or that is likely to cause a Multiple Unit trip (*MUT* **PROCEDURE AND ACCEPTANCE CRITERIA** ***1. Frequency deviation survey:*** Carry out a survey on the capability of critical plant confirming that it will resume normal operation for *frequency* deviations as defined figure 2.2.1.6. Document Findings.

		A generating unit or *Power Station* must not trip or unduly reduce load for system *frequency* changes in the range specified in 2.2.1.6. ***2. Voltage magnitude deviation survey:*** Carry out a survey on the capability of critical plant confirming that it will resume normal operation for voltage deviations as defined in 2.2.1.6. Document Findings. Also consider *Protection* and other tripping functions on critical plant. Document all findings. A generating unit or *Power Station* must not trip or unduly reduce load for system voltage changes in the range specified in 2.2.1.6. **3. Dip proofing inverter integrity testing:** • Generating unit must be off load. Relevant board isolated and earthed. For outside or central plant, section of plant must be off boards off and isolated. • Injection test DPIs according to *OEM* requirements. *DPI* must be capable of producing the VA Output and change-over time faster than that specified by the *OEM*. Every five years on every critical board. • Isolate all Drives on the board. • Select all drives to manual or local control. • Supply an independent *AC* supply to the input of the *DPI*. • Close the contractors of drives.

		• Subject the *DPI* supply to an interruption of 0.5 s. Document all results. All contractors must remain closed. Report to be submitted to *Transmission* one *Month* after testing. Routine studies, and survey reports to be submitted one moth after expiry of due date.

10.5.11 Unit Load and De-loading Rate Capability *Grid Code* Requirements *GCR* 13

Parameter	***Grid Code*** **Reference**	

Loading and De-loading Rates		**TYPE** ***Prototype study:*** All new *Power Station*s coming on line or *Power Station*s where major refurbishment or upgrade of the Unit have taken place. ***Routine test:*** All Units to be monitored continuously, additional tests may be requested by the *System Operator* **PURPOSE** Prove Unit can meet the minimum requirements of the *Grid Code* **PROCEDURE** 1. The Unit is to be ramped up and down. 2. The plant is to be monitored and recorded to ensure the plant continues to operate in a stable and controlled mode during and after the ramps. **ACCEPTANCE CRITERIA** **The Unit shall be ramped up and down in a stable and controlled mode and shall meet the minimum requirements of the *Grid Code*.**

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

3 of 8 Code Documents - The System Operation Code

Version 2

1st March 2017

Table of Contents

1. <u>Introduction</u>

(1) This code sets out the responsibilities and roles of the *Participants* as far as the operation of the *Interconnected Power System (IPS)* is concerned, and more specifically issues related to -

(a) Reliability, *Security* and Safety;

(b) Operation Planning;

(c) *Ancillary Services*;

(d) Scheduling and Dispatch operation actions required by the *System Operator*;

(e) Independent actions required and allowed by customers;

(f) Operation of the *IPS* under normal and abnormal conditions; and

(g) Field operation, maintenance and maintenance co-ordination / outage planning.

2. <u>Operation of the *IPS*</u>

(1) The *System Operator* shall be responsible for the safe and efficient operation of the *IPS*.

(2) The *System Operator* shall operate the *IPS* in accordance with the provisions of this code.

(3) All *Participants* shall co-operate in setting up operational procedures under the direction of the *System Operator* to ensure proper operation of the *IPS*.

(4) The *System Operator* shall have ultimate authority and accountability for the operation of the *IPS*.

(5) *Power Pool* and other international tie-line operations shall be governed by the *Power Pool* and related agreements.

2.1 System Operator ***obligations***

(1) The *System Operator* shall be responsible for the following:

2.1.1 System reliability and safety

(1) The *IPS* shall be operated to achieve the highest degree of reliability practicable and appropriate remedial action shall be taken promptly to relieve any abnormal condition that may jeopardise reliable operation. Power transfers as determined by the energy *Scheduling* arrangements, and other transfers as far as feasible, shall be adjusted as required to achieve or restore reliable *IPS* operation

(2) Voltage control, operating on the *IPS* and *Security* monitoring shall be co-ordinated on a system-wide basis in order to ensure safe, reliable, and economic operation of the *IPS*.

(3) During or after a system disturbance, high priority shall be given to keeping all synchronised *units* running and connected to the *IPS*, or *islanded* on their own auxiliaries, in order to facilitate system restoration.

(4) *Black start* services shall be provided as available from *units*.

(5) The *System Operator* shall make all reasonable endeavours to retain international interconnections unless it becomes evident that continued parallel operation of the affected parts of the *IPS* would jeopardise the remaining system or damage equipment.

(6) Should it become unsafe to operate *units* in parallel with the system when critical levels of *frequency* and voltage result on the *IPS* from a disturbance, the separation and/or safe shut down of units shall be accomplished in such a way as to minimize the time required to resynchronise and restore the system to normal.

(7) In the event of a system separation, the *System Operator* shall ensure that the part of the *IPS* with a generation deficit shall automatically remove sufficient load to permit early recovery of voltage and *frequency* so that system integrity may be re-established.

(8) *Customer* load shall be shed for a reasonable period of time rather than risking the possibility of a cascading failure or operating at abnormally low *frequency* or voltage for an extended period of time.

(9) An internationally *Interconnected Power System Operator* may request that the *System Operator* takes any available action to increase or decrease the active energy transfer into or out of its external system by the way of *emergency* assistance. Such requests shall be met by the *System Operator* providing it has the capability to do so.

2.1.2 System *Security*

(1) The *IPS* shall be operated as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency. Multiple outages of a credible nature shall be examined and, whenever practical, the *IPS* shall be operated to protect it against instability, uncontrolled separation and cascading outages.

(2) The *System Operator* is responsible for efficient restoration of the *Transmission System (TS)* after supply *interruptions*.

(3) The *System Operator* shall operate and maintain primary and *emergency control centres* and facilities to ensure continuous operation of the *IPS*.

2.1.3 Operational measures

(1) Operating instructions, procedures, standards and guidelines shall be established to cover the operation of the *IPS* under all system conditions.

(2) The *IPS* shall, as far as reasonably possible, be operated within defined technical standards and equipment ratings.

(3) The *System Operator* shall manage constraints on the *TS* through the determination of operational limits the scheduling of *sufficient generation, demand and ancillary service to relieve constraints*.

(4) To achieve a high degree of service reliability, the *System Operator* shall ensure adequate and reliable communications between all *control centres*, *Power Stations* and *substations*. Communication facilities to be provided and maintained by *customers* are specified in the *Information Exchange Code*.

(5) The *System Operator* shall be responsible for the determination of the *TS Protection* philosophy (as contrasted to equipment *Protection*) by means of applicable analytical studies.

(6) The *System Operator* shall determine, and review on a regular basis, relay settings for main and back-up *Protection* on the *IPS*.

3. <u>Operation Planning</u>

3.1 Operations Plans.

3.1.1 Introduction.

(1) The *generators* and the *System Operator* are responsible for maintaining a set of current plans which are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each *generator*, working with the *System Operator*, is responsible for using available personnel and system equipment to implement these plans to assure that the *IPS* reliability is maintained.

3.1.2 Objectives.

(1) The objectives of the Operations Plans are-

(a) to inform all *generators, distributors* or big *consumers* whose Systems are connected to the *TS*, of the procedures and responsibilities which are required to execute the operations plans; and

(b) to enable the *System Operator* to co-ordinate operations and outages of centrally dispatched *generating units* taking into account transmission system outages, so as to provide the maximum reliability of electric power delivery at the lowest cost.

3.1.3 Operation Plan Requirements.

(1) The operations plans for the *IPS* shall cover at least the following

(a) Normal Operations, where each generator, working with the *System Operator*, shall plan its future operations so that normal interconnection operation proceeds in an orderly consistent manner and each distributor shall provide its best estimate of demand to the *System Operator* so that the *System Operator* can develop the total demand forecast.

(b) Emergency Operations - A set of plans shall be developed, maintained and implemented, by each generator and the *System Operator*, to cope with operating emergencies. These plans shall be conducted with other generators and the *System Operator* as appropriate.

3.2 Annual Operations Plan.

3.2.1 Annual Operations Plan Requirements.

(1) The annual operations plan shall contain sufficient information in a suitable form to assess the following-

(a) the adequacy and capability of *generating units* to meet forecast demand and energy for the next year to 5 years ahead.

(b) verification that generation and transmission outages are planned to maximise resource utilisation, optimise placement of generation outages to produce a minimum running cost.

(c) ensure that the operational problems likely to be encountered are highlighted and alternative solutions considered and evaluated; and

(d) verification that the actions taken and emergency procedures issued to deal with possible abnormal system conditions are adequate and satisfactory.

(2) The formal operations planning procedures to implement these major steps require-

(a) the dates by which relevant programs shall be issued;

(b) determination of the responsibility for the *System Operator* and the *generators* and *distributors* to produce and provide data;

(c) definition of the work necessary for the *System Operator* and the generators and distributors to contribute towards the annual operations plan; and

(d) the lines of communication and interaction between the *System Operator* and the *generators* and *distributors*.

3.2.2 Implementation Procedure for Annual Operations Plan.

(1) These procedures shall be prepared by the *System Operator* and published in a document for reference by relevant parties.

3.2.3 Data Requirements.

(1) A list of response capability data required in connection with *spinning reserve* for each *generating unit* shall be submitted to the *System Operator* before the unit comes into commercial operation and shall be updated by the end of April each calendar year and shall be within the parameters set out in the Connection Agreement between the *System Operator* and the generator. The *System Operator* shall be informed promptly of any change in these parameters.

3.3 Weekly Operations Plans.

(1) Each week by 15.00 hours on Thursday the *System Operator* shall issue a preliminary weekly operations plan which shall run from 00.00 hours on the following Monday to 00.00 hours on the subsequent Monday. The weekly operations plan shall include all generating units that are on standby duty as *quick reserve*.

(2) By 10.00 hours on Saturday, the *System Operator* shall prepare a Weekly Operations Plan that takes into account the *generating unit's* unavailability.

(3) Each week the *System Operator* shall determine the allocation of reserve margin to each generator, with due consideration to start-up prices, response characteristics of the generating units on the *TS*, system constraints, availability of *generating units*, hydro dam levels and the lake inflows rates in its Weekly Operations Plan.

(4) The weekly operations plan shall state the amount of operating reserve to be utilised by the *System Operator* in the scheduling and dispatching process.

(5) The Weekly Operations Plan may include the possibility of shared *spinning reserves* with neighbouring systems.

3.4 Transmission Operations Planning.

3.4.1 Introduction.

(1) Reliable operation of the *TS* facilities requires co-ordination among all participants. A high level of reliability is achieved in the operation of a *IPS* when-

(a) transmission equipment is operated within its normal rating, except for temporary conditions after a contingency has occurred;

(b) the capability of components of the *TS* for both normal and emergency conditions has been established by technical studies and operating experience;

(c) when line loading, equipment loading or voltage levels deviate from normal operating limits or is expected to exceed emergency limits following a contingency, and if reliability of the bulk power supply is threatened, the *System Operator* shall take immediate steps to relieve the conditions.

These steps include notifying other systems, adjusting generation, changing schedules between *control areas*, initiating load relief measures, and taking such other action as may be required; and

(d) system operation shall be co-ordinated among systems and control areas. This includes co-ordination of equipment outages, voltage levels, *MW* and *MVAR* flow monitoring and switching that affects two or more systems of transmission components.

3.4.2 *TS* Operations Planning Procedures.

(1) In order to accomplish the needed level of co-ordination, the *System Operator* shall perform studies to determine the *TS* operating configurations, how the system is to be operated within emergency transfer limits, how protective relaying is to be co-ordinated and how maintenance outages are to be co-ordinated.

3.4.3 *TS* Co-ordinating Studies.

(1) Studies shall be made on a co-ordinated basis-

(a) to determine the facilities on each system which may affect the operation of the co-ordinated area;

(b) to determine operating limitations for normal operation when all transmission components are in service; and

(c) to determine operating limitations of transmission facilities under abnormal or emergency conditions.

(2) In determining ratings of transmission facilities, consideration shall be given to thermal and stability limits, short and long time loading limits and voltage limits.

(3) Periodic studies shall be made to determine the Emergency Transfer Capability of transmission lines interconnecting control areas. Studies shall be made annually or at such other time that changes are made to the bulk-system which may affect the Emergency Transfer Capability.

(4) Studies shall be made to develop operating voltage or reactive schedules for both normal and outage conditions.

(5) Neighbouring systems shall use uniform line identifications and ratings when referring to transmission facilities of a *Transmission System* network. This shall foster consistency when referring to facilities and reduce the likelihood of misunderstandings.

(6) The scheduling of outages of transmission facilities which may affect neighbouring systems shall be co-ordinated with the relevant *Power Pool*.

(7) Any forced outage which may have a bearing on the reliability of the *TS* shall be communicated to all systems which may be affected.

3.4.4 Emergency Transfer Capability.

(1) Emergency Transfer Capability is defined as the total amount of power above the net contracted purchases and sales which can be scheduled with assurance of adequate system reliability for transfers over the transmission network for periods up to several days, based on the most limiting of the following constraints-

(2) all transmission loadings initially within long-term emergency ratings and voltages initially within acceptable limits;

(3) bulk power system capable of remaining stable after absorbing the initial power swings and upon the loss of any single transmission circuit, transformer, bus section, or generating unit; and

(4) all transmission loadings within their respective short-time emergency ratings and voltages within emergency limits after the initial power swings following the disturbance but before system adjustments are made (and in the event of a permanent outage of a facility, transfer schedules may need to be reviewed).

3.4.5 Protection Co-ordination.

(1) The satisfactory operation of the *TS*, especially under abnormal conditions, is greatly influenced by the relay equipment and relay schemes in effect. Relaying of tie points between the *TS* is of primary concern to the respective systems, although internal system relaying often directly affects the adjacent systems.

(2) Individual generators and distributors have an obligation to implement relay application, operation, and preventive maintenance criteria according to the specifications on relays in the Technical Code.

(3) The application of the relay systems of the *generators* and *distributors* shall be co-ordinated by the *System Operator* to enhance the system reliability and yet have the least adverse effect on the *TS*.

4. *Scheduling* and Dispatch of generation and *ancillary services*

(1) The *System Operator* shall provide the scheduling and dispatch of generation, demand forecast and *ancillary services* for the *IPS* in accordance with the Scheduling and Dispatch Code.

(2) The scheduling of the operation of the generators shall ensure reliable operating margins.

(3) The responsibility for executing the energy and a*ncillary services* schedules shall lie with the *System Operator*.

(4) Rescheduling during unplanned events shall be undertaken by the *System Operator* on the basis of rules provided by the Scheduling and Dispatch Code.

(5) International tie-line operations shall be co-ordinated from the Tanzanian side by the *System Operator* within the common *Power Pool* arrangements.

5. Ancillary services

(1) The *System Operator* shall be responsible for the technical specification and execution of all short term (daily) reliability services for the *IPS*. These include restoration, the balancing of supply and demand, the provision of quality voltages and the management of the real-time technical risk. Suitable *ancillary service* levels for the following year shall be calculated annually.

(2) Reliability targets shall be selected to minimise the sum of the cost to the *IPS* of providing the reliability plus the cost to the *customer* of limited reliability.

(3) The *System Operator* shall be responsible for procuring the required *ancillary services* that are economically efficient and needed to provide the required reliability.

(4) All *Generators* shall inform the *System Operator* of their *ancillary services* technical capability and shall not withhold *ancillary services* for non technical reasons

(5) The acquisition of *ancillary services* shall take place on a non-discriminatory basis.

(6) The following services are defined as *ancillary services*:

(a) Operating reserves

(b) *Black Start*

(c) Reactive power compensation and voltage control from units

5.1 Operating reserves

(1) Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand. If there is a larger share of non-dispatchable generation in the power system, the planning of reserve power will have to consider possible power gradients of the non-dispatchable generation as well. There shall be three categories of operating reserves: ***Spinning Reserve*, *Regulating Reserve and Quick Reserve***.

5.1.1 *Spinning Reserve*

(1) The requirement is to keep the *frequency* above 49.0 *Hz* following all credible single contingency *Losses*. The largest loss is the loss of a *unit* at full load, i.e. currently a Kihansi *unit* at 60 *MW*.

(2) The *Spinning Reserve* requirement for the *System* shall be determined by the *System Operator* at least once a year. The requirement shall be made available to all *Participants*.

5.1.2 *Quick Reserve*

(1) *Quick Reserve* is a less frequently used reserve and is used when the *IPS* is not in a normal condition. The reserve can be used for supply and demand balancing, network stability and voltage constraints. This reserve must be activated, on request, within 10 minutes and must be sustainable for two hours.

(2) The *Quick Reserve* requirement for the *System* shall be determined by the *System Operator* at least once a year. The requirement shall be made available to all *Participants*. Individual contracts may be aggregated into blocks executed as defined. The aggregated block must be contracted as one block. The reserve must also be under direct control from the *System Operator control centre*. These requirements are due to the need to take quick action when abnormal conditions prevail on the system.

5.1.3 *Regulating Reserve*

(1) *Regulating Reserve* is reserve that is under *AGC* and can respond within 10 seconds and be fully active within 10 minutes of activation. This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore *instantaneous reserve* within 10 minutes of the disturbance.

(2) Sufficient *Regulation Reserve* shall be maintained at all times to ensure that under normal conditions the frequency is maintained within:-

(a) 50Hz ± 0.5 Hz when not interconnected to any Power Pool

(b) Stringiest Power Pool requirements when interconnected to one or more Power Pools

(3) The *Regulating Reserve* requirement for the *System* shall be determined by the *System Operator* at least once a year. The requirement shall be made available to all *Participants*. The *IPS* needs *Regulating Reserve* every hour to balance supply and demand and to keep the *frequency* and tie-lines within acceptable limits.

5.2 Black start

(1) *Units* capable of *Black start* shall be certified by the *System Operator* and entitled to payment for the service.

(2) To ensure optimal operation of the *IPS*, the *System Operator* may deploy network *Islanding* schemes on the network, e.g. an out-of-step tripping scheme.

(3) The *System Operator* shall determine the minimum requirements for each *Black start* supplier and ensure that the contracted suppliers are capable of providing the service.

5.3 Reactive power compensation and voltage control from units

(1) Voltage control and the supply or consumption of reactive power is inter-related in the sense that the voltage is affected by changes in the reactive power flow. System stability depends on the voltage profile across the system. In view of these considerations it is necessary from time to time to employ certain *Power Stations* to supply or consume reactive power whether or not they are producing active power, for the purpose of voltage control.

(2) The *unit* shall be able to provide reactive power without having to produce or consume a large quantity of real power. The amount of reactive power shall be controlled by the *System Operator*. This may be done directly through the energy management system or by telephone.

(3) When a *unit* is generating or pumping, reactive power supply is mandatory in the full operating range as specified in the Network Code.

(4) The *System Operator* shall ensure there is sufficient *reactive power* and reactive power reserve to maintain transmission voltages within prescribed limits for single contingencies

6. Operational authority

(1) The *System Operator* shall have operational authority over the *TS*. Operational authority for other networks shall lie with the respective asset owners.

(2) Normal control of the various networks shall be in accordance with the operating procedures as agreed between the *Participants*.

(3) Except where otherwise stated in this section, no *Participant* shall be permitted to operate the equipment of another without the permission of such other *Participant*. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with his own standards before such permission is granted.

(4) Not withstanding the provisions of section 2.1, *Participants* shall retain the right to safeguard the health of their equipment.

7. Operating procedures

(1) The *System Operator* shall develop and maintain operating procedures for the safe operating of the *TS*, and for assets *connected to the TS*. These operating procedures shall be adhered to by *Participants* when operating equipment on the *TS* or *connected to the TS*.

(2) Each *customer* shall be responsible for his own safety rules and procedures. The *System Operator* shall ensure the compatibility with regard to the safety rules and procedures of all *Participants*. However, if a dispute affecting the interpretation and/or application of safety rules and procedures should arise, such dispute shall be resolved in accordance with the procedures specified by the *System Operator*.

(3) The *Power Pool* operating agreements shall apply in the case of operational liaison with all international power systems *connected to the TS*.

8. Operational liaison, permission for synchronisation

(1) The *System Operator* shall sanction the switching, including shutting down and synchronising, of *units* and changing over of auxiliaries on all units.

(2) If any *Participant* experiences an *emergency*, the other *Participants* shall assist to an extent as may be necessary to ensure that it does not jeopardise the operation of the networks/plant.

(3) A *customer* shall enter into an operating agreement with the *System Operator*, if it is physically possible to transfer load or *embedded generators* from one *Point of Supply* to another by performing switching operations on his network. This operating agreement shall cover at least the operational communication and notice period requirements and switching procedures for such load transfers.

9. *Emergency* and contingency planning

(1) The *System Operator* shall develop and maintain contingency plans to manage system contingencies and emergencies that are relevant to the performance of the *IPS*. Such contingency plans shall be developed in consultation with all *Participants*, shall be consistent with internationally acceptable utility practices, and shall include but not be limited to -

(a) Under-*frequency* load shedding;

(b) Meeting disaster management requirements including the necessary minimum load requirements;

(c) *Forced outage*s at all points of interface; and

(d) Supply restoration.

(2) *Emergency* plans shall allow for quick and orderly recovery from a partial or complete system collapse, with minimum impact on *customers*.

(3) *Emergency* plans shall comply with applicable *Power Pool* agreements and guidelines.

(4) All contingency/*emergency* plans shall be periodically verified by actual tests to the greatest practical extent, as agreed by the parties, without causing undue risk or undue cost. The costs of these tests shall be borne by the respective asset owners. The *System Operator* shall ensure the coordination of the tests in consultation with all affected *Participants*.

(5) The *System Operator* shall specify minimum *emergency* requirements for *distributor control centres*, *Power Station* local *control centres* and *substations* to ensure continuous operation of their control, recording, enunciator and communication facilities.

(6) Other *Participants* shall comply with the *System Operator's* requirements for contingency and *emergency* plans.

(7) Automatic and *Manual Load Shedding* schemes shall be made available under the direction of the *System Operator*.

(8) The *System Operator* shall be responsible for determining all operational limits on the *TS* by means of the applicable analytical studies.

(9) Load flow studies shall be conducted regularly to determine the effect that various component failures would have on the reliability of the *IPS*. At the request of the *System Operator*, *distributors* shall perform related load flow studies on their part of the network and make the results available to the *System Operator*.

10. System *frequency* and *ACE* control under abnormal *frequency* or interchange imbalance conditions

(1) The *System Operator* shall be responsible for the balancing of supply and demand in real time through the implementation of the energy schedules and utilisation of *ancillary services*.

10.1 Description of normal frequency *or balancing conditions*

(1) The *control area* is considered to be under normal *frequency* conditions when -

(a) The immediate demand can be met with the available scheduled resources, including any expensive contingency resources; and

(b) the ACE deficit does not exceed the available reserves for longer than 10 minutes; and

(c) the frequency is not less than 49.8 Hz for longer than 10 minutes; and

(d) Applicable *Power Pool* control performance criteria are not violated; and

(e) The *frequency* is within the range 50-2.5% to 50+2.5% *Hz*; and

(f) The interconnection is intact; and

(g) There are no *Security* and safety issues.

(2) The *control area* is considered to be under abnormal conditions if it is not in a normal condition as defined above.

10.2 Operation during abnormal conditions

(1) When abnormal conditions occur, corrective action shall be taken until the abnormal condition is corrected.

(2) The corrective action includes both supply-side and demand-side options. Where possible, warnings shall be issued by the *System Operator* on expected utilisation of any contingency resources.

(3) The *System Operator* shall have a designated person to refer to in periods of abnormal operation in particular, emergencies.

(4) The order in which *emergency* resources are to be used may change from time to time. An updated list shall be issued by the *System Operator*.

(5) Termination of the use of *emergency* resources shall occur as the plant shortage situation improves and after *frequency* has returned to normal.

(6) Automatic under-*frequency* systems shall be kept armed at all times.

11. Independent action by *Participants*

(1) Each *Participant* shall have the right to reduce or disconnect a *Point of Connection* under *emergency* conditions if such action is necessary for the *Protection* of life or equipment. Advance notice of such action shall be given where possible and no financial penalties shall apply for such action. Examples include hot connections, solid breakers, malfunctioning *Protection*, etc.

(2) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with agreed procedures.

(3) Following such *emergency* operations as may be necessary to protect the integrity of the *IPS* or the safety of equipment and human life, the *Participants* shall work diligently towards removing the cause of the *emergency* and the supply shall be reconnected immediately after the *emergency* conditions have passed.

12. Connection and Reconnection Requirements for Type 2 Generating Units

(1) A connection or re-connection of a commissioned Type 2 generating unit shall be admissible only under the conditions specified in Section 3.1.15 of the Network Code (Document 2 of the Tanzanian Grid Code).

13. Voltage control

(1) The *System Operator* shall be responsible for the voltage control of the *TS*, at *Transmission* level voltages as well as at the interface between Transmission and its *customers*.

(2) Electricity shall be supplied at three phase alternating current which shall have a nominal voltage between phases and range, at the *points of supply*, as agreed between the *Participants* from time to time.

(3) *TS* voltages shall be controlled during normal operation to be at least within statutory limits at the *points of supply*, except where otherwise agreed between *participants*.

14. Fault reporting and analysis/incident investigation

(1) *Generators* shall report loss of output and tripping of *units* and *governing* to the *System Operator* within 15 minutes of the event occurring.

(2) *Distributors* and *end-use customers* shall report the loss of major loads (>5MVA) to the *System Operator* within 15 minutes of the event occurring. Warning of the reconnection of such loads shall similarly be given with at least 15 minutes advance notice.

(3) Incidents on the *IPS* involving sabotage or suspected sabotage, as well as threats of sabotage shall be reported to the *System Operator*.

(4) Any incident that materially affected the quality of the service to another *Participant* shall be formally investigated. These include *interruptions of supply*, disconnections, under or over voltage incidents, quality of supply contraventions, etc. A preliminary incident report shall be available after three working days and a final report within three months. The *System Operator* shall initiate such an investigation, arrange for the writing of the report and involve all affected *Participants*. All these *Participants* shall make all relevant required *information* available to the *System Operator*. The confidentiality status of *information* is described in the *Information Exchange Code*.

(5) A major incident is defined as an incident where -

(a) More than 20 *System Minutes* of load was interrupted;

(b) Severe damage to plant has occurred.

(6) A major incident shall have the following additional requirements:

(a) Any *Participant* shall have a right to request an independent audit of the report, at their own cost, if they are not satisfied with it.

(b) Recommendations shall be implemented by the *Participants* within the time frames specified.

(7) Incidents shall also be reported to the Authority as defined in the licence conditions.

(8) *System Operator* shall be responsible for developing and maintaining an adequate system of fault statistics.

15. Commissioning

(1) The *System Operator* shall verify commissioning/maintenance programmes concerning operating at major *substations* as far as is needed to ensure adequate co-ordination and reliability of the *IPS*.

(2) All aspects of commissioning, by *customers*, of new equipment associated with the *Transmission* connection, or re-commissioning of such existing equipment, shall be agreed with the *System Operator* in writing before such commissioning starts.

(3) The said aspects shall include, but not be limited to the following:

(a) Commissioning procedures and programmes

(b) Documents and drawings required

(c) Proof of compliance with standards

(d) Documentary proof of the completion of all required tests

(e) *SCADA* information to be available and tested before commissioning

(f) Site responsibilities and authorities, etc.

(4) A minimum notice period of one *Month* shall apply from the date of receipt of the request for all commissioning or re-commissioning.

(5) When commissioning equipment at the connection point, the *Transmission* shall liaise with the affected *customers* on all aspects that could potentially affect the *customers'* operation.

(6) *Transmission* and *customers* shall perform all commissioning tests required in order to confirm that the *Transmission* and the *customers*' plant and equipment meets all the requirements of the *Grid Code* that have to be met before going on-line.

(7) Where commissioning is likely to involve a requirement for dispatch and/or operating for test purposes, the *customer* shall, as soon as possible, notify the *System Operator* of this requirement, including reasonable details as to the duration and type of testing required.

16. Risk of trip

(1) *Generators* shall identify and report all tripping risks to the *System Operator*. The reporting shall be done after commissioning and when there are changes from the previously reported tripping risks.

(2) *Participants* shall minimise the risk of tripping / loss of output on their own plant and equipment, associated with their operation and maintenance.

(3) Special care shall be taken by all *Participants* when planning or executing work on *Protection* panels. The normal outage process described in the maintenance coordination / outage planning section shall be followed. All such work shall be treated as *Risk-related Outages* by the *System Operator.*

(4) When a risk of trip of equipment or loss of output with an impact exceeding 5*MW* could occur on any part of the *IPS*, owing to such operation and maintenance, the affected *Participants* shall be consulted as to who shall accept the risk before work may commence. The *System Operator* shall always be informed of such events and shall in general coordinate these requests and accept the risks.

(5) The affected *Participants* shall be informed when the risk has been removed.

17. Maintenance coordination / outage planning

(1) Optimal reliability of the *IPS* shall be achieved by co-ordinating scheduled outages of generation, *Transmission*, *distributor* , *end-use customer*, *Metering*, communication and control facilities affecting *IPS* operation. The maintenance coordination / outage planning shall be done in collaboration with the *Single Buyer.*

17.1 Definition of roles and responsibilities

17.1.1 Outage Requester

(1) An outage requester is a person requesting an outage on plant for planned maintenance, repairs, auditing, *emergency* repairs, construction, refurbishment, inspection, testing or to provide safety clearance for other activities such as servitude clearance, line crossings and underpasses. This shall be a *distributor* , *generator*, *end-use customer* or *Transmission* employee or agent, formally nominated.

17.1.2 *Transmission* Outage Scheduler

(1) *Transmission* outage scheduler is a person appointed by *Transmission* to check for multiple requests for an outage of the same network unit. If another outage request for the same bay(s) is noticed, the *Transmission* outage scheduler requests the *parties* involved to combine their requests into a single outage. In the case of conflicting outages, the *Transmission* outage scheduler considers the priority and relative urgency of the requests and reflects this against the validated request. The *Transmission* outage scheduler is also responsible for ensuring that negotiations of *Risk-related Outages* have taken place.

17.1.3 *System Operator* Outage Scheduler

(1) The *System Operator* outage scheduler is appointed to assess the viability of a scheduled outage and either to confirm or to turn down the request. The *System Operator* outage scheduler shall develop and implement a non-discriminatory mechanism for resolving any scheduling maintenance conflicts. This scheduler shall optimise plant utilisation by evaluating network load capabilities, different system configurations and risk factors. It is also the responsibility of the scheduler to co-ordinate and schedule plant that affects international customers.

17.1.4 *System Operator* Shift Controller

(1) The *System Operator* controller on shift at the time of the outage is responsible for finally sanctioning (or alternatively refusing) the outage and ensuring that the relevant operating instructions are issued.

17.2 Outage process

(2) The *System Operator* shall develop and maintain an electronic *TS* maintenance *Scheduling* system for the coordination of all *TS* outages.

(3) *Transmission* shall inform all *customers* of the name and contact details of the respective *the Transmission* outage scheduler(s) in the different geographic parts of the country.

(4) The *System Operator* shall make available to *customers* an outage schedule of all *Planned Outage*s on the *TS*. The outage schedule shall cover a period of one year rolling and shall indicate the status of the outage, i.e. whether confirmed or not.

(5) When the need for an outage is first identified it shall be entered into a *Transmission* maintenance *Scheduling* system as a requested outage with *Planned Outage* dates, times, reason, type of maintenance and request urgency assigned to it. The outage requester shall enter this request into the maintenance *Scheduling* system if the requester has access to this system. If no access is available, the requester shall contact the relevant *Transmission* outage scheduler or the *System Operator* outage scheduler with the request.

(6) When the *Transmission* outage scheduler is satisfied with the request(s) and, in the case of a calculated risk, has ensured that negotiation has taken place with the relevant *Stakeholders* this scheduler shall mark it as a scheduled outage.

(7) At this point the *System Operator* outage scheduler shall confirm the outage if it satisfies all the necessary requirements. If acceptable this scheduler shall change the validated request to a confirmed booking. If it is subject to the outcome of another booking, the booking shall reflect that it is linked to

another confirmed booking. If the request cannot be accommodated, it shall be marked as refused, with a reason and/or an alternative suggestion for a time being given

(8) When it is time for the confirmed booking to be executed (the outage becoming effective), the status shall be changed to taken by the *System Operator* shift controller if sanctioning (i.e. not refusing) the outage. While an outage is in progress the responsible *Participants* may report the actual state of the progress to the *System Operator* shift controller, who shall enter this information into the system. This allows for the progress of the outage to be monitored by those concerned.

(9) When the outage has been completed it shall be the responsibility of the *System Operator* shift controller receiving the hand back, to change the status of the outage as completed.

(10) When an outage is cancelled or refused it is the responsibility of the person cancelling or refusing the outage to furnish the reasons for cancellation or refusal. The person receiving the cancellation or refusal shall then enter this information into the system when changing the status to cancelled.

(11) This shall also apply to outages that are postponed.

17.3 Risk-related Outages

(1) All *Risk-related Outages* shall be scheduled a minimum of 14 days in advance with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of *Transmission*.

(2) These contingency plans are, in some cases, of a permanent nature and will be in force every time the same system conditions apply. These contingency plans will therefore only have to be prepared once and will come into force again (with minimal changes if needed) when the same outage is scheduled.

(3) Contingency plans shall consist of five parts:

(a) *Security* linking prior to the outage, to ensure minimal risk to customers.

(b) Returning the plant that is on outage back to service as soon as possible.

(c) Restoring supply to customers by utilising by-pass schemes.

(d) Load shedding if necessary (load profiles shall be made available by the *customer*).

(e) List of contact persons.

(4) Responsibilities during the compilation of contingency plans are as follows:

(a) The *System Operator* shall be responsible for identifying *Risk-related Outage*s.

(b) The *System Operator* and *customer control centre*s shall be responsible for the *Security*-linking instructions in the said contingency plan.

(c) It shall be the responsibility of *Transmission* to supply the information relating to returning the plant to service.

(d) *Transmission* shall develop by-pass schemes with assistance from the *System Operator* and the *customer control centre*.

(e) The *System Operator* and *customer control centre*s shall be responsible for identification of the load at risk and load shedding in the said contingency plan.

(f) With an increasing number of embedded generation, load shedding schemes have to take into account that with disconnection of a network feeder, embedded generation may be disconnected as well (depending on the installed embedded generation in the particular feeder).

(5) If the contingency plan indicates that load shedding must take place it shall include the following details:

(a) The total amount of load to be shed in relation to the load profile.

(b) The point at which customers' load must be shed for optimal results.

(6) The relevant *control centres* shall confirm that it is possible to execute the contingency plan successfully.

(7) To ensure that the *control centre* is in possession and aware of the contingency plan the outage scheduler shall contact the *control centre* a *day* prior to the outage.

(8) Negotiation of all *Risk-related Outages*, shall take place with affected *customers* a minimum of 14 days prior to the outage being executed, unless otherwise agreed. Where a request comes from a *generator* with a requirement for 28 days' notice, this time period shall be respected by the parties. *Customers* shall be involved in the planning phase of projects and outages that will affect them.

(9) These conditions shall also apply to all outages affecting international *customers*.

(10) *Transmission* shall give *distributors* and *end-use customers* at least 14 days' notice of *Planned Interruptions*.

17.4 Maintenance planning between Transmission and generators

(1) Over and above the requirements mentioned above, all *generators* shall provide the *System Operator* with the following documents in the pro-forma format specified in the Information Exchange Code, Appendix 4, to enable it to execute its short-term power system reliability responsibility:

(a) A 52-weeks-ahead outage plan per *Power Station*, showing *Planned Outage* and return dates and other known generation constraints, updated weekly by 15:00 every Monday (or first working *day* of the week).

(b) An annual maintenance / outage plan per *Power Station*, looking five years ahead, showing the same information as above and issued by 31 December of each year.

(c) A monthly variance report, explaining the differences between the above two reports.

(2) Each *generator* shall invite *Transmission* to provide inputs into the compiling of the five-year-ahead annual maintenance plans mentioned above, on the basis of ensuring system reliability, and shall not unreasonably reject such inputs. Any such rejection shall be substantiated by providing *Transmission* with documentary proof of the reasons.

(3) Plant versus system risks shall be carefully weighed up by the affected *Participants* under all circumstances. Joint risk assessments shall be undertaken and joint contingency plans under these outage conditions shall be prepared by the affected *Participants*.

(4) Each *generator* shall ensure the absolute minimum deviation from its annual outage plan. Each deviation shall be negotiated with the *System Operator*.

(5) The *System Operator* shall coordinate network outages affecting *unit* output with related *unit* outages to the maximum possible extent.

(6) The objectives to be used by the *System Operator* in this maintenance coordination, are firstly maintaining adequate reserve levels at all times, secondly ensuring reliability where *TS* constraints exist, and thirdly maintaining acceptable and consistent real-time technical risk levels.

17.5 Refusal/cancellation of outages

(1) No *Participant* may unreasonably refuse or cancel a confirmed outage, or the risks associated with that refusal/cancellation shall be transferred to that *Participant*. In the case of the *System Operator* cancelling the request owing to system conditions, the outage requesting *Party* shall bear the cost of such cancellation.

18. <u>Communication of system conditions, operational information and *IPS* performance</u>

(1) The *System Operator* shall determine system conditions from time to time, and communicate these, or changes from a previous determination, to all *Participants*.

(2) These system conditions shall typically be based on a steady state and dynamic simulation of the *IPS* and include measures that will enhance reliability.

(3) The *System Operator* shall be responsible for providing *Participants* with operational *information* as may be agreed from time-to-time and as specified in the Information Exchange Code. This shall include information regarding *planned and forced outages* on the *IPS*.

(4) The *System Operator* shall report on both technical and energy aspects of *IPS* performance monthly and annually. This shall include daily demands, energies, *Losses*, interruptions and *QOS* aspects as detailed in the Information Exchange Code. This information shall be available to all *Participants* on request.

19. <u>Tele-control</u>

(1) Where tele-control facilities are shared between *Participants*, operating procedures shall be agreed.

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

4 of 8 Code Documents - The Scheduling and Dispatch Code

Version 2

1st March 2017

Table of Contents

1. **Introduction**

(1) This code sets out the responsibilities and roles of the *Participants* as far as the *Scheduling* and Dispatch of *generator*s is concerned, and more specifically issues related to -

(a) *Generation Scheduling*;

(b) *Generation* Dispatch;

(c) *System Operator* roles and responsibilities;

2. ***Generation* Scheduling**

(1) Scheduling the operations of *generating units* is a major component of operations plans. *Scheduling* of the *generating units* depends upon the pattern of demand by the system, the order-of-merit operation of *generating units*, the availability of *generating unit*s, the flexibility of operation of *generating units*, constraints on the *TS*, security requirements, and system *losses*.

(2) *Generation Scheduling* procedures include the following-

(a) The submission of an Availability Declaration by each *generator* to the *System Operator*.

(b) The submission to the *System Operator* of any revised *generation scheduling* and dispatch parameters for the following availability Declaration Period by each *generator*.

(c) The submission of certain system *data* by each *generator* to the *System Operator.*

(d) The issue to the *System Operator* of a *Generation* Schedule the *day* before the schedule *day*.

(e) Where an externally interconnected *party* outside the country is connected to the *IPS* for the purpose of system security enhancement and economic operation (e.g. sharing of spinning reserve), the *generation scheduling* and hence, power transaction shall be governed by Power Pool Rules, Inter-Utility Joint Operation Agreements and any other Inter-Utility Agreements.

(f) *Generation scheduling* requires *generator data* to enable the System Operator to prepare a Merit Order to be used in *scheduling* (Unit Commitment) and dispatch (Economic Dispatch) and the preparation and issue of a *Generation* Schedule. Based on this *data,* the System Operator is required to ensure that there is sufficient *generation* to meet system demand at all times in the most economic manner, together with an appropriate margin of reserve, while maintaining the integrity of the *IPS* and security and quality of supply.

2.1 Scheduling Procedure.

(1) The computation of the *generation* schedule shall require the following *information*-

(a) Availability declaration.

(b) *Generation scheduling* and *generation* dispatch parameters.

(c) Other relevant *generation data*.

(2) By 10.00 hours each *day*, each *generator* shall submit to the System Operator in writing (or by such agreed electronic *data* transmission facilities) the above *information* which shall be applicable for *generation* for the next period (following *day*) from 00.00 hours to 24.00 hours.

(3) The *generation data* to be submitted shall be as specified by the *Grid code - Information* Exchange Code.

(4) The *generation* schedule shall be submitted by the *System Operator* to the relevant *generator* by 14.30 hours.

(5) Availability Declaration.

(a) The Availability Declaration is to be expressed in a whole number of MW per *generator* unit, in respect of any time period (specifying the time at which each time period begins and ends). Such Availability Declaration shall replace any previous Availability Declaration Period. For existing plant which has availability declaration obligations set out in a PPA, the requirement to only declare availability per unit is not enforced. The code allow for flexibility of expressing declared availability either per unit or per plant capacity.

(b) A revised Availability Declaration for a *generating unit* which, since the time at which the availability declaration for that *generation* unit under this paragraph was prepared, has either-

(i) become available at a different wattage to that which such *generating unit* was proposed to be made available for *generation* in any such Availability Declaration whether higher or lower (including zero); or

(ii) in the case of a *generating unit* declared to be not available for *generation* in an Availability Declaration, has become available for *generation*. A revised Availability Declaration submitted by a *generator* under this clause shall state, for any *generating unit* whose availability for any *generation* is revised, the time periods (specifying the time at which each time period begins and ends) in the relevant availability declaration and, if such *generating unit* is available at what wattage, expressed in a whole number of MW, for each such time period.

2.2 Generation Scheduling and Dispatch Parameters.

(1) The *generation Scheduling* and Dispatch Parameters shall reflect the true operating characteristics of *generating unit*s. Any revision to the *generation scheduling* and dispatch parameters from those submitted under a previous declaration shall be submitted for application for the following period. If such parameters are not revised, the previously submitted *generation scheduling* and dispatch parameters shall apply for the next following Availability Declaration period.

(2) A *generation* schedule shall be compiled daily by the System Operator as a statement of which units may be required for the next following schedule *day*-

(a) In compiling the *generation* schedule, the System Operator shall take account of and give due weight to the following factors-

(i) *TS* constraints from time to time, as determined by the System Operator and as advised by *generator*s;

(ii) for *generating unit*s, their parameters registered as *generation Scheduling* and Dispatch Parameters (including indications of *generating unit* inflexibility);

(iii) the requirements, as determined by the System Operator and as advised by *Distributor*s, for voltage control and MVAR reserves;

(iv) the need to provide operating margins (by using the various categories of reserves as specified in *Grid code* – System Operations Code), as determined by the System Operator;

(v) the requirements as determined by the System Operator for maintaining *Frequency* Control;

(vi) the weather forecast for network areas with a considerable number of generation based on wind or solar power (embedded generation may be treated as negative load).

(b) The *Generation* Schedule shall be compiled by the *System Operator* to schedule such *generating unit*s taking into account the above factors and in accordance with Offered Availability

(i) in accordance with the Merit Order Table and taking into account the start-up price element of the *Generation* Offer price;

(ii) as shall in aggregate be sufficient to match at all times (to the extent possible having regard to the offered availability) the forecast system demand together with an appropriate margin of reserve, as identified in the Weekly Operational Policy; and

(iii) as shall in aggregate be sufficient to maintain *Frequency* Control.

(c) After the completion of the *scheduling* process, but before the issue of the *Generation* Schedule, the System Operator may deem it necessary to make the adjustments to the output of the *scheduling* process. Such adjustments may be made necessary by the following factors-

(i) changes of Offered Availability or *Generation Scheduling* of Dispatched Parameters of *generating unit*s, notified to the System Operator after the commencement of the *scheduling* process;

(ii) changes to System Demand forecasts;

(iii) changes to transmission constraints, emerging from the necessarily interactive process of *scheduling* and network security assessment, including either-

1. changes to the numerical values prescribed to existing constraint groups; or

2. identification of new constraint groups;

(iv) changes to *generating unit* requirements within constrained groups, following notification to the System Operator of the changes in capability;

(v) changes of *generating unit* requirements within constrained groups, following re-appraisal of Demand forecast within that constraint group;

(vi) changes to any conditions which in the opinion of the System Operator, would impose increased risk to the *IPS* and would therefore require the System Operator to increase operational reserve levels. Such conditions include-

1. unpredicted transmission equipment outages which places more than the equivalent of one large *generating unit* at risk to any fault;

2. un-predicted outage of *generator*'s equipment which imposes increased risk to the station output;

3. volatile weather situation giving rise to low confidence in demand forecasts;

4. severe (unpredicted) weather conditions imposing high risk to the *IPS*; and

(vii) limitations or deficiencies of the System Operator *scheduling* process computational algorithms.

(d) For the following situations, a written record of these adjustments shall be kept by the System Operator, for a period of at least 12 *month*s-

(i) adverse weather is anticipated;

(ii) a yellow warning has been issued;

(iii) demand control has been instructed by the System Operator; or

(iv) a total or partial collapse exists.

(3) These factors may mean that a *generating unit* is chosen other than in accordance with the Merit Order. Any other deviations from the use of the Merit Order by dispatch shall be reported by the System Operator including those responsible for the deviation. These reports shall be consolidated into a weekly report by the System Operator to the *generator*s, *Distributor*s and the Authority.

(4) Content of *Generation* Schedule.

(a) The *information* contained in the *Generation* Schedule shall indicate for a *generating unit* or Interconnection Power Transaction, the period for which it is scheduled during the following Schedule *Day*. It shall also include *generating unit*s or Interconnection Power Transactions running as a result of non-System reason (such as test purposes) and system requirements (such as Reactive Power Reserve) and *generating unit*s and Externally Interconnected Parties assigned to a specific reserve role.

2.3 Special Actions.

(1) The *Generation* Schedule may be followed by a list of special actions (either pre or post-fault) that the System Operator may request a *generator* to take in respect of *generating unit*s, or an Externally Interconnected *Party* to take in respect of a *Generation* Power Transaction, in order to maintain the integrity of the *IPS*. For consumers directly connected to the *Transmission System* to which *power station* or consumers are also connected, these special actions shall generally involve Load Transfer between the Grid Supply Points or arrangements for Demand reduction by manual or automatic means.

(2) For Externally Interconnected Parties these special actions shall generally involve an increase or decrease of net power flows across an External Interconnection by manual or automatic means.

(3) These special actions shall be discussed and agreed upon with the *generator*, externally interconnected *party*, *distributor* or consumer concerned. If not agreed, *generation* may be restricted or demand may be at risk.

2.4 Other relevant Generation Data.

(1) Other relevant generation *data* include-

(a) details of any special factors which in the opinion of the *generator* may have a material effect on the likely output of such *generating unit*s;

(b) details of any *generating unit*'s commissioning or changes in the commissioning programs submitted earlier.

2.5 Distribution System Data.

(1) By 10.00 hours each *day*, *Distributor*s shall submit to the System Operator in writing confirmation or notification of the following for the following Availability Declaration period-

(a) constraints on its *distribution system* which the System Operator may need to take into account;

(b) the requirements of voltage control and MVAR reserves which the System Operator may need to take into account for system security reasons. The form of the submission shall be that of a *Generation* output (both MW and MVAR) required in relation to that *Distribution System* following Availability Declaration Period.

2.6 Revision of generation schedule.

(1) If a revision in the Availability Declaration, *distribution scheduling* and dispatch parameters or other relevant *generation data* is received by the System Operator prior to 15.00 hours on the *day* prior to the relevant schedule *day*, the System Operator shall, if there is sufficient time prior to the issue of the *generation* schedule, take into account the revised Availability Declaration, *generation scheduling* and dispatch parameters or other relevant *generator data* in preparing the *generation* schedule.

(2) If a revision in Availability Declaration *generation scheduling* and dispatch parameters of other relevant *generation data* is received by the System Operator at or after 15.00 hours in each *day* but before the end of the next following schedule *day*, the System Operator shall, if it re-schedules the units available to generate, take into account the revised Availability Declaration, *generation scheduling* and dispatch parameters or other relevant *generation data* in that re-*scheduling*.

2.7 Issue of Generation Schedule.

(1) The *Generation Schedule* shall be issued to *generator*s and *distribution*s or otherwise to the *generator* direct by 14.30 hours each *day*. If an event on the *IPS* (for example loss of *generation* in a critical part of the *IPS*) occurs which requires a substantial amendment in the *data* being used in preparing the *generation* schedule, the System Operator reserves the right to issue a revised *generation* schedule to the extent necessary as a result of such Events.

(2) The System Operator may instruct units before the issue of the *Generation Schedule Day* to which the instruction relates, if the length of the Notice to Synchronise requires the instruction to be given at that time.

(3) When the length of the time required for the Notice to Synchronise is within 30 minutes of Synchronisation causing the unit to be unable to meet the indicative Dispatch instructions, the *generator* shall immediately inform the System Operator.

(4) The *Generation Schedule* received by each *generator* shall contain only information relating to its units.

3. ***Generation* Dispatch**

3.1 Merit Order Operation.

(1) To meet the continuously changing demand on the *IPS* in the most economical manner, *generating unit*s shall, as far as practicable be put on load and loaded up in accordance with the least "variable operation and maintenance costs inclusive of cost of fuel (where applicable) and consumables" (hereinafter "operating costs") of producing electricity from each *generating unit*. Fixed costs are not taken into consideration. At any time the total generating plant with the least Operating Costs is used to meet the demand with a satisfactory margin.

(2) For this purpose *generating unit*s are listed according to the lowest-to highest operating costs for each *generating unit* and such a list is known as an "Order-of-Merit-*Schedule*".

(3) The order-of-merit schedule for a hydro System is divided into 2 sections-

(a) Merit Order for *scheduling generation* on and off the system. The next unit that is not operating with the lowest operating cost is the next to go on the system and the last unit is the first to go off.

(b) For a merit-order-for determining the generated output of *generating unit*s which are on load, the flexibility of the units shall determine how they operate on the system. The more flexible a unit is, the more likely it shall be used to follow the load changes that occur during the *day*. The less flexible units shall operate better at more constant loads. This merit order shall take into account the costs of operating the units at different loading of the turbine along with constraints in changing loads to determine the operational sequence of the *generating unit*s.

(4) The order-of-merit shall be updated by the offered *generator data* for the next availability declaration period. The updating shall take into account not only changes to the cost of fully loaded units, but also the difference in the loading cost curves for each unit and for each plant.

3.2 Hydro Turbine Loading Charts.

(1) The efficiency of a hydro turbine varies with the changes in head across it and loading charts are prepared for each unit to show the relationship between efficiency and output over the range of turbine heads which can occur due to fluctuation in storage and tailrace levels. For convenience, these changes normally take the form of water consumption or output for various station gross heads. Significant tunnel or tailrace *losses* are taken into account when preparing the charts.

(2) The rate of change of water consumption in hydro turbines gives the incremental rate curve. When several turbines are operating in a station, the minimum consumption of water is achieved by loading each set at the same incremental rate. Similarly, incremental rate curves of turbines at different stations, when calculated for equivalent heads, are used to allocate loading.

(3) When additional *generation* is added to meet a load less than that of one machine, average rate curves are used in order to determine if it is more economical to run one or two machines. This method is used to determine Merit Order.

3.3 Economic Dispatch.

(1) Each *day* is divided into a number of operating periods, depending upon the number of peaks, troughs and constant levels in the estimated demand curve.

(2) For each operating period, unit commitment requirement on line is determined by computer simulations. This value is the sum of the estimated maximum demand for the period and the specified spinning reserve units.

(3) Units which are required to run for *security* or inflexibility purposes are allocated first. This is followed by hydro units in accordance with the required Hydro Merit Order.

(4) In cases where only partial loading of a set is required for *security* or inflexibility reasons, the assessment of whether or not to use the remainder of the set capacity is determined, by the hydro loading curves specified in section 3.2.

(5) When *scheduling* over a trough, the duration of the period may be too short to shut down a less flexible unit and bring it on load again for the next period. In this case, this unit is considered as inflexible and allocated a minimum load equal to its minimum stable *generation*.

(6) Scheduling shall also take into account the rates of loading and unloading of units and other station constraints such as the time intervals between synchronising or shutting down sets to each station.

4. ***System Operator* roles and responsibilities.**

(1) In order to operate the *IPS*, the System Operator shall prepare *generating unit*s operations schedules and issue unit dispatch instructions.

(2) The *Information* which the System Operator shall use in issuing dispatch instructions are as follows-

(a) The *generation* schedule used in dispatching the *generating unit*s shall be based on the schedule prepared and supplied under the *generation scheduling* procedures in this clause. This takes into account *information* regarding Availability Declaration, unit commitment, offer prices, and system *security* constraints, Grid demand forecast, *generation* trading contracts and other relevant operational *data*.

(b) Commercial *Ancillary Services*.

4.1 Re-optimisation of Generation Schedule or subsequent schedules.

(1) The System Operator shall re-optimise the schedules when in its judgement a need arises. As it may be the case that no notice shall be given prior to this re-optimisation, it is important that *generator*s always keep the System Operator informed of changes of availability declarations and dispatch parameters immediately as they occur.

(2) Indicative synchronising and de-synchronising times of *generating unit*s in the re-optimised schedule shall be made available to the *generator*s who shall immediately acknowledge the times, together with their compliance of the synchronising instructions.

4.2 Generation Dispatch Instructions.

(1) The System Operator shall issue Dispatch Instructions to all *generator*s for the schedule *day* at any time during the period beginning immediately after the issue of the *Generation* Schedule for that schedule *day*.

(2) Dispatch instructions shall recognise the Offered Availability Declared, *Generation Scheduling* and Dispatch Parameters and other relevant *generation data* supplied to the System Operator. A Dispatch Instruction may be subsequently cancelled or varied. Units declared available but not included in the *generation* schedule may be Issued Dispatch Instructions.

(3) In addition to instructions relating to dispatch of active power, Dispatch Instructions may include-

(a) details of the reserve to be carried on each *generating unit* including specification of the time scale in which that reserve may be transferable into increased *generation* output;

(b) an instruction for *generating unit*s to provide *Ancillary Services*;

(c) Target (at instructed MW level) voltage levels or the individual reactive power output from *generating unit*s. In the event of sudden change in system voltage, *generating unit*s shall not take any action to override automatic MVAR response unless instructed otherwise by the System Operator, or unless immediate action is necessary to comply with stability limits. *Generator*s may take such action as is necessary to maintain the integrity of the *generating unit*s;

(d) notice and change in notice to synchronise or desynchronise *generating unit*s in a specific time-scale;

(e) an instruction for *generating unit*s to operate in Synchronous Compensation mode; and

(f) an instruction to carry out tests as specified in *Grid code* System Operations Code.

(4) The form of instructions and terms to be used by the System Operator in issuing instructions together with their meanings are to be mutually agreed by all relevant parties.

4.3 Communication with Generators and Distributors.

(1) System regulation shall be performed automatically using *Automatic Generation Control* (AGC) facilities by the System Operator or Dispatch Instruction shall be given by telephone or voice links (and shall include exchange of operator names) or by automatic logging devices and shall be formally acknowledged immediately by *generator*s. In the event that while carrying out Dispatch Instructions, an un-foreseen problem arises caused by safety reasons, the System Operator shall be notified without delay by telephone. Additional or backup means of communication to be used by the SO, Generators and distributors are to be mutually agreed by all relevant parties.

4.4 Action required by generators.

(1) Each *generator* shall comply with all Dispatch Instructions properly given by the System Operator. If an unforeseen problem arises which affects the safety of the plant or personnel, the *generator* shall disregard Dispatch Instructions and take necessary corrective actions after which the System Operator shall be notified immediately.

(2) De-synchronising may take place without the System Operator's prior agreement if it is done purely on safety grounds. Synchronisation or de-synchronisation or desynchronisation as a result of inter-trip schemes or low *frequency* relay operation shall be reported to the System Operator immediately.

(3) Each *generating unit* shall be operated with AVRs and VAR limiters in-service unless released from this obligation by the System Operator.

(4) To preserve the *IPS* synchronously connected system integrity under *emergency* conditions, the System Operator may issue Dispatch Instructions to change *generation* output even when this is outside the parameters so registered or amended. This may, for example, be an instruction to trip a *generating unit*. A refusal may only be given on safety grounds (relating to person or plant).

4.5 Generators Response Time.

(1) The response times for units operating under different modes, and the procedure by which the response time shall be changed, shall be agreed from time to time between the System Operator and *generator*s.

4.6 Generating Unit Changes.

(1) *Generator*s shall without delay notify the System Operator by telephone of any changes or loss (temporary or otherwise) to the operational capability of any unit that is synchronised or units that had been instructed to synchronise within 3 hours.

4.7 Instructions to Distributors.

(1) The System Operator shall issue instructions directly to *distributor*s for Special Actions and Demand Control. These instructions may include-

(a) a demand reduction, disconnection or restoration of load and load transfer; and

(b) a demand inter-trip.

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

5 of 8 Code Documents - The Metering Code

Version 2

1st March 2017

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1. Introduction

(1) This code ensures a *Metering* standard for all current and future *Participants*. It specifies *Metering* requirements to be adhered to, and clarifies levels of responsibility.

(2) The NRS 057:2008 *Metering* specification shall be used as the *Metering* requirements for the *Grid Code*. The Energy and Water Utilities Regulatory Authority *(*EWURA*)* however reserves the right to override some sections of the NRS specifications should it find them inadequate or divergent from the principles of the *Grid Code*.

(3) This code covers some aspects not fully or clearly addressed within the NRS 057 specification. All areas written into this code will therefore take precedence over the mentioned specifications.

(4) All the standards refer to in this code complies with IEC standards.

2. Application of the *Metering* Code

(1) This code shall apply to all *Participants* in respect of any *Metering* point at the boundary of the *Grid.*

(2) This code sets out provisions relating to -

(a) Main *Metering Installations* and check *Metering Installations* used for the measurement of active and reactive energy;

(b) The collection of *Metering data*;

(c) The provision, installation and maintenance of equipment;

(d) The accuracy of all equipment used in the process of electricity *Metering*;

(e) Testing procedures to be adhered to;

(f) Storage requirements for *Metering data*;

(g) Competencies and standards of performance; and

(h) The relationship of entities involved in the electricity *Metering* industry.

3. Principles of the *Metering* Code

(1) The following points shall have a *Metering Installation*:

(a) Each *Point of Supply* connecting a *distributor* or *customer* to the *Grid.*

(b) Each *Point of Connection* between a generating unit and a *distributor* or the *Grid.*

(c) Each point connecting Tanzania's networks to a neighbouring country.

(2) The type of *Metering Installation* at each *Metering* point shall comply with NRS 057 *Metering* specifications.

(3) Each *Metering* point shall be installed with main and check *Metering* where practical and economical. Customers with a maximum demand of at least 5 *MVA* or with a maximum generation of at least 5 *MVA* shall have main and check *Metering*. There shall be separate main and check *CT* cores but one dedicated *VT* shall be allowed.

(4) A *Metering* point may be located at a point other than the *Point of Connection* or the *Point of Supply* by mutual agreement between the *Participants*.

(5) Customers may request the installation of their own separate check meters. Any extra costs shall be borne by the requesting *Party*. The *Transmission Metering Administrator (TMA)* shall install and control such meters.

4. Responsibility for *Metering Installations*

(1) For the purposes of this code *the (Transmission) System Operator (TSO*) shall fulfil the role of the *Transmission Metering Administrator (TMA)* and is the owner of the meter.

(2) The *(Transmission) System Operator (TSO*) shall be responsible for ensuring that all points identified as *Metering* points in accordance with the principles of the previous section's have *Metering Installations*.

(3) The *TMA* shall be responsible for managing and collecting *Metering* information.

(4) *Participants* connected to or wanting to connect to the *Transmission system* (*TS)* shall provide the *TMA* with all information deemed necessary to enable performance of its *Metering* duties.

(5) In the event of a *Metering Installation* being positioned between two *distributors*, the following shall apply:

(a) Both distributors shall be responsible for installing and maintaining the *Metering Installation* in accordance with the requirements of this section.

(b) All costs related to this *Metering Installation* shall be borne by both distributors.

(c) The distributors shall ensure that the *TMA* is given remote/electronic access to the *Metering Installation*. Should access to the *Metering Installation* compromise the *Security* of the installation, then *Metering data* shall be supplied to the *TMA* on a daily basis in an appropriate format.

5. *Metering Installation* components

(1) The following principles shall apply to all *Metering Installations*:

(a) The meter(s) or recorder(s) shall be able to store *data* in memory for 35 days or more.

(b) *Data* stored in either a meter or a recorder shall be remotely (where possible) and locally retrievable.

(c) A meter shall be remotely interrogated on a daily basis where possible or as mutually agreed by the affected *Participants*.

(d) A meter shall be visible and accessible, but such access shall be restricted to authorised access only. *Data* for customers shall be historical *data* situated on a secure server. As and when required, *Metering* impulses shall be provided.

(e) A telecommunications medium shall be connected to the meter/recorder where possible.

(f) The meter *data* retrieval process shall be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories.

(g) The accuracy of meters and recorders shall be in accordance with the minimum requirements of NRS 057-2.

(h) Commissioning of the *Metering Installation* and *Metering data* supporting systems shall take place in accordance with the requirements of NRS 057.

(i) Both active and reactive energy shall be measurable without compromising any requirements of this code.

(j) The meters shall measure both active and reactive energy flow in both directions.

(k) The meters shall be configured to store/record *Metering data* in half-hourly integration periods.

(2) In the event of a *Metering Installation* being used for purposes other than *Metering data* –

(a) Such use shall not in any way obstruct *Metering data* collection and accuracy requirements;

(b) The secondary use shall be communicated to all *Participants* who may be affected by the secondary use of the installation;

(c) No secondary user shall interfere with *VT*/*CT* circuitry.

(3) *Metering Installations* shall be audited in accordance with NRS 057 or equivalent.

6. ***Data* validation and verification**

6.1 Data validation

(1) *Data* validation shall be carried out in accordance with NRS 057.

(2) Data verification will be carried out in the event of –

(a) Electronic access to the meters not being possible;

(b) An *emergency* bypass or other scheme having no *Metering* system; or

(c) Metering *data* not being available

(3) Any of the following may be resorted to by the *TMA*:

(a) Manual meter *data* downloading

(b) Estimation or substitution subject to mutual agreement between the affected parties

(c) Profiling

(d) Reading of the meter at scheduled intervals

(4) In the event of an estimation having to be made, the following shall apply:

(a) A monthly report shall be produced for all estimations made.

(b) No estimation shall be made on three or more consecutive time slots, and if such estimation had to be made, the *TMA* shall ensure that the meters are downloaded for the billing cycle.

(5) Not more than ten (10) slots may be estimated per meter point per *Month*. If such estimation had to be made, the *TMA* shall ensure that the meters are downloaded for the billing cycle.

6.2 Meter verification

(1) In addition to the NRS057 verification requirements, meter readings shall be compared with the *Metering data* base at least once a year.

7. Metering database

(1) The *TMA* shall create, maintain and administer a *Metering* database containing the following information:

(a) Name and unique identifier of the *Metering Installation*

(b) The date on which the *Metering Installation* was commissioned

(c) The connecting parties at the *Metering Installation*

(d) Maintenance history schedules for each *Metering Installation*

(e) Telephone numbers used to retrieve information from the *Metering Installation*

(f) Type and form of the meter at the *Metering Installation*

(g) Fault history of a *Metering Installation*

(h) Commissioning documents for all *Metering Installations*

(2) *Information* relating to raw and official values as indicated in NRS 057-4 section 4.2 shall form part of the *Metering* database and shall be retained for at least five years for audit trail purposes.

8. Testing of *Metering Installations*

(1) Commissioning, auditing and testing of *Metering Installations* shall be done in accordance with the NRS 057-4 specification.

(2) Any *Participant* may request the Authority or agency acting on its behalf that testing of a *Metering Installation* be performed. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of the requesting *Participant* if the meter is found to be accurate and to the account of the *TMA* if the meter is found to be inaccurate.

9. Metering *data* base inconsistencies

(1) In the event of testing revealing that *data* in the *Metering* database is inconsistent with the *data* in the meter, the *TMA* shall inform all affected *Participants* and corrections shall be made to the official *Metering data*.

10. Access to *Metering data*

(1) Metering *data* shall be accessed through a central database that shall store all *customer* information.

(2) The *TMA* shall control access to all *Metering Installations.*

(3) No electronic access to the meters shall be granted to the *customer* or any other *Party* unless special permission has been granted by the Authority.

(4) Schedules for accessing *Metering data* from the central database shall be administered by the *TMA* in line with NRS 057-4 section 4.2.3.

(5) All *Security* requirements for *Metering data* shall be as specified in NRS 057.

11. Confidentiality

(1) Metering *data* and passwords are confidential *information* and shall be treated as such at all times.

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

6 of 8 Code Documents - The Information Exchange Code

Version 2

1st March 2017

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1. Introduction

(1) The Information Exchange Code defines the reciprocal obligations of parties with regard to the provision of information for the implementation of the *Grid Code*. The information requirements, as defined for the *service providers*, the Energy and Water Utilities Regulatory Authority *(*EWURA) and *customers,* are necessary to ensure non-discriminatory access to the *transmission system (TS)* and the safe, reliable provision of *transmission* services.

(2) The information requirements are divided into planning information, operational information and post-dispatch information.

(3) Information criteria specified in the Information Exchange Code are supplementary to the other codes within the *Grid Code*. In the event of inconsistencies between other codes and the Information Exchange Code with respect to information exchange, the requirements of the Information Exchange Code shall prevail.

2. Information exchange interface

(1) The *parties* shall identify the following for each type of information exchange:

- The name and contact details of the person(s) designated by the *information owner* to be responsible for provision of the information
- The names, contact details of, and the parties represented by persons requesting the information
- The purpose for which the information is required.

(2) The *parties* shall agree on appropriate procedures for the transfer of information.

3. System planning information

(1) *Customers* shall provide such information as *TANESCO* may reasonably request on a regular basis for the purposes of planning and developing the TS. *Customers* shall submit the information to TANESCO without unreasonable delay. Such information may be required so that TANESCO can plan and develop the TS, monitor current and future power system adequacy and performance, and fulfil its statutory or regulatory obligations.

(2) *Customers* shall submit to TANESCO and to all relevant *service providers* the information listed in Appendix 2 (for *distributors* or *end-use customers*) or Appendix 3 (for *generators*) and Appendix 9. *TANESCO* may request additional information reasonably required.

(3) Transmission shall provide the *generators* with information about equipment and systems installed in *HV yards* as defined in Appendix 10.

(4) *TANESCO* shall keep an updated technical database of the *IPS* for purposes of modelling and studying the behaviour of the *IPS*.

(5) *TANESCO* shall provide *customers* or potential *customers*, upon any reasonable request, with any relevant information that they require to properly plan and design their own networks/installations or comply with their other obligations in terms of the *Grid Code.*

(6) *TANESCO* shall make available all the relevant information related to network planning as described in the Network Code, section 7.

(7) *Customers* shall, upon request to upgrade an existing connection or when applying for a new connection, provide Transmission with information relating to the following:

Commissioning	Projected or target commissioning test date
Operating	Target operational or on-line date
Reliability of connection requested	Number of connecting circuits, e.g. one or two feeders, or firm/non-firm supply required (subject to Network and Tariff Code requirements)
Location map.	Upgrades: name of existing point of supply to be upgraded and supply voltage New connections: provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, co-ordinates of the point of connection to be specified
Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed point of supply, and where applicable, the transmission line route from the facility boundary to the point of supply, clearly marked
Electrical single-line diagram	Provide an electrical single-line diagram of the customer intake substation

(8) *TANESCO* may estimate any system planning information not provided by a *customer* as specified in Appendix 2 or 3. *TANESCO* shall take all reasonable steps to reach agreement with the *customer* on estimated data items. *TANESCO* shall indicate to the *customer* any data items that have been estimated. The obligation to ensure the correctness of data remains with the *customer*.

(9) *Generators* shall submit weekly to Transmission and the *System Operator* all the maintenance planning information detailed in Appendix 4 with regard to each *unit* at each *power station*.

(10) Transmission shall provide the *generators* with a monthly rolling maintenance schedule for all planned work in *HV yards* for a period of one year in advance. Log books on all vessels under pressure for receivers installed in *HV yards* shall be made available on request from the *generator*.

4. Operational information

4.1 Pre-commissioning studies

(1) *Customers* shall meet all system planning information requirements before the commissioning test date. (This will include confirming any estimated values assumed for planning purposes or, where practical, replacing them with validated actual values and with updated estimates for the future.)

(2) The *System Operator* shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified plant to the TS, using data supplied by *customers* in accordance with section 3, to verify that all control systems are correctly tuned and planning criteria have been satisfied.

(3) The *System Operator* may request adjustments prior to commissioning should tuning adjustments be found to be necessary. The asset owner shall ensure that all system planning information records are maintained for reference for the duration of the operational life of the plant. Information shall be made available within a reasonable time on request from the *System Operator* upon notification of such a request.

4.2 Commissioning and notification

(1) All *participants* shall ensure that exciter, turbine governor, *FACTS* and *HVDC* control system settings are implemented and are as finally recorded by the *System Operator* prior to commissioning.

(2) *Participants* shall give the *System Operator* notice, as defined in the System Operation Code, of the time at which the commissioning tests will be carried out. The *System Operator* and the *participant* shall agree on the timeout provision of operational data items as per Appendix 5.

(3) Records of commissioning shall be maintained for reference by the asset owner for the operational life of the plant and shall be made available, within a reasonable time, to the *System Operator* upon notification of such request.

(4) The asset owner shall communicate changes made during an outage to commissioned equipment, to the *System Operator and Transmission*, before the equipment is returned to service. *TANESCO* shall keep commissioning records of operational data as per Appendix 5, for the operational life of the plant connected to the TS.

4.3 General data acquisition information requirements

(1) Measurements and indications to be supplied by *customers* and *Transmission* to the *System Operator* shall include the formats defined in Appendix 5. Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information, such participant shall report and restore or correct the signals and/or indications as soon as reasonable.

(2) The *System Operator* shall notify the *participant*, where the *System Operator*, acting reasonably and in consultation with the *customer*, determines that additional measurements and/or indications in relation to a *participant's* plant and equipment are needed to meet a TS requirement. The costs related to the participant's modifications for the additional measurements and/or indications shall be for the account of the providing *participant*.

(3) On receipt of such notification from the *System Operator* the *participant* shall promptly ensure that such measurements and/or indications are made available at the *unit's communications Gateway equipment*.

(4) The data formats to be used and the fields of information to be supplied to the *System Operator* by the various *participants* are defined in Appendix 5.

(5) Transmission shall provide periodic feedback to customers regarding the status of equipment and systems installed in *the substations where they are connected to the TS*. The feedback shall include results from tests, condition monitoring, inspections, audits, failure trends and calibration. The frequency of the feedback shall be determined in the operating agreement, but will not exceed one year.

(6) Plant status reports provided by Transmission will also include contingency plans where applicable.

(7) The *System Operator* needs to inform *customers* where in the network out-of-step relays are installed, and how the relays are expected to operate. Furthermore, the characteristics of such an islanded network shall be provided, based on the most probable local network configuration at such a time.

(8) The cost of the installation of the data terminal equipment will be paid for by the *participant*.

(9) The *participant* shall decide on the location of the data terminal equipment (DTE).

(10) The *participant* will be responsible for the maintenance of communications links between the generating plant *Gateway* and the data terminal equipment.

(11) The *System Operator* shall be responsible for the maintenance, upkeep and communications charges of the DTE.

4.4 *Unit* scheduling

(1) The *System Operator* shall provide the data defined in Appendix 6 to relevant *Participants*.

4.4.1 Schedules

(1) The *System Operator* shall provide the relevant *Participants* with the next day's twenty-four (24) hours day-ahead energy schedule not later than 21h40 each day. The energy schedule shall be made available hourly on the day, 10 minutes before each hour. The *System Operator* shall import the energy schedule hourly, at five (5) minutes to the hour, for dispatch.

(2) The *System Operator* shall provide the relevant *Participants* with the daily twenty-four (24) hours day-ahead *ancillary service* schedule before 21h40 each day. The *ancillary service* schedule shall be made available hourly thereafter to ensure the transfer of a new schedule owing to a reschedule by the *System Operator*. The *System Operator* shall import the *ancillary service* schedule hourly, at five (5) minutes to the hour, for dispatch.

(3) All information exchange requirements for *ancillary services* that are contracted annually shall be included in the contract between the *parties*.

4.4.2 File transfers

(1) The format of the file used for data transfer through file transfers shall be decided by the *System Operator*. The data shall be made available in a common, electronically protected directory.

File	Description	Trigger event	Frequency
Dispatch schedule	The combined 24-hour day-ahead energy and *ancillary services* schedules. Hourly day-ahead energy and other schedules that identify the unit with the next 24 hourly values for it.	Generation dispatch schedule	Daily

4.5 Inter *control centre* communication

(1) *Customers* shall ensure that their *control centres* provide the *System Operator* with network information that is considered reasonable for the security and integrity of the TS on request. The *System Operator* shall communicate network information as requested to the *customer control centres*, as required for safe and reliable operation. The information exchange between *control centres* shall be electronic and/or paper-based, and within the time frame agreed upon between the participants.

(2) The *participants* shall optimise redundant control centre facilities where required for the safe operation and control of the TS.

4.6 Communication facilities requirements

(1) The minimum communication facilities for voice and data that are to be installed and maintained between the *System Operator* and *participants* shall comply with the applicable *IEC* standards for *SCADA* and communications equipment.

(2) The communication facilities standards shall be set and documented by the *System Operator*, acting reasonably, in advance of design. Any changes to communication facility standards impacting on customer equipment shall be designed in consultation with *customers* and shall be informed by a reasonable business motivation.

4.6.1 Telecontrol

(1) The *participant's* plant shall support data acquisition to and from the plant *Gateway*. The *System Operator* shall be able to monitor the state of the *IPS* via telemetry from the *Gateway* connected to the *participant's* plant.

(2) The signals and indications required by the *System Operator* are defined in Appendix 5, together with such other information as the *System Operator* may from time to time reasonably require by notice to the *participant*.

(3) *Participants* shall interface via the standard digital interfaces, as specified by the *System Operator*. Interface cabinets shall be installed in the *participant's* plant and equipment room if required. The provision and maintenance of the wiring and signalling from the *participant's* plant and equipment to the interface cable shall be the responsibility of the *participant*.

(4) *Participants* shall comply with such telecontrol requirements as may be applicable to the primary *control centre* and, as reasonably required, to the emergency *control centre* of the *System Operator*. Any changes to telecontrol requirements impacting on *customer* equipment shall be designed in consultation with *customers* and shall be informed by a reasonable business motivation.

4.6.2 Telephone/facsimile

(1) Each *participant* shall be responsible for the provision and maintenance of no fewer than one telephone and one facsimile unit on separate lines that shall be reserved for operational purposes only, and shall be continuously attended to and answered without undue delay.

(2) The *System Operator* shall use a voice recorder for historical recording of all operational voice communication with participants. These records shall be available for at least three (3) months. The *System Operator* shall make the voice records of an identified incident in dispute available within a reasonable time period after such a request from a participant and/or the Authority.

4.6.3 Electronic mail

(1) The *participants* shall provide the *System Operator* with the electronic mailing address of the contact person as defined in this Information Exchange Code and vice versa. The provider of this service shall be selected to meet the real-time operational requirements of the *System Operator*

4.7 SCADA and communication infrastructure at *points of supply*

4.7.1 Access and security

(1) The *System Operator* shall agree with *participants* the procedures governing security and access to the *participants*' *SCADA*, computer and communications equipment. The procedures shall allow for adequate access to the equipment and information by the *System Operator* or its nominated representative for purposes of maintenance, repair, testing and the taking of readings.

(2) Each *participant* shall designate a person with delegated authority to perform the duties of *information owner* in respect of the granting of access to information covered in this code to third parties, and shall disclose that person's name and contact details to the Authority. A *party* may, at its sole discretion, designate more than one person to perform these duties.

4.7.2 Time standards

(1) All information exchange shall be *GPS* satellite time signal referenced. The *System Operator* shall ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence.

4.7.3 Integrity of installation

(1) Where the electrical plant does not belong to TANESCO, TANESCO shall enter into an agreement with the *customer* for the provision of reliable and secure facilities for the housing and operation of *TANESCO* equipment. This includes access to, at no charge to TANESCO, an uninterruptible power supply with an eight-hour standby capacity.

4.8 Data storage and archiving

(1) The obligation for data storage and archiving shall lie with the *information owner*.

(2) The systems that store the data and/or information to be used by the *parties* shall be of their own choice and for their own cost.

(3) All the systems must be able to be audited by the Authority. The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the *parties*.

(4) The *information owner* shall store the information in a manner that will allow for such information to be retrieved on request and shall ensure that the contents remain unaltered from its original state. The information shall be retained for a period of at least five (5) years (unless otherwise specified in the *Grid Code*) commencing from the date the information was created.

(5) *Parties* shall ensure reasonable security against unauthorised access, use and loss of information (i.e. have a backup strategy) for the systems that contain the information.

(6) *Parties* shall store *outage* planning information as defined in clause 3(9) and clause 3(10) electronically for at least five (5) years. Other system planning information as defined in section 3 shall be retained for the life of the plant or equipment concerned, whichever is the longer.

(7) The *System Operator* shall archive operational information, in a historical repository sized for three (3) years' data. This data includes

- *GS* time-tagged status information, change of state alarms, and event messages
- hourly scheduling and energy accounting information
- operator entered data and actions.

(8) An audit trail of all changes made to archived data should be maintained. This audit trail shall identify every change made, and the time and date of the change. The audit trail shall include both before and after values of all content and structure changes.

5. Post-dispatch information

5.1 Dispatch information

(1) The *System Operator* and TANESCO shall provide participants, with the information specified in the Scheduling and Dispatch Code.

5.1.1 Generation settlement

(1) The *Marketing Group* shall request all data required for settlement of the energy from *System Operator*. The System Operator shall make this information available, within an agreed time period. Should this information be classified as confidential, both parties shall treat it accordingly.

5.1.2 *Ancillary services* settlement

(1) The ***Marketing Group*** shall request all data required for settlement of the *ancillary services* from TANESCO. The *TANESCO* shall make this information available, within an agreed time period. Should this information be classified as confidential, both parties shall treat it accordingly.

5.1.3 Additional *unit* post dispatch information

(1) The *System Operator* shall provide operational information regarding *unit* dispatch and overall dispatch performance as specified in Appendix 7.

5.1.4 Hourly demand *metering* data

(1) The *TANESCO* shall provide participants with hourly-metered data pertaining to their installations.

5.2 File transfers

(1) The format of the files used for data transfer shall be negotiated and defined by the supplier and receiver of the information. The file transfer media shall be negotiated and defined by both *parties* involved.

(2) The *parties* shall keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures.

File	Description	Trigger Event	Frequency
AGC pulses	The total pulses sent to a unit by the AGC system to move the set-point up or down	Ongoing, file created at end of hour	Hourly
Power Pool Performance and settlement data	As required by relevant Power Pool Rules	Ongoing, file appended at end of hour	Daily
System near real-time data	Historic near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Unit near real-time data	Historic near real-time unit data files on readings as required for post dispatch	Communication failure	To be agreed

5.3 Performance data

5.3.1 *Generator* performance data

(1) *Generators* shall provide the *System Operator* monthly with performance indicators in relation to each *unit* at each *power station* in respect of availability, reliability, etc., as detailed in Appendix 8.

(2) *Generators* shall report significant events, such as catastrophic failures, to the Authority within one (1) week of occurrence of such event.

5.3.2 *Distributor* and *end-use customer* performance

(1) The performance measurement of all *distributors* and *end-use customers* shall be supplied to Transmission in accordance with the operating agreement requirements as defined in the Network Code, section 3.2.

(2) Distributors shall report periodic testing of under-frequency load shedding relays in the following format:

Distributor: Date: Substation: Fed from *transmission substation* (directly or indirectly):				
	Activating frequency		Timer setting	
	Required	As tested	Required	As tested
Stage 1				
Stage 2				
Stage 3				
	Feeders selected (required)		Feeders selected (as tested)	
Stage 1				
Stage 2				
Stage 3				

5.3.3 *TANESCO* and *Transmission* performance

(1) *TANESCO* shall make the following TS performance indicators available monthly to the Authority and *customers:*

Indicator	**Month**	**Year to date**	**12 MMI**	**Unit**
System minutes lost				minutes
No. of interruptions				
No. of statutory voltage transgressions				
Mandatory under-*frequency* load shedding				
Customer voluntary load shedding				
GS losses				%

(2) Transmission shall provide *customers* with all performance indicators at each *point of supply* in accordance with the Network Code, section 3.2.

5.3.4 System operational performance information

(1) The following *IPS* operational information shall be *published* by the *System Operator* to all *participants*:

Daily:

- The hourly actual demands of the previous day (*MW*)
- The reserve amounts over the morning and evening peaks of the previous day (*MW*)

Monthly:

- MW generated, Imports, exports, available for distribution/sale and transmission losses.
- Generation Plant availability
- Regulating reserve Hours deficit over total hours
- No of frequency excursions > 50.05 or <49.5
- For each abnormal network condition the action taken by the SO to restore normal operations.
- Network constraints (details to be defined by the Authority)

Annually:

- Annual peak (MW), date and hour
- Annual minimum (MW), date and hour

(2) Transmission shall make available all information collected via recorders installed at substations, to the *System Operator* for analyses. The *System Operator* shall make this information available to affected *customers* on request.

6. Confidentiality of information

(1) Information exchanged between *parties* governed by this code shall not be confidential, unless otherwise stated.

(2) Confidential information shall not be transferred to a third party without the written consent of the *information owner*. *Parties* shall observe the proprietary rights of third parties for the purposes of this code. Access to confidential information within the organisations of *parties* shall be provided as reasonably required.

(3) *Parties* receiving information shall use the information only for the purpose for which it was supplied.

(4) The *information owner* may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, and is provided. A pro forma agreement is included in Appendix 1.

(5) The *parties* shall take all reasonable measures to control unauthorised access to confidential information and to ensure secure information exchange. *Parties* shall report any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak, and shall provide the *information owner* with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the *information owner).*

APPENDIX 1: Information confidentiality

SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES

CONFIDENTIALITY AGREEMENT

BETWEEN

………………………………….

(HEREINAFTER REFERRED TO AS THE INFORMATION OWNER)

AND

……………………………………………….

(HEREINAFTER REFERRED TO AS THE RECIPIENT)

IN RESPECT OF INFORMATION SUPPLIED TO PERFORM THE FOLLOWING WORK:

……

(HEREINAFTER REFERRED TO AS THE WORK)

ON BEHALF OF

……………………………………………………………………………………………………….

(HEREINAFTER REFERRED TO AS THE CLIENT).

1. The Recipient agrees to treat all information (hereinafter referred to as the Information) received from the Information Owner, whether in hard copy or electronic format, as strictly confidential.

2. The Recipient agrees to disclose the Information only to persons who are in his permanent employ, and who require access to the Information to perform their duties in respect of the Work on behalf of the Client.

3. Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, shall enter into separate Confidentiality Agreements with the Information Owner prior to receiving the Information.

4. The Recipient undertakes to use the Information only to perform the Work on behalf of the Client, and for no other purpose whatsoever.

5. On completion of the Work, the Recipient shall at his expense return to the Information Owner all hard copy material and electronic media containing the Information supplied to him by the Information Owner. The Recipient shall furthermore ensure that all duplicate copies of the Information in his or his employees' possession (electronic as well as hard copy format) are destroyed.

6. The Recipient shall take all reasonable measures to protect the security and integrity of the Information.

7. If requested to do so by the Information Owner, the Recipient shall forthwith at his expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him by the Information Owner. The Recipient shall furthermore ensure that all duplicate

copies of the Information in his or his employees' possession (electronic as well as hard copy format) are destroyed.

8. The Recipient shall report any leak of the Information, howsoever caused, to the Information Owner as soon as practicable after he/she becomes aware of the leak, and shall provide the Information Owner with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the Information Owner).

Signed at ………………………………………………… on this the ………… day of ……………………………. by (full name) ……………………………………….in his/her capacity as ………………………………………. on behalf of ………………………………………, the Information Owner

………………………………………

Signed at ………………………………………………… on this the ………… day of ……………………………. by (full name) ……………………………………….in his/her capacity as ………………………………………. on behalf of ………………………………………, the Recipient

………………………………………

APPENDIX 2: Distributor and end-use customer data

Unless otherwise indicated, the following information shall be supplied to TANESCO prior to connection and then updated as and when changes occur.

(a) Demand and network data

Connection capacity	Connection capacity required (MW)
Measured and forecast data (annually)	For each point of supply, the information required is as follows: • A 10-year demand forecast (see Appendix 9) • A description setting out the basis for the forecast • The season of peak demand • Quantification of the estimated impact of embedded generation (see Appendix 9)
User network data	• Electrical single-line diagram of user network to a level of detail to be agreed with the service providers, including the electrical characteristics of circuits and equipment (R, X, B, R0, X0, B0, continuous ratings) • Contribution from customer network to a three-phase short-circuit at point of connection • Information pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVC's, etc., to the point of supply for the purposes of conducting harmonic resonance studies. • Electrical characteristics of all circuits and equipment at a voltage lower than secondary voltage levels of the customer connected the TS that may form a closed tie between two connection points on the TS
Standby supply data (annually)	The following information is required for each distributor and end-use customer that can take supply from more than one supply point: • Source of standby supply (alternative supply point(s)) • Standby capacity required (MW)
General information	For each new connection from a distributor or end-use customer, the following information is required: • Number and type of switch bays required • Load build-up curve (in the case of new end-user plant) • Supply date (start of load build-up)

	• Temporary construction supply requirements • Load type (e.g. arc furnaces, rectifiers, rolling mills, residential, commercial, etc.) • Annual load factor • Power factor (including details of harmonic filters and power factor correction equipment) • Special requirements (e.g. quality of supply) • Other information reasonably required by the service providers to provide the customer with an appropriate supply (e.g. pollution emission levels for insulation design)
Disturbing loads	Description of any load on the power system that could adversely affect the System Operator target conditions for power quality and the variation in the power quality that can be expected at the point connected to the TS. (The areas of concern here are, firstly, motors with starting currents referred back to the nominal voltage at the point of supply exceeding 5% of the fault level at the point of supply; and secondly, arc furnaces likely to produce flicker levels at the point of supply in excess of the limits specified in NRS048. The size limit for arc furnaces is subject to local conditions in respect of fault levels at the point of supply and background flicker produced by other arc furnaces and other equipment that will produce harmonics and/or negative and zero sequence current components, such as large AC/DC rectification installations.)

(b) Transmission system connected transformer data

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		A
Transformer rating		MVA
Transformer tertiary rating		MVA
Transformer nominal LV voltage		kV
Transformer nominal tertiary voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		HV/MV/LV/None

		(Delete what is not applicable)
Transformer ratio at all transformer taps		
Transformer impedance (resistance R and reactance X) at all taps	R+jX	% on rating MVA
• For three-winding transformers, where there are external connections to all three windings, the impedance (resistance R and reactance X) between each pair of windings is required, measured with the third set of terminals open-circuit	Z_{HVMV}, Z_{HVLV}, & Z_{MVLV}	% on rating MVA % on rating MVA % on rating MVA
Transformer zero sequence impedances at nominal tap		
• Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals open-circuit	$Z_{HT\,0}$	Ohm
• Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals short-circuited to the neutral	$Z_{HL\,0}$	Ohm
• Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals open-circuit	$Z_{LT\,0}$	Ohm
• Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals short-circuited to the neutral	$Z_{LH\,0}$	Ohm
• Zero phase sequence leakage impedance measured between the HV terminals (shorted) and the LV terminals (shorted), with the Delta winding closed	$Z_{L\,0}$	Ohm
Earthing arrangement, including LV neutral earthing resistance and reactance core construction (number of limbs, shell or core type)		
Open-circuit characteristic		Graph

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on reasonable request.

(c) Shunt capacitor or reactor data requirements

For each shunt capacitor or reactor or power factor correction equipment or harmonic filters with a rating in excess of 1 MVAr connected to or capable of being connected to a customer network, the customer shall inform TANESCO and, if required, shall provide TANESCO with the specific shunt capacitor or reactor data as well as network details necessary to perform primarily harmonic resonance studies. The customer shall inform TANESCO of his intention to extend or modify this equipment.

If any participant finds that a capacitor bank of 1 MVAr or less is likely to cause harmonic resonance problems on the TS, he shall inform TANESCO. The 1 MVAr minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and TANESCO shall inform the affected participants of this fact and request the additional data. If the affected network is modified or reinforced to the extent that capacitor banks of 1 MVAr or less no longer cause harmonic resonance problems on the TS, TANESCO shall inform the affected participants that information reporting requirements have returned to normal.

Any party to this code investigating a complaint about harmonic distortion shall have the right to request such additional information (including, but not restricted to, data from harmonic distortion measuring devices) from parties in the vicinity of the source of the complaint as may reasonably be required to complete the investigation.

Shunt capacitor or reactor rating	Rating (MVAr)
Reactor/capacitor/harmonic filter	(delete what is not applicable)
Location (station name)	
Voltage rating	kV
Resistance/reactance/susceptance of all components of the capacitor or reactor bank	Ohm values or p.u. on 100MVA base (specify)
Fixed or switched	
If switched	Control details (manual, time, load, voltage, etc.)
If automatic control	Details of settings. If under FACTS device control (e.g. SVC), which device?

(d) Series capacitor or reactor data requirements

Series capacitors are installed in long transmission lines to increase load transfer capability.

Series reactors are installed to limit fault levels, or to balance load sharing between circuits operated in parallel that would otherwise not share load equitably, or to balance load sharing on an interconnected network.

Reactor/capacitor	(Delete what is not applicable)
Location (specify substation bay where applicable)	
Voltage rating	kV
Impedance rating	Ohm or MVAr
Current rating (continuous and emergency, maximum times for emergency ratings)	Continuous: A Hours A Hours A

	Hours	A

Note: if a series capacitor or reactor is located in a dedicated reactor or capacitor station (i.e. a substation built to hold only the series reactor or capacitor), the lines or cables linking it to each remote end substation must be specified as separate circuits under line or cable data.

(e) FACTS devices and HVDC data

FACTS devices

FACTS devices enable system parameters (voltage, current, power flow) to be accurately controlled in real time. Because of their cost, they are generally used only if cheaper, more conventional, solutions cannot deliver the required functionality.

Applications requiring rapid control capability include the following:

- Voltage regulation following loss of a system component, generation, large load, or HVDC link disturbance
- Arc furnace voltage flicker mitigation
- Negative phase sequence voltage compensation
- SSR (sub-synchronous resonance) damping
- Machine transient stability enhancement
- System load transfer capability enhancement
- Load sharing control in interconnected, deregulated, networks
- Master power controller for HVDC schemes

The most commonly used FACTS device is the SVC (static Var compensator). Other FACTS devices made possible by advances in power electronics and control systems include STATCOM (static compensator), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power flow controller). The common factor is rapid control capability.

Because FACTS devices are purpose-designed for their specific applications, the following data is required:

Name	Station, HV voltage, device number
Type	(SVC, STATCOM, TCSC, etc.)
Configuration: provide a single line diagram showing all HV components and their MVA/MVAr and voltage ratings, with all controlled components identified as such	

Control system: provide a block diagram of the control system suitable for dynamics modelling	
Primary control mode	Voltage control, arc furnace flicker mitigation, negative phase sequence voltage control, etc.

Customers are required to perform, or cause to be performed, harmonic studies to ensure that their installation does not excite harmonic resonance, and that harmonic distortion levels at the PCC with the TS do not exceed the limits specified in NRS048.

HVDC

Strictly speaking, HVDC is a form of FACTS device because of the rapid control capabilities. However, HVDC is treated separately because its primary function is the transmission of real power.

HVDC is used to connect two systems that are not necessarily interconnected via the AC network (and thus in synchronism), or even at the same nominal frequency.

Customers wishing to connect HVDC systems to the TS shall supply a single line diagram showing all HV plant (including valve bridges) forming part of the HVDC system, plus additional HV plant required for its proper operation, e.g. harmonic filters, synchronous condensers, FACTS devices, etc. Customers and TANESCO shall co-operate in performing, or causing to be performed, studies to determine network strengthening requirements needed to accommodate the HVDC system without violating the planning criteria specified in the Network Code. In addition, customers shall thereafter perform, or cause to be performed, studies to demonstrate that the proposed HVDC system does not contravene the QOS parameters specified in NRS048, and where applicable shall specify what additional HV plant will be required to ensure compliance with NRS048.

(f) Information on customer networks

If a customer will have two or more points of supply from the TS, including the one applied for, the customer shall specify the amount of load to be transferred from existing points of supply to the new one under normal conditions as well as under contingencies. The same requirement applies to any embedded generators within the customer’s network, since they affect fault levels as well as net load on the system.

The customer shall also specify whether he intends to interconnect two or more transmission points of supply via his network. In such circumstances the customer shall provide detailed information on the lines and cables used.

Where a circuit consists of two or more segments of different characteristics (different overhead line tower and/or conductor bundle types and/or underground cable types), each section shall be specified separately.

Overhead line data

	Units
Line description	Name (“from” busbar, “to” busbar, circuit number and, where applicable, line section number numbered from the “from” busbar end)

Line voltage (specify separately for dual voltage multi-circuit lines)	kV
Single/double/multiple circuit	
Standard suspension tower information (to confirm impedance): supply copy of tower drawing, or sketch drawing showing co-ordinates of shield wire and phase conductor bundle attachment points relative to tower centre line and ground level at nominal tower height	
Phase sub-conductor type (per circuit)	
Number of sub-conductors per phase conductor bundle	
Sub-conductor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)	mm
Number of earth wires	
Earthwire description	
Line length	Km
Conductor parameters (R, X, B, R0, X0, B0)	Ohm values or p.u. on 100MVA base (specify)
Conductor normal and emergency ratings	Ampere or 3-phase MVA at nominal voltage

Cable data

Cable description	Name ("from" busbar, "to" busbar, circuit number, and where applicable, line section number numbered from the "from" busbar end)
Voltage rating	kV
Type (copper/aluminium)	(Delete what is not applicable)
Size	mm^2
Impedance (R, X, B, R_0,X_0,B_0)	Ohms or p.u. on 100MVA base (specify)
Length	Km
Continuous and (where applicable) emergency current rating and time limit	Amp or MVA at nominal voltage (specify), hours maximum at emergency rating

APPENDIX 3: Generator planning data

Unless otherwise indicated, the following information shall be provided to TANESCO prior to connection and then updated as and when changes occur.

(a) Power station data

Generator name	
Power station name	
Number of units	
Primary fuel type/prime mover	For example, gas, hydro, fossil or nuclear
Secondary fuel type	For example, oil
Capacity requirement	Generation sent-out connection capacity required (MW)
"Restart after station blackout" capacity	Provide a document containing the following: Start-up time for the first unit (time from restart initiation to synchronise) and each of the following units assuming that restarting of units will be staggered
Black starting capacity	A document stating the number of units that can be black started at the same time, preparation time for the first unit black starting, restarting time for the first unit, and restarting time for the rest of the units
Partial load rejection capability	A description of the amount of load the unit can automatically govern back, without any restrictions, as a function of the load at the point of governing initiation
Multiple unit tripping (MUT) Risks	A document outlining all systems common to more than one unit that is likely to cause a MUT; discuss the measures taken to reduce the risk of MUT

(b) Unit data

Unit number	
Capacity	Unit capacity (MW)

Description	Units
Maximum continuous generation capacity:	MW
Maximum continuous sent out capacity	MW

Unit auxiliary active load	MW
Unit auxiliary reactive load	MVAr
Maximum short term output	MW
Minimum continuous generating capacity	MW
Minimum continuous sent out capacity	MW
Generator rating	MVA
Maximum lagging power factor	-
Maximum leading power factor	-
Governor droop	
Forbidden loading zones	MW
Terminal voltage adjustment range	KV
Short-circuit ratio	
Rated stator current	Amp
Time to synchronise from warm	Hour
Time to synchronise from cold	Hour
Minimum up-time	Hour
Minimum down-time	Hour
Loading rate	MW/min
Deloading rate	MW/min
Can the generator start on each fuel?	
Ability to change fuels on-load	
Available modes (lean burn etc.)	
Time to change modes on-load	
Control range for secondary frequency regulation operation	MW
Partial load rejection capability	% MW name plate rating
Minimum time unit operates in island mode	Hour
Maximum time unit operates in island mode	Hour

Description	Data

Capability chart showing full range of operating capability of the generator, including thermal and excitation limits	Diagram
Systems that are common and can cause a multiple unit trip	Description
Open-circuit magnetisation curves	Graph
Short-circuit characteristic	Graph
Zero power factor curve	Graph
V curves	Diagram

Documents	Description
Protection settings document	A document agreed and signed by the System Operator containing the following: • A section defining the base values and per unit values to be used • A single line diagram showing all the protection functions and sources of current and voltage signals • Protection tripping diagram(s) showing all the protection functions and associated tripping logic and tripping functions • A detailed description of setting calculation for each protection setting relevant to the TS connection, discussion on protection function stability calculations, and detailed dial settings on the protection relay in order to achieve the required setting • A section containing a summary of all protection settings on a per unit basis • A section containing a summary for each of the protection relay dial settings/programming details • An annex containing plant information data (e.g. OEM data) on which the settings are based • An annex containing OEM information sheets or documents describing how the protection relays function
Excitation setting document	A document agreed and signed by the System Operator containing the following: • A section defining the base values and per unit values to be used • A single line diagram showing all the excitation system functions and all the related protection tripping functions • An excitation system transfer function block diagram in accordance with IEEE or IEC standard models • A detailed description of setting calculation for each of the excitation system functions, discussion on function stability calculations, and detailed dial settings on the excitation system in order to achieve the required setting • A section containing a summary of all settings on a per unit basis • A section containing a summary for each of the excitation system dial settings/programming details. • An annex containing plant information data (e.g. OEM data) on which the settings are based • An annex containing OEM information sheets or documents describing the performance of the overall excitation system and each excitation function for which a setting is derived

Unit model document	The document shall include models of the turbine, boiler, engine, reactor, penstock and the relevant controls, which together can be used by the SO to simulate the dynamic performance of the unit, specifically load ramping and frequency support within the normal operating range of the unit. The generator may obtain guidance about the modelling requirements from IEEE documentation or any other standard agreed to by the SO. The document, to be agreed and signed by the SO, will contain the following: • The operating parameters on which the model is based, with the per unit and corresponding base values • A governor (turbine controller) single-line diagram showing all the governor system functions • A model for the dynamic response of the unit in block diagram form, in accordance with IEEE standard models or any other model standard agreed to by the SO • A detailed list of gains, constants and parameters, with explanations of the derivations for each of the modeled functions of the governor system model • Plant test data from which the model was derived

(c) Reserve capability

The generator shall provide the System Operator with the reserve capability of each unit at each power station. The reserve capability shall be indicated as per each reserve category: spinning reserve, standby reserve and regulation reserve.

(d) Unit parameters

	Symbol	Units
Direct axis synchronous reactance	X_d	% on rating
Direct axis transient reactance saturated	$X'_{d_{sat}}$	% on rating
Direct axis transient reactance unsaturated	$X'_{d_{unsat}}$	% on rating
Sub-transient reactance unsaturated	$X''_d = X''_q$	% on rating
Quad axis synchronous reactance	X_q	% on rating
Quad axis transient reactance unsaturated	$X'_{q_{unsat}}$	% on rating

Negative phase sequence synchronous reactance	X_2	% on rating
Zero phase sequence reactance	X_{0q}	% on rating
Turbine generator inertia constant for entire rotating mass	H	MW s/MVA
Stator resistance	Ra	% on rating
Stator leakage reactance	X_L	% on rating
Poiter reactance	X_P	% on rating
Generator time constants:		
• Direct axis open-circuit transient	Tdo’	sec
• Direct axis open-circuit sub-transient	Tdo’’	sec
• Quad axis open-circuit transient	Tqo’	sec
• Quad axis open-circuit sub-transient	Tqo’’	sec
• Direct axis short-circuit transient	Td’	sec
• Direct axis short-circuit sub-transient	Td’’	sec
• Quad axis short-circuit transient	Tq’	sec
• Quad axis short-circuit sub-transient	Tq’’	sec
Speed damping	D	
Saturation ratio at 1 pu terminal voltage	S(1.0)	
Saturation ratio at 1.2 pu terminal voltage	S(1.2)	

(e) Excitation system

The generator shall fill in the following parameters or supply a Laplace domain control block diagram in accordance with IEEE or IEC standard excitation models (or as otherwise agreed with the System Operator) completely specifying all time constants and gains to fully explain the transfer function from the compensator or unit terminal voltage and field current to unit field voltage. Customers shall perform, or cause to be performed, small signal dynamic studies to ensure that the proposed excitation system and turbine governor do not cause dynamic instability. The criteria for such dynamic instability shall be supplied by the System Operator. Where applicable, a PSS (power system stabiliser) shall be included in the excitation system to ensure proper tuning of the excitation system for stability purposes.

	Symbol	Units

Excitation system type (AC or DC)		Text
Excitation feeding arrangement (solid or shunt)		Text
Excitation system filter time constant	Tr	Sec
Excitation system lead time constant	Tc	Sec
Excitation system lag time constant	Tb	Sec
Excitation system controller gain	Ka	
Excitation system controller lag time constant	Ta	Sec
Excitation system maximum controller output	Vmax	p.u.
Excitation system minimum controller output	Vmin	p.u.
Excitation system regulation factor	Kc	
Excitation system rate feedback gain	Kf	
Excitation system rate feedback time constant	Tf	Sec

(f) Control devices and protection relays

The generator should supply any additional Laplace domain control diagrams for any outstanding control devices (including power system stabilisers) or special protection relays in the unit that automatically impinge on its operating characteristics within 30 seconds following a system disturbance and that have a minimum time constant of at least 0,02 seconds.

(g) Pumped storage

	Symbol	Units
Reservoir capacity		MWh pumping
Max pumping capacity		MW
Min pumping capacity		MW
Efficiency (generating/pumping ratio)		%

(h) Unit step-up transformer

	Symbol	Units
Number of windings		

Vector group		
Rated current of each winding		Amps
Transformer rating		MVA_{Trans}
Transformer nominal LV voltage		KV
Transformer nominal HV voltage		KV
Tapped winding		
Transformer ratio at all transformer taps		
Transformer impedance at all taps (for three winding transformers the HV/LV1, HV/LV2 and LV1/LV2 impedances together with associated bases shall be provided)		% on rating MVA_{Trans}
Transformer zero sequence impedance at nominal tap	Z_0	Ohm
Earthing arrangement, including neutral earthing resistance and reactance		
Core construction (number of limbs, shell or core type)		
Open-circuit characteristic		Graph

(i) Unit forecast data

The generator shall provide TANESCO with expected maintenance requirements, in weeks per annum, for each unit at a power station.

(l) Mothballing of generating plant:

Mothballing of generating plant is the withdrawal of plant from commercial service for six months or longer, with the intention of returning it to commercial service at a later date. Mothballing can have a profound impact on the operation and integrity of the TS. Customers wishing to mothball generating plant shall supply TANESCO with the following information:

Generator name	
Power station name	
Unit number	
Date withdrawn	Date unit is to be withdrawn from commercial service
Return to commercial service	Envisaged return to service date (recommissioning tests completed and unit available for commercial

	service)
Auxiliary power requirements	

(k) Return to service of mothballed generating plant:

Once the customer has decided to return mothballed generating plant to service, TANESCO requires the information specified for new connections.

(l) Decommissioning of generating plant:

Decommissioning of plant is the permanent withdrawal from service of generating plant. The TANESCO requires the following with a one-year notice period:

Generator name	
Power station name	
Unit number	
Date to be removed from commercial service	
Auxiliary supplies required for dismantling and demolition	kVA, point at which supply is require, duration

APPENDIX 4: Generator maintenance plan

a) The 52-weeks-ahead maintenance plan per week per generator shall be supplied weekly to the System Operator.

Generator:

DATE (week starting)				
WEEK NUMBER:	n	n+1	…	n+51

MAINTENANCE (MW)

WEEKEND OUTAGES	0	0	0	0
Power Station 1	0	0	0	0
Power Station 2	0	0	0	0
Power Station 3	0	0	0	0
Power Station n	0	0	0	0
TOTAL MAINTENANCE				
FUTURE KNOWN UNPLANNED:	0	0	0	0

MAJOR CHANGES SINCE LAST WEEK:

Notes:	
FUTURE KNOWN UNPLANNED:	a) b)

b) The annual maintenance/outage plan per generator, looking five years ahead, shall be supplied to the System Operator.

The format shall be as per the 52-weeks-ahead outage plan per week per generator**,** but extending for five years.

c) A monthly variance report, explaining the differences between the above two reports, shall be supplied to the System Operator.

Variance Report Template

Station and	MW	Start Date	Outage Completion Date				
Outage Code	Cap	Official	Official	Revised	Urg	Outage Description	Reason for Difference

APPENDIX 5: Operational data

This appendix specifies the data format to be used by the SCADA system for the mapping of *Gateway* data into the SCADA database. The database has a definition for each bay in the HV yard. Each bay definition specifies a different bay type, e.g. transformers, units, feeders, etc., and is accompanied by a picture showing the bay and all its associated devices as they would be indicated on the *system operator* operational one-line displays. In each instance, the picture defines the primary devices and is followed by the points belonging to each device.

Description of table column headings used in this section:

Device	01_State	10_State	Category	Type	Control

Device : Gives the name of the device and acts as a collector of all point information belonging to the device. The System Operator shall define the requirements where grouping is used.

Each binary status point can be mapped to one or two binary bits. In the case of a breaker or isolator, the state is reported via two bits. In the case of single-bit alarm points, only one bit is used to report the state of the indication.

In the following sections, the TYPE column indicates the number of bits used to report the state of the point in question. The column headings indicate two bits but for single-bit points ignore the left-hand 0 or 1 value in the headings "01-State" and "10-State".

1_state This is the **alarm** state of the point.

0_state This is the **normal** state of the point.

Double bit Where an indication uses two bits to report the state, the right-hand bit is used report that the state is OPEN and the left-hand bit to report the state when it is CLOSED. Thus an open condition will be "01" and a closed state will be "10".

It is thus illogical for a device to have a permanent value of either "00" or "11". However, if the device is in transit between "01" and "10" then a temporary value of "00" is possible. The SCADA system reports a state of "00" as "In transit", which will normally only be seen on slow-moving devices such as isolators.

Category Defines the category the point belongs to: Health, Main Protection, Back-up Protection or Information.

Classical alarm systems attempt to set priorities on alarm points. However, the priority of a point changes as the system changes, which means having a fixed priority is not useful. As an alternative, the approach used here is to assign the point to the area that is affected by the indication. In this case we have four areas, namely:

Health	All alarm indications that refer to the health of the primary or secondary plant are assigned to this category.

Main Protection	All protection activity that is triggered by the Main 1 protection circuits is assigned to this category.
Backup Protection	Where backup protection is installed, such as on transformers, or where Main 2 protection is used, these alarms are assigned to this category.
Information	Pure state change data such as the state of a breaker or isolator are assigned to this category. As such, no alarming is associated with these points – the data presented is pure information.

Type Indicates the type of point – single-bit, double-bit, analogue or binary change detection.

Control Indicates if there is a supervisory control associated with the point

A5.1 Generator

The generator shall install operational measurements to specification from the System Operator so as to provide continuous operational information for both real-time and recording purposes in relation to each unit at each power station in respect of the following:

Data Acquisition from *generator* to Gateway

Measurements of MW, MW set point and Mvar analog shall update the SCADA value from the source to the Gateway if the value changes by more than 0.5 MW or 0.5 Mvar. The maximum delay in this update shall be no longer than one second as shown in Figure 1 - Data collection time frame.

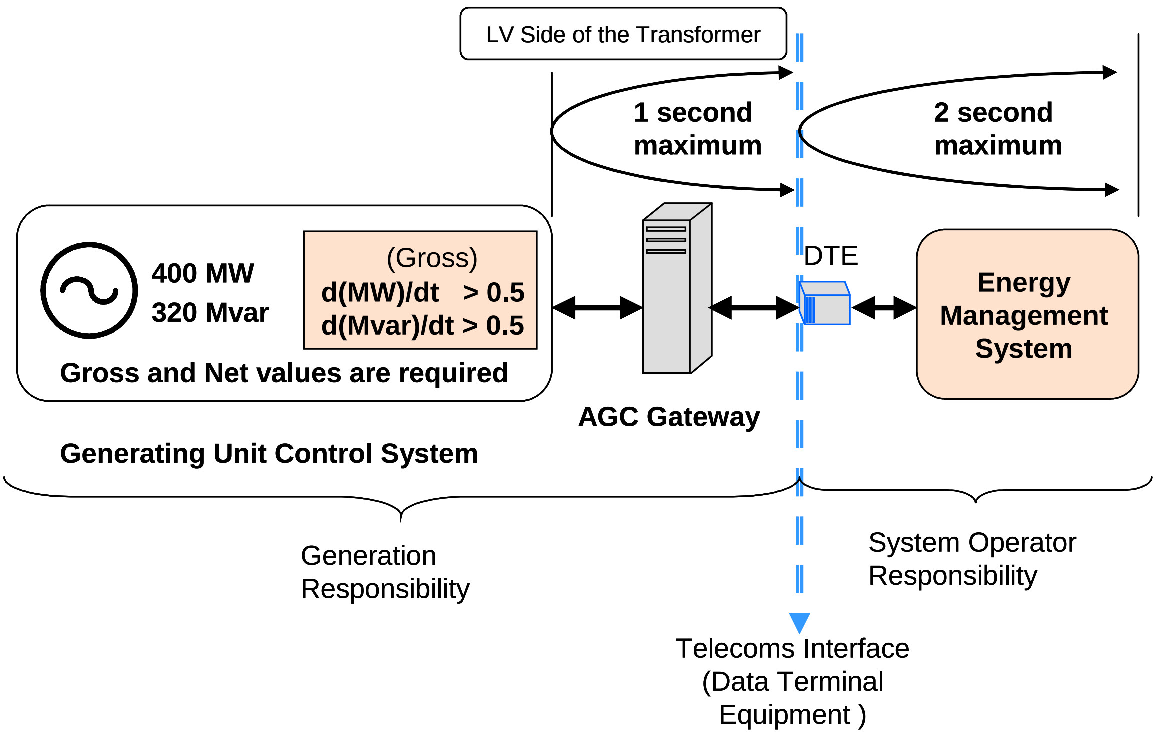


Figure 1 - Data collection time frame

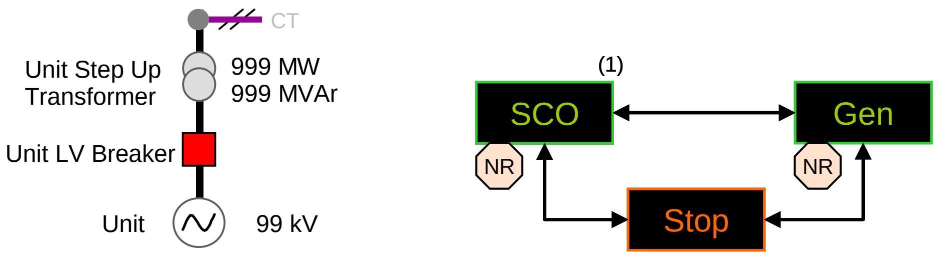
Data Acquisition

The *participant* is responsible for the provision of communications facilities between the plant and the data terminal equipment as shown in Figure 1. See section 4 above for additional clarity related to the *participant's* communication obligations.

The maximum delay for updating the Energy Management System shall be no longer than two seconds as shown in Figure 1.

The *generator* will provide the facility to set the jitter value of the measured data to a value between 1 and 5 bits to prevent the unnecessary messages being sent whilst maintaining the 0,5 MW or 0,5 Mvar accuracy required above. The *System Operator* will determine the exact number of bits required to be set for jitter tolerance for every installation.

(a) Gas turbines, gas engines and heavy fuel engines



[1]

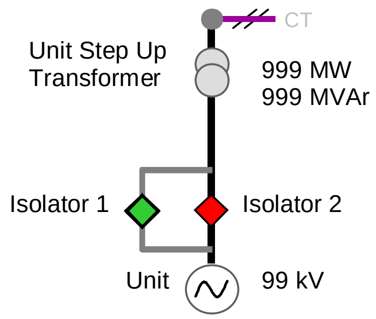
Unit Analogs			**Category**	**Type**	**Control**
Frequency			Info	Analog	
Gross MW			Info	Analog	
Gross Mvar			Info	Analog	
Net MW			Info	Analog	
Net Mvar			Info	Analog	
Rotor RPM			Info	Analog	
Stator kV			Info	Analog	

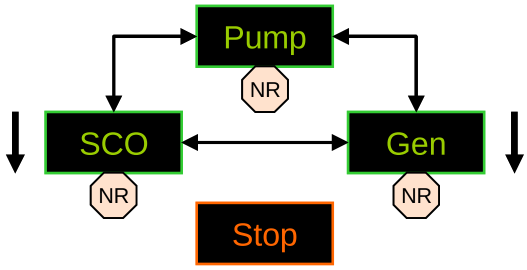
Unit Status Points	**01_State**	**10_State**	**Category**	**Type**	**Control**
Engine A	Ready	Not ready	Health	Single	

[1] Note that where modes or functions are not available, such as *SCO,* the associated signals are not required.

Engine B	Ready	Not ready	Health	Single	
GEN to SCO mode	Active	Off	Info	Single	True
SCO to GEN mode	Active	Off	Info	Single	True
Remote control	On	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	
GEN start not ready	Alarm	Normal	Health	Single	
Under-frequency start	Armed	Off	Health	Single	
Unit at Standstill	Yes	No	Info	Single	
Unit auto load to base	Yes	No	Info	Single	True
Unit auto load to minimum	Yes	No	Info	Single	True
Unit in GEN mode	Yes	No	Info	Single	
Unit in SCO mode	Yes	No	Info	Single	
Unit load rate	Fast	Slow	Info	Single	True
Unit to GEN mode	Yes	No	Info	Single	True
Unit to SCO mode	Yes	No	Info	Single	True
Unit to Standstill	Yes	No	Info	Single	True
Unit tripped and locked out	Alarm	Normal	Info	Single	
Unit under-frequency start	Initiate	No	Info	Single	
Unit islanded	Alarm	No	Health	Single	

(b) Hydro units





[2]

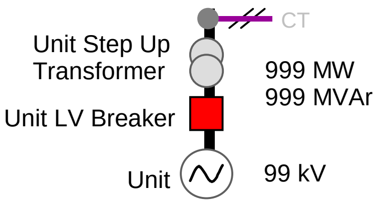
Unit Analogs			**Category**	**Type**	**Control**
Frequency			Info	Analog	
Gross MW			Info	Analog	
Gross Mvar			Info	Analog	
Net MW			Info	Analog	
Net Mvar			Info	Analog	
Stator kV			Info	Analog	
Rotor RPM			Info	Analog	

Unit Status Points	01_State	10_State	Category	Type	Control
Auto load	Active	Normal	Info	Single	True
Automatic power factor regulator	On	Off	Info	Single	True
Emergency Shutdown	Operated	Normal	Info	Single	
GEN start not ready	Alarm	Normal	Health	Single	
GEN to PUMP mode	Active	Off	Info	Single	
GEN to SCO mode	Active	Off	Info	Single	
Pump start not ready	Alarm	Normal	Health	Single	
Pump to GEN mode	Active	Off	Info	Single	
Pump to SCO mode	Active	Off	Info	Single	
SCO start not ready	Alarm	Normal	Health	Single	

[2] Note that where modes or functions are not available, such as *SCO*, the associated signals are not required.

SCO to GEN mode	Active	Off	Info	Single	
SCO to PUMP mode	Active	Normal	Info	Single	
Turning in gen direction	Yes	No	Info	Single	
Turning in motor direction	Yes	No	Info	Single	
Under-frequency start	Armed	Off	Health	Single	
Unit at standstill	Yes	Normal	Info	Single	
Unit in GEN mode	Yes	No	Info	Single	
Unit in PUMP mode	Yes	No	Info	Single	
Unit in SCO mode	Yes	No	Info	Single	
Unit synchronising	Yes	No	Info	Single	
Unit to GEN mode	Active	Off	Info	Single	True
Unit to PUMP mode	Active	Off	Info	Single	True
Unit to SCO mode(1)	Active	Off	Info	Single	True
Unit to Standstill	Active	Off	Info	Single	True

(c) Steam units



Unit LV Breaker	01_State	10_State	Category	Type	Control
Unit breaker state	Closed	Tripped	Info	Double	False

Unit Signals	**01_State**	**10_State**	**Category**	**Type**	**Control**
Gross MW			Info	Analog	
Gross Mvar			Info	Analog	
Net MW			Info	Analog	
Net Mvar			Info	Analog	

Unit islanded	Alarm	No	Health	Single	

(e) AGC signals

All generating units providing *AGC* shall provide and receive the following signals

AGC signals from generator	01_State	10_State	Category	Type	Control
High regulating limit			Health	Analog	
Low regulating limit			Health	Analog	
Ramp rate			Info	Analog	
Set-point active power			Info	Analog	True
AGC – unit Status	On	Off	Info	Single	
Frequency Bias	On	Off	Info	Single	
Raise Block (optional)	High	Normal	Health	Single	
Lower Block (optional)	Low	Normal	Health	Single	

AGC signals to generator	01_State	10_State	Category	Type	Control
AGC Setpoint Command			Info	Analog	True

Signal description

High regulating limit

This value gives the maximum allowable output *AGC* can raise the active power output. This is set at the *generator*. The high regulating limit can either be net active power or gross active power

Low regulating limit

This value gives the minimum allowable output *AGC* can lower the *generator*. The low regulating limit can either be net active power or gross active power.

Maximum Unit Gradient

This is the maximum rate in (MW/min) which the unit can change whilst on *AGC*.

Setpoint Value

The setpoint value comes from the control equipment of the *generator*. To change the active power output of the generator, the output setpoint has to be adjusted. *AGC* controls the setpoint when *AGC* is on. The setpoint can either be net active power or gross active power.

AGC – *Generator* Status – (Set by the Power Station staff)

This signal indicates if the *generator* is allowing *AGC*. Only when signal is "on" can the *System Operator* select the generator to *AGC* operation. When this signal is "off", all raise/lower commands from *System Operator* should be ignored.

Frequency Bias On

This indicates that primary governing is "on".

Raise Block

In the event that the generator chooses not to allow *AGC* raise commands then the Raise Block is set. When this indication is set, all raise commands from the *System Operator* should be ignored.

Lower Block

In the event that the *generator* wants to prevent *AGC* lower commands then the Lower Block is set. When this indication is set, all lower commands from *System Operator* should be ignored.

AGC Setpoint Command

The AGC Setpoint command consists of a message from the *System Operator*'s *AGC* program instructing a particular unit to a particular active power output.

(f) Unmanned *unit* or *System Operator* remote operation signals

All units that are not manned for full or portion of the day or if it is agreed that the generator must be capable of remote operation by the *System Operator*, then the following signals shall be provided and facilitated.

Signals from *generator*	**01_State**	**10_State**	**Category**	**Type**	**Control**
Under frequency start ready	Yes	No	Info	Double	
Under frequency start armed	Yes	No	Info	Double	
Generator MW Setpoint (Gross or Nett)			Info	Analog	
Regulation MW High Limit			Info	Analog	
Regulation MW Low Limit			Info	Analog	
Generator Mvar Setpoint			Info	Analog	
Generator kV Setpoint			Info	Analog	
Voltage or Q control mode	V - Mode	Q - Mode	Info	Double	
Unit Controller status	Yes	No	Info	Double	
Unit Load Limit [3]			Info	Analog	

[3] Maximum Load limit setting

Unit local AGC status	AGC	Local	Info	Double	

Signals to generator	**01_State**	**10_State**	**Category**	**Type**	**Control**
AGC Generator Status on	on	off	Info		True
Regulation High Limit			Info	Analog	True
Regulation Low Limit			Info	Analog	True
Generator MW Setpoint			Info	Analog	True
Generator Mvar Setpoint			Info	Analog	True
Generator kV Setpoint			Info	Analog	True
Voltage or Q control mode	V - Mode	Q - Mode	Info		True
Primary Governing	On	Off	Info		True

A5.2 Distributor and end-use customer

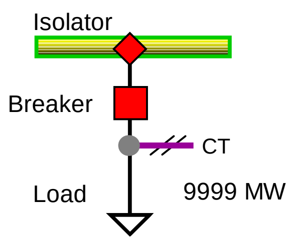
(a) Transmission equipment

The Customer shall provide operational information for both real-time and recording purposes in relation to each feeder, transformer and compensation device at each substation required for the full functionality of an SVC, as well as full control by the System Operator.

(b) Interruptible load

All interruptible loads shall meet the minimum requirements. The System Operator shall negotiate and integrate the conditions as presented in bilateral agreements and additional contracts without reducing the requirements as defined in this Grid Code.

The interruptible load shall install operational measurements to specification so as to provide operational information for both real-time and recording purposes in relation to each controllable energy block in respect of the following minimum requirements for operation and control of an interruptible load:



Isolator	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Isolator state	Closed	Open	Info	Double	False
Breaker	01_State	10_State	Category	Type	Control
Unit breaker state	Closed	Tripped	Info	Double	True
Current Transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Load	01_State	10_State	Category	Type	Control
Load reduction acknowledged	No	Yes	Info	Single	True
Load interrupt acknowledged	No	Yes	Info	Single	True
Block load reduction acknowledged	No	Yes	Info	Single	True
Return to service acknowledged	No	Yes	Info	Single	True

Load active power			Info	Analogue	False

The availability of the interruptible load shall be integrated into the ancillary service schedules by the System Operator.

APPENDIX 6: Schedule information

The System Operator shall provide the following minimum day-ahead schedule information for each hour of the following day in relation to each unit at each power station:

No	Data description	Format	Size	Unit
1	Unit energy schedule	Real	999,9	MW
2	Unit spinning reserve schedule	Real	999,9	MW
3	Unit standby reserve schedule	Real	999,9	MW
4	Unit regulation reserve schedule	Real	999,9	MW
5	AGC	Integer		on / off

APPENDIX 7: Post-dispatch information

The System Operator shall provide the following minimum operational information in near real time and as historic data in relation to each unit at each power station:

No	Data description	Format	Size	Unit
1	Unit high limit	Real	999,99	MW
2	Unit low limit	Real	999,99	MW
3	Unit AGC mode BP(0,2,3)/EX(0,1,2,3)	Character	3	
4	Unit AGC status AUT/OFF/MAN	Character	3	
5	Unit set-point	Real	999,9	MW
6	AGC set-point	Real	999,9	MW
7	Unit sent out	Real	999,99	MW
8	Unit auxiliary	Real	999,99	MW
9	Unit schedule	Real	999,9	MW
10	Unit spinning reserve	Real	999,9	MW
11	Unit standby reserve	Real	999,9	MW
12	Unit regulation reserve	Real	999,9	MW
13	32-bit flag on AGC settings	Integer		32 bits

The system operator shall provide the following minimum operational information in near real time in relation to the overall dispatch performance:

No	Data description	Format	Size	Unit
1	ACE area control error	Real	999,99	MW
2	Average ACE previous hour	Real	999,99	MW
3	HZ system frequency	Real	99,999	MW
4	Frequency distribution current hour	Real	999,99	MW
5	Frequency distribution previous hour	Real	999,99	MW
6	System total generation	Integer	99999	MW

7	Control area total actual interchange	Integer	99999	MW
8	Control area total scheduled interchange	Integer	99999	MW
9	System operating reserve	Integer	99999	MW
10	System sent out	Integer	99999	MW
11	System spinning reserve	Integer	99999	MW
12	AGC regulating up	Integer	99999	MW
13	AGC regulating down	Integer	99999	MW
14	AGC regulating up assist	Integer	99999	MW
15	AGC regulating down assist	Integer	99999	MW
16	AGC regulating up emergency	Integer	99999	MW
17	AGC regulating down emergency	Integer	99999	MW
18	AGC mode	Char	TLBC /CFC	
19	AGC status	Char	ON/ OFF	
20	Area control error output	Real	999.99	MW
21	System transmission losses	Real	999.99	MW
22	Relevant international tie-line flows	Integer	99999	MW
23	AGC performance indicators			

APPENDIX 8: Generator performance data

Measurement of availability

The Unipede/Eurelectric standard for the measurement of plant availability must be used. Availability is measured with the use of an indicator known as the energy availability factor (EAF).

EAF represents the network point of view.

The EAF has the same conceptual content as the equivalent availability factor used by USA operators, e.g. the NERC-GADS data bank.

Energy availability factor is defined as the ratio of the available energy generation (b) over a given time period (PH) to the reference energy generation over the same period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available energy generation (b) for the purpose of calculating EAF is the energy that could have been produced under reference ambient conditions considering limitations within and beyond the control of the plant management.

- $$b = Pd \times PH$$

Reference energy generation (Y) is the energy that could be produced during a given time period if the unit were operated continuously at reference unit power (PM) under reference ambient conditions throughout the period.

- $$Y = PM \times PH$$

Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Alternative definition: The "energy availability factor" (f), over a specified period, is the ratio of energy (b) that the available capacity (Pd) could have produced during this period to the energy (Y) that the net maximum electrical capacity (PM) could have produced during the same period.

The energy produced (b) (or capable of being produced) by the available capacity (Pd) may also be calculated as the difference between the energy (Y) (the maximum electrical capacity – PM – that could have been produced) and the unavailable energy (c) (which was not produced or not able to be produced) by the total unavailable capacity (Pit).

- $$f = \frac{b}{Y} = \frac{Y - c \times 100\%}{Y}$$

Note: For the Eskom reporting systems c is calculated from a summation of unavailable MWh due to outages and restrictions (planned, unplanned, external and non-engineering) occurring throughout the period from MW capacity loss x duration (hr) of the loss.

Components of the energy availability factor (EAF)

$$EAF = UCF - OCLF$$

Unplanned capability loss factor (UCLF)

The purpose of this indicator is to monitor industry progress in minimising outage time and power reductions that result from unplanned equipment failures or other conditions. This indicator reflects the effectiveness of plant programmes and practices in maintaining systems available for safe electrical generation.

Other capability loss factor (OCLF)

Other capability loss factor is an indicator to monitor outage time and power reductions due to causes beyond the control of plant management.

Planned capability loss factor (PCLF)

Planned capability loss factor is defined as the ratio of the planned energy losses during a given period of time to the reference energy generation expressed as a percentage.

Planned energy loss is energy that was not produced during the period because of planned shutdowns or load reductions due to causes under plant management control. Energy losses are considered to be planned if they are scheduled at least four weeks in advance.

Unit capability factor (UCF)

Note: UCF represents the *GENERATOR'S* POINT OF VIEW

The purpose of this indicator is to monitor progress in attaining high unit and industry energy production availability. This indicator reflects effectiveness of plant programmes and practices in maximising available electrical generation and provides an overall indication of how well plants are operated and maintained.

$$UCF = 100 - PCLF - UCLF$$

Measurement of availability and reliability

The Unipede/Eurelectric standard for the measurement of plant reliability must be used.

Reliability is measured with the use of two specific indicators, namely unplanned automatic grid separations (UAGS) and successful start-up rate (SSUR)

Unplanned automatic grid separations per 7 000 operating hours (UAGS/7000h)

The purpose of this indicator is to enable monitoring of an important aspect of the reliability of service supplied to the electrical grid. It takes into account success in improving reliability by reducing the number of turbo generator trips. It also provides an indication of plant operation and maintenance performance.

Taking account of the number of operating hours when the turbo generator set is connected to the electrical grid enables assessment of required reserves. Furthermore, using a common standard for all grid separation data for each unit provides a uniform basis for comparison among units with values for the industry as a whole.

Intentional (manual) grid separations are not taken into account since operators should not be discouraged from taking action to protect equipment.

This indicator may be defined as corresponding to the number of unplanned (unintentional) automatic grid separations of internal origin that occur per 7 000 operating hours. This definition can be clarified as follows:

"Unplanned" means that grid separation is not an anticipated part of a planned test, nor part of an operating programme designed to adjust output to demand (e.g. a controlled shutdown). Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

"Grid separation" means the opening of the generator breaker or HV yard breaker where no generator breaker exists. This could be an opening signal actuated by overshooting of a safety threshold, or a spurious trip. Grid separation can only occur during grid service of the units. Grid service is obtained when the start-up is successful for requested start-ups or when loads in excess of the first synchronising load are reached for “contracted” or “other start-ups” (i.e. house or block load as programmed into the automatic synchronising equipment).

“Automatic” (unintentional) means that the grid separation is not the result of an action by the operator either on one of the switches to trigger a unit trip or grid separation or to simulate operation of a protection system.

Trips caused by the operator in error, e.g. opening the wrong switch leading to a trip, are excluded from the “manual” category. Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

“Operating" means that the turbo generator set is connected to the off-site grid (*transmission* of generated power) even if the alternator is operating in synchronous motor mode owing to exceptional circumstances.

"Of internal origin" means that the trip is due to an unspecified internal installation failure resulting in a loss of reliability – even if the initial event can be traced to an off-site cause. The signal that triggered grid separation must originate from one of the sensors (or protection logic) for monitoring unit parameters (turbo generator set and power *transmission*, up to and including the generator transformer HV breaker, and boiler). Grid separations actuated by protection systems for the physical parameters of the grid are not included unless they were incorrectly controlled.

The selected figure of 7 000 hours represents the typical number of on-line hours for most plants operating at base load or semi-base load. The indicator thus represents an approximate value of the actual number of grid separations occurring in one year.

The following data are required to determine the value for this indicator:

- The number of unplanned automatic grid separations (U) with the generator circuit breaker (or HV breaker where no generator breaker exists) in initially closed position
- The number of operating hours (OPH)

All automatic trips are counted for the UAGS indicator, including those auto trips occurring within +30 minutes of all requested start-ups that comply with the ±15-minute time limit for synchronisation.

$$\frac{UAGS}{7000h} = \frac{U \times 7000}{OPH}$$

Data for new units is included in the calculation of industry values beginning January 1 of the first calendar year following the start of commercial operation. However, in order to be included in the industry value, the unit must have at least 1 000 operating hours per year. This minimum operating period requirement reduces the effects of plants that are shut down for long periods of time and for which limited data may not be statistically valid.

Summarised definition of UAGS per 7 000 hours: This indicator tracks the average grid separation rate per 7 000 operating hours (approximately one year of operation) for units having at least 1 000 operating hours during the year. Only trips of internal origin to the installation are included and trips for the physical parameters of the grid are not included unless they were incorrectly controlled.

Successful Start-up Rate (SSUR)

The "successful start-up rate" is the ratio of the number of successful start-ups to the number of contracted start-ups over a given period of time. It measures the reliability of the service that is rendered to the *customers*.

$$SSR = \frac{NumberOfSuccessfulStartUps \times 100\%}{NumberOfContractedStartUps}$$

Start-up comprises the set of operations that enable the unit to be connected to the off-site power grid. Connection of the unit to the grid (closing the line circuit breaker) is the purpose of the first start-up phase, before loading and stabilisation at the required power level. Only this initial start-up phase, the success of which results in sustained grid connection, is considered here.

The contracted start-up refers to an agreement between the grid administrator (through any medium, e.g. verbally, telephonically, etc.) and the station, following a request from the grid administrator or the station. This forms part of a grid management schedule (hereafter referred to as the “real” National Control programme) for the full range of power generation resources (excluding tests). The request for a start-up in advance of the synchronising time corresponds to the technical delay due to equipment start-up times. This delay time can be reduced to almost zero in the case of start-up of peak-supply gas turbines with centralised, automatic control systems. For any given start-up contract, a precise time for grid connection and an implementation schedule are required (except for peak-load gas turbines). In the event of a sudden modification by the grid administrator of the grid connection contract time, within the start-up capabilities of the unit, a new contract needs to be entered into.

APPENDIX 9: Planning schedules

Schedule 1: Ten-year demand forecast

	Demand = Total Demand + Distribution Losses – Embedded Generation					
			Maximum demand		Expected minimum demand	
Year		**GWh**	**MW**	**MVAr**	**MW**	**MVAr**
Measured (year 0)						
Year 1						
Year 2						
Year 3						
Year 4						
Year 5						
Year 6						
Year 7						
Year 8						
Year 9						
Year 10						

Schedule 2: Embedded generation > 5MVA

Generator	Tx substation name at closest connection point	Operating power factor	Installed capacity (MW)	Plant type	On-site usage		Net sent out		Generation net sent out contribution at peak									
					Normal	Peak	Normal	Peak	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10

APPENDIX 10: Generator HV yard information

Transmission shall provide the following information to *generators* about equipment and systems installed in HV yards from TANESCO. The *TANESCO* shall provide the stability criteria.

Equipment	Requirement
Circuit breaker	MCR rating, peak rating, operating time, OEM, installation date
CT and VT	CT and VT ratings, classes of equipment, burdening, OEM, installation date
Surge arrestor	OEM, age, installation date, number of operations
Protection	Description of protection philosophy for all protection schemes and functions installed, including ARC; protection reliability information shall be available annually
Power consumption	List the power consumption requirement by equipment requiring supply from power station, including from AC, DC and UPS
Link	MCR rating, peak rating, OEM, installation date
Outgoing feeder	MCR rating, peak rating, erection date, length, impedance, transposition characteristics, thermal limits, installed protection, shielding
Transformer	Transformer specifications for coupling transformers in HV yards; the records of coupling transformers in HV yards must be available on request
Compressed air system	Compressed air system specifications including schematic drawings
Fault recorder	Fault recorder specifications including resolution, record time, triggering criteria, data format shall be provided on request; TANESCO shall review the fault levels and impedance to network centre from HV yard, annually

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Grid Code

7 of 8 Code Documents - Transmission Tariff Code

Version 2

1st March 2017

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1 INTRODUCTION

(1) This code sets out the objectives of *transmission* service pricing and the broad approach to revenue and tariff regulation with reference to the procedure to be followed in applications to change revenue requirements or the tariff structure.

(2) The Authority shall regulate the setting of prices and the structure of tariffs in the industry. *Licensees* shall therefore be regulated with regard to the prices and pricing structures they may charge *customers*.

(3) *Customers* shall contract with their service provider for the payment of charges related to *transmission* services. These charges shall reflect the different services provided.

2 AUTHORITY

(1) In terms of the Electricity Act, 2008 and the *EWURA Act*, the *Authority* is mandated with the obligation and is granted the powers approve and enforce tariffs and fees charged by *licensees* within the *electricity supply industry*.

(2) Such regulation of charges covers tariffs and fees for services the various *licensed activities* set out in the Electricity Act, 2008. In line with the medium term plans for the ring-fencing of separate business areas within the power sector, the Transmission Tariff Code sets out key aspects relating to the economic regulation of *licensed transmission* services.

(3) The Tariff Code sets out the objectives and principles of *transmission* service pricing, application of charges and fees and the procedure to be followed in applications by *licensees* to change revenue requirements, tariff levels or tariff structure.

3 SCOPE AND APPLICABILITY

(1) The Authority will review and approve the levels of costs and the resultant revenue requirement for TANESCO. The Authority will furthermore regulate the structure of *transmission* service charges in the industry. This will serve as input into the total revenue requirement and associated charges to *customers* via end-user tariffs.

(2) TANESCO is operated as a vertically integrated company carrying out *generation*, *transmission* and *distribution* services. As such the revenue requirment and tariffs are regulated for TANESCO as a whole.

(3) Short to medium term reform plans for the industry encompass the ring-fencing of TANESCO into separate *generation*, *transmission*, and *distribution* companies. This would entail the establishment and regulation of separate revenue requirements for each of the ringfenced entities.

(4) The Transmission Tariff Code sets out the key principles and approach to the establishment of the revenue requirement for the TANESCO *transmission* business. It also outlines the options and considerations in respect of tariff structure for *transmission* services. These aspects are applicable to the tariffs charged by TANESCO.

(5) The Transmission Tariff Code shall be read in conjunction with other documents associated with the regulation of tariffs and charges in the *electricity supply industry*. These include:

- (a) The EWURA Tariff Application Guidelines of 2009; and
- (b) The EWURA (Rates and Charges Applications) Rules, 2009.

(6) In the longer term, depending on the reform process the Transmission Tariff Code may be amended to provide for full unbundling of the *transmission* business and the application of separate *transmission* charges to *customers* and between the different business entities in the *electricity supply industry.*

4 OBJECTIVES OF THE TRANSMISSION TARIFF CODE

(1) The Tariff Code shall support the duties of the *Authority* as set out in the *EWURA Act*, namely to:

(a) Promote effective competition and economic efficiency;

(b) Protect the interests of consumers;

(c) Protect the financial viability of efficient suppliers;

(d) Promote the availability of regulated services to all consumers;

(e) Enhance public knowledge, awareness and understanding of the regulated sectors; and

(f) Take into account the need to protect and preserve the environment.

(2) The Transmission Tariff Code is aimed at ensuring that the approved revenue requirement supports a viable and efficient *transmission* business.

(3) In the longer term, taking cognizance of the reform goal of unbundling, the Tariff Code will seeks to ensure that *transmission* tariffs are designed in pursuit of the following objectives:

(a) Open access to *transmission* services at equitable, non-discriminatory prices for all *customers*;

(b) Pricing levels that recover the approved revenue requirements of *transmission licensee(s)*;

(c) Revenue requirements that support a viable and efficient *transmission* business;

(d) Predictable prices over time to *customers*;

(e) Pricing signals that reflect the underlying cost structure of the services provided;

(f) Optimal asset utilization; and

(g) Unbundling of service offerings and cost-reflective pricing of each service component.

5 PRINCIPLES FOR REGULATION OF INCOME

(1) The Authority shall employ a published regulatory guideline to define the form of regulation and the methodology by which the revenue requirements and associated tariffs/charges shall be determined.

(2) In broad terms, the revenue requirement and tariffs/charges approved by the Authority shall reflect prudently incurred costs, including depreciation, interest expense, applicable taxes, operating expenses and a reasonable return on invested capital for facilities that are used and useful in providing the regulated service.

(3) The regulatory framework applied is set out in the “Tariff Application Guidelines of 2009” published by the Authority.

6 DETERMINATION OF TARIFF LEVELS AND STRUCTURE

6.1 TARIFF LEVEL – REVENUE REQUIREMENT

(1) The regulatory tariff methodology shall identify the key considerations in respect of cost elements insofar as they impact on the revenue requirements of the *transmission* business.

(2) The high level categories of costs that make up the revenue requirement shall include:

(a) Depreciation

(b) Investment return

(c) Operation and maintenance costs;

(d) Cost of network losses;

(e) Customer service and administration costs.

(3) Key considerations realting to each of these are set out below.

6.1.1 DEPRECIATION

(1) Together with regulatory returns, an allowance for depreciation ensures that investors are properly compensated for their capital investments. There are a number of factors to be considered in determining the allowed depreciation levels. Given that depreciation is based on asset values, the charge methodology identifies allowable versus non-allowable assets as well as the method of asset valuation to be applied. These aspects enable the establishment of the regulatory asset base (RAB), which serves as a vital determinant of the revenue requirement and associated prices.

6.1.1.1 ALLOWED ASSETS

(1) It is noted that the following asset classes are typically included in the rate base:

(a) Used and Useful Assets - assets used in the *transmission* of electricity as well as in the operation of the wholesale market and control of the power system.

(b) Inventory. This includes materials, spares and fuel stock holdings.

(c) Net Working Capital. To fund ongoing operations

(2) The methodology identifies certain asset classes to be specifically excluded from the regulatory asset base. These typically include:

(a) Subsidized Assets. These are assets not paid for or funded by the utility. Partially paid for and funded assets are allowed on a proportional basis. The inclusion of subsidized assets in the regulatory asset base would allow the benefit of an income stream that the regulated entity has not financed.

(b) Future Assets. These should be excluded from the regulatory asset base until they are used and useful (i.e. enter into commercial operation).

6.1.1.2 ASSET VALUATION APPROACH

(1) The most common asset valuation methods are identified below, noting that the methods vary substantially and yield diverse asset valuations, each with specific preferred areas of application. These include

(a) Historic Cost Accounting (HCA):

(b) Current Cost Accounting (CCA)

(c) Indexation approach.

(d) Absolute valuation (revaluation) approach.

(e) Modern Equivalent Asset (MEA)

6.1.1.3 Depreciation Method and Period

(1) The depreciation method and period are important in determining the depreciation expense allowed as well as depreciated asset values. It is anticipated that, unless agreed otherwise, depreciation is based on the prevailing accounting approach for each regulated entity.

6.1.2 Investment Returns

(1) Transmission infrastructure is highly capital-intensive with long asset lives. Hence it is pointed out that regulators do not typically allow transmission companies to recover the cash costs associated with investments via tariffs, but rather facilitate such recovery via an allowable return. This approach implicitly takes account of the cost of capital and, if set at the appropriate level, allows the utility to fund investments.

(2) In this regard it is important to ascertain the regulatory asset base upon which such return is earned as well as a fair return level to sustain the business(es). The allowed Rate of Return (ROR) is a key regulatory parameter for the revenue requirement.

(3) The choice of a real or nominal ROR is informed by the valuation approach adopted. The Historic Cost Accounting approach proposed requires the application of a **nominal** ROR to ensure that inflationary impacts are properly incorporated. Similarly, current or revalued asset values require the application of a **real** ROR.

(4) The methodology, furthermore defines whether a pre-tax or a post-tax ROR is applied.

(5) The determination of a "fair" or "reasonable" ROR is defined as the risk-adjusted return that suppliers of funds to the business would require. In general, businesses use a combination of debt and equity to finance investments. The appropriate return on capital is thus the weighted average cost of debt and equity financing. This debt weighted average is referred to as the Weighted Average Cost of Capital (WACC).

6.1.3 Operating and Maintenance costs

(1) Network operating and maintenance costs are the costs associated with operation and maintenance of the various lines and substations. This includes a range of costs including the cost of employees associated with the maintenance and operation of the network equipment and facilities.

(2) There are may also be operating costs related to the activities of the System Operator (and Market Operator). This includes costs associated with control centres, facilities and staffing for power system operations and management and administration of the wholesale market as well as supporting information, control and scheduling, dispatch and settlement systems.

6.1.4 Customer Service and Administration related costs

(1) Customer Service costs generally include the costs associated with meter reading, billing, invoicing, and customer support as well as all the other costs related to customer and revenue management cycle activities. Administration costs include the costs of buildings, administrative staff, overheads etc.

(2) For transmission network companies, these costs are typically small and are therefore often included with the operating and maintenance cost category.

6.1.5 Cost of Network Losses

(1) Electrical losses arise from the physical laws that govern the transport of electricity. The cost of losses thus represents a legitimate expense that must be recovered.

(2) In terms of costing losses, charges may be based on marginal or average losses. Although marginal loss based charges tend to provide stronger pricing signals, these result in over-recovery against the actual costs of losses. By contrast charges based on average losses would be more cost-reflective and consistent with the overall approach of ensuring full cost recovery.

(3) The tariff methodology spells out the approach followed in respect of network losses.

6.2 Tariff Structure

6.2.1 Tariff Differentiation

(1) Tariff differentiation represents an important element of tariff structuring. In broad terms, pricing may be differentiated on the basis of a number of cost drivers. For electricity pricing, the most important of these include geographic location, voltage level, and time-of-use.

6.2.1.1 Geographic location

(1) Geographically differentiated tariffs are typically considered where there are significantly different costs imposed by delivery to particular geographic locations. There are several possibilities for geographic variation including

(a) Postage Stamp Pricing

(b) Zonal Pricing

(c) Nodal Pricing

(2) In terms of geographic differentiation, postage stamp and nodal pricing approaches represent two extremes ranging from the simplest to the very complex. Zonal pricing is often deemed to represent a good compromise between the two extremes.

6.2.1.2 Voltage level

(1) Electricity supply tariffs are often differentiated by voltage level as different customer off-take voltages generally entail different infrastructure and associated different costs. In particular, electricity delivery at a lower voltage is often deemed to use both higher voltage and lower voltage networks whereas electricity delivery to higher voltage is deemed to use only higher voltage networks.

6.2.1.3 Time of Use Differentiated Tariffs

(1) Time differentiation of tariffs is based on the recognition that costs vary by time. In particular, network use during times of peak stress on particular network elements drives the need for new capacity and hence occasions greater costs than network use at other times.

(2) Time-of-use differentiation is considered to be a powerful tool for ensuring cost-reflectivity and promoting energy efficiency and to align with the approach applied in the Generation Charge Methodology for energy charges it is proposed that time of use differentiation be applied to the network energy charges that cover losses.

6.2.1.4 SPECIAL TARIFF

In the event of customer demanding for specific quality of power supply than the TSO network performance, the following procedure would be used:

1) If the customer claims for better contractual levels than the normal ones, he/she can ask TSO for customized contractual levels in his contract, paying an extra charge (i.e. special tariffs). Customers who have customized contractual levels must have a monitoring recorder installed (it can be owned by the customers themselves or by TSO). The procedure for attaining such power quality contract would be:

   i) TSO would declare its network power quality status for the customer to verify if is satisfied or not satisfied with the level of quality of power supply.

   ii) A customer will requests a level of electricity quality that exceeds what the TSO system can deliver.

   iii) TSO will perform a technical study of the customers plant and power networks in order to determine the sensitivity of plant equipment and how often power disturbances occur.

   iv) TSO will develop and design the solutions to meet the required power quality performance levels required by customer.

   v) Both parties (TSO and Customer) will negotiate and agree on a monthly charge for the required performance level.

   vi) TSO will purchase, install and commission the necessary power conditioning equipment at the customer plant.

   vii) TSO will carry out maintenance on the supplied equipments during the period of agreement.

   viii) The special Tariff agreement processes must involve TSO, CUSTOMER and The Authority.

2) With regards to power supply reliability, the network configuration should be taken into consideration. If there is no possibility feeding the customer from more than one point in case of tripping (as the case of radial circuit) TSO would not guarantee reliability of power supply for 24 hours a day, 30 days a month and 12 months a year due to the limiting factors in the power system configuration.

3) TSO would try to do its level best to achieve the maximum reliability of power supply possible to its customer as per targets to be set by the Authority.

7 TARIFF REVIEW PERIOD

(1) In terms of Section 24(2) of the Electricity Act, the *Authority* is required to make amendments to or review tariffs charged by a *licensee* once in every 3 years.

(2) In addition, Section 24(3) of the Electricity Act makes provision for the inclusion of automatic tariff adjustments, as approved by the *Authority* to incorporate periodic changes in:

   (a) the cost of fuel;

   (b) the cost of power purchases or the rate of inflation; and

   (c) currency fluctuation.

(3) In addition, the EWURA Tariff Application Guidelines of 2009 stipulate that, subject to sector legislation, the *Authority* shall not consider a new rate or charge application within twelve months after the effective date of an

initial or changed tariff or methodology. A *licensee* may, however, petition the *Authority* for a waiver of this provision if it can be shown that a material undue hardship would occur in the absence of such a revision.

8 TARIFF APPLICATION, APPROVAL AND NOTIFICATION PROCESSES

(1) The *transmission* applicant shall submit the tariff application in accordance with the EWURA Tariff Application Guidelines of 2009.

(2) The tariff application shall be accepted, evaluated and approved by the Authority in accordance with the provisions of the EWURA Tariff Application Guidelines of 2009.

(3) The *transmission* applicant shall notify its *customers* as set out in the EWURA Tariff Application Guidelines of 2009.

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1 INTRODUCTION

(1) The Governance Code describes the provisions necessary for the overall administration and review of the various aspects of the Grid Code. This code shall be read in conjunction with the relevant legislation, licences issued to *generators*, *transmission* companies and *distributors*, and other operating codes that relate to the *electricity supply industry*.

(2) The accountabilities of various entities in the governance of the Grid Code are set out in Figure 1 below.

FIGURE 1: GRID CODE ACCOUNTABILITIES

Body	**Function**
The Authority	Approval, Governance and dispute mediation
Grid Code Advisory Committee (GCAC)	Recommendations
Experts	Expert opinions and drafting
Grid Code Secretariat (GCS)	Administration
Grid Code Participants	Implementation and compliance

2 ADMINISTRATIVE AUTHORITY

(1) The Energy and Water Regulatory Authority (EWURA) is the administrative authority for the Grid Code. The Authority shall ensure that the Grid Code is implemented for the benefit of the industry.

3 THE GRID CODE ADVISORY COMMITTEE

(1) The Authority shall constitute the Grid Code Advisory Committee (GCAC). Subsequent to its constitution the Authority shall ensure the proper functioning of the GCAC.

(2) The GCAC is established to:

(a) Ensure a consultative stakeholder process is followed in the formulation and review of the Grid Code,

(b) Review and make recommendations regarding proposals to amend the Grid Code,

(c) Review and make recommendations regarding proposals for exemption to comply with the Grid Code and

(d) Facilitate the provision of expert technical advice to the Authority on matters related to the Grid Code.

3.1 CONSTITUTION OF THE GCAC

(1) The GCAC shall be a stakeholder representative panel, representing participants.

(2) Members of the GCAC shall ensure that they consult with their constituencies with respect to their respective roles on the GCAC.

(3) The Authority shall annually review the composition of and constituencies represented by the GCAC to ensure that it is at all times reflective of the evolving industry. The Authority may decide to expand the

composition of the GCAC as part of the membership review process in consultation with the GCAC. The Authority shall ensure that members on the GCAC are able to make meaningful contributions towards the review process. The GCAC shall consist of at least the following:

(a) One member representing the *System Operator* (SO),

(b) One member representing *transmission* company/companies,

(c) Three members representing *generators*,

(d) Two members representing *distributors*,

(e) One member representing large end-use *customers* and

(f) Two EWURA members, one to chair and the other to assist the GCS.

(4) The members shall be identified as follows:

(a) If an industry association represents the larger part of the constituency, the association will be requested to make the nomination(s).

(b) If the constituency consists of more than one association and/or a relatively small number of entities, calls for nominations will be sent to all entities. The Authority may decide on the member if more than the required number of nominations is received. The Authority may choose the member if no nominations are received.

(c) If there is no identifiable entity, a public call for nomination will be sent out by the Authority. The Authority may decide on the member if more than the required number of nominations is received.

(5) The Authority shall publish changes in membership within 14 days, on the Authority website.

(6) GCAC members shall serve a three-year term, after which they shall be eligible for re-appointment. Their constituency may also replace members at any given time, provided 14 days' written notice is given to the GCS and the Authority. The Authority may request the replacement of members by their constituency upon recommendation of the GCAC, if they have not attended three consecutive meetings.

(7) Members shall nominate an alternative representative. Such nomination shall be made in writing to the GCS.

3.2 FUNCTIONING OF THE GCAC

(1) The GCAC shall review all proposals for amendment of or exemptions from the Grid Code.

(2) The GCAC shall schedule at least annual review sessions. The format of a session may be determined by the GCAC, but should include a work session if proposed changes are of a substantive nature. Agenda items shall be circulated at least 14 days in advance of the review session.

(3) The GCAC shall determine its own meeting procedures and code of conduct subject to the constitutional provisions set out in this section. These procedures and code of conduct shall be published on the Authority website.

(4) The Authority member shall chair the GCAC meetings. When the Authority member or alternate is unable to attend the GCAC meeting, he/she shall make arrangements for an alternative chairperson for the duration of the meeting.

(5) A quorum shall consist of 50% of members plus one member of the GCS. Decisions by the GCAC shall be taken by means of a majority vote of the duly constituted GCAC. If votes are even then the Chairperson shall have the deciding vote.

(6) Alternate members shall be allowed to vote only when the main member is not available for voting.

(7) If a quorum is not present within 30 minutes of the stipulated starting time of the meeting, provided the GCS gave proper notice, the meeting shall make the necessary recommendation(s). The GCS shall circulate this electronically to all GCAC members for decision within five work days and such decisions to be returned to the GCS. Such decisions shall be immediately effective if voted on by a quorum. These decisions shall be minuted as confirmed at the next GCAC meeting where a quorum is present.

(8) Decisions of the GCAC shall be recorded together with dissenting views expressed by GCAC members.

(9) The Authority shall fund the administrative activities of the GCAC. Members shall be responsible for their own travel and subsistence expenditure.

(10) The GCAC may co-opt experts with the purpose of allowing expert opinion to be obtained regarding complicated submissions. Industry participation and consultation shall be encouraged in, and obtained through, the activities of these experts. The GCAC shall provide the experts with a full scope of work and an urgency indicator for each task referred to them.

3.3 THE GRID CODE SECRETARIAT

(1) The *System Operator* is appointed as the Grid Code Secretariat (GCS). This decision may be reviewed by The Authority. The GCS is accountable to the Authority and the GCAC for its activities.

(2) The GCS shall perform the following functions:

(a) Ensure procedures are developed and published for the review of proposed amendments and exemptions by the GCAC,

(b) Provide standard submission forms to *Grid Code Participants*,

(c) Assist, when requested, in the preparation of submissions to the GCAC,

(d) Prepare amendment and exemption proposals for submission to the Authority following review by the GCAC,

(e) Manage Grid Code documentation,

(f) Disseminate relevant information,

(g) Inform participants of the progress with applications for amendment or exemption,

(h) Co-ordinate the activities of the GCAC,

(i) Keep and circulate minutes of meetings and documentation of proceedings of the GCAC and

(j) Function as a formal communication channel for the GCAC.

(3) The GCS shall make the latest version of the Grid Code available electronically and notify all participants of approved amendments or exemptions within one week of receipt of approval from the Authority.

(4) The GCS shall make hard copies of the latest version of the Grid Code available to requesting entities, for which a nominal fee may be charged to recover reproduction costs.

4 Registration and De-registration

(1) The GCS shall be responsible for making entries in the register of Grid Code Participants upon receipt of notification from the Authority of licensed entities and from *Transmission* of *Transmission Connected Customers*.

(2) *Grid Code Participants* shall be registered in different categories: Generator, Distributor, Transmission, System Operator, Electricity Trader, Transmission-Connected Customer etc.

(3) No entity shall have access to the *Transmission System* before being registered as a *Grid Code Participant*.

(4) A Grid Code Participant whose license has been withdrawn by the Authority ceases to be a *Grid Code Participant*.

(5) A Grid Code Participant who wishes to de-register shall notify the GCS at least six months before the intended date of de-registration. De-registration will be carried out in accordance with guidelines as determined by the Authority.

5 Grid Code Amendment or Exemption Procedure

(1) The Authority is the approval authority for the Grid Code. Only The Authority shall therefore approve any amendments to or exemptions from the Grid Code upon recommendation by GCAC.

(2) Any *Grid Code Participant*, member of the GCAC or the Authority may propose amendments to the Grid Code.

(3) Any *Grid Code Participant* can apply for an exemption. Exemption from the obligation to comply with provisions of the Grid Code may be granted by the Authority for the following reasons:

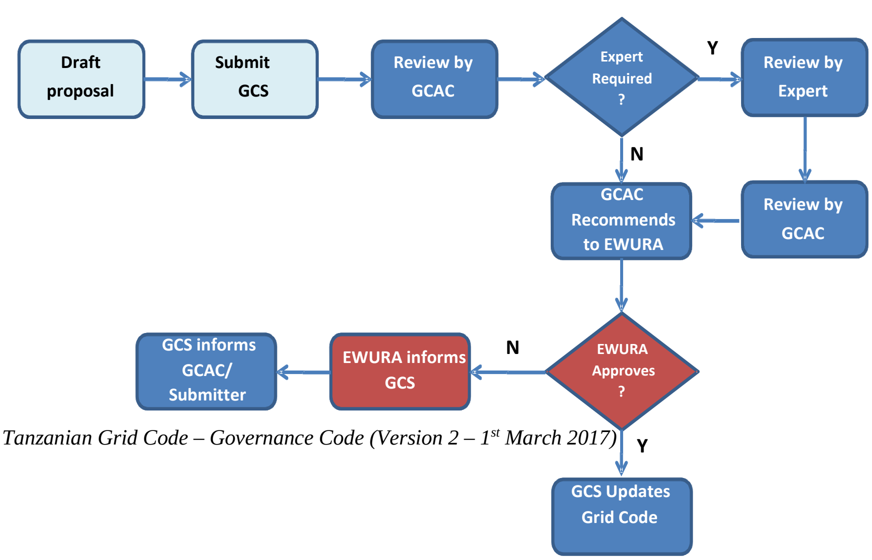
(a) To provide for existing equipment that has not been designed with consideration for the provisions of the Grid Code,

(b) To facilitate transition through interim arrangements, and

(c) To facilitate temporary conditions necessitating exemption.

(4) The procedure for amendment to or exemption from the Grid Code is set out in Figure 2 below:

FIGURE 2: GRID CODE AMENDMENT/EXEMPTION PROCEDURE



5.1 SUBMISSIONS TO THE GCAC

(1) The GCS shall make available a list of submission dates aligned with GCAC annual meetings for each year by November of the preceding year.

(2) Urgent submissions shall be dealt with at ad hoc meetings of the GCAC as decided by the Chairperson upon advice from the GCS.

(3) The GCS shall issue guidelines for submissions to the GCAC. The guidelines shall be published together with the submission dates on the Authority website.

(4) All applications for an amendment or exemption shall be submitted, in accordance with the guidelines, to the GCS. The applicant shall state the relevant clauses of the Grid Code and give reasons for the application.

(5) The GCAC shall initiate the review process without delay and shall:

   (a) Firstly, if deemed necessary, ensure that the submission is referred to an expert team(s) for detailed assessment, clarification, reformulation and/or recommendation, and

   (b) finally forward the recommendation to the Authority for consideration once it has been finalized.

(6) The GCAC shall take the complexity and importance of the amendment/exemption into account in deciding on the composition of the expert team that will deal with the submission.

(7) The GCS shall inform the applicant of the expected time frames for dealing with the submission.

(8) The applicant shall be allowed to make representation to the expert team sessions and/or the GCAC prior to the formulation or finalization of the GCAC recommendation to the Authority.

5.2 RECOMMENDATION TO THE AUTHORITY

(1) Once the GCAC has reviewed submissions, the GCS shall prepare the formal recommendation to the Authority for a decision on all proposed amendments and exemptions to the Grid Code. The recommendation(s) to the Authority shall also include a clear expression of divergent views on such proposals, if any were received. The recommendation shall include an appropriate implementation date for the proposed amendments and exemptions.

(2) Full or partial exemption from complying with a certain provision of the Grid Code may be granted to *Grid Code Participants*.

(3) All exemptions granted shall prevail over the relevant section of the Grid Code.

(4) Amendments and exemptions shall become effective after approval by the Authority .

(5) EWURA shall give notice to the GCS of the decisions reached by the Authority . The GCS is responsible for communicating these decisions to *Grid Code Participants*.

(6) The GCS shall update the Grid Code with the approved amendments and exemptions.

6 DISPUTE MEDIATION, RESOLUTION AND APPEAL MECHANISM

(1) In addition to the provisions of the Electricity Act that address dispute settlement, registered *Grid Code Participants* shall have access to a documented procedure for handling disputes arising under the Grid Code. The procedure shall cover the aspects described in Sections 6.3 and 6.4.

6.1 COMPLAINTS ABOUT THE OPERATIONS OF THE GCS OR THE GCAC

(1) Any complaint regarding the operations of the GCS or the GCAC shall firstly be addressed in writing to the GCS. The GCAC shall attend to such complaints at or before the next session.

(2) If the complaint is not resolved, the matter shall be referred to the Authority as a dispute as described in Section 6.33.

6.2 APPEAL AGAINST DECISIONS MADE BY THE AUTHORITY

Grid Code Participants may appeal to the Fair Competition Tribunal against decisions made by the Authority.

6.3 COMPLAINTS BETWEEN/AMONG CUSTOMERS AND GRID CODE PARTICIPANTS

(1) The procedure for handling complaints shall include the incident report and non-conformance report requirements as described in Sections 6.3.1 and 6.3.2.

(2) The Authority shall develop a database of disputes resolved to assist in the resolution of future disputes. Where the outcome of a dispute resolution proceeding would require or imply an amendment to the Grid Code, the Authority shall first consult with the GCAC.

6.3.1 INCIDENT REPORT (IR)

(1) An Incident Report should be seen as formal communication of a problem.

(2) A customer may issue an Incident Report to a *Grid Code Participant* on becoming aware of a problem or a possible breach of the Grid Code. The *Grid Code Participant* shall provide a reasonable explanation and, if appropriate, indicate what action it will take to address the problem.

(3) A *Grid Code Participant* may issue an Incident Report to a customer, where the customer is suspected of not complying with the necessary Grid Code requirements. The customer shall provide the *Grid Code Participant* with a reasonable explanation and, where appropriate, indicate the measures that will be taken to address the problem.

(4) *Grid Code Participants* shall keep a log of all Incident Reports received and a log of all incident reports communicated to *customers*.

(5) Incident Reports are operational in nature and generally require action only by technical and customer relations staff.

6.3.2 NON-CONFORMANCE REPORT (NCR)

(1) A *customer* may issue a Non-Conformance Report when it is suspected that:

(a) the *Grid Code Participant* has failed to provide a reasonable explanation,

(b) the *Grid Code Participant* has wilfully misrepresented the facts concerning an incident,

(c) the *Grid Code Participant* has failed to implement the agreed preventative actions within the agreed time frame,

(d) the number of incident reports is excessive in relation to historical performance or

(e) the actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to.

(2) A *Grid Code Participant* may issue a non-conformance report when it is suspected that:

(a) the *customer* has failed to provide a reasonable explanation,

(b) the *customer* has wilfully misrepresented the facts concerning an incident,

(c) the *customer* has failed to implement the agreed preventative actions within the agreed time frame,

(d) the number of incident reports is excessive in relation to historical performance or

(e) the actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to.

(3) Non-conformance reports are indications of problems that require managerial intervention by the *Grid Code Participant* or *customer*.

(4) In the case where the parties agree with the NCR, recommended action shall be agreed upon. Both participants shall implement these recommendations within an agreed time frame.

(5) *Grid Code Participant* shall report annually to the Authority on the following aspects of the procedure:

(a) Number of NCRs for each customer category,

(b) Number of closed out NCRs for each customer category and

(c) Number of disputes resolved.

(6) A dispute may be declared when the parties cannot agree on the NCR or the recommendations of the NCR or when the agreed recommendations are not implemented in the agreed time frame.

6.4 SUBMISSION OF DISPUTES TO THE AUTHORITY

(1) Disputes are unresolved complaints between parties that require intervention. Any *Grid Code Participant* may submit a dispute to the Authority provided the required process of either Section 6.1 or Section 6.3 has been followed.

(2) When a dispute is raised with the Authority, parties shall provide the following information:

(a) Full history of relevant incident reports,

(b) Detailed NCR and accompanying information that gave rise to the dispute and

(c) Written report from each participants detailing the reason for not being able to close out the NCR.

(3) When a dispute that has not followed the relevant procedure reaches the Authority, the Authority shall generally refer the party to the correct process.

(4) Any dispute between *Grid Code Participants* that remains unresolved after following the procedures set out above may be referred to the Authority for mediation.

(5) Should the dispute mediation process succeed, the parties shall strive to honour their respective undertakings/actions agreed upon to the best of their abilities.

(6) If mediation by the Authority fails to provide the parties with an agreed solution, the parties shall refer the matter for arbitration for final decision.

(7) There shall be one arbitrator who shall be, if the issue is:

(a) primarily an accounting matter, an independent Chartered Accountant,

(b) primarily a legal matter, a practising Senior Counsel, or

(c) primarily a technical matter, a person with suitable technical knowledge.

(8) The appointment of the arbitrator shall be agreed between the parties, but failing agreement between them within a period of 14 days after the arbitration has been demanded, either of the parties shall be entitled to request the Authority to make the appointment and, in making its appointment, to have regard to the nature of the dispute.

(9) The following shall be considered, amongst other things, during the arbitration process:

(a) Existing and historical performance trends or practices,

(b) Reference standards,

(c) Appropriate network design or operation standards,

(d) Precedents with similar events,

(e) Historical agreements between the participants and

(f) Total cost impact.

(10) The ruling of the arbiter shall include a time frame for implementation and shall be final and binding on the parties.

7 COMPLIANCE

(1) All *Grid Code Participants* shall comply with the Grid Code as updated from time to time.

(2) *Grid Code Participants* shall inform the Authority of any non-conformance report of a material nature that has been submitted to another participant in accordance with Section 6.3.2.

(3) The Authority may require a *Grid Code Participant* to provide information that is deemed necessary for the proper administration of the Grid Code. This information shall, upon request, be treated as confidential.

8 CODE AUDITS

(1) A *Grid Code Participant* may request from another *Grid Code Participant*, any material in the possession or control of that Participant relating to compliance with a section of the Grid Code. The requesting participant may not request such information in relation to a particular section of the Grid Code within six months of a previous request made under this clause in relation to the relevant section.

(2) A request under this clause shall include the following information:

(a) nature of the request,

(b) name of the representative appointed by the requesting participant to conduct the investigation, and

(c) the time or times at which the information is required.

(3) The relevant participant may not unreasonably withhold any relevant information requested. It shall provide a representative of the requesting participant with such access to all relevant documentation, data and records (including computer records or systems) as is reasonably requested. This information shall be treated as confidential if requested. Any request or investigation shall be conducted without undue disruption to the business of the participant.

9 CONTRACTING

(1) The Tanzanian Grid Code shall comprise one of the standard documents that form part of the contracting arrangements players in the electricity supply industry. Other contractual documents and arrangements include:

(a) Connection Agreements

(b) Use of System Agreements

(c) Operating Agreements

(d) Power: Purchase Agreements and/or Supply Agreements

(e) Ancillary Services Agreements

10 VERSION CONTROL

(1) The Grid Code will evolve as the electricity supply industry in Tanzania evolves.

(2) Each of the sections and codes that collectively form the Tanzanian Grid Code shall have separate version control and approvals.

(3) The GCS shall be responsible for version control.

SECOND SCHEDULE - THE DISTRIBUTION CODE

SECOND SCHEDULE

(Made under Rule 4)

THE DISTRIBUTION CODE

ENERGY AND WATER UTILITIES REGULATORY AUTHORITY (EWURA)

The Tanzania Electricity Distribution Code

Version 1

1st March 2017

Table of Contents

Acronyms

Standard SI symbols and abbreviations are used throughout the Distribution Code without re-definition here.

AC: Alternating Current

KVA: Kilo Volt Ampere

CAIDI: Customer Average Interruptions Duration Index

CAIFI: Customer Average Interruptions Frequency Index

CT: Current Transformer

CTI: Confederation of Tanzania Industries

EAPP: Eastern Africa Power Pool

EAPP IC: Eastern Africa Power Pool and East African Community Interconnection Code

E/F: Earth Fault

EMS: Energy Management System

EPP: Emergency Power Producer

EWURA: Energy and Water Utilities Regulatory Authority

DCMC: Distribution Code Management Committee

DNO: Distribution Network Operator

FCT - Fair Competition Tribunal

HV: High Voltage

Hz: Hertz

ICC: Installation completion Certificate

IEC: International Electrotechnical Commission

MAIFI: Momentary Average Interruptions Frequency Index

MV: Medium Voltage

MVA: Megavolt-Ampere

MW: Megawatt

PoC: Point of Connection

PPC: Point of Common Coupling

REA: Rural Energy Agency

SAIDI: System Average Interruptions Duration Index

SAIFI: System Average Interruptions Frequency Index

SCADA: Supervisory Control and Data Acquisition

SPP: Small Power Producer

SPD: Small Power Distributor

EPP: Emergency Power Producer

SO: System Operator

TCCIA: Tanzania Chamber of Commerce Industry and Agriculture

THD: Total Harmonic Distortion

VSPP: Very Small Power Producer

1. Preamble

1.1. Introduction

The preamble provides the context for the Distribution Code and its various sub-sections. It also contains detailed definitions and acronyms of the terms used in the Distribution Code.

1.2. Policy

1.2.1. Electricity Industry Structure

a) The current structure of the power sector in Tanzania is illustrated in figure 1 bellow.

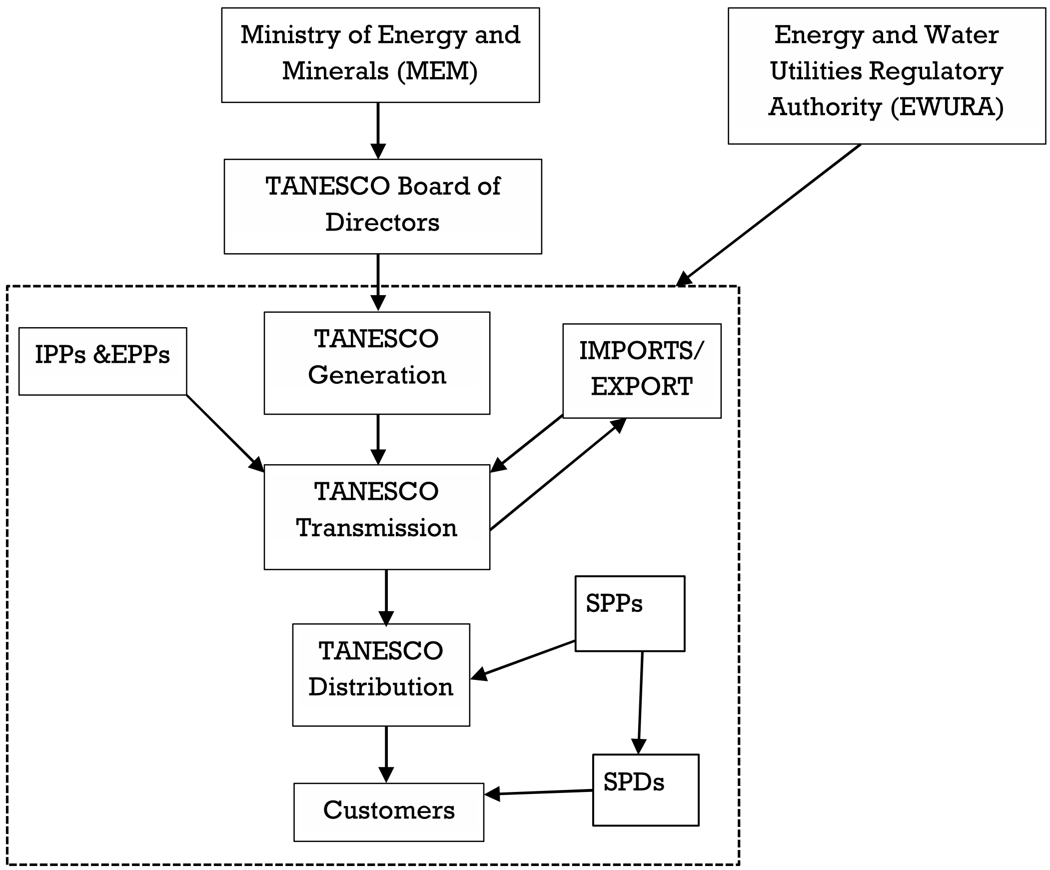


Figure 1: Tanzania Power Sector Structure

b) The Ministry of Energy and Minerals (MEM) oversees the power sector direction, and appoints TANESCO's Board of Directors. The Energy and Water Utilities Regulatory Authority (EWURA) is an autonomous multi-sectoral regulatory authority. It is responsible for technical and economic regulation of, among others, the electricity sector.

c) The Tanzania Electric Supply Company Limited (TANESCO) is a state owned, vertically integrated company carrying out generation, transmission and distribution. Under the current market structure, the System Operator is part of TANESCO Transmission.

d) Independent Power Producers (IPPs) are licensed to operate in the generation segment. In addition, interconnections with Zambia and Uganda enable imports of electricity. TANESCO Transmission acts as the single buyer for the purchases of this power.

e) Tanzania electricity market is vertically integrated; TANESCO generates imports and buys power in bulk from IPPs under a single buyer model and transports it over the transmission and distribution networks for resale to its customers.

f) Small Power Producer" ("SPP") is a licensed entity that generate electricity in the capacity between one hundred (100) kW and ten (10) MW using Renewable Energy, fossil fuels, a cogeneration technology, or some system combining fuel sources mentioned above, and either sells the generated power to TANESCO at wholesale, or directly to a Customer or Customers. An SPP may have an installed capacity greater than ten (10) MW but shall only export power at the Interconnection Point not exceeding ten (10) MW[1];

g) Small Power Distributor (SPD) is a licensed entity that purchases electricity at wholesale prices from TANESCO or some other bulk supplier and resells at retail prices to Customers. An SPD may also have a generator that qualifies for SPP or VSPP status and may use this generator to sell power to a DNO or some other Buyer, or to provide a backup supply of power to its own Customers;

h) Emergency Power Producer (EPP) is a licensed entity that generates electricity and sells to TANESCO on short term basis, following an emergency declaration by the Minister responsible for electricity supply.

1.2.2. Electricity Industry Reform

Tanzania will continue to pursue its on-going reform programme in the power sector in phases as follows:

a) In the immediate term TANESCO is expected to, among other things, ring fence its Strategic Business Units, reduce system losses, assess human capital needs, undertake capacity building and prepare for appropriate regulatory environment.

b) In the short term, the reform will result in unbundling of the generation segment from transmission and distribution, designation of an Independent System Operator (ISO) and the Independent Market Operator (IMO); creation of semi-autonomous Zones, reduction of system losses, development of management programs to support existing and new roles.

c) In the medium-term, reform will see the unbundling of distribution from transmission segment into Zonal distribution entities thus allowing generators to sell electricity directly to bulk off-takers while paying wheeling charges for the company responsible for transmission infrastructure; strengthening the IMO; increasing electricity connection levels, reducing system losses and setting up of retail market.

d) In the long term, the plan ultimately envisages the evolution from a single buyer market structure, with long-term PPAs with TANESCO, to a wholesale power market, in which the producers sell directly (or through a pool or voluntary electricity exchange) to distribution companies. Under this future market

[1] A generator shall not split its capacity that is greater than 10 MW in order to be eligible as an SPP and sign more than one contract for the total capacity available

structure, the roles and relationships associated with Transmission, System Operation and Distribution are likely to change and that the Distribution Code will need to be updated accordingly.

e) In order to ensure that the goals of the reform process are achieved, it is imperative that various arrangements are put in place that outline how the various parties in the electricity supply industry are expected to interact. The Distribution Code represents one such arrangement with the aims of facilitating and governing open and non-discriminatory access to the distribution system, setting standards for reliable and stable operation of the interconnected system, technically and commercially. The Distribution Code thus addresses the needs of the current market structure while taking cognisance of anticipated market reforms.

1.3. Authority

1.3.1. Legislation

a) The Distribution Code derives its legal mandate from the Electricity Act, Cap. 131 and from the Energy and Water Utilities Regulatory Authority (EWURA) Act, Cap. 414.

b) The Authority shall pursuant to Section 5 of the Electricity Act, have powers to:

i) award licences to entities undertaking or seeking to undertake a licensed activity;

ii) approve and enforce tariffs and fees charged by licensees;

iii) approve licensees' terms and conditions of electricity supply; and

iv) approve initiations of the procurement of new electricity supply installations.

c) Sections 8(1) and (2) of the Electricity Act specify the following activities as requiring a licence, unless the person or activity is exempted by the Authority:

i) Generation;

ii) Transmission;

iii) Distribution;

iv) Supply;

v) System Operation;

vi) Cross-border electricity trade;

vii) Physical and financial trade in electricity; and

viii) Electrical installation.

d) Furthermore, Section 45 (b) (vi) of the Electricity Act states that the Authority may, make Rules with respect to codes of conduct to be complied with. The Distribution Code is one such code of conduct.

1.3.2. Multiple Licences

a) Several of the licences identified above may be held by a single entity. The decision to grant multiple licences to a single entity depends on the functions that the company must fulfil.

b) A DNO may, for example, hold licences for transmission, supply, system operation, cross-border electricity trade, physical and financial trade in electricity and electrical installation.

1.3.3. Applicability

a) All licensees are required to comply with the provisions of the Act, Regulations and approved codes, specifically Section 21(2) of the Electricity Act requires a distribution licensee to comply with the applicable requirements of the Distribution Code, subject to conditions of licence and rules issued by the Authority. Any breach could result in the suspension or withdrawal of the licence or fine.

b) In terms of Section 18(1) of the Electricity Act, the Authority may grant exemptions to the licence conditions and code requirements.

c) The Distribution Code is applicable to all Distribution System Participants registered in accordance with the Distribution Code Governance.

1.4. Distribution Code

1.4.1. Definition

The Electricity Act defines the Distribution Code as technical and procedural rules and standards issued by the Authority governing matters pertaining to the distribution of electricity.

1.4.2. Objectives

a) The objective of this Code is to regulate the Distribution activities so that they are undertaken in a safe, efficient, reliable and economical manner.

b) In order to achieve this goal, the Distribution Code must:

   i) be objective;

   ii) be transparent;

   iii) be non-discriminatory;

   iv) be consistent with Government policies;

   v) define the obligations and accountabilities of all the parties;

   vi) specify minimum technical requirements for the Distribution system; and

   vii) be available.

c) The Distribution Code provides the following assurances:

   i) To the Authority, the assurance that the licensees operate according to the respective licence conditions.

   ii) To customers, the assurance that licensees operate transparently and provide non-discriminatory access to their defined services.

   iii) To licensees, the assurance that customers will honour their mutual Distribution Code obligations and that there is industry agreement on these.

1.4.3. Distribution Code Overview

a) The Distribution Code covers a range of issues, including governance, technical, commercial and operational. In order to present these issues in a structured way, the Distribution Code is divided into ten (10) sections as follows:

i) Preamble;

ii) Governance;

iii) Connection Requirement;

iv) Operations;

v) Metering;

vi) Performance Standards;

vii) Planning;

viii) Information Exchange;

ix) Asset Management; and

x) General Conditions.

b) The key aspects of each of these sections are briefly described below.

i) **Preamble** provides the context for the Distribution Code and its various subsections. It also contains detailed definitions and acronyms of the terms used in the Code.

ii) **Governance** sets out how the Distribution Code will be managed, which includes the formation of Distribution Code Management Committee and its operating procedures; transparency and non-discrimination procedures, as well as complaints and dispute resolution procedures.

iii) **Connection Requirement** focuses on equipment which has to be provided by the DNO; customers connection arrangements to the distribution system; customer application procedures; connection conditions; health, safety and emergency handling procedures; disconnections and reconnection procedures and handling of illegal electricity supply issues.

iv) **Operations** deals with procedures for operating a distribution network, including responsibilities of participants; authority of participants; operational liaison; emergency and contingency planning; abnormal conditions operations; independent action by participants; demand and voltage control; fault and reporting analysis; maintenance programs; testing and monitoring; safety coordination; disconnection and reconnections procedures; commissioning and connection; outage scheduling and coordination as well as tele-control.

v) **Metering** explains procedures for handling metering system issues which include, installations; maintenance; security; testing and commissioning; meter audit and accuracy testing as well as metering disputes.

vi) **Performance Standards** focuses on requirements of power quality issues including, quality and reliability of supply; protection; load power-factor; earthing; losses and guaranteed service level.

vii) **Planning** sets out framework for distribution network planning development and network investment criteria.

viii) **Information Exchange** sets out requirements for information exchange interface during planning and operations.

ix) **Asset Management** sets out requirements and procedures for good asset management in the distribution network.

x) **General Conditions** explain about liability, Force Majeure as well as health, safety and environment.

1.5. Definitions

The glossary of definitions and acronyms is set out taking cognisance of the international and regional context, recognising that some terms are, however, only used in the Tanzanian market.

Act – means the Electricity Act, Cap. 131.

Authority – means the Energy and Water Utilities Regulatory Authority established under EWURA Act, Cap. 414.

Bus bar- means an electrical conductor at a substation where incoming and outgoing electric lines, transformers and other equipment are connected.

Cross-border electricity trade – means trading in electricity between two countries sharing a common border through an interconnector power line, but linked through a power pool, which involves export or import of energy between the countries.

Customer Service Charter – means a document that sets out terms and conditions of provision of service, rights and obligations of a licensee and customers.

Customer – means a person who purchases or receives electricity for own use or sale.

Data – means factual information in numerical form (measurements or statistics) used as a basis for reasoning, discussion, or calculation (See Information).

Day - A period of 24 consecutive hours commencing at 00:00 hours and ending at 24:00 hours.

Distribution - means the transportation of electric energy and power by means of medium to low voltage lines, substation equipment and associated meters, including the construction, installation, operation, management and maintenance of such lines, equipment and meters.

Distribution Code – means the technical and procedural rules and standards issued by the Authority governing matters pertaining to the distribution of electricity.

Distribution Licensee – means a licensee authorised to undertake distribution activities.

Distribution System - mean an electricity network consisting of assets (including: substations, transformers, cables, lines and associated equipment), which are operated at Medium Voltage and Low Voltage.

Distributor Network Operator- means a licensed entity that owns operates and maintains a Distribution system.

Distribution Code Participant - means any legal entity that falls under the mandate of the Distribution Code and registered as set out in the Distribution Code.

Electricity supply industry – includes electricity generation, electric power transmission, electricity distribution and electricity supply.

Eligible Customer – means any person who is authorised by the Authority to enter into contract for the supply of electricity directly with any person licensed to generate electricity.

Embedded generator - means an electricity generator, other than a co-generator, that is supplying electricity in the Distribution Network and not directly connected to the Transmission System.

Emergency - means a situation where Transmission or Distribution licensees have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their system demand.

Emergency outage - means an outage when plant has to be taken out of service so that repairs can immediately be effected to prevent further damage or loss.

End-use customer - means a user of electricity of different classes such as Domestic, Commercial and Industrial.

Energy Management System - means a system of (usually computer-aided) tools used by operators of electric utility Distributions to monitor, control, and optimize the performance of the generation and/or transmission system. The monitoring and control functions are known as System Control and Data Acquisition (SCADA); the optimization packages are often referred to as "advanced applications".

EWURA Act – means the Energy and Water Utilities Regulatory Authorities Act, Cap. 414.

Fair Competition Tribunal- means a tribunal established under the Fair Competition Act, 2003.

Forced outage - means an outage that is not a Planned Outage.

Frequency - means the number of oscillations per second on the AC waveform.

Generation – means the production of electric energy and power from any primary source of energy.

Generating Unit - means a device used to produce electrical energy.

Generator - means a legal entity operating a licensed Generating Unit or Power Station.

High Voltage – means ac or dc voltage whose nominal r.m.s. value lies in the range $33kV < Un \leq 500$ kV.

Information - means any type of knowledge that can be exchanged, always expressed (i.e. represented) by some type of data.

Information Owner - means the party to whose system or installation the information pertains.

Instruction – means any command, given by the network operator either orally (via telephone), written or via remote control, to a generator in order to perform an action, enable/disable or block functionalities of a power station.

Interruption of Supply - means an interruption of the flow of power to a Point of Supply not requested by the customer.

Licence – means a licence issued by the Authority pursuant to the EWURA Act, relating to the electricity supply industry.

Licensed activity – means the activities specified as requiring a licence as set out in Sections 8(1) of the Electricity Act.

Licensee – means any person licensed to provide services under the licensed activities in the electricity market.

Low Voltage – ac or dc voltage whose upper limit of nominal r.m.s. value is 1 kV plus or minus five percent.

Losses - The technical and non-technical energy losses incurred on the distribution system.

Medium Voltage – ac or dc voltage whose nominal r.m.s. value lies in the range 1kV < Un ≤ 33kV plus or minus ten percent.

Metering - All the equipment employed in measuring the supply together with the apparatus directly associated with it.

Metering Installation - An installation that contains metering.

Minister – means the Minister responsible for electricity matters.

Month - A calendar month comprising a period commencing at 00:00 hours on the first day of that month and ending at 24:00 hours on the last day of that month.

Non-dispatchable generation - A generator can be non-dispatchable because of two reasons:

1. The generation technology does not allow a dispatch. This is mainly the case for fluctuating primary resources, like wind power or solar power. Such non-dispatchable power stations can be of any size in terms or MW. Depending on its size the point of connection might be at high, medium or low voltage, i.e. in transmission or distribution network.

2. The power generating installation is too small for individual consideration in the scheduling and dispatch process. This is the case for distributed generation in the low-voltage networks.

Participant - means distribution system participant.

Performance Agreement – means an agreement between a licensee and the Authority, which establishes incentives and penalties, related to the measurable performance of the licensee, and which is designed to improve the efficiency and effectiveness of the licensee.

Planned Interruption - means a Planned Outage that will interrupt customer supply.

Planned Outage - means an outage of equipment that is requested, negotiated, scheduled and confirmed a minimum of 14 days prior to the outage taking place.

Point of Common Coupling - means the electrical node, normally a bus bar, in a transmission substation where different feeds to customers are connected together for the first time.

Point of Connection - means the electrical node in a distribution substation where a customer's assets are physically connected to the distribution company assets.

Point of Delivery - See Point of Supply.

Point of Supply - means a distribution substation where energy can be supplied to customers/retailers (also known as Point of Delivery).

Power Station - means one or more Generating Units at the same physical location, including other necessary facilities, including buildings.

Primary Substation Equipment - means a high voltage equipment installed at substations.

Priority customers – means customers of a distribution licensee who, due to the essential nature of their activities, are prioritised by the Authority to receive supply when the licensee suspends electricity supply services.

Protection - means the process of preventing or clearing a fault on the IPS in order to protect plant and people.

Related business – means any business or company, which directly or indirectly, in whole or in part, is owned by the licensee; or is owned by a company, which owns or is owned by the licensee.

Scheduling - means a process to determine which unit or equipment will be in operation and at what loading.

Security - means the probability of not having an unwanted operation.

Service Provider - means any licensed entity that provides services to Distribution Code Participants pursuant to the Distribution Code, including:

i) Network Operator;

ii) System Operator; and

iii) Market Operator (if/when appointed).

Stakeholders - means the persons or entities affected by or having a material interest in the Distribution Code. This includes customers and other industry participants.

Substation - means a site at which switching and transformation equipment is installed.

Supply – means the sale of electricity to end customers.

System Operator – means a person licensed to provide system operation services.

Total Harmonic Distortion – is an indicator for distortion of the sinusoidal waveform of voltage or current and evaluated by the Total Harmonic Distortion factor THD using the following expression:

THD of voltage:

$$THD = \sqrt{\sum_{h=2}^{N} (U_h)^2}$$

where U_h is the r.m.s. value of the hth harmonic or interharmonic voltage component, as a percentage (relative amplitude (U_h) related to the fundamental frequency voltage U_1,) and N is the highest harmonic considered in the calculation. [2]

THD of current:

$$THD = \sqrt{\sum_{h=2}^{N} (I_h)^2}$$

where I_h is the r.m.s. value of the h^{th} harmonic or interharmonic current component, as a percentage (relative amplitude (I_h) related to the fundamental frequency current I_1,) and N is the highest harmonic considered in the calculation.

Note: The value of N is 40 if no other value is defined in the applicable standard referred to at the specific requirement of this code.

Transmission – means the transportation of electrical energy and power by means of high voltage lines, facilities and associated meters, including the construction, operation, management and maintenance of such lines, facilities and meters.

Transmission-Connected Customer – A Customer connected directly to the Transmission system.

Transmission Companies - means the entity responsible for provision of electricity transmission services, including transmission infrastructure owners and operators, System Operator and Ancillary services providers.

Type 1 Generating Unit – A generating units is of Type 1, if it uses a synchronous generators, which is synchronously connected to the grid (directly or via a machine transformer). A Type 1 generating unit is for example the synchronous generator of a steam power plant, a hydro power plant or a conventional combustion engine unit. In this paragraph, the term “generator” refers to the electric device (not to the entity).

Type 2 Generating Unit – A generating unit is of Type 2, if it uses any generator technology which is different from a synchronously grid-connected synchronous generator. A Type 2 generating unit is for example a photovoltaic inverter, a wind turbine with fully rated converter, a wind turbine with doubly-fed induction generator, etc. or a simple induction generator. In this paragraph, the term “generator” refers to the electric device (not to the entity).

1.5.2. Notices and domicile

a) Communication with the Authority in respect of the normal operations of this Distribution Code shall be sent to the following address:

The Director General,

Energy and Water Utilities Regulatory Authority,

P.O. Box 72175,

7th Floor, LAPF Pension Funds Towers,

Opposite Makumbusho Village, Kijitonyama,

Dar es Salaam, Tanzania.

Email: info@ewura.go.tz

Fax: (+255 -22) 292 3519

b) Any notice given in terms of this Distribution Code shall be in writing and shall

i) if delivered by hand, be deemed to have been duly received by the addressee on the date of delivery and a receipt will have to be produced as proof of delivery;

ii) if posted by pre-paid registered post, be deemed to have been received by the addressee 14 days after the date of such posting;

iii) if successfully transmitted by facsimile, be deemed to have been received by the addressee one day after dispatch.

iv) Notwithstanding anything to the contrary contained in this Distribution Code, a written notice or communication actually received by one of the parties from another, including by way of facsimile transmission shall be adequate written notice or communication to such party.

2. Governance under this Distribution Code

2.1. Introduction

This section describes the Governance provisions necessary for the overall administration and review of the various aspects of the Distribution Code. This code shall be read in conjunction with the relevant legislation, licences issued to generators, transmission companies, Market Operator, Distribution Network Operators and Suppliers, and other operating codes that relate to the electricity supply industry.

Pursuant to Section 1 and Section 45 (b) (vi) of the Act the Authority is mandated to promulgate and enforce the Distribution Code. The Authority shall establish a Distribution Code Management Committee (DCMC) to monitor, evaluate, review, and report and advice the Authority on compliance of the Distribution Code.

2.2. Purpose and Scope Distribution Code Management Committee (DCMC)

2.2.1. Purpose

The purpose of Distribution Code Management Committee is to:

a) ensure that all users of the distribution system are represented in reviewing and making recommendations pertaining to connection, operation, maintenance, and development of the distribution system;

b) facilitate the monitoring compliance with the Distribution Code at the operational level; and

c) Specify the process for the settlement of disputes, enforcement and revision of Distribution Code.

2.2.2. Scope

The function of the Distribution Code Management Committee covers the activities of:

a) Distribution Network Operators (DNOs);

b) Other DNOs connected to the distribution system;

c) System Operator;

d) Embedded Generators;

e) Retail Suppliers; and

f) End Users (including eligible Customers).

2.3. Distribution Code Management Committee

2.3.1. Constitution of Distribution Code Management Committee (DCMC)

The DCMC shall be composed of the following members who shall be appointed by the Authority:

a) Two members nominated by DNOs;

b) One member nominated to represent industrial and commercial customers;

c) One member nominated by EWURA CCC to represent residential customers;

d) One member nominated by System Operator;

e) One member nominated to represent embedded generators;

f) One member nominated by REA;

g) One Member from Ministry responsible for energy; and

h) One Members from the Authority.

The representative from the industrial and commercial consumers shall be nominated by the respective associations (CTI, TCCIA).

The members of DCMC shall have sufficient technical background and experience to fully understand and evaluate the technical aspect of distribution system operation, planning and development.

The Chairman of DCMC shall be selected by the Authority from a list of three (3) members nominated by DCMC.

2.3.2. Term of office of DCMC members

All members to DCMC shall have a term of three years, and shall be allowed for one re – appointment. In case a member is not able to continue until the end of the term, the same shall be replaced by a suitable candidate from the relevant group to complete the remaining period of the term.

2.3.3. DCMC operating cost

a) The DCMC operating costs shall be borne by the Authority;

b) The Authority shall provide secretariat services to the DCMC;

c) The DCMC shall prepare and submit annual work plan and budget requirements to the Authority by March every year;

d) Any direct and incidental expenses to DCMC shall be determined and paid for by the Authority.

2.3.4. DCMC Conduct of Business Procedures

The DCMC shall, within six months of being formed, establish and publish its own procedures relating to the conduct of its business. The procedures shall be approved by the Authority. The procedures shall include, but not limited to:

a) Administration and operation of the committee;

b) Establishment and operation of DCMC subcommittees;

c) Evaluation of distribution system operations reports;

d) Coordination of dispute resolution process related to the Distribution Code;

e) Monitoring of Distribution Code enforcement;

f) Revision of distribution code provisions;

g) Review of distribution development plans; and

h) Review of major distribution system reinforcement and expansion projects.

i) Where necessary, DCMC may establish subcommittees on specific issues as may be deemed necessary.

2.4. Transparency & Non-discrimination

2.4.1. Publication of Procedures

a) The DNOs shall develop and publish in detail all the requirements, qualifications and administrative procedures to be fulfilled or followed by those seeking to be provided services by the DNOs.

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

c) The qualifications shall include all legal, financial and technical qualifications to be fulfilled.

d) The administrative procedures shall include all administrative, financial, technical and any other procedures to be followed prior to the commissioning of the connection as well as the obligations of the main actors for the continued provision of the service.

e) The Authority shall publish the Distribution Code on its website and where possible copies will be made available to the public.

2.4.2. Equal Application Of Distribution Code

The Distribution Code shall be fairly and uniformly applied to all participants of distribution activities. All conditions and situations that are similar shall also receive consistent and equitable treatment.

2.4.3. Exercise of Discretion by The DNOs & Other Officials

a) The DNO or any other participant shall not make a decision that is inconsistent with the Distribution Code in respect of the usage or provision of services from the distribution network.

b) The DNO may use its discretion and good judgment in making decisions on any matter on which this Distribution Code does not contain complete or adequate stipulations.

c) The exercise of a discretionary power shall however be justified in writing to the Authority and the affected party at the same time that such decision is taken.

d) The principles and rationale for any discretion exercised or decision taken by the DNO shall be published and made available to any person upon request.

e) Person aggrieved by a discretionary decision taken by the DNO may request for a review by the Authority as necessary.

f) The Authority shall consider the complaint and uphold or recommend a reconsideration of the decision.

2.4.4. Charges For Distribution Network Services

Charges for the use of the distribution network or the services of the DNO shall not exceed those approved by the Authority.

2.5. Complaints and Dispute Resolution

a) A DNO must handle a complaint by a customer in accordance with the provisions of the Act, Regulations and Rules issued by Authority.

b) The DNO must include information on its complaint handling processes in the DNOs' Customer Service Charter.

c) When a DNO responds to a customer's complaint, the DNO must inform the customer;

   i. that the customer has the right to raise the complaint to a higher level within the DNOs' management structure; and

   ii. if, after referring the complaint to a higher level the customer is still not satisfied with the DNOs' response, the customer has the right to refer the complaint to the Authority, and if not satisfied with the Authority decisions, the customer can further refer the matter to the Fair Competition Tribunal (FCT).

3. Connection requirements

3.1. Introduction

This section describes the connection procedures for connecting to the distribution system.

3.2. Objective

The object of this section is to set the basic procedures of connecting to the distribution system that will ensure that all users are treated in a non-discriminatory manner and specify the technical requirements that will ensure safety and reliability of the Distribution System.

3.3. Equipment

In respect of each location address which is in a DNO's designated area, the DNO must provide, install and maintain standard metering and necessary associated equipment, at a suitable location to be provided by the customer in respect of that location address.

3.4. New Connection

3.4.1. Connection Arrangement

a) Customers seeking a new connection to the Distribution System shall lodge an application to connect to the Distribution System with the relevant DNO. Each DNO shall develop its own application form in line with this code.

b) Customers applying for MV and HV supplies should provide additional information on fluctuating loads, capacitor banks and reactors that could affect the performance of the Distribution System.

c) Upon receiving the application for connection the DNO shall comply with all other requirements relevant to the connection process specified in this code

3.4.2. Application for Connection

a) Upon receipt of an application for connection to the Distribution System, the DNO shall advise whether the applicant can be connected to the existing system and / or what technical improvements are required to enable the new connection.

b) The DNO shall provide an offer to connect, and if accepted by the customer, both parties shall enter into a connection agreement.

c) The connection agreement shall include information such as project planning data, inspection, testing and commissioning programs, electrical diagrams and any other information the DNO may deem necessary to proceed with the processing of the application for connection.

d) If the application for connection has been declined, the DNO shall advise the customer on the alternative options available for connection to make the connection successful.

e) If the customer and the DNO cannot reach an agreement on the proposed connection, a dispute resolution process, as outlined in the Governance Section, shall be followed.

f) Subject to clauses 3.4.2. (b) and 3.4.2 (c), the DNO shall prepare an offer to connect the customer within the period specified in the customer service charter of the DNO.

g) The offer to connect issued by the DNO, shall be fair and reasonable and may contain alternative options available to the customer.

h) Any negotiations taking place between the parties shall be conducted in good faith, and both parties shall treat any information provided in a confidential manner.

3.5. Condition for Connection

The DNOs' obligation to connect is subject to:

a) an adequate supply of electricity being available at the required voltage at the point of connection;

b) an dully filled Installation Completion Certificate (ICC) being provided to the DNO in respect of the customer's electrical installation;

c) Payment of respective connection fees;

d) The customer complying with reasonable technical requirements required by the DNO; and

e) the customer providing acceptable identification.

3.6. DNOs Equipment on Customer Premises

a) A customer must:

   i) not interfere, and must use best endeavours not to allow interference with the DNO's distribution network including any of the DNO's equipment installed in or on the customer's premises; and

   ii) provide and maintain on the customer's premises any reasonable or agreed facility required by its DNO to protect any equipment of the DNO.

b) Provided official identification is produced by the DNO's representatives on request, a customer must provide to the DNO's representatives at all times convenient an unhindered access:

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

   ii) to the customer's electrical installation for the purposes of:

      A. the inspection or testing of the customer's electrical installation to ascertain whether customer is complying with this Code; or

      B. connecting, disconnecting or reconnecting supply, and safe access to and within the customer's premises

c) If necessary, the customer must provide safety equipment and appropriate safety instructions to representatives of the DNO to ensure safe access to the customer's premises.

d) In cases other than emergencies, a DNO must use best endeavours to access a customer's premises at a time, which is reasonably convenient to both the customer and the DNO.

4. Operations

4.1. Introduction

This section describes operational procedures and responsibilities of the distribution system participants.

4.2. Objective

The objective of this section is to set out the responsibilities and roles of the participants as far as the operation of the Distribution System is concerned and more specifically issues related to:

a) economic operation, reliability and security of the Distribution System;

b) operational authority, communication and contingency planning of the Distribution System;

c) management of power quality;

d) operation of the Distribution System under normal and abnormal conditions; and

e) field operation, maintenance and maintenance coordination/ outage planning; and safety of personnel and public.

4.3. Responsibilities

4.3.1. Distribution Network Operator

a) The DNO shall operate the Distribution System to achieve the highest degree of reliability and shall promptly take appropriate remedial action to relieve any condition that may jeopardise reliability.

b) The DNO shall co-ordinate voltage control, demand control, operating on the distribution System, and security monitoring in order to ensure safe, reliable, and economic operation of the distribution System.

c) In the event of an embedded generator having to shut down or island plant because of a disturbance on the distribution network, the DNO shall carry out network restoration to minimise the time required to resynchronise the shed embedded generating units.

d) Ensuring that the availability and reliability of every power station supply is maximised at all times under normal and abnormal conditions.

e) The DNO may shed customer load to maintain system integrity. Following such action, the customer load shall be restored as soon as possible after restoring and maintaining system integrity.

f) The DNO shall operate the Distribution System as far as practical so that instability, uncontrolled separation or cascading outages do not occur.

g) The DNO is responsible for efficient restoration of the Distribution System after supply interruptions. The restoration plans shall be prioritised in accordance with customer requirements and as prescribed in the governing legislations.

h) The DNO shall ensure it has sufficient resources to continuously monitor and operate the Distribution System.

i) The DNO shall establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the Distribution System under normal and abnormal system conditions.

j) The DNO shall operate the distribution System within defined technical standards and equipment operational ratings.

k) The DNO shall ensure adequate and reliable communications to all major users of the distribution System.

4.3.2. Embedded Generators and Other Customers

a) When conditions on the Distribution System, under normal or abnormal conditions, become such that it may jeopardise plant or personnel of customers, customers shall immediately disconnect from the distribution system.

b) The Embedded Generator shall ensure that its generating units are operated within the capabilities defined in the Connection Agreement entered into with the DNO.

c) The Embedded Generator shall reasonably cooperate with the DNO in executing all the operational activities during an emergency generation condition.

d) Customers shall assist the DNO in correcting quality of supply problems caused by the Customer's equipment connected to the Distribution System.

e) Customers shall at all times operate their appliances or equipment in a manner that ensures their compliance with the conditions specified in Chapter 7 together with firm establishment of settings as agreed with the responsible DNO.

f) All customers must declare any generating plant that may be paralleled with the Distribution network via switching, and specify the interlocking mechanism to prevent inadvertent parallel operation with the DNO's network. For generating units with a nominal active power of 100 kW or less, a declaration of the manufacturer of the generating unit about the fulfilment of the connection / reconnection conditions according to Section 7.2.3, 7.3.3 or 7.4.3 respectively is sufficient, instead of a specification of the interlocking mechanism.

g) Embedded generators with Type 1 generating units shall have the required protection to trip in the event of a momentary supply loss causing an island condition to prevent paralleling out of synchronism due to auto-reclose functionality on the DNO's network.

4.4. Operational Authority

a) The DNO shall have the authority to instruct operating on the Distribution System. Operational authority for other networks operators shall lie with the respective asset owners.

b) Network control, as it affects the interface between the DNO and a customer, shall be in accordance with the operating agreements between the participants.

c) Except where otherwise stated in this code, no participant shall be permitted to operate equipment of another participant without the permission of such other participant. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with its own standards before such permission is granted.

d) Notwithstanding the provisions of clause 4.3.1 of this code, participants shall retain the right to safeguard their own equipment.

4.5. Procedures

a) The DNO shall develop and maintain operating procedures for the safe operating of the Distribution System, and for assets connected to the Distribution System. These operating procedures shall be adhered to by participants when operating equipment on the Distribution System or connected to the Distribution System.

b) Each customer shall be responsible for his own safety rules and procedures at least in compliance with the relevant safety legislation. Customers shall ensure that these rules and procedures are compatible with the DNO developed procedures defined in clause 4.5 (a) above.

c) Customers and service providers shall enter into operating agreements, where not included in the supply agreement, as defined in the service provider licences.

4.6. Operation Liaison

a) The DNO shall be responsible for ensuring adequate operational liaison with other connected participants.

b) The participants shall appoint competent personnel to operate their network, and where needed shall establish direct communication channels amongst themselves to ensure the flow of operational information between the participants.

c) If any participant experiences an emergency, the DNO may call upon other participants to assist to an extent as may be necessary to ensure that such emergency does not jeopardise the integrity of the Distribution System.

d) Pursuant to clause 4.5 (c) above, the relevant participant shall ensure that the emergency notification contains sufficient details in describing the event including the cause, timing and recording of the event to assist the DNO in assessing the risk and implications to the distribution system and all the affected Customers' equipment.

e) For planned events, which have an identified operational effect on the Distribution System, or on Customers’ equipment connected to the Distribution System, the relevant participant shall notify the DNO.

f) Where it is possible for a customer to parallel supply points or transfer load or embedded generation from one point of supply to another by performing switching operations on the customer’s network, the operating agreement shall cover at least the operational communication, notice period requirements and switching procedures for such operations.

g) The DNO and customers shall agree on the bus-bar configuration(s) at each point of supply during normal and emergency conditions. The DNO shall keep updated records of such agreements.

4.7. Emergency and Contingency Planning

a) The DNO shall develop and maintain emergency and contingency plans to manage the system contingencies and emergencies that affect the delivery of the Distribution System and the Interconnected Power System. Such plans shall be developed in consultation with all affected participants, and shall be consistent with internationally acceptable best practices, and shall include but not be limited to:

i) under-frequency load shedding,

ii) Prevention of voltage slide and collapse,

iii) meeting any national disaster management requirements including the necessary minimum load requirements,

iv) forced outages at any point of connection,

v) restoration and continuation of supply to every power station during normal and abnormal conditions is to be classified as a high priority, and

vi) supply restoration.

b) Emergency plans shall enable the safe and orderly recovery from a partial or complete system collapse, with minimum impact on customers.

c) All contingency and emergency plans shall be reviewed biennially or in accordance with changes in network conditions.

d) All contingency and emergency plans shall be verified by audits, if possible by using on-site inspections and actual tests. In the event of such tests causing undue risk or undue cost to a participant, the DNO shall take such risks or costs into consideration when deciding whether to conduct the tests. Any tests shall be carried out at a time that is least disruptive to the participants. The costs of these tests shall be borne by the respective asset owners. The DNO shall ensure the co-ordination of the tests in consultation with all affected participants.

e) The DNO shall, in consultation with the transmission company and system operator, set the requirements and implement:

i) Automatic and manual under frequency load shedding in accordance with the System Operator's requirements.

ii) Automatic and manual under voltage load shedding to prevent voltage collapse.

iii) Manual load shedding to maintain network integrity.

f) Participants shall make available loads and schemes to comply with these requirements.

g) The DNO shall be responsible for determining emergency operational limits on the Distribution System, updating these periodically and making these available to the participants.

h) The DNO shall conduct network studies, which may include but not be limited to load flow, fault level, stability and resonance studies to determine the effect that various component failures would have on the reliability of the Distribution System.

4.8. Operations during abnormal condition

a) During abnormal operating conditions the DNO shall be obliged to take necessary precautionary measures to prevent network disturbances from spreading and to restore supply to consumers as quickly as possible.

b) The DNO shall cooperate with the system operator and transmission network service provider in taking corrective measures in the event of abnormal conditions on the Distribution System. The corrective measures shall include both supply-side and demand-side options. Where possible, warnings shall be issued by the DNO to affected participants on expected utilisation of any contingency resources.

c) The DNO shall be entitled to disrupt some sections of the network in the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken.

d) Termination of the use of emergency resources shall occur as the order of return being determined by the most critical loads, first in terms of safety and then plant.

e) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with procedures prepared by the DNO.

4.9. Independent Action by Participant

Each participant shall have the right to reduce supply or demand, or disconnect a point of connection under emergency conditions, if such action is necessary for the protection of life or equipment and shall give advance notice of such action where possible.

4.10. Demand and Voltage Control

a) The DNO shall implement demand control measures when:

   i) Instructed to by the System Operator;

   ii) Abnormal conditions exist on the Distribution System;

   iii) Multiple outage contingency exists resulting in island grid operation; and

   iv) Any other operational event the DNO deems to warrant the implementation of demand control measures for the safe operation of the Distribution System.

b) Demand control shall include but not limited to:

   i) Customer demand management;

   ii) Automatic under-frequency load shedding;

   iii) Automatic under-voltage load shedding;

   iv) Emergency manual load shedding; and

   v) Voluntary load curtailment.

c) The DNO shall develop load reduction procedures, which shall be regularly updated, to reduce load in a controlled manner taking cognisance of the type of load.

d) The DNO shall endeavour to maintain system voltage to be within statutory limits at the points of supply or otherwise as agreed in the operating/ supply agreement.

4.11. Fault Reporting and Analysis

a) The end-user customers and embedded Generators shall report the loss of major loads or generation (as agreed by the participants) to the DNO within 15 minutes of the event occurring. Notice of the intention to reconnect such load shall be given with at least 15 minutes advance notice to enable the DNO to take any necessary action required.

b) The DNO shall investigate all incidents that materially affected the quality of supply to another participant. The DNO shall initiate and coordinate such an investigation and make available the findings of such investigation to affected participants on request.

c) The findings of such an investigation shall include where relevant:

   i) Date and time of the incident.

   ii) Location of the incident.

   iii) Duration of the incident.

   iv) Equipment involved.

   v) Cause of the incident in compliance with applicable national standards.

   vi) Demand control measures undertaken specifically recording the customer MWs shed and energy lost as a result of the measures taken.

   vii) Supply restoration details.

   viii) Embedded Generation interrupted.

   ix) Under-frequency Load Shedding response.

   x) Estimated date and time of return to normal service.

   xi) Customer load tripped MW and energy lost when incident occurred or as a direct result of incident not including any Demand Control Measures taken.

   xii) Estimate number of customers having lost supply.

   xiii) Recommendations.

d) Any participant shall have a right to request an independent audit of the findings, at its own cost. If these audit findings disagree with the original findings, the participant may follow the dispute resolution mechanism as specified in the Governance section.

4.12. Maintenance Program

a) Each DNO shall have a maintenance philosophy against which their maintenance practices and programs are compiled and documented in accordance with applicable national standards. These documented maintenance programs must be auditable.

b) The DNO shall compile at least an annual maintenance plan in line with the budget period.

c) Accurate records of maintenance done shall be kept for a period of at least 5 years.

d) Scheduling of planned outages should coincide with the maintenance requirements of other participants connected to the affected network.

e) All participants that may be affected by the planned outages will be informed at least 2 days or 48 hours in advance.

4.13. Testing and Monitoring

a) A participant has the right to request to test and / or monitor any equipment at the point of connection to the Distribution System to ensure that the participants are not operating outside the technical parameters specified in any part of the Distribution Code and other applicable standards which the participants are required to comply with. Such testing and / or monitoring shall be carried out as mutually agreed by the parties.

b) A participant found to be operating outside the technical parameters shall, within such time agreed upon by the parties involved, remedy the situation or disconnect from its network the equipment causing problems.

c) Any dispute arising out of the test and monitoring process shall be resolved through the dispute resolution mechanism in the Governance section.

4.14. Safety Coordination

a) The DNO shall comply with relevant legislation and develop Operating Regulations to ensure safety of personnel, whilst operating on the Distribution System or any equipment connected to the Distribution System.

b) Where operational boundaries exist, there shall be a joint agreement on operating procedures to be complied with by all affected participants.

c) There shall be written authorisation of personnel who operate on or work on live equipment forming part of or connected to the Distribution System.

d) The "Operating Regulations" referred to in clause 4.14(a) of this code shall include rules and regulations for the safe operating of plant, continuity of supply and authorisation of personnel related to the operating of HV, MV and LV equipment.

4.15. Disconnection and Reconnection

4.15.1. Non-compliance

A DNO may disconnect supply to a customer's supply address if:

a) the customer has not fulfilled an obligation to comply with this Code;

b) the DNO has given the customer a written notice of disconnection in accordance with the existing legislation; and

c) the customer fails to comply with a written notice of non-compliance issued by the DNO or any arrangement entered into by the DNO and the customer which the customer has failed to comply with including non-compliance with the DNO applicable standards.

4.15.2. Health, Safety or Emergency

a) A DNO may disconnect supply to a customer's supply 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.

b) 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 DNO must not disconnect a customer’s supply under clause 4.15.2(a) unless the DNO has:

   i) given the customer written notice of the reason; and

   ii) allowed the customer reasonable time in accordance with relevant legislations from the date of receipt of the notice to eliminate the cause of the potential danger.

c) The DNO shall have the right to interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the Customer’s premises or on the Distribution System.

4.15.3. Retailer’s request

a) A DNO must disconnect supply to a customer’s supply address if the customer’s retailer has requested disconnection.

b) Upon the receipt of a valid request by the customer’s retailer, where the DNO is able to disconnect supply to the customer’s supply address by de-energising the customer’s supply address remotely and reasonably believes that it can do so safely, subject to clause 4.15.6, the DNO must use its best endeavours to disconnect supply to the customer’s supply address within two hours.

c) Part (b) does not apply to a request for disconnection at a scheduled time.

4.15.4. Customer’s request

a) A DNO must disconnect supply to a customer if the customer has requested disconnection and must use best endeavours to disconnect supply in accordance with the customer’s request.

b) Upon such a request, where the DNO is able to disconnect supply to the customer by de-energising the customer’s supply remotely and reasonably believes that it can do so safely, subject to clause 4.15.6 the DNO must use its best endeavours to disconnect supply to the customer within two hours of a request being validated by the DNO.

c) Paragraph (b) does not apply to a request for disconnection at a scheduled time.

d) Customer (connected at MV and HV levels) shall give written notice to the DNO of any intended voluntary disconnection.

4.15.5. Illegal supply

A DNO may disconnect supply to a customer 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 the supplied electricity at a customer's premises to another supply premise;

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.

4.15.6. No disconnection

a) A DNO must not disconnect supply to a customer's supply address except in the case of an emergency or under clause 4.15.5 or otherwise as agreed with a customer:

   i) after 2 pm on a weekday; or

   ii) on a Friday, a weekend, public holiday or on the day before a public holiday.

b) Despite any other provision of this Code, a DNO must not disconnect supply to a customer:

   i) if the customer's supply address is registered as a life support machine supply address except in the case of an emergency; or

   ii) for non-compliance under clause 4.15.1 if:

      A. the customer is a tenant and is unable to remedy the non-compliance as it is not the owner of the supply address;

      B. there is a dispute between the customer and the DNO which has been notified by the customer under clause 2.5 and is still being dealt with by the DNO under that clause, or is the subject of proceedings before the Authority or other relevant external disputes resolution body; or

   iii) if the DNO reasonably considers that disconnecting supply would in any way immediately endanger the health or safety of any person.

4.15.7. Reconnection of Supply

a) If a DNO has disconnected a customer as a result of:

   i) non-compliance with this Code under clause 4.15.1 and the customer has remedied the non-compliance; or

   ii) danger under clause 4.15.2 has been eliminated by the customer; or

   iii) a request from a retailer, on request by the customer or by a retailer on behalf of the customer, but subject to other applicable laws and codes and the customer paying any reconnection charge (determined by reference to its approved statement of charges), the DNO must reconnect the customer.

b) If a customer, or a retailer on behalf of a customer, makes a request for reconnection under clause 4.15.7 (a) (iii) to a DNO:

   i) before 3 pm on a working day, the DNO must reconnect the customer on the day of the request; or

   ii) after 3 pm on a working day, the DNO must reconnect the customer on the next working day.

   iii) where the DNO is able to reconnect the customer by re-energising the customer's supply address remotely, subject to paragraphs (i) and (ii), the DNO must use its best endeavours to reconnect the customer within two hours of a request being validated by the DNO.

c) Notwithstanding 4.15.7 (b) above, DNO and a customer may agree later times and a customer has to apply to the DNO for reconnection.

A DNO is not obliged to reconnect a customer under clause 4.15.7 (b) unless the DNO reasonably believes that it can do so safely.

4.16. Commissioning and Connection

a) MV and HV customers shall supply commissioning programmes to the DNO control and operating facility at least 1 month in advance. Subsequently, a notice of first connection shall be given to the DNO control and operating facility at least 2 weeks before actual connection. Details of the information required shall include but not be limited to the following:

   i) Commissioning procedures and programmes

   ii) Documents and drawings required

   iii) Proof of compliance with standards

   iv) Documentary proof of the completion of all required tests

   v) SCADA information, to be available and tested before commissioning

   vi) Site responsibilities and authorities.

b) When commissioning equipment at the point of connection, the DNO shall liaise with the affected participants on all aspects that could potentially affect their operation.

c) The DNO and customers shall perform all commissioning tests required in order to confirm that the DNO's and the customers' plant and equipment meet all the requirements of the Distribution Code before being connected to and energised from the Distribution system.

4.17. Outage Scheduling and Coordination

4.17.1. Responsibilities of the Distribution Network Operator

a) DNO shall, with reference to the relevant network Service Providers outage plans and relevant Generators outage programs, compile the daily outage schedule which shall:

   i) endeavour to cater for the planned maintenance and commissioning of new equipment.

   ii) describe the planned outage.

   iii) Identifies the risks and impact on network performance.

   iv) describe the practical contingency plans devised to counter risks, and

   v) define the roles and responsibilities of the personnel designated to manage and minimise the impact of these outages on the Distribution System and its users.

b) Notwithstanding clause 4.17.1 (a) above, the DNO shall co-ordinate relevant outages with the system operator.

c) In addition to clause 4.17.1 (a) above, the DNO may require information from the Customers regarding major plant and associated equipment, which may affect the performance of the Distribution System and may require additional resources to be committed during the outage planning process.

d) Customers with co-generation and Embedded Generators with the maximum capacity greater than 1MW shall furnish to the DNO information on planned outages in order for the DNO to properly plan, and coordinate its control, maintenance and operation activities.

e) The Distribution outage schedule shall be submitted to the Authority upon request.

4.17.2. Risk-related Outages

a) All risk-related outages shall be scheduled with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of the relevant DNO.

b) Contingency plans shall address:

   i) Safety of personnel.

   ii) Security and rating of equipment

   iii) Continuity of supply

c) The relevant control centres shall confirm that it is possible to execute the contingency plan successfully.

4.17.3. Communication of System Conditions, Operational Information and Distribution System Performance

a) The DNO shall be responsible for providing participants with operational information as may be agreed from time to time. This shall include information regarding planned and forced outages on the DNO.

b) The DNO shall inform participants of any network condition that is likely to impact the short and long-term operation of that participant.

c) The DNO shall record operational information as specified in the Information Exchange section. This information shall be made available to all participants on request.

4.18. Unplanned Interruptions or Outages

a) In case of unplanned interruptions or outages the DNO may require a customer to comply with reasonable and appropriate instructions from the DNO and may further:

   i) Require the customer to provide the DNO emergency access to customer owned distribution equipment normally operated by the DNO or DNO owned equipment on customer's property.

   ii) Interrupt supply to the customer to effect repairs to the Distribution System.

b) Subsequent to clause 4.18 (a), the DNO shall make arrangements to keep customers informed about the expected duration and other details following unplanned interruptions.

4.19. Refusal/Cancellation of Outages

a) No participant may unreasonably refuse an outage request.

b) No participant may unreasonably postpone or cancel a previously accepted outage.

c) The direct costs related to the cancellation / postponement of an outage shall be borne by the respective asset owners.

4.20. Planned Interruptions or Outages

For planned interruptions or outages the DNO shall act in accordance with its Customer Service Charter and provide the affected Customers with information relating to the expected date of the outage, time and duration of the outage, and shall established reasonable means of communication to the Customers for outage related enquiries.

4.21. Tele-control

Where Tele-control facilities are shared between the DNO and other participants, the DNO shall ensure that operating procedures are established in consultation with the participants.

5. Metering

5.1. Introduction

The purpose of this Distribution Metering section is to specify the technical and operational criteria, including the procedures to be complied with by the DNO, in carrying out its obligation to provide metering services to Distribution Network Users at each Metering Point. It also applies to Distribution Network Users in so far as their equipment may affect the Distribution System.

5.2. Application

The Distribution Metering section applies to the following:

i) DNOs; and

ii) Distribution Network Users connected to, or seeking connection to the Distribution System.

The DNO shall:

a) own, install, verify, operate, maintain, inspect and replace all Metering Systems at Metering Points on the Distribution System, except Metering Systems situated at Connection Points to the Transmission System;

b) ensure that each Metering System installed on its Distribution System meets the performance, functional and technical requirements set out in this code;

c) ensure that each Metering System installed on its Distribution System is certified where so required by the Authority, is in working condition and has been tested for accuracy;

d) retrieve data from each Metering System installed on its Distribution System for the purposes of billing and settlement;

e) process data retrieved from each Metering System installed on its Distribution System for the purposes of billing and settlement;

f) notify the Authority of all Metering Systems where the DNO cannot comply with the Distribution Metering requirements.

g) fully implement Net Metering systems, as appropriate.

5.3. Obligations

5.3.1. Installation and Replacement of Metering Equipment

a) The installation of Metering Equipment shall be in accordance with the technical requirements of the DNO.

The DNO may replace Metering Equipment for which it is responsible at any time after it has been installed, subject to the provisions of this code. The DNO shall notify the Distribution Network User in advance of any replacement, unless that replacement is an urgent condition.

The DNO shall:

i) assign a unique identifier to the metering system, cross referenced to the location of the metering system;

ii) record the date of installation of the metering system;

iii) record the functionality of the meter and the unit of measurement used to measure energy flowing through the metering system or maximum load, as it corresponds;

iv) record the identification of the ancillary equipment;

v) record any site-specific loss adjustment factors to be applied;

vi) record redundancy details and sources of check metering data and identification of the meters designated as the main meter and as the check meter;

vii) record the initial meter register reading;

viii) ensure that the metering data stored in the metering system is retrieved and, where a meter is removed, shall ensure that a final meter reading is obtained.

b) The DNO shall maintain the following information for each Metering System:

i) location of the Metering System;

ii) a record of any malfunction of the Metering System including any test results and of repairs made to the metering System; and

iii) documentation of meter testing prior to installation.

c) The DNO shall, on request, make the information available for each metering system to:

i) the Distribution Network User;

ii) the Authority.

5.4. Standard Metering Systems

a) Each metering Point shall be situated as close as is reasonably practicable to the relevant Connection Point.

b) Prior to the installation of any meter or current and voltage transformers that form part of a metering system, such metering equipment shall be:

i) Submitted by the DNO to a laboratory for testing and certification; or

ii) Received by the DNO directly from a manufacturer with a test certificate endorsed by an independent laboratory.

c) Copies of all test certificates shall be retained by the DNO for the metering equipment that is in service and for metering equipment that is no longer in use for a minimum period of five years. The DNO shall produce these certificates upon notice from the Authority.

d) No metering equipment shall be certified unless the DNO has received the relevant test certificates from the relevant accredited laboratory or manufacturer.

e) The DNO shall install and maintain at the power delivery point an appropriate metering system which shall be equipped with the following:

   i) a multifunction meter type with accuracy of class 1 or better and which is able to store historical information with integrated interval of 20 minutes for kVA registration;

   ii) Current and voltage transformers with an accuracy of 0.5 or better.

5.5. Additional Requirement for Metering System

Upon the request of a distribution network user, the DNO may arrange for a metering System to install a check meter, or to contain features or equipment in addition to those specified in this code, provided that:

a) The distribution network user agrees to pay the full costs of the additional features or equipment, including the costs of installation, operation, maintenance, repairs and replacement; and

b) The additional features or equipment are compatible with the rest of the metering system and do not lead to any degradation of the capability of the metering system that would cause the metering system to fail to meet any standards contained in this code.

5.6. Faulty Metering Equipment

a) A Metering System shall be considered faulty and not in compliance with this Code if it is determined that any part of that metering system does not comply with this code.

b) If a Metering System fault occurs, the DNO shall repair or replace the metering system as soon as is reasonably practicable and in any event within two working days of the DNO discovering that the fault exists.

c) The distribution network user shall use metering equipment in a safe and prudent manner and shall take due care to avoid damage. The Distribution Network User shall notify the DNO of any damage to the metering equipment, however caused.

d) The DNO shall ensure that suitable data is obtained or estimated for the period of time commencing when a meter or metering Equipment becomes faulty until the completion of the repair or replacement. Where the check meter exists then it should be used.

e) The DNO shall record all relevant Meter parameters for a replacement Meter in that Metering System.

5.7. Technical Requirement and Accuracy of Meters

a) The DNO shall ensure that the accuracy of each Meter in each Metering System is certified by an accredited Meter test laboratory and meets the applicable accuracy limits.

b) In the event of non-compliance with the required standards, the DNO shall ensure that the accuracy of any Meter in that Metering System is restored to comply with the accuracy standards as soon as is reasonably practicable.

c) The DNO shall maintain certification records and test results relating to the accuracy class and compliance with the relevant standards for the particular type and model of Meter in that Metering System.

d) The DNO shall maintain records of the information referred to in this section for each Metering System, either in use or no longer in use, as per clause 5.4 (c), and shall produce these records when required by the Authority.

5.8. Audit and Installation Tests

a) The DNO shall ensure that each metering system is inspected according to the minimum frequencies specified:

   i) Medium and high Voltage: Once every year.

   ii) Low Voltage, including prepayment: Once every 5 years.

b) The DNO may carry out periodic, random and unannounced inspection and or testing of any metering system and associated data for the purpose of ascertaining whether the metering system complies with the requirements of this code.

c) The distribution network user may request the DNO to carry out such inspection and or testing, provided that the distribution network user pays the cost, unless an error or malfunction not caused by the distribution network user is discovered. In addition, the Authority may carry out its own unannounced inspection and or test, in which case the distribution network user shall grant access to the Authority.

d) The DNO shall, as soon as practicable, make the results of any inspection and or tests conducted pursuant to this section available to the requesting party and to the distribution network user associated with the metering system.

5.9. Access to Metering System

a) The distribution network user shall grant access to the DNO to enable the DNO to fulfill its obligations. This right of access is conditional upon;

   i) where practicable, prior notice by the DNO; and

   ii) the production of identification by the DNO's staff or contractor.

b) Prior arrangement by the DNO shall not be required in respect of routine meter reading or periodic, random and unannounced audits or when the DNO is performing urgent metering repairs.

5.10. Security of Metering System

a) Appropriate seals shall be applied to each metering system.

b) Seals shall be replaced following work requiring the removal of any seals.

c) The DNO shall have procedures for the control of seals and sealing pliers.

d) The DNO shall, so far as is reasonably practicable, ensure that physical access to each meter contained in each metering system is protected by:

   i) Sealing all associated links, circuits, data storage and data processing systems;

   ii) ensuring that the metering system meets the requirements for the security of metering systems;

e) The DNO shall use reasonable endeavours to ensure that all metering data within each metering system is secure.

5.11. Metering Disputes.

a) If the DNO receives a complaint about the accuracy of metering data or the calculation of any substitute or estimated metering data from the Distribution Network User, the DNO shall investigate the complaint.

b) The investigation shall include a review of all available information, including any information supplied by the Distribution Network User.

c) If the DNO determines that there is an inaccuracy due to Meter error, malfunction or error in the metering data, the DNO shall take appropriate steps to remedy the defect, including repair or replacement of equipment and adjustment of metering data.

d) Appropriate adjustments shall also be made to the Distribution Network User's bill.

e) In the event of a dispute, the dispute shall be settled using the procedure specified in this code.

6. Performance Standards

6.1. Introduction

This section describes the quality and reliability of power supply, protection requirements, losses and performance levels.

6.2. Quality of Supply

a) The DNO and other participants shall comply with the applicable National standards and the Authority's directives regarding the parameters listed below:

  i) Voltage harmonics and inter-harmonics

  ii) Voltage flicker

  iii) Voltage unbalance

  iv) Voltage dips

  v) Interruptions

  vi) Voltage regulation

  vii) Frequency

  viii) Voltage surges and switching disturbances

b) Special quality of supply criteria apply to Embedded Generator, as specified in Chapter 7.

6.3. Reliability of Supply

a) Before end of year, a DNO must publish on its website, and in a newspaper circulating in the area in which its distribution system is located, its targets for reliability of supply for the following year.

b) As a minimum, these targets must include for customers supplied from Industrial feeders, urban feeders and rural feeders:

  i) average duration in minutes of interruptions per customer (SAIDI) due to planned interruptions;

  ii) average duration in minutes of interruptions supply per customer (SAIDI) due to unplanned interruptions;

  iii) average number of unplanned interruptions per customer (SAIFI), excluding momentary interruptions;

  iv) average number of momentary interruptions per customer (MAIFI); and

  v) average cumulative duration of unplanned interruptions (CAIDI).

c) A DNO may interrupt supply at any time for the following reasons:

  i) planned maintenance, repair, or augmentation of the distribution system;

ii) unplanned maintenance or repair of the distribution system in circumstances where, in the opinion of the DNO, the customer's electrical installation or the Distribution System poses an immediate threat of injury or material damage to any person, property or the distribution system;

iii) to shed energy because the total demand for electricity at the relevant time exceeds the total supply available;

iv) as required by Transmission Utility's System Operator;

v) the installation of a new supply to another customer;

vi) in the case of an emergency; or

vii) to restore supply to a customer.

d) In the case of an unplanned interruption or an emergency, a DNO must:

i) within 30 minutes of being advised of the interruption or emergency, or otherwise as soon as practicable, make available, by way of a 24 hour telephone service, radio announcement and by way of frequently updated entries on a prominent part of its website, information on the nature of the interruption and an estimate of the time when supply will be restored or when reliable information on restoration of supply will be available;

ii) provide options for customers who call the service to be directly connected to a telephone operator if required; and

iii) use best endeavours to restore the customer's supply as soon as possible making allowance for reasonable priorities.

e) Wherever reasonable and practicable, a DNO must provide prior information to customers who may be interrupted by load shedding.

f) In the case of a planned interruption, the DNO must provide each affected customer with at least 2 days written notice of the interruption. The notice must:

i) specify the expected date, time and duration of the interruption; and

ii) include a 24 hour telephone number for enquiries.

g) The DNO must use best endeavours to restore the customer's supply as quickly as possible.

h) Interruption Performance Indices

i) The Authority shall be responsible for setting the format in which the Distribution Reliability Indices are reported.

ii) The Authority shall annually evaluate the Distribution System Reliability Indices to compare each DNO's actual performance with the DNO unique targets set by the Authority and the Authority shall publish these comparative results

6.4. Protection Requirement

a) The DNO's protection system shall be appropriately designed and maintained to ensure optimal discrimination, safety and minimum interruptions to customers.

b) The customer shall install and maintain protection, which is compatible with the existing Distribution System protection. The customer's protection settings shall ensure coordination with the DNO's protection.

c) The customer shall, on request, provide the DNO with test certificates, prior to commissioning, of the protection system/s that are installed at the point of interface with the DNO.

d) Participant's protection system shall, where applicable, make provisions to safeguard their own equipment from faults or conditions that may occur at the point of connection including loss of one or two phases of the three phase supply and low voltages on the phases and any auto-reclosing or sequential switching features that may exist on the Distribution System.

e) Where equipment or protection schemes are shared, the participants shall provide the necessary equipment and interconnections to the equipment of the other party.

f) Embbeded generators have to fulfil the requirements specified in Chapter 7, in addition to the requirements described in this section.

6.5. Load Power Factor

a) Customers, except for embedded generators, (with demand exceeding 100kVA) shall ensure that the power factor shall not be less than 0.9 lagging nor shall it go leading unless otherwise agreed to with the relevant DNO.

b) Should the power factor go beyond these limits, participants shall take corrective action within a reasonable timeframe or as agreed between the parties, to remedy the situation.

c) The participant intending to install power factor correction equipment for the purpose of complying with the power factor requirements shall inform the relevant DNO.

d) Requirements for embedded generators are specified in Chapter 7.

6.6. Earthing Requirement

a) The DNO shall advise customers upon request about the neutral earthing methods used in the Distribution System.

b) The method of neutral earthing used on those portions of Customer's installations that are physically connected to the Distribution System shall comply with the DNO's applicable earthing standards for loads and for embedded generators.

c) Protective earthing of equipment must be done in accordance with the applicable national standard.

d) In cases where the calculated Ground Potential Rise exceeds 5kV the responsible party shall inform the affected participants.

e) Approved designed lightning protection requirements shall be applied to the Distribution System and switching yards.

f) Substation earthing requirement shall be in accordance with the National standards.

6.7. Losses

a) Losses shall be classified into two categories:

   i) Technical Losses; and

   ii) Non-Technical Losses

b) The DNOs shall endeavour to keep the distribution losses at economically acceptable levels in compliance with the Authority's directives on distribution losses given from time to time.

6.8. Equipment Requirement

a) Equipment at the connection point shall comply with the technical requirements specified in Chapter 7, the DNO's prescribed standards or any equivalent national standards prevailing at the time.

b) The DNO shall, upon request, provide the customer with the necessary information to enable the customer to install equipment with the required rating and capacity.

c) The participants shall ensure that all equipment at the connection point is maintained at least in accordance with the manufacturers' specifications or an alternate industry recognised methodology.

d) The participants connected at MV and HV levels shall retain the test results and maintenance records relating to the equipment at the connection point and make this information available if requested.

6.9. Guaranteed Service Levels.

DNOs shall comply with Guaranteed Service Level Standards as prescribed in the approved Customer Service charter and Performance agreement between DNO and the Authority.

7. Technical Requirements

7.1. Technical Requirements for Generation with Type 1 Generating Units and a PoC at MV

a) The Subsection “Generator Connection Conditions” of The Network Code [1] of the Grid Code applies to generation with Type 1 generating units and a point of connection (PoC) at medium voltage (MV) in the same way as with a PoC at high voltage (HV).

7.2. Technical Requirements for Generation with Type 2 Generating Units and a PoC at MV

a) This section describes technical requirements for generation with Type 2 generating units and a PoC in an MV network, including Isolated Mini Grids.

b) These requirements do not apply to micro off-grids. However, if it is intended to let off-grid generating units run in parallel to the grid once an off-grid is interconnected to the main network, it is recommended to consider these requirements as far as possible during off-grid operation as well.

7.2.1. Operating Voltage Band

a) The generation facility must be able to fully operate in steady-state in a voltage band of +/- 5%, i.e. 0.95 p.u. through 1.05 p.u. around the nominal voltage at the point of connection (PoC).

7.2.2. Operating Frequency Band

a) The generation facility must be able to operate in steady-state in a frequency band of +/- 2.5% around the nominal frequency of 50 Hz, i.e. 48.75 Hz through 51.25 Hz.

b) In island systems and Isolated Mini Grids the maximum deviation from standard frequency can be larger (up to +/- 5% [2]). Therefore a capability to operate in steady-state in a frequency band of +/- 5.0% around the nominal frequency is recommended in these systems, but not mandatory.

7.2.3. Connection and Reconnection Requirements

a) A connection of a power generating unit shall be admissible only if the network voltage at the PoC is inside its normal operating voltage band (0.95 p.u. – 1.05 p.u.) and the frequency is between 47.5 Hz and 50.5 Hz (which are the lower frequency band limit under extreme system operation of fault conditions and the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System). In Isolated Mini Grids the threshold values may differ from the values given above and have to be specified by the responsible network operator with respect to the voltage and frequency bands in the Isolated Mini Grid.

b) If the voltage at the PoC is outside of the above mentioned voltage band (0.95 p.u. – 1.05 p.u.), connection shall be blocked.

c) If the frequency is below 47.5 Hz or above 50.5 Hz, connection shall be blocked. A different value for the setting may be applied in agreement with the responsible DNO (especially in island systems or Isolated Mini Grids).

d) The reconnection of a power generating unit after being disconnected for protection with respect to Section 7.2.9 or Section 7.2.10, is only allowed:

   i. if the voltage at the PoC is within the normal operating voltage band of 0.95 p.u. – 1.05 p.u.,

ii. if the frequency is above 47.5 Hz and below 50.5 Hz (a different value for the setting may be applied in agreement with the responsible DNO, especially in island systems or Isolated Mini Grids),

iii. if there is no Instruction from the network operator for disconnection or for power limit of 0%, compare Section 7.2.11, and

e) If the power station consists of several generating units, the responsible DNO can specify a minimum delay time interval between the connection/reconnection of the individual units in order to limit impact on voltage and ensure desired power quality (e.g. flicker).

7.2.4. Harmonics and Flicker

a) The power station shall withstand and function correctly in the presence of harmonic voltages up to the compatibility levels for MV networks specified in [2] (long-term and short-term).

b) The power station is not allowed to inject harmonic currents into the network which lead to harmonic voltages or a THD at the PCC which are higher than the compatibility levels for MV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

c) If the compatibility levels for harmonic voltages or THD at the PCC are exceeded in operation, the responsible DNO has to carry out measurements in accordance to [2] in combination with [3] or if applicable in combination with [4] in order to find the most disturbing device. If this device belongs to the power station, the generator has to do countermeasures to lower the harmonic disturbance.

d) The power station shall withstand and function correctly in the presence of voltage flicker up to the compatibility level for MV networks specified in [2].

e) The power station is not allowed to perform power changes which lead to voltage flicker at the PCC which are higher than the compatibility levels for MV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

7.2.5. Reactive Power Capability

a) If the generating units run with nominal active power, the reactive power flow at the point of connection (PoC) of the installation shall be sufficient to provide a power factor at the PoC of at least 0.95 overexcited to 0.95 underexcited, i.e. 0.95 or lower for voltage increasing operation and 0.95 or lower for voltage decreasing operation, if the voltage at the PoC is within 0.95 through 1.05 p.u.

b) In partial load operation, the power station shall have the capability to inject/absorb the same amount of reactive power as at nominal active power of the generating units, down to 20% of the nominal active power of the power station, as depicted in Figure 7.1.

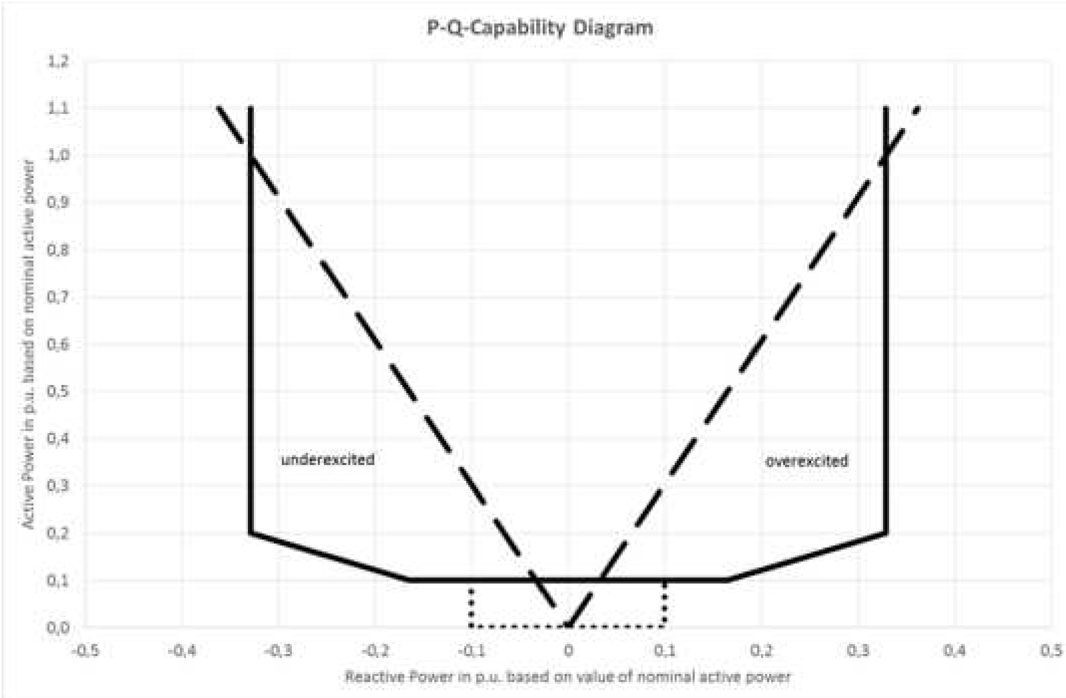


Figure 7.1: P-Q-Capability Diagram (generation oriented),
solid curve: requirement,
dashed curve: power factor = 0.95
dotted curve: area of 10% reactive power below 10% active power

c) Between 10% and 20% of the nominal active power of the power station, the reactive power requirement is as depicted Figure 7.1.

d) Below 10% of the nominal active power of the power station, the reactive power injection/absorption shall not be larger than 10% based on the value of the nominal active power of the installation (i.e. inside the dotted line of Figure 7.1). This requirement does not apply, if an operation in synchronous condenser or STATCOM mode has been agreed with the network operator.

e) With respect to voltage-dependency of the reactive power capability.

i. above 1.02 p.u. voltage at the PoC, the same underexcited reactive power (absorption of reactive power) is require as at 1.00 p.u. voltage, but less overexcited reactive power (injection of reactive power), as depicted in Figure 7.2,

ii. below 0.98 p.u. voltage at the PoC, the same overerexcited reactive power (injection of reactive power) is require as at 1.00 p.u. voltage, but less underexcited reactive power (absorption of reactive power), as depicted in Figure 7.2.

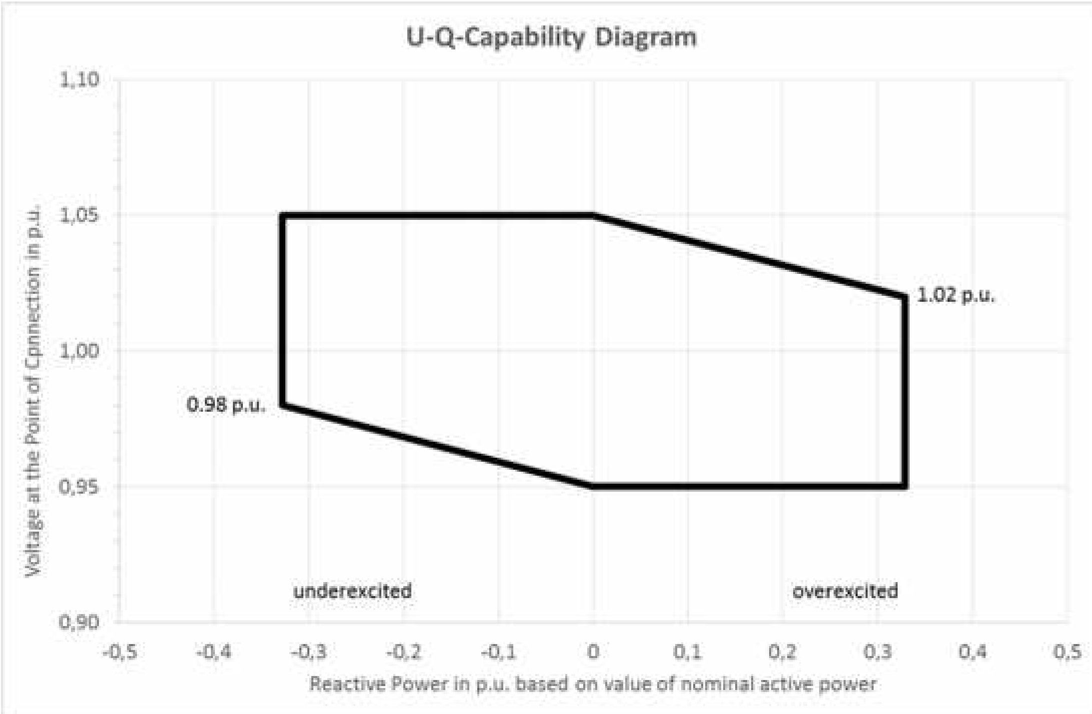


Figure 7.2: U-Q-Capability Diagram solid line = requirement for 20% to 100% nominal active power

f) The generator shall document the maximum possible reactive power capability in terms of five P-Q-Capability Diagrams of the power station as follows, and a U-Q/Pmax-Profile of the power station and provide the information to the network operator. Voltage drop and voltage rise within the power station and loading of the equipment within the power station (e.g. cables, transformers) has to be considered.

   i. P-Q-Capability Diagram of the installation for 0.95 p.u. voltage at the PoC

   ii. P-Q-Capability Diagram of the installation for 1.00 p.u. voltage at the PoC

   iii. P-Q-Capability Diagram of the installation for 1.05 p.u. voltage at the PoC

   iv. U-Q/Pmax-Profile of the installation

g) In order to achieve the requirement at the PoC, usually the generating units have to provide a larger reactive power capability at their terminals. If the generating units cannot provide sufficient reactive power to fulfil the requirement of the installation at the PoC, additional devices such as capacitor banks, shunt reactors, STATCOMs or synchronous condensers can be installed within the power station.

7.2.6. Power Factor Control Capability

a) A power station with Type 2 generating units shall provide the capability of the following two control modes effective at the point of connection (PoC) of the power station:

   i. reactive power (constant Q)

   ii. power factor (constant cos phi)

b) For power stations with Type 2 generating units, the network operator selects the control mode which has to be activated for operation and specifies the parameter settings, depending on the location of the PoC in the network.

c) A power station with Type 2 generating units shall be able to operate in any operating point of the reactive power capability diagram specified in Section 7.2.5, for the active power range which is possible to operate with respect to the primary power source of the power station.

d) For an adjusted control mode and parameter set, the power station with Type 2 generating units shall be able to settle each accessible operating point with respect to the control mode within 30 seconds.

7.2.7. Voltage Control Capability

a) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 30%[2] of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have voltage control capability, in addition to the power factor control capabilities described in Section 7.2.6.

b) In order to run stable with neighbouring power stations, the voltage control has to be equipped with a voltage/reactive power droop functionality.

7.2.8. Behaviour During Network Faults

a) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV is smaller than or equal to 15% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), these generating unit shall disconnect from the grid as fast as possible by means of protective disconnection devices, if the voltage at the PoC becomes lower than 0.9 p.u.

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 15% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have Under-Voltage-Ride-Through (UVRT) and Over-Voltage-Ride-Though (OVRT) capability. Any new generating unit and any equipment of a new power station shall be designed with anticipation of the following voltage conditions at the Point of Connection:

    i. A voltage deviation in the range of 95% to 105% for protracted periods.

    ii. A voltage dip to zero for up to 0.2 s, to 75% for 2 s, or to 85% for 60 s provided that during the 3 minute period immediately following the end of that 0.2 s, 2 s, or 60 s periods the actual voltage remains in the range 95-105% of the nominal voltage (compare Section "External supply disturbance withstand capability" of The Network Code [1]).

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[2] The limitation of the requirement with respect to share of the sum of nominal power of Type 2 generating units shall allow easier network access as long as there are not as many installations with Type 2 generating units with PoC at MV, but guarantee a strict enough requirement if Type 2 generating units reach a share with considerable impact on the system.

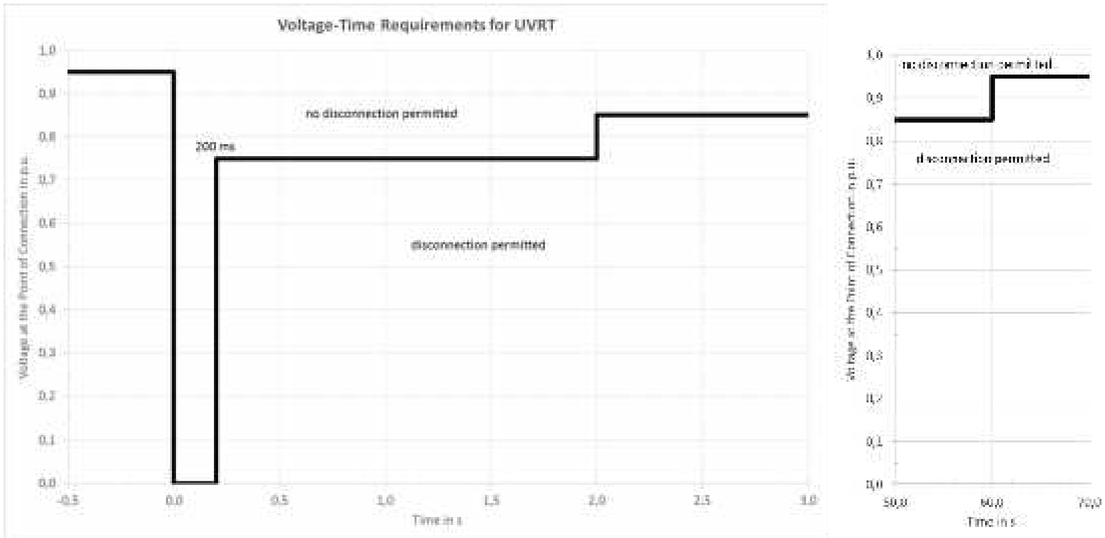

Figure 7.3: Voltage-Time Requirements for Under-Voltage-Ride-Through (UVRT)

iii. A voltage rise to 120% for 2 s, or to 110% for 60 s provided that during the 3 minute period immediately following the end of that 2 s, or 60 s periods the actual voltage remains in the range 95-105% of the nominal voltage.

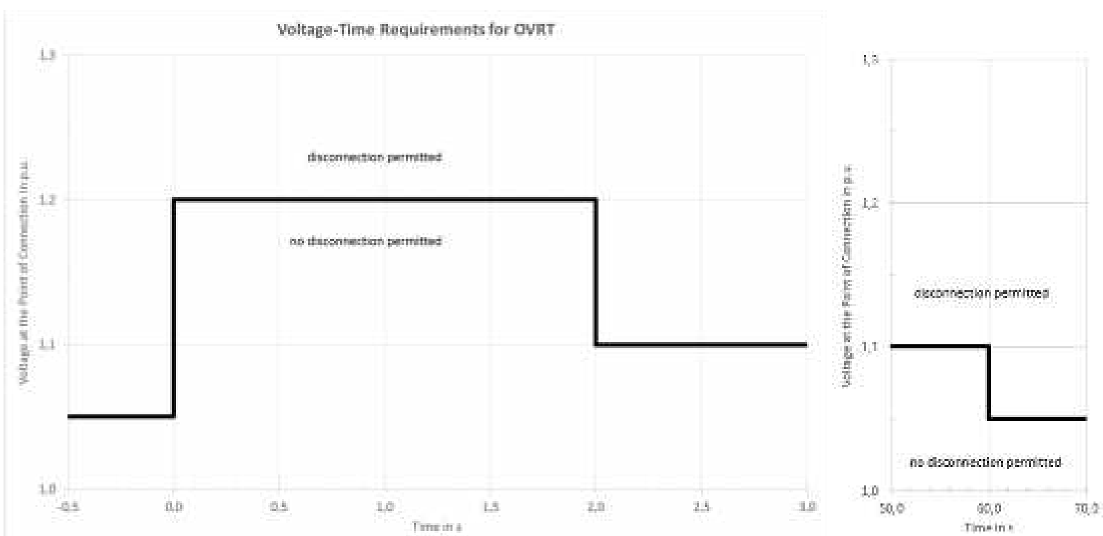

Figure 7.4: Voltage-Time Requirements for Over-Voltage-Ride-Through (OVRT)

iv. The voltage to be considered is:

the lowest of the three line-to-line voltages in cases of voltages below 100% of the nominal voltage, and the highest of the three line-to-line voltages in cases of voltages above 100% of the nominal voltage.

v. During UVRT or OVRT the injected active and reactive current has to be reduced to the minimum possible current (reduction to zero is recommended).

c) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must inject additional reactive during to support the voltage during the aboe specified Under-Voltage-Ride-Through (UVRT) and Over-Voltage-Ride-Though (OVRT):

i. Generating units of Type 2 shall start to inject an additional reactive current ΔI_Q at their terminals in proportion to the deviation of the voltage U from the pre-fault voltage U_0, following the equation given below, if the voltage at the unit's terminal is 10% (percentage based on nominal voltage) below the pre-fault voltage U_0, as depicted in Figure 7.5.

$$\Delta I_Q / I_n = K \cdot (-\Delta U)/U_n = -K \cdot (U - U_0)/U_n$$

The equation is written generation oriented, i.e. the additional current is an overexcited reactive current (supporting voltage) in case of a voltage dip.

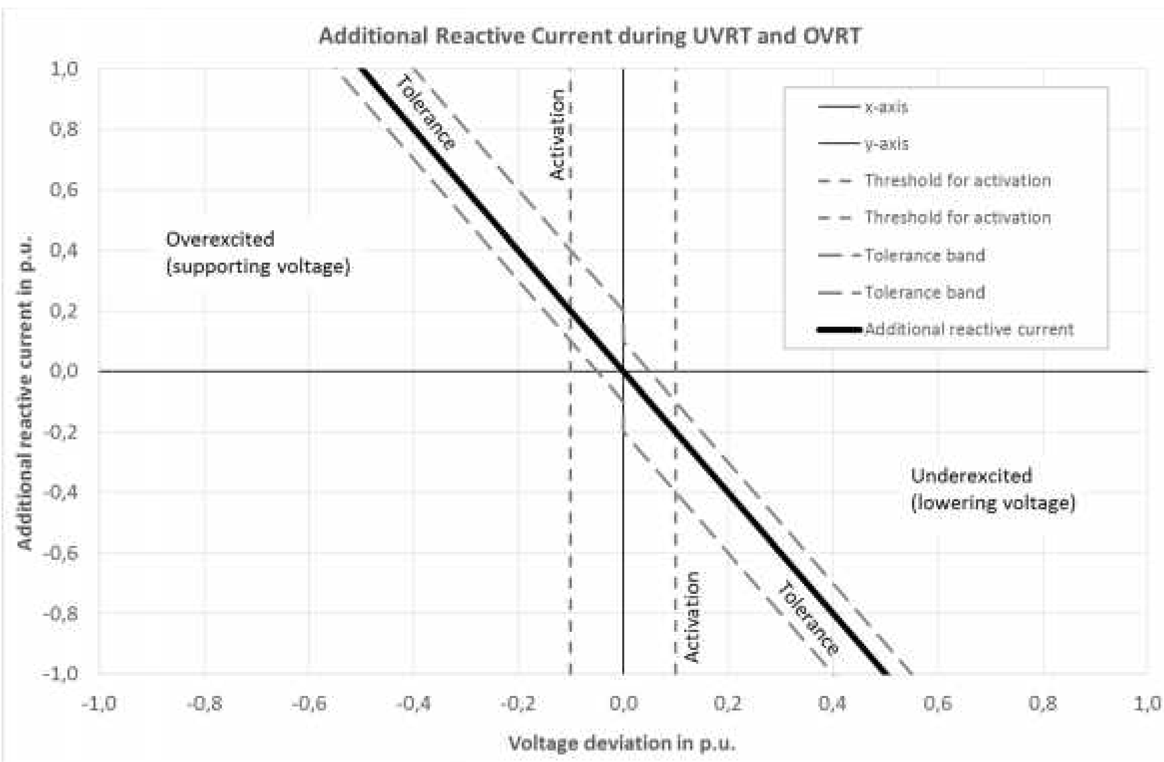

Figure 7.5: Requirement for additional reactive current

Note: The diagram is drawn in a generation-oriented way, i.e. positive additional reactive current is overexcited operation, increasing the voltage.

ii. The factor K is an integer number and has to be adjustable in the range from 0 to 8. The default setting is 2. The network operator may require a different value within the range from 0 to 8, if needed.

iii. The voltage U in the equation given in Paragraph i is the positive sequence value of the fundamental frequency at the generating unit terminals.
The pre-fault voltage is the 1-minute mean value of the RMS value of the voltage at the generating unit terminals.

iv. It is allowed to adjust the threshold for activating the additional reactive current injection (10% below the pre-fault voltage U_0) to a value closer to the pre-fault voltage U_0, i.e. 0%-10% below U_0 (0% means a permanent voltage control).

v. With the pre-fault reactive current I_{Q0}, the total injected reactive current I_Q is:

$$I_Q = I_{Q0} + \Delta I_Q$$

vi. The tolerance band for accuracy of the magnitude $|\Delta I_Q|$ of the additional reactive current is -10% and +20% of the nominal current of the generating unit, as depicted in Figure 7.5.

vii. In case of a three-phase fault, the generating unit must be able to inject a reactive current I_Q of at least 100% of the generating unit's nominal current.
In case of a single-phase fault or a two-phase fault, the generating unit must be able to inject a reactive current I_Q of at least 40% of the generating unit's nominal current.

viii. The additional reactive current has to be settled within 60 ms after beginning of the fault, i.e. 60 ms after beginning of the fault the additional reactive current has to be and stay within the tolerance band.

ix. The additional reactive current has to reach the tolerance band for the first time within 30 ms after beginning of the fault.

x. Note: There is no deadband for the additional reactive current. Once the voltage is below the activation band of 10% below the pre-fault voltage, the additional current has to be injected according to equation given in Paragraph i

xi. During UVRT or OVRT generating units of Type 2 shall give priority to reactive current injection, it is allowed to reduce active current. It is recommended to reduce active current I_P in proportion to the deviation of the voltage, as indicated by the following equation or similar:

$$I_P/I_n = (I_{P0} - \Delta I_P)/I_n = (I_{P0}/I_n) - |(-\Delta U/U_n)| = (I_{P0}/I_n) - |(U - U_0)/U_n|$$

xii. The responsible DNO has to announce if this functionality of dynamic voltage support (additional reactive current during UVRT and OVRT) shall be activated and which value shall be used for the K factor (default value is 2). The DNO has the right at any time in the future to require the activation of this functionality.

7.2.9. Over-Current and Earth-Fault Protection

a) Over-current protection shall be provided as short-circuit protection.

b) The connection of a power station to the MV network is implemented either by means of circuit breakers or through an on-load-switch-fuse combination.

c) A power station connected through a circuit breaker shall be equipped at least with over-current time protection as short-circuit protection.

d) Short-circuit protection of a power station connected by means of a combined on-load-switch-fuse is ensured by the fuse.

e) The short-circuit protection devices and earth-fault protection devices of the power station must be integrated into the overall protection concept of the network operator. For this reason, the protection scheme shall be agreed with the network operator at the stage of planning. The protection equipment settings are specified by the network operator as far as they have an impact on his network.

f) The generator is responsible himself for the reliable protection of his power station (e.g. short-circuit, earth-fault and overload protection, protection from electric shock, etc.).

7.2.10. Protective disconnection devices

a) The function of protective disconnection devices described here is to disconnect the power station or the individual generating units from the network in the event of disturbed operating conditions. Examples are network faults, islanding, or a slow build-up of the network voltage after a fault in the transmission system. The reason for disconnection can be either to avoid unstable or unsecure operation of the power system, or to protect the installations and other customer facilities connected to the network. The generator is responsible for a reliable protection of his power station.

b) The following functions of the protective disconnection equipment shall be realized:

   i. Over-frequency protection f>

   ii. Under-frequency protection f<

   iii. Over-voltage protection U> and U>>

   iv. Under-voltage protection U< and U<<

c) The settings of the protective disconnection devices are not allowed to counteract other requirements.

d) The parameter settings have to be agreed with the responsible DNO.

e) The settings for the under-frequency protection shall allow to ride through typical under-frequency fault cases which might happen in the system and which shall be withstand by the system, for example the temporary frequency drop subsequent to the loss of a power station in the system (compare Section "System Frequency Variations" of the Network Code [1]).

f) If a power station consist of more than one generating unit, the settings must be chosen in a way to disconnect the individual generating units at slightly different thresholds or time settings in order to minimize the power change to the system at one instant in time. The DNO may provide accordingly different settings to different power stations in the network to minimize the power change to the system at one instant in time.

g) Protective disconnection can be realized within a self-sufficient device or within the control system of the generating unit. The loss of the auxiliary voltage of the protection equipment or of the power station's control system must lead to an instantaneous tripping of the switch. Tripping through integrated protection relays must not be inadmissibly delayed by other functions of the control system.

h) Protective disconnection devices are installed at the Point of Connection and/or at the terminals of the power generating units.

7.2.11. Power Reduction on Demand

a) Power reduction to zero (i.e. stop of power injection) must be possible upon Instruction (e.g. telephone call). To run the customer's facility in an isolated mode, disconnected from the network of public supply, is allowed.

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 15% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have a remote-control connection to reduce the power by the distribution network operator (DNO). The technical requirements for the remote control connection have to be specified by the responsible DNO.

7.2.12. Frequency Sensitive Mode

a) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 15% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must be able to run in a limited frequency sensitive mode in cases of over-frequencies:

   i. In cases of frequency above 50.5 Hz (which is the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System), power stations shall reduce active power output with a droop of 4%, starting from 50.5 Hz. This refers to as Limited Frequency Sensitive Mode – Over-Frequency (LFSM-OF). The droop s of the LFSM-OF is defined as given in the equation below with the momentary value of the active power output of the installation at the instant of time when exceeding the 50.5 Hz threshold as P_{ref}.

$$s[\%] = 100 \cdot \frac{f - 50.5\ \mathrm{Hz}}{50.0\ \mathrm{Hz}} \cdot \frac{P_{ref}}{|\Delta P|}$$

   The responsible network operator can specify other values for the droop and the activation threshold for LFSM-OF, if technically justified. At 52.0 Hz and above it is allowed to reduce active power output to zero, if agreed with the responsible network operator.

   Hint: In other African Grid Codes the LFSM-OF may refer to as "power curtailment during over-frequency".

   ii. The following equation defines the required power change for cases in which the frequency f is higher than 50.5 Hz.

$$\Delta P = \frac{100}{s[\%]} \cdot \frac{-(f - 50.5\ Hz)}{50.0\ Hz} \cdot P_{ref}$$

   A droop of 4% results in a power change ΔP of 50% of P_{ref} per Hz.

   iii. The power station shall be capable of activating active power frequency response as fast as technically feasible with an initial delay that shall be as short as possible (usually within 2 seconds).

   iv. The power station shall be capable of continuing operation at its minimum regulating level when reaching it.

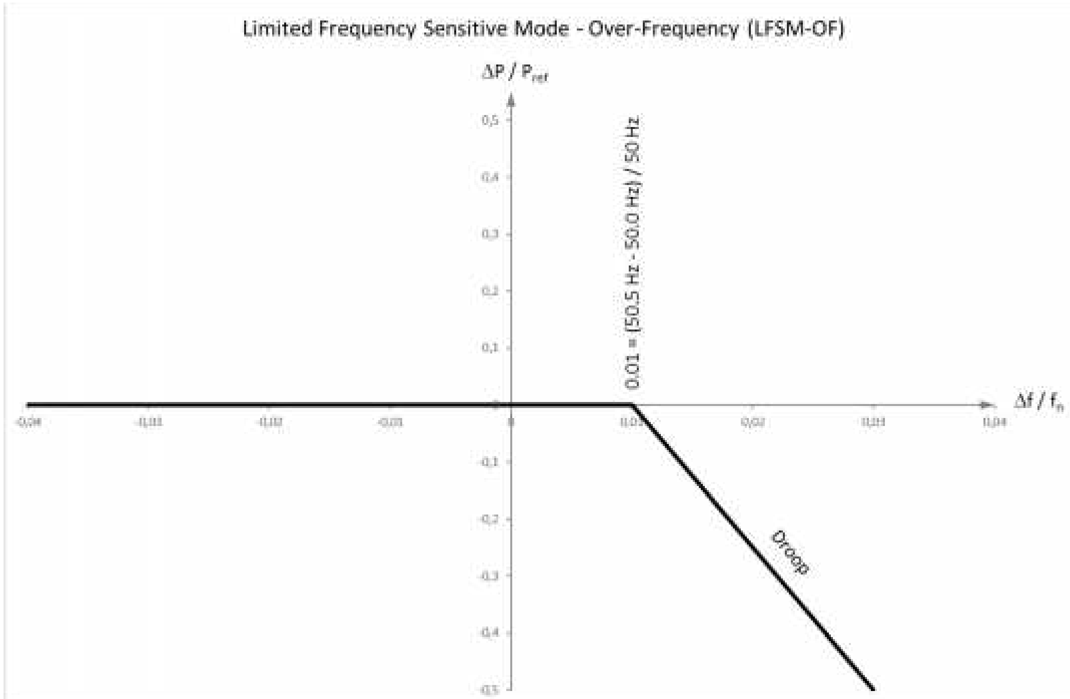

Figure 7.6 Limited Frequency Sensitive Mode – Over-Frequency (LFSM-OF)

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at MV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must be able to run in full frequency sensitive mode, i.e. they must be able to participate in frequency control of the system.

i. In case of over-frequency, the active power frequency response is limited by the minimum regulating level.

ii. In case of under-frequency, the active power frequency response is limited by maximum capacity, which depend on environment conditions in cases of wind and solar for example.

iii. The initial activation of active power frequency response required shall be provided within 2 seconds.

iv. Activation of a minimum response of 3% of maximum continues rating shall be provided within 10 seconds.

v. The power station shall be capable of providing full active power frequency response for a period of 10 minutes.

vi. Deviant settings may be provided by the network operator.

vii. Deviant settings must be agreed with the network operator.

viii. During operation of the power station, the responsible network operator can ask to activate or deactivate the frequency sensitive mode via instruction. The generator has to follow the instruction. The network operator and the generator have to mutually agree on the way how the instruction is transferred and received.

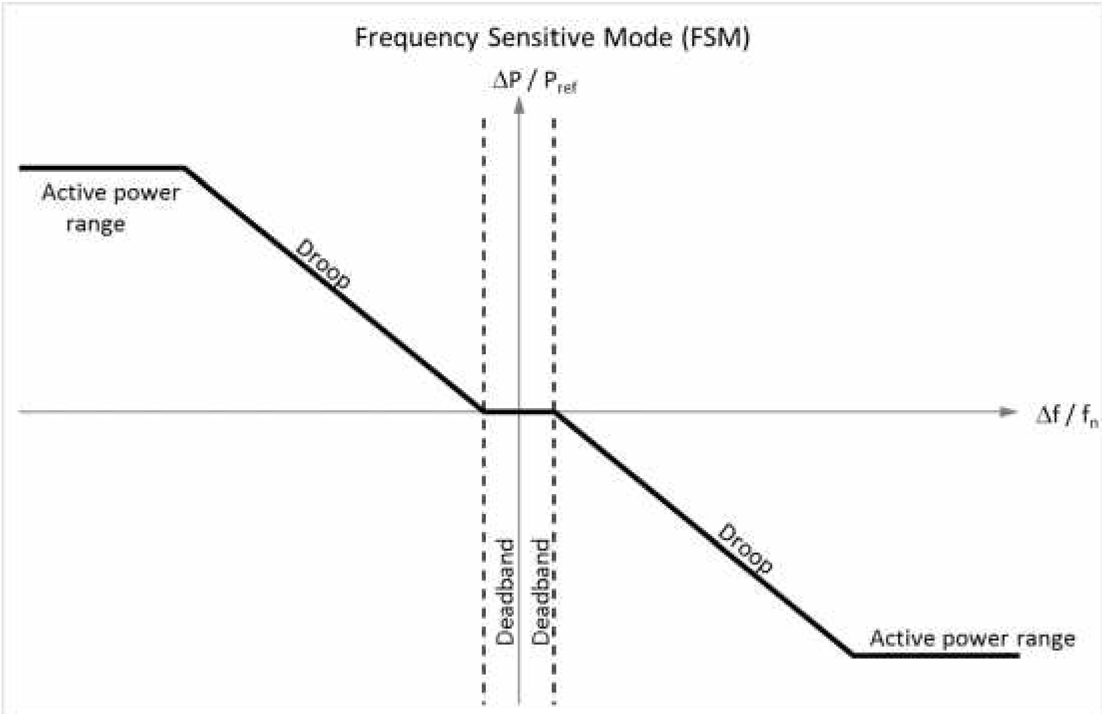

Figure 7.7: Frequency Sensitive Mode (FSM)

$$s[\%] = 100 \cdot \frac{|\Delta f|}{50.0\,\text{Hz}} \cdot \frac{P_{ref}}{|\Delta P|}$$

$$\Delta P = \frac{100}{s[\%]} \cdot \frac{-(\Delta f \mp deadband)}{50.0\,\text{Hz}} \cdot P_{ref}$$

7.3. Technical Requirements for Generation with Type 1 Generating Units and a PoC at LV

a) This section describes technical requirements for generation with Type 1 generating units and a PoC in an LV network, including Isolated Mini Grids.

b) These requirements do not apply to micro off-grids. However, if it is intended to let off-grid generating units run in parallel to the grid, once an off-grid is interconnected to the main network, it is recommended to consider these requirements as far as possible during off-grid operation already.

c) It is assumed that generation with a PoC at LV is non-dispatchable generation.

7.3.1. Operating Voltage Band

a) The generation facility must be able to fully operate in steady-state in a voltage band of +/- 5%, i.e. 0.95 p.u. through 1.05 p.u. around the nominal voltage at the point of connection (PoC).

7.3.2. Operating Frequency Band

a) The generation facility must be able to operate in steady-state in a frequency band of +/- 2.5% around the nominal frequency of 50 Hz, i.e. 48.75 Hz through 51.25 Hz.

b) In island systems and Isolated Mini Grids the maximum deviation from standard frequency can be larger (up to +/- 5% [2]). Therefore a capability to operate in steady-state in a frequency band of +/- 5.0% around the nominal frequency is recommended in these systems, but not mandatory.

7.3.3. Connection and Reconnection Requirements

a) A connection of a power generating unit shall be admissible only if the network voltage at the PoC is inside its normal operating voltage band (0.95 p.u. – 1.05 p.u.) and the frequency is between 47.5 Hz and 50.5 Hz (which are the lower frequency band limit under extreme system operation of fault conditions and the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System). In Isolated Mini Grids the threshold values may differ from the values given above and have to be specified by the responsible network operator with respect to the voltage and frequency bands in the Isolated Mini Grid.

b) If the voltage at the PoC is outside of the above mentioned voltage band (0.95 p.u. – 1.05 p.u.), connection shall be blocked.

c) If the frequency is below 47.5 Hz or above 50.5 Hz, connection shall be blocked. A different value for the setting may be applied in agreement with the responsible DNO (especially in island systems or Isolated Mini Grids).

d) The reconnection of a power generating unit after being disconnected for protection with respect to Section 7.3.8 or Section 7.3.9, is only allowed:

   i. if the voltage at the PoC is within the normal operating voltage band of 0.95 p.u. – 1.05 p.u.,

   ii. if the frequency is above 47.5 Hz and below 50.5 Hz (a different value for the setting may be applied in agreement with the responsible DNO, especially in island systems or Isolated Mini Grids),

iii. if there is no Instruction from the network operator for disconnection or for power limit of 0%, compare Section 7.3.10, and

e) If the power station consists of several generating units, the responsible DNO can specify a minimum delay time interval between the connection/reconnection of the individual units in order to limit impact on voltage and ensure desired power quality (e.g. flicker).

7.3.4. Voltage Unbalances, Harmonics and Flicker

a) If the power station consists of several single-phase units, the single-phase units shall be connected to the Point of Connection in a way, that the power output is distributed as symmetric as possible to the three phases, in order to keep the voltage unbalance as small as possible.

b) Single-phase installations shall be distributed among the three phases of the network (for example within a network feeder) as balanced as possible. Therefore single-phase installations should be connected to phase A, B, or C, but not always at the same phase. The selection of the particular phase to which an installation is connected shall be agreed with the network operator.

c) The compatibility level for voltage unbalance in LV three-phase networks shall be 2% [2]. In networks with a predominance of single-phase or two-phase devices connected, a compatibility level of 3% may be applied [2].

d) The power station shall withstand and function correctly in the presence of harmonic voltages up to the compatibility levels for LV networks specified in [2] (long-term and short-term).

e) The power station is not allowed to inject harmonic currents into the network which lead to harmonic voltages or a THD at the PCC which are higher than the compatibility levels for LV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

f) Usually it can be assumed that generating units of Type 1 do not inject relevant harmonic currents and thus fulfil the requirement related to harmonic voltages of this code without any further verification.

g) Nevertheless, if the compatibility levels for harmonic voltages or THD at the PCC are exceeded in operation, the responsible DNO has to carry out measurements in accordance to [2] in combination with [3] in order to find the most disturbing device. If this device belongs to the power station, the generator has to do countermeasures to lower the harmonic disturbance.

h) The power station shall withstand and function correctly in the presence of voltage flicker up to the compatibility level for LV networks specified in [2].

i) The power station is not allowed to perform power changes which lead to voltage flicker at the PCC which are higher than the compatibility levels for LV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

j) If a generating unit or a device of the power station with a rated current less or equal to 16 A fulfils the requirement of IEC 61000-3-3 [6], it is assumed to fulfil the requirement related to voltage changes, voltage fluctuations and flicker of this code without any further verification.

7.3.5. Reactive Power Capability

a) Generating units of Type 1 shall have a reactive power capability of at least a power factor of +/- 0.9.

7.3.6. Power Factor Control Capability

a) A power station with Type 1 generating units shall provide the capability of the following two control modes effective at the point of connection (PoC) of the power station:

   i. reactive power (constant Q)

   ii. power factor (constant cos phi)

b) For power stations with Type 1 generating units, the network operator selects the control mode which has to be activated for operation and specifies the parameter settings, depending on the location of the PoC in the network.
As long as not specified individually by the responsible network operator, a power factor of 1.00 (reactive power equal to 0 Mvar) shall be used as operating setpoint.

c) A power station with Type 1 generating units shall be able to operate in any operating point of the reactive power capability specified in Section 7.3.5.

d) For an adjusted control mode and parameter set, the power station with Type 1 generating units shall be able to settle each accessible operating point with respect to the control mode within 30 seconds.

7.3.7. Behaviour During Network Faults

a) Type 1 generating units with PoC at LV shall disconnect from the grid as fast as possible by means of protective disconnection devices, if the voltage at the PoC becomes lower than 0.9 p.u. The voltage to be considered is the lowest of the three line-to-line voltages.

b) Type 1 generating units with PoC at LV must have Over-Voltage-Ride-Though (OVRT) capability which shall be designed with anticipation of the following voltage conditions at the Point of Connection:

   i. A voltage rise to 120% for 2 s, or to 110% for 60 s provided that during the 3 minute period immediately following the end of that 0.1 s, 2 s, or 60 s periods the actual voltage remains in the range 95-105% of the nominal voltage.

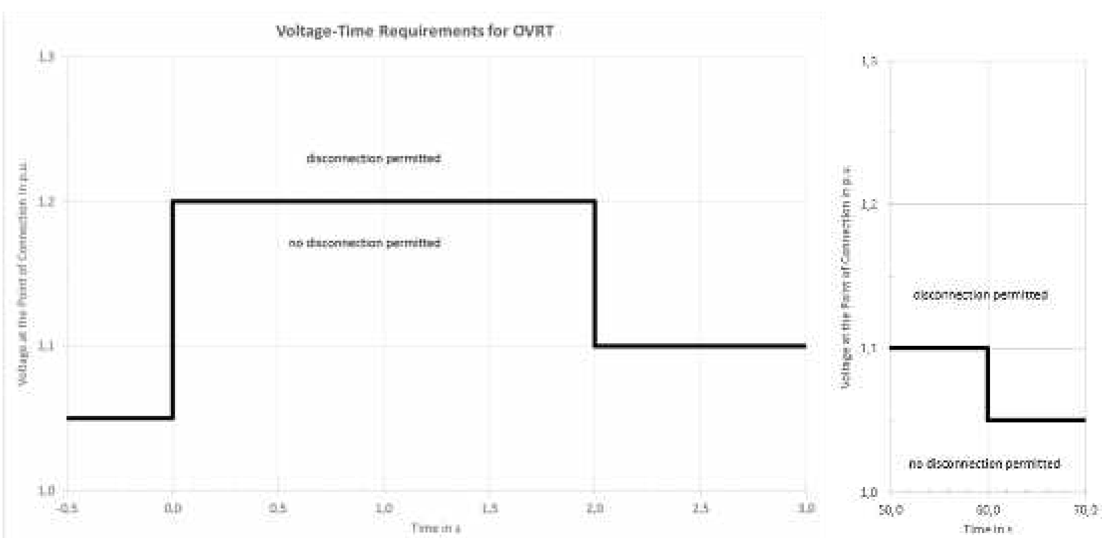

Figure 7.8: Voltage-Time Requirements for Over-Voltage-Ride-Through (OVRT)

ii. The voltage to be considered is the highest of the three line-to-line voltages in cases of voltages above 100% of the nominal voltage.

7.3.8. Over-Current and Earth-Fault Protection

a) Over-current protection shall be provided as short-circuit protection.

b) The connection of a power station to the LV network is implemented either by means of circuit breakers or through an on-load-switch-fuse combination or a simple fuse.

c) A power station connected through a circuit breaker shall be equipped at least with over-current time protection as short-circuit protection.

d) Short-circuit protection of a power station connected by means of a combined on-load-switch-fuse is ensured by the fuse.

e) A fuse is sufficient for over-current protection, if no circuit breaker or on-load-switch-fuse combination is used.

f) The short-circuit protection devices and earth-fault protection devices of the power station must be integrated into the overall protection concept of the network operator. For this reason, the protection scheme shall be agreed with the network operator at the stage of planning. The protection equipment settings are specified by the network operator as far as they have an impact on his network.

g) The generator is responsible himself for the reliable protection of his power station (e.g. short-circuit, earth-fault and overload protection, protection from electric shock, etc.).

7.3.9. Protective disconnection devices

a) The function of protective disconnection devices described here is to disconnect the power station or the individual generating units from the network in the event of disturbed operating conditions. Examples are network faults, islanding, or a slow build-up of the network voltage after a fault in the transmission system. The reason for disconnection can be either to avoid unstable or unsecure operation of the power system, or to protect the installations and other customer facilities connected to the network. The generator is responsible for a reliable protection of his power station.

b) The following functions of the protective disconnection equipment shall be realized:

  i. Over-frequency protection f>

  ii. Under-frequency protection f<

  iii. Over-voltage protection U> and U>>

  iv. Under-voltage protection U< and U<<

c) The settings of the protective disconnection devices are not allowed to counteract other requirements.

d) The parameter settings have to be agreed with the responsible DNO.

e) If a power station consists of more than one generating unit, the settings must be chosen in a way to disconnect the individual generating units at slightly different thresholds or time settings in order to minimize the power change to the system at one instant in time. The DNO may provide accordingly different settings to different power stations in the network to minimize the power change to the system at one instant in time.

f) Protective disconnection can be realized within a self-sufficient device or within the control system of the generating unit. The loss of the auxiliary voltage of the protection equipment or of the power station's control system must lead to an instantaneous tripping of the switch. Tripping through integrated protection relays must not be inadmissibly delayed by other functions of the control system.

g) Protective disconnection devices are installed at the Point of Connection and/or at the terminals of the power generating units.

h) If the share of the sum of the nominal power of all Type 1 generating units with PoC at LV compared to the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid) becomes as large as so that a potential loss of these generating units may have a considerable impact on the frequency of the system, the settings for the under-frequency protection newly commissioned generators shall allow to ride through typical under-frequency fault cases which might happen in the system and which shall be withstand by the system, for example the temporary frequency drop subsequent to the loss of a power station in the system (compare Section "System Frequency Variations" of the Network Code [1]). This capability to ride through such under-frequency fault cases is also recommended (but not mandatory) if the share of the sum of the nominal power of all Type 1 generating units with PoC at LV is smaller than described at the beginning of this paragraph

7.3.10. Power Reduction on Demand

a) Power reduction to zero (i.e. stop of power injection) must be possible upon Instruction (e.g. telephone call). To run the customer's facility in an isolated mode, disconnected from the network of public supply, is allowed.

b) If the share of the sum of the nominal power of all Type 1 generating units with PoC at LV becomes larger than 30%[3] of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have a remote control connection to reduce power injection to zero by the distribution network operator (DNO). The technical requirements for the remote control connection have to be specified by the responsible DNO.

7.3.11. Frequency Sensitive Mode

a) If the share of the sum of the nominal power of all Type 1 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must be able to run in a limited frequency sensitive mode in cases of over-frequency.

    i. In cases of frequency above 50.5 Hz (which is the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System), power stations shall reduce active power output with a droop of 4%, starting from 50.5 Hz. This refers to as Limited Frequency

[3] The limitation of the requirement with respect to share of the sum of nominal power of Type 1 generating units shall allow easier network access as long as there are not as many installations with Type 1 generating units with PoC at LV, but guarantee a strict enough requirement if Type 1 generating units reach a share with considerable impact on the system.

Sensitive Mode – Over-Frequency (LFSM-OF). The droop s of the LFSM-OF is defined as given in the equation below with the momentary value of the active power output of the installation at the instant of time when exceeding the 50.5 Hz threshold as P_{ref}.

$$s[\%] = 100 \cdot \frac{f - 50.5\,\text{Hz}}{50.0\,\text{Hz}} \cdot \frac{P_{ref}}{|\Delta P|}$$

The responsible network operator can specify other values for the droop and the activation threshold for LFSM-OF, if technically justified. At 52.0 Hz and above it is allowed to reduce active power output to zero, if agreed with the responsible network operator.

Hint: In other African Grid Codes the LFSM-OF may refer to as "power curtailment during over-frequency".

ii. The following equation defines the required power change for cases in which the frequency f is higher than 50.5 Hz.

$$\Delta P = \frac{100}{s[\%]} \cdot \frac{-(f - 50.5\,Hz)}{50.0\,Hz} \cdot P_{ref}$$

A droop of 4% results in a power change ΔP of 50% of P_{ref} per Hz.

iii. The power station shall be capable of activating active power frequency response as fast as technically feasible with an initial delay that shall be as short as possible (usually within 2 seconds).

iv. The power station shall be capable of continuing operation at its minimum regulating level when reaching it.

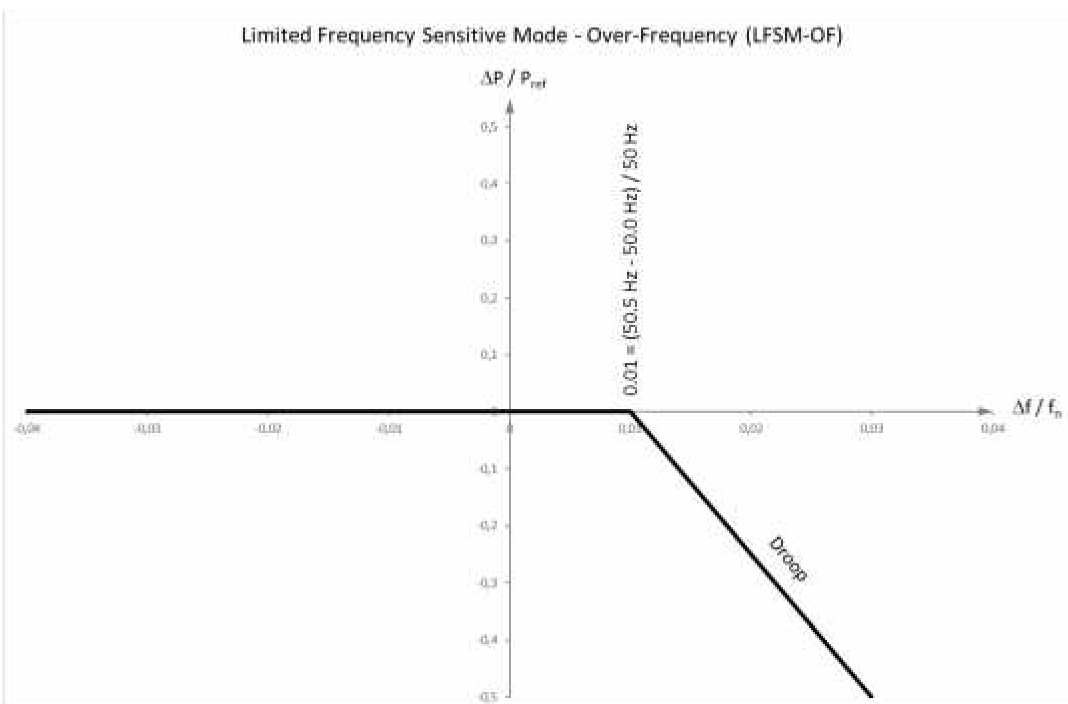

Figure 7.9: Limited Frequency Sensitive Mode – Over-Frequency (LFSM-OF)

7.4. Technical Requirements for Generation with Type 2 Generating Units and a PoC at LV

a) This section describes technical requirements for generation with Type 2 generating units and a PoC in a Tanzanian LV network, including Isolated Mini Grids.

b) These requirements do not apply to micro off-grids. However, if it is intended to let off-grid generating units run in parallel to the grid, once an off-grid is interconnected to the main network, it is recommended to consider these requirements as far as possible during off-grid operation already.

c) It is assumed that generation with a PoC at LV is non-dispatchable generation.

7.4.1. Operating Voltage Band

a) The generation facility must be able to fully operate in steady-state in a voltage band of +/- 5%, i.e. 0.95 p.u. through 1.05 p.u. around the nominal voltage at the point of connection (PoC).

7.4.2. Operating Frequency Band

a) The generation facility must be able to operate in steady-state in a frequency band of +/- 2.5% around the nominal frequency of 50 Hz, i.e. 48.75 Hz through 51.25 Hz.

b) In island systems and Isolated Mini Grids the maximum deviation from standard frequency can be larger (up to +/- 5% [2]). Therefore a capability to operate in steady-state in a frequency band of +/- 5.0% around the nominal frequency is recommended in these systems, but not mandatory.

7.4.3. Connection and Reconnection Requirements

a) A connection of a power generating unit shall be admissible only if the network voltage at the PoC is inside its normal operating voltage band (0.95 p.u. – 1.05 p.u.) and the frequency is between 47.5 Hz and 50.5 Hz (which are the lower frequency band limit under extreme system operation of fault conditions and the upper frequency band limit under normal operation in the EAPP Interconnected Transmission System). In Isolated Mini Grids the threshold values may differ from the values given above and have to be specified by the responsible network operator with respect to the voltage and frequency bands in the Isolated Mini Grid.

b) If the voltage at the PoC is outside of the above mentioned voltage band (0.95 p.u. – 1.05 p.u.), connection shall be blocked.

c) If the frequency is below 47.5 Hz or above 50.5 Hz, connection shall be blocked. A different value for the setting may be applied in agreement with the responsible DNO (especially in island systems or Isolated Mini Grids).

d) The reconnection of a power generating unit after being disconnected for protection with respect to Section 7.4.8 or Section 7.4.9, is only allowed:

   i. if the voltage at the PoC is within the normal operating voltage band of 0.95 p.u. – 1.05 p.u.,

   ii. if the frequency is above 47.5 Hz and below 50.5 Hz (a different value for the setting may be applied in agreement with the responsible DNO, especially in island systems or Isolated Mini Grids),

iii. if there is no Instruction from the network operator for disconnection or for power limit of 0%, compare Section 7.4.10, and

e) If the power station consists of several generating units, the responsible DNO can specify a minimum delay time interval between the connection/reconnection of the individual units in order to limit impact on voltage and ensure desired power quality (e.g. flicker).

7.4.4. Voltage Unbalances, Harmonics, Flicker and DC Current Injection

a) If the power station consists of several single-phase units, the single-phase units shall be connected to the Point of Connection in a way, that the power output is distributed as symmetric as possible to the three phases, in order to keep the voltage unbalance as small as possible.

b) Single-phase installations shall be distributed among the three phases of the network (for example within a network feeder) as balanced as possible. Therefore single-phase installations should be connected to phase A, B, or C, but not always at the same phase. The selection of the particular phase to which an installation is connected shall be agreed with the network operator.

c) The compatibility level for voltage unbalance in LV three-phase networks shall be 2% [2]. In networks with a predominance of single-phase or two-phase devices connected, a compatibility level of 3% may be applied [2].

d) The power station shall withstand and function correctly in the presence of harmonic voltages up to the compatibility levels for LV networks specified in [2] (long-term and short-term).

e) The power station is not allowed to inject harmonic currents into the network which lead to harmonic voltages or a THD at the PCC which are higher than the compatibility levels for LV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

f) If a generating unit or a device of the power station with a rated current less or equal to 16 A fulfils the requirement of IEC 61000-3-2 [5], it is assumed to fulfil the requirement related to harmonic voltages of the Tanzanian Distribution Code without any further verification.

g) If the compatibility levels for harmonic voltages or THD at the PCC are exceeded in operation, the responsible DNO has to carry out measurements in accordance to [2] in combination with [3] or if applicable in combination with [4] in order to find the most disturbing device. If this device belongs to the power station, the generator has to do countermeasures to lower the harmonic disturbance.

h) The power station shall withstand and function correctly in the presence of voltage flicker up to the compatibility level for LV networks specified in [2].

i) The power station is not allowed to perform power changes which lead to voltage flicker at the PCC which are higher than the compatibility levels for LV networks specified in [2]. The responsible DNO may provide lower planning limits in order to ensure that the compatibility levels at the PCC are met.

j) If a generating unit or a device of the power station with a rated current less or equal to 16 A fulfils the requirement of IEC 61000-3-3 [6], it is assumed to fulfil the requirement related to voltage changes, voltage fluctuations and flicker of this code without any further verification.

k) The installation shall not inject a DC current greater than 1% of its rated output current into the Point of Connection under any operating condition.

7.4.5. Reactive Power Capability

a) As long as the share of the sum of the nominal power of all Type 2 generating units with PoC at LV is lower than or equal to 30%[4] of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), the reactive power output or demand of a generating unit of Type 2 shall be as small as possible, no reactive power capability is required.

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), all newly commissioned generating units shall have a reactive power capability of at least a power factor of +/- 0.9.

7.4.6. Power Factor Control Capability

a) As long as the share of the sum of the nominal power of all Type 2 generating units with PoC at LV is lower than or equal to 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), the power factor shall be above 0.98 ("close to 1.00"), while operation with a power factor at or close to 1.00 is recommended. When operating with partial active power, the reactive power output or demand shall not be larger than the reactive power that corresponds to a power factor of 0.98 ("close to 1.00") at nominal active power.

b) Only if the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), all newly commissioned generating units shall have the following power factor control capabilities.

c) A power station with Type 2 generating units shall provide the capability of the following two control modes effective at the point of connection (PoC) of the power station:

   i. reactive power (constant Q)

   ii. power factor (constant cos phi)

d) For power stations with Type 2 generating units, the network operator selects the control mode which has to be activated for operation and specifies the parameter settings, depending on the location of the PoC in the network.

e) A power station with Type 2 generating units shall be able to operate in any operating point of the reactive power capability specified in Section 7.4.5, for the active power range which is possible to operate with respect to the primary power source of the power station.

f) For an adjusted control mode and parameter set, the power station with Type 2 generating units shall be able to settle each accessible operating point with respect to the control mode within 30 seconds.

7.4.7. Behaviour During Network Faults

a) If the share of the sum of the nominal power of all Type 2 generating units with PoC at LV is smaller than or equal to 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), these

[4] The limitation of the requirement with respect to share of the sum of nominal power of Type 2 generating units shall allow easier network access as long as there are not as many installations with Type 2 generating units with PoC at LV, but guarantee a strict enough requirement if Type 2 generating units reach a share with considerable impact on the system.

generating units shall disconnect from the grid as fast as possible by means of protective disconnection devices, if the voltage at the PoC becomes lower than 0.9 p.u.

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have Under-Voltage-Ride-Through (UVRT) and Over-Voltage-Ride-Though (OVRT) capability. Any new generating unit and any equipment of a new power station shall be designed with anticipation of the following voltage conditions at the Point of Connection:

   i. A voltage deviation in the range of 95% to 105% for protracted periods.

   ii. A voltage dip to zero for up to 0.2 s, to 75% for 2 s, or to 85% for 60 s provided that during the 3 minute period immediately following the end of that 0.2 s, 2 s, or 60 s periods the actual voltage remains in the range 95-105% of the nominal voltage (compare Section “External supply disturbance withstand capability“ of The Network Code [1]).

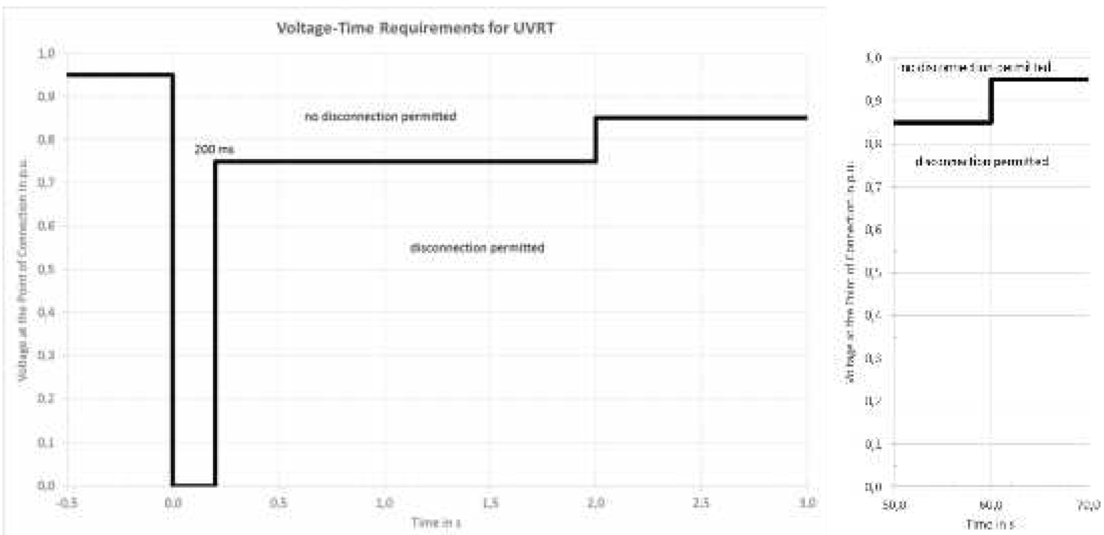

Figure 7.10: Voltage-Time Requirements for Under-Voltage-Ride-Through (UVRT)

   iii. A voltage rise to 120% for 2 s, or to 110% for 60 s provided that during the 3 minute period immediately following the end of that 0.1 s, 2 s, or 60 s periods the actual voltage remains in the range 95-105% of the nominal voltage.

Figure 7.11: Voltage-Time Requirements for Over-Voltage-Ride-Through (OVRT)

iv. The voltage to be considered is:

the lowest of the three line-to-line voltages in cases of voltages below 100% of the nominal voltage, and

the highest of the three line-to-line voltages in cases of voltages above 100% of the nominal voltage.

v. During UVRT or OVRT the injected active and reactive current has to be reduced to the minimum possible current (reduction to zero is recommended).

7.4.8. Over-current and Earth-Fault Protection

a) For Generation with Type 2 Generating Units and a PoC at LV, with respect to over-current and earth-fault protection, the same requirements apply as for Generation with Type 1 Generating Units and a PoC at LV. Refer to Section 7.3.8.

7.4.9. Protective disconnection devices

a) For Generation with Type 2 Generating Units and a PoC at LV, with respect to protective disconnection devices, the same requirements apply as for Generation with Type 1 Generating Units and a PoC at LV. Refer to Section 7.3.9.

b) Paragraph h) of Section 7.3.9 applies to Generation with Type 2 Generating Units and a PoC at LV, if the share of the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid).

7.4.10. Power Reduction on Demand

a) Power reduction to zero (i.e. stop of power injection) must be possible upon Instruction (e.g. telephone call). To run the customer's facility in an isolated mode, disconnected from the network of public supply, is allowed.

b) If the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must have a remote control connection to reduce power injection to zero by the distribution network operator (DNO). The technical requirements for the remote control connection have to be specified by the responsible DNO.

7.4.11. Frequency Sensitive Mode

a) If the share of the sum of the nominal power of all Type 2 generating units with PoC at LV becomes larger than 30% of the installed capacity in the system (i.e. in main grid or in Isolated Mini Grid), newly commissioned generators must be able to run in a limited frequency sensitive mode in cases of over-frequency (Limited Frequency Sensitive Mode – Over-Frequency, LFSM-OF).

b) The LFSM-OF is defined for Type 2 generating units with PoC at LV in the same way as for Type 1 generating units with PoC at LV. Refer to Section 7.3.11.

8. Planning

8.1. Introduction

This section describe framework of the distribution network, network investment overview and criteria, dedicated and premium customers connection procedures, and strategic investments issues.

8.2. Framework for Distribution Network Planning and Development

a) The DNO shall source relevant data from various sources to establish the need for network strengthening including the following where relevant:

   i) National resource planning authorities,

   ii) Local government resource planning,

   iii) National Development Plan,

   iv) customer information,

   v) system performance statistics,

   vi) Distribution network load forecast, and

   vii) Government and customer development plans

a) The DNO shall annually compile a 5-year load forecast at the DNO’s incoming points of supply including DNO's cross-boundary connections.

b) The DNO shall be responsible for compiling network development plans with a minimum window period of five years. These network development plans shall be reviewed at least every 3 years. The aim of network development plans is to ensure a capable network and should therefore include all relevant activities such as electrification and refurbishment. Such plans should be drawn up taking into account only available information. Unexpected loads or customer requests can be retrospectively added to the plan.

c) The network development plans and post release changes shall be submitted to the Authority upon request.

d) The network development plans shall be made available to customers on request.

8.3. Network Investment Criteria

8.3.1. Overview

a) Distribution tariffs should be sufficient to allow the necessary investments in the networks to be carried out in a manner allowing these investments to ensure the viability of the networks.

b) The DNO shall invest in the Distribution System when the required development meets the technical and investment criteria specified in this section.

c) The need to invest must first be decided on technical grounds. All investments must be the least lifecycle cost technically acceptable solution, that is, shall provide for standard supply:

   i) Minimum quality requirements in terms of National Standards.

   ii) Minimum reliability and operational requirements as determined by this code and the Authority.

d) The investment choice must be justified by considering technical alternatives on a least- life cycle cost approach. Least life cycle cost is the discounted least cost option over the lifetime of the equipment, taking into account the technical alternatives for investment, operating expenses and maintenance.

e) Calculations to justify investment shall assume a typical project life expectancy of 20 years, except where otherwise dictated by plant life or project life expectancy.

f) The following key economic and financial parameters shall be determined by the Authority approved process:

   i) Discount rate.

   ii) Customer interruption cost (cost of un-served energy).

   iii) Other parameters, such as tariffs and additional economic parameters.

8.3.2. General Investment Criteria

a) Investments should be prudent (that is justified) as a least life-cycle cost solution after taking into account, where applicable, alternatives that consider the following:

   i) The investment that will minimize the cost of the energy supplied and the customer interruption cost (cost of un-served energy).

   ii) Current and projected demand on the network.

   iii) Reduction of life-cycle costs (e.g. reduction of technical losses, operating and maintenance costs and telecommunication projects).

   iv) Current condition of assets and refurbishment and maintenance requirements

   v) Demand and supply options.

   vi) Any associated risks.

b) General (shared) network investments shall be evaluated on the least-life-cycle economic cost. Economic cost will consider the least life cycle total cost of the electricity related investment to both the DNO and the customer.

c) Investments made by the DNO dedicated to a particular customer shall be evaluated on a least life-cycle DNO cost. DNO cost will consider only the least-life cycle investment cost to the DNO.

d) The DNO shall evaluate investments in terms of the following categories:

   i) Shared network investments.

ii) Dedicated customer connections.

iii) Statutory investments.

iv) International connections (cross-border connections).

8.3.3. Least economic cost criteria for shared network investments

a) Shared network investments are:

i) Investments on shared infrastructure (not-dedicated) assets.

ii) Investments required providing adequate upstream network capacity.

iii) Investments required to maintain or enhance supply reliability and/or quality to attain the limits or targets, determined in section 6.1of this code, on existing network assets.

iv) Refurbishment of existing standard dedicated connection assets.

b) All shared network investments are to be justified on least economic cost. In determining the least economic cost for shared network investments the investment must be justified to minimize the cost to the electricity industry and not just to the DNO.

8.3.4. Least life cycle cost criteria for standard dedicated customer connections

a) A standard connection is defined as the lowest life-cycle costs for a technically acceptable solution and will be charged for as described in the Electricity (Tariff Setting) Rules issued by the Authority.

b) Dedicated customer connections are:

i) New connection assets created for the sole use of a customer to meet the customer’s technical specifications.

ii) Dedicated assets are assets that are unlikely to be shared in the DNO's planning horizon by any other end-use customer.

c) All dedicated connection investments are to be justified on the technically acceptable least life-cycle costs.

d) Where the investment meets the least life-cycle cost, the customer shall be required to pay a standard connection charge as shall have been approved by the Authority

e) For certain customer groupings, as approved by the Authority, the investments shall be justified collectively as per customer grouping and not per customer.

f) The DNO will refurbish / replace / reconfigure all equipment in terms of its new standards to meet standard supply criteria at no cost to the customer and this will allowed to be recovered in the use-of system (network charges). This will be a non-discriminatory approach where no consideration will be given to the special or unique requirements of the customer.

8.3.5. Investment criteria for premium customer connections

a) The DNO shall investigate these additional requirements and will provide a least life-cycle cost solution.

b) If the customer agrees to the solution, all costs to meet the customer requirement in excess of what is considered the least life-cycle cost investment is payable as a premium connection charge by the customer as described in Electricity (Tariff Setting) Rules. Such costs shall be appropriately pro-rated, if a portion of the investment can be justified based on improved reliability or reduction of costs.

c) The refurbishment of identified premium connection assets will occur when the equipment is no longer reliable or safe for operation. The DNO must justify the need for refurbishment of the premium assets to the customer, and the customer must agree to the continuance of the premium supply.

d) At the time of refurbishment, should the customer have any requirements that cannot be met in as per clause 7.3.4 (e), any additional investment will be seen as a premium connection.

e) Where the refurbishment of a supply in accordance with current technical standards will result in additional cost to the customer, an engineering solution that minimizes the sum of the DNO's and the customer's costs will be found. This least economic cost option will be implemented but any expenditure in excess of the DNO least life-cycle cost solution (as per clauses 7.3.2 and 7.3.4 (e) above, will be borne by the customer through a new premium connection charge and shall not be recovered through use-of-system (network) charges

8.3.6. Statutory or strategic investments

a) DNO will be obligated to make statutory investments in terms of clause 7.3.6 (c) below.

b) Statutory and strategic investments will be motivated on a least economic cost basis, as defined in clause 7.3.3.

c) Strategic and statutory projects include the following:

   i) Investments formally requested in terms of published government policy but not considered dedicated customer as under clause 7.3.4.

   ii) Projects necessary to meet environmental legislation, e.g. the construction of oil containment dams.

   iii) Expenditure to satisfy the requirements on the DNO to comply with the Occupational Health and Safety Act; this classification is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission.

   iv) Possible compulsory contractual commitments.

   v) Generators.

9. Information Exchange

9.1. Introduction

The section defines obligations of participants with regard to the provision and exchange of planning, operational and maintenance information for the implementation of the Distribution Code.

9.2. Information Exchange Interface

a) The parties shall identify the following for each type of information exchange:

   i) The name and contact details of the person(s) designated by the information owner to be responsible for provision of the information.

   ii) The names, contact details of, and the parties represented by persons requesting the information.

   iii) The purpose for which the information is required.

   iv) The parties shall agree on appropriate procedures for the transfer of information.

b) Participants (with installed capacity of more than 100kVA) shall exchange information, prior to commissioning, of new or altered equipment connected at the point of connection or changes to the operational regimes that could have an adverse effect on the distribution system to enable proper modifications to any affected participants networks and related systems.

9.3. Provision and exchange of Information during the planning and connection process

a) Each DNO shall have a supply application form, which shall request, at minimum, the information stipulated in this section

b) Customers requesting supply at low voltage shall provide the DNO with the information relating to:

   i) New or change in connected loads.

   ii) Type of load to be connected to the Distribution System.

   iii) Requested connection date.

   iv) Proposed network connection point address.

c) Customers requesting supply at HV or MV shall, in addition to 8.3b above, provide the DNO with the following information:

   i) Requested supply voltage

   ii) Expected and / or projected maximum demand (in kVA)

   iii) Expected load power factor

   iv) Switched customer capacitor banks and reactors, which could affect the Distribution System

v) Whether the load is capable of producing Harmonics as specified by equipment manufacturers

vi) The nature and type of process the supply is requested for

vii) Minimum required fault levels

viii) Start-up requirements

ix) Whether the customer has any standby generator.

d) The DNO may request Customers to provide information on the Customer's proposed installation and equipment at the Point of Connection.

e) Participants shall exchange information relating to the protection of Distribution System and customer equipment protection coordination at the point of connection.

f) Upon any reasonable request, the DNO shall provide customers or potential customers with any relevant information that they require to properly plan and design their own networks/installations. This may include but not limited to:

i) Nominal voltage at which connection will be made.

ii) Method of connection, extension and/or reinforcement details.

iii) The maximum and minimum fault levels.

iv) Method of earthing.

v) Maximum installed Capacity at the point of connection.

vi) Specification of any accommodation of equipment requirement.

vii) Individual customer limits relating to:

A. Harmonic Distortion

B. Voltage Flicker

C. Voltage Unbalance

viii) Expected lead time of providing connection (following formal acceptance of terms for supply).

ix) An indication of network single contingency capability.

x) An indication of current network performance and power quality.

xi) Cost of connection.

xii) Range of current approved tariff structures.

9.4. Operational Information

a) Commissioning and notification

i) Customers shall confirm that all information given in the application for supply and additional information subsequently requested by the DNO is correct before the commissioning.

ii) The commissioning dates shall be negotiated between the parties. Participants will agree on the type of operational data to be submitted prior to commissioning, which shall include test and commissioning report.

iii) The asset owner (DNO or Customer) shall ensure that all equipment records, that affect the integrity of the Distribution System or relevant to the interconnection, are maintained for reference for the duration of the operational life of the plant. On request from the DNO, information shall be made available within a reasonable time.

iv) The DNO shall indicate to the customer what information is relevant in terms of this section.

b) Sharing of Assets and Resources

DNO sharing assets and resources shall enter into agreements for the provision and sharing of their assets, resources, services and information.

c) Additional Information Requirements

Should one participant, acting reasonably, determine that additional measurements and/or indications are needed in relation to another participant's plant and equipment; the requesting participant shall consult with the affected participant(s) to agree on the manner in which the need may be met. The costs related to the modifications for the additional measurements and/or indications shall be for the account of the causal participant.

d) Communication and Liaison

i) Participants shall establish a communication channel for exchange of information required for distribution operations, which may include the installation of DNO's SCADA equipment at the customer's or DNO's installation to facilitate the flow of information and data to and from the DNO and / or Transmission control facilities.

ii) Each participant shall designate a person with delegated authority to perform the duties of information owner in respect of the granting of access to information covered in this code to third parties. A party may, at its sole discretion, designate more than one person to perform these duties.

iii) The DNO shall take reasonable steps to exchange information with the DNO's affected customers for distribution system and transmission system outages.

iv) Customers shall exchange information with the DNO within an agreed lead time on all operations on their installations, which may have an adverse effect on the Distribution System including any planned activities such as plant shutdown, or scheduled maintenance.

v) The communication facilities standards shall be set and documented by the DNO. Any changes to communication facilities standards impacting on participant equipment shall be brought to the attention of the participant well in advance of the proposed upgrade.

vi) Any back up or emergency communication channels established by the DNO and deemed necessary for the safe operation of the Distribution System shall be agreed upon by the DNO and the participant affected.

e) Data Storage and Archiving

   i) The obligation for data storage and archiving shall lie with the information owner.

   ii) The systems that store the data and/or information to be used by the participants shall be of their own choice and for their own cost.

   iii) All data storage systems must be able to be audited by the Authority. The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the parties.

   iv) The information owner shall keep all information, except voice recorded information, in its original format for a period of at least five (5) years (unless otherwise specified differently in other parts of this code) commencing from the date the information was created.

   v) Participants shall ensure reasonable security against unauthorized access, use and loss of information for the systems that contain the information.

   vi) DNO shall use a voice recorder for historical recording of all operational voice communication with participants. These records shall be available for at least three (3) months except where there is an incident involved, in which case the requirements of any applicable legislation shall apply. The DNO shall make the voice records of an identified incident in dispute available within a reasonable time period after such a request from a participant and/or the Authority.

   vii) An audit trail of all changes made to archive data should be maintained. This audit trail shall identify every change made, and the time and date of the change. The audit trail shall include both before and after values of all content and structure changes.

9.5. Confidentiality of information

a) Information exchanged between participants governed by this code shall not be confidential, unless otherwise stated.

b) Participants receiving information shall use the information only for the purpose for which it was supplied.

c) The information owner may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, is provided.

d) Confidential information shall not be transferred to a third party without the written consent of the information owner. Parties shall observe the proprietary rights of third parties for the purposes of this code. Access to confidential information within the organisations of parties shall be provided as reasonably required.

e) The participants shall take all reasonable measures to control unauthorised access to confidential information and to ensure secure information exchange. Parties shall report any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak, and shall provide the information owner with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the information owner).

10. Assets Management

10.1. Introduction

This section covers assets management issues including customers' electrical installations and equipment, and DNO's equipment on customer's premises.

10.2. Good Asset Management

a) A DNO must use best endeavours to:

i) assess and record the nature, location, condition and performance of its distribution network assets;

ii) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution network assets:

A. to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;

B. to minimize the risks associated with the failure or reduced performance of assets; and

C. in a way which minimises costs to customers taking into account distribution losses; and

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

10.3. Customer's Electrical Installation and Equipment

a) A customer must use best endeavours to ensure that:

i) the customer's electrical installation and any equipment within it complies with this Code and is maintained in a safe condition; and

ii) Protection equipment in the customer's electrical installation is at all times effectively coordinated with the electrical characteristics of the distribution network.

b) A customer must use best endeavours to:

i) ensure that the distribution network and the reliability and quality of supply to other customers are not adversely affected by the customer's actions or equipment;

ii) not allow a supply of electricity to its electrical installation to be used other than at the customer's premises nor supply electricity to any other person;

iii) not take electricity supplied to another supply address at the customer's supply address;

iv) not allow electricity supplied to the supply address to bypass the meter;

v) not allow electricity supplied under a domestic tariff to be used for non-domestic purposes; and

vi) not allow electricity supplied under a specific purpose tariff to be used for another purpose.

10.4. Distribution Network Operator’s Equipment on Customer Premises

a) A customer must:

i) not interfere, and must use best endeavours not to allow interference with the DNO distribution network including any of the DNO’s equipment installed in or on the customer’s premises; and

ii) provide and maintain on the customer’s premises any reasonable or agreed facility required by its DNO to protect any equipment of the DNO.

b) Provided official identification is produced by the DNO’s representatives on request, a customer must provide to the DNO representatives at all times convenient and unhindered access:

i) to the DNO’s equipment for any purposes associated with the supply, metering or billing of electricity; and

ii) to the customer’s electrical installation for the purposes of the inspection or testing of the customer’s electrical installation in order to assess whether the customer is complying with this Code or connecting, disconnecting or reconnecting supply, and safe access to and within the customer’s premises for the purposes described in this code.

11. General Conditions

11.1. Liability

a) A DNO shall only be liable to a customer and a customer shall only be liable to a DNO for any damages which arise directly out of the wilful misconduct or negligence:

i) of the DNO in providing distribution services to the customer;

ii) of the customer in being connected to the DNO's network; or

iii) of the DNO or Customer in meeting their respective obligations under this Code, their licences and any other applicable law.

b) Notwithstanding Clause 10.1 (a), neither the DNO nor the customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contact or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise. The DNO shall educate its customers on the use of appropriate equipment to control loss or damage, which may result from poor quality or reliability of electricity supply within its distribution network.

c) A customer shall be liable to the DNO for any loss or damage resulting from the use of electricity in a manner that will make the DNO's system unsafe.

11.2. Force majeure

a) Neither party shall be held to have committed an event of default in respect of any obligation under this Code if prevented from performing that obligation, in whole or in part, because of a force majeure event.

b) If a force majeure event prevents a party from performing any of its obligations under this Code and the applicable Connection agreement, that party shall:

i) Promptly notify the other party 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 as soon as reasonably practicable.

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

iii) 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;

iv) Keep the other party continually informed of the efforts to mitigate the effects of the force majeure event; and

v) Provide written notice to the party when it resumes performance of any of its obligations affected by the force majeure event.

c) Notwithstanding any of the foregoing, settlement of any strike, lockout, or labour dispute constituting a force majeure event shall be within the sole discretion of the party to the agreement involved in the strike, lockout, or labour dispute. The requirement that a party must use its best efforts to remedy the cause of the force majeure event, mitigate its effects, and resume full performance under this Code shall not apply to strikes, lockouts, or labour disputes.

11.3. Health, Safety & Environments

a) DNO shall show good utility practice in operating and maintaining its distribution network and shall abide by the safety rules and regulations that apply to routine work.

b) DNO shall implement an industry recognized health and safety programme that includes training and regularly conducted audits. This programme also will include Public Education and Public Safety Initiatives.

c) Any problems that a DNO identifies as part of the audit shall be remedied as soon as possible or in accordance with the DNO's health and safety programme.

d) DNO shall have a corporate policy that addresses environmental stewardship that applies to all the DNO's operations. A documented programme supporting procedures and appropriate training should be in place to ensure compliance with environmental regulations and indicate a proactive approach to environmental damage avoidance.

e) Before any civil works are undertaken, due notice in writing shall be given to all utilities whose services may be in conflict with the proposed cable route, e.g. telephone, water, sewage, road and railway, etc. Where cables are to be installed in roads, footpaths or streets, it is advisable to liaise closely with the roads authority and police to ensure that all necessary measures are taken to minimize the hazards and disruptive effects of installation works.

f) Working signs, bollards, danger tapes, light 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.

g) DNO shall ensure that a line marker is placed and maintained as close as practical over each buried underground cable:

    i) at each crossing of a public road and railway; and

    ii) whenever necessary to identify the location of the buried underground cable to reduce the possibility of damage or interference.

h) DNO shall ensure that the following is written legibly on a background of a sharply contrasting colour on each line marker:

    i) the word "Warning", "Caution", or "Danger" followed by the words "MV Cable" or "LV Cable"; and

    ii) the name of the Distribution Utility and telephone number, on which the Distribution Utility can be reached at all times.

12. References

[1] Energy and Water Utilities Regulatory Authority (EWURA): The Tanzanian Grid Code – The Network Code

[2] Tanzania Bureau of Standards (TBS): Tanzania Standard – Power quality – Quality of supply

[3] IEC 61000-4-7, International Standard: Electromagnetic compatibility (EMC) – Part 4-7: Testing and measurement techniques – General guide on harmonics and interharmonics measurements and instrumentation, for power supply systems and equipment connected thereto

[4] IEC 61400-21, International Standard: Wind turbines – Part 21: Measurement and assessment of power quality characteristics of grid connected wind turbines

[5] IEC 61000-3-2, International Standard: Electromagnetic compatibility (EMC) – Part 3-2: Limits - Limits for harmonic current emissions (equipment input current ≤ 16 A per phase)

[6] IEC 61000-3-3, International Standard: Electromagnetic compatibility (EMC) – Part 3-3: Limits – Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems, for equipment with rated current ≤16 A per phase and not subject to conditional connection