RWANDA GRID CODE

Adopted by the Regulatory Board of the

RWANDA UTILITIES REGULATORY AUTHORITY (RURA)

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RWANDA UTILITIES REGULATORY AUTHORITY

(RURA)

THE RWANDA GRID CODE

Preamble

1 of 7 Code Documents

Version 1.0

RURA, Rwanda

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1 Introduction

(1) The *Preamble* document provides the industry context for the Rwanda *Grid Code* and its various components. It also contains detailed definitions and acronyms of the terms used in the Grid Code documents.

2 Policy and Structure

2.1 Policy Objectives for the Rwandan Electricity Industry[1]

(1) The main policy objectives of the Electricity Supply Industry (ESI) are the following:

(a) Address challenges in projects currently under implementation and develop plans to successfully complete them;

(b) Secure the necessary funding for planned electricity projects;

(c) Involvement of local communities (to the extent possible) in developing electricity projects;

(d) Enhanced access to electricity, particularly in rural areas;

(e) Reduction in the cost of electricity (least cost electricity *Generation* mix and network development);

(f) Diversification in sources of electricity supply;

(g) Encourage increased participation by the local and foreign private sector in the electricity industry;

(h) Enhanced regional cooperation in electricity to reduce overall costs and improve security of supply

(i) Clarification of roles within public sector structures and development of skills in planning, procurement, and transactions' negotiation;

(j) Development of the legal, regulatory, institutional and financial framework for rapid development of the electricity industry.

(2) In addition, the introduction of privatisation and competition within the electricity industry is a long-term policy.

[1] 2011, Ministry of Infrastructure (MININFRA), Electricity Development Strategy: 2011-2017

2.2 Institutional Overview of the Electricity Industry

(1) Figure 1summarises key institutions and roles in the Rwanda electricity industry

Name	Entity				Main Roles and Functions in the ESI
	Ministry	GOR Body	Public	Private	
MoE	⊙				1 Overall coordination of the energy sector 2 Develop institutional and legal frameworks 3 National electricity policy formulation 4 Energy planning, strategies and master plans 5 Regional integration and harmonisation 6 Human resource capacity building 7 Procurement 8 Supervise and monitor other government agencies in implementation of policies, strategies and master plans 9 Work with government agencies to assist private investors
The Authority		⊙			1 Regulation of the electricity licensing 2 Tariff setting 3 Facilitate private sector participation 4 PPP development 5 Quality of Supply standards and performance indices 6 Licensee compliance monitoring
NSA		⊙			1 Define and set national industry standards 2 Ensure products adhere to national standards 3 Ensure trade equity by enforcing standardisation 4 Approve products in public tenders 5 Setup a national certification/accreditation system 6 Collaborating with other relevant establishments with similiar responsibilities at regional/international level
RDB		⊙			1 Fast track PPP development 2 Promote local and foreign direct investment 3 Promote exports to regional/international markets 4 Carry out and monitor privatisation programmes 5 Facilitate private business setup 6 Participate in policy/strategy initiation and implementation 7 Advise government on fast track development
NEP			⊙		1 Investment management & implementation 2 Design, finance, build and operate/maintain power plant i.e. *GenCo* 3 Operate the Interconnected Power System (IPS) of Rwanda i.e. System Operator (SO)

Name	Entity				Main Roles and Functions in the ESI
	Ministry	GOR Body	Public	Private	
					4 Design, finance, build and operate/maintain transmission assets i.e. *TransCo* 5 Design, finance, build and operate/maintain distribution assets i.e. *DisCo* 6 Buy and sell electricity locally/internationally i.e. *TradeCo* and international *TradeCo*
IPP				⊙	1 Design, finance, build and operate/maintain power plant i.e. *GenCo*

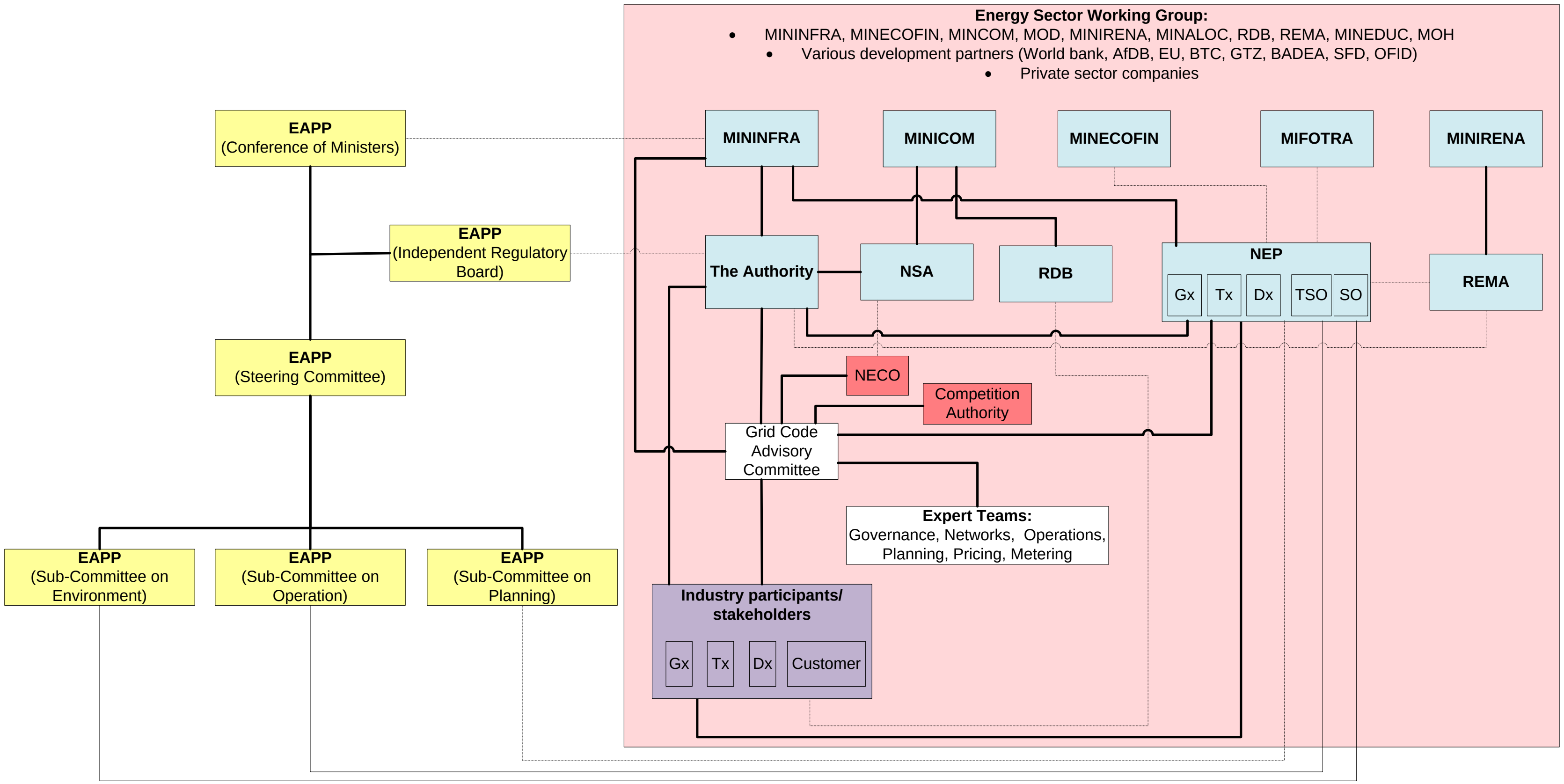
Figure 1: Summary of the current key Institutions and their Roles and Responsibilities in the Rwandan ESI

2.3 Current Electricity Industry Structure

(1) The current structure of all the bodies involved in *the Electricity Supply Industry (ESI)* in Rwanda is shown in Figure 2.

(2) It is important to note that the *Transmission System Operator (TSO)* and *System Operator (SO)* functions currently reside inside the *NEP.* This results in the *NEP* owning *Generation, Transmission* and *Distribution* as well as dispatching all *Generation* and operating the networks. In order for full transparency and independence as well as for *the Authority* to regulate the functions of the ESI accurately, these functions should either:

a. Be financially ring fenced inside *NEP* to ensure no cross-subsidisation across the value chain (*Generation, Transmission* and *Distribution*, system operation as well as network planning and development).



Key:

MININFRA	Ministry of Infrastructure
MINICOM	Ministry of Commerce
MINECOFIN	Ministry of Public Services and Labour
MIFOTRA	Ministry of Public Services and Labour
MINIRENA	Ministry of Natural Resources
REMA	Rwandan Environmental Management Agency
NEP	National Energy Provider
RDB	Rwandan Development Board
RBS	Rwanda Bureau of Standards
NEC	National Electro-technical Council
EAPP	Eastern African Power Pool
TSO	Transmission System Operator
Gx	Generation
Tx	Transmission
Dx	Distribution

- Rwanda government entities
- Rwanda Grid Code entities
- EAPP entities
- Industry entities (public/private)
- Other entities
- Formal control/jurisdiction
- General interaction/relationship

Figure 2 Current structure of all bodies involved in the Rwanda ESI (including prospective Grid Code entities)

(3) The interactions between the main functional bodies the Rwandan ESI are illustrated in Figure 3.

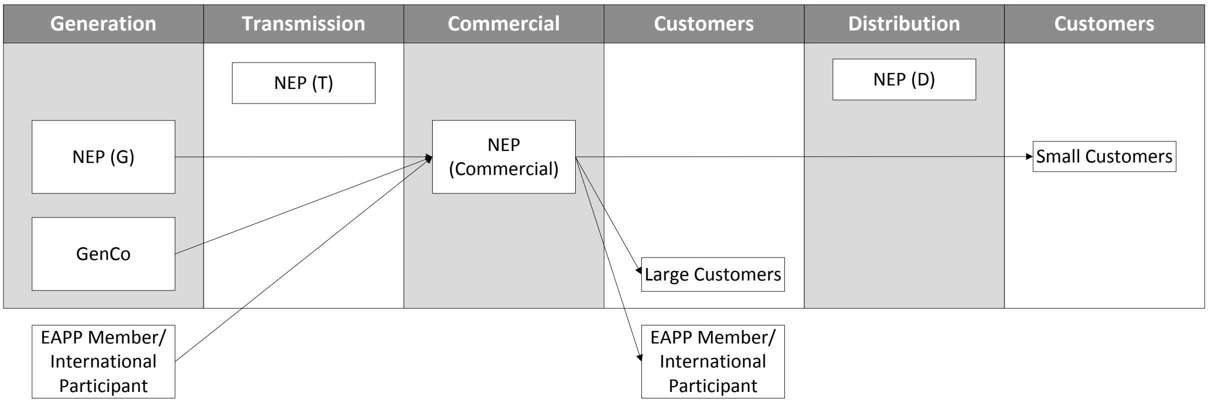


Figure 3: Current Rwandan functional ESI Structure

(4) The above figure shows that the *National Energy Provider (NEP)* is currently responsible for:

(a) *Generation* i.e. NEP (G)

(b) *Transmission* i.e. NEP (T)

(c) *Distribution* i.e. NEP (D)

(d) Purchasing of power from NEP (G) and GenCos (IPPs) i.e. *NEP (Commercial)*

(e) Trading of electricity via *NEP (Commercial)* with regional entities e.g. *SINELAC* and *Eastern Africa Power Pool (EAPP)* member utilities.

(f) Safe, efficient and reliable operation of the *Transmission* and *Distribution* system i.e. the *System Operator (SO).*

(g) Selling of electricity to *Customer*s via *NEP (Commercial).*

2.4 Electricity Industry Reform

(1) For a number of reasons the GOR have embarked on an electricity market reform process to allow private entities to fulfil a much bigger role in the electricity industry. The *Electricity Law* governing the electricity industry in Rwanda provides a deeper insight into the future electricity market structure. Figure 4 interprets the intended future industry for domestic transactions.

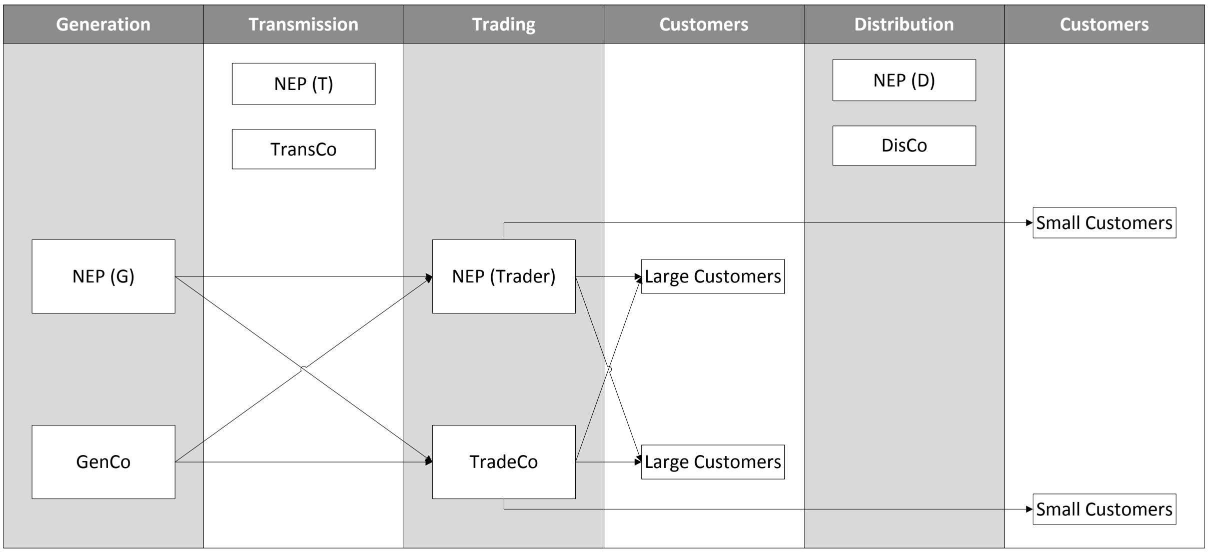


Figure 4: Intended functional Rwanda ESI structure for domestic transactions

(2) The above figure shows:

(a) The following activities in the electricity industry require a license from *the Authority*:

- *Generation*
- *Transmission*
- *Trading*
- *Distribution*

(b) Multiple *Generators* (*GenCos*) are allowed, including *NEP* (G)

(c) Multiple *Transmitter*s (*TransCos*) are allowed, including *NEP* (T)

(d) Multiple *Distributors* (*DisCos*) are allowed, including *NEP* (D)

(e) Multiple Traders (TradeCos) are allowed, including *NEP* (Trader)

(f) TradeCos, including *NEP* (Trader), can buy electricity from any GenCo, including *NEP* (G)

(g) TradeCos, including *NEP* (Trader), can sell electricity to any *Large* and/or *Small Customers.*

(h) *Large* and/or *Small Customers* can buy electricity from any licensed *TradeCo*, including *NEP* (Trader).

(i) The new market structure allows for greater competition between *GenCos* and *TradeCos* and more choice for *Large Customer*s.

(3) The *Electricity Law* also allows for *Participants* to apply for an International Trading License (to become and International *TradeCo*). This license will grant the holder the opportunity to procure power and ancillary services for export and/or import. The market structure inclusive of the above mentioned International Trading License is slightly more complex and is shown in Figure 5.

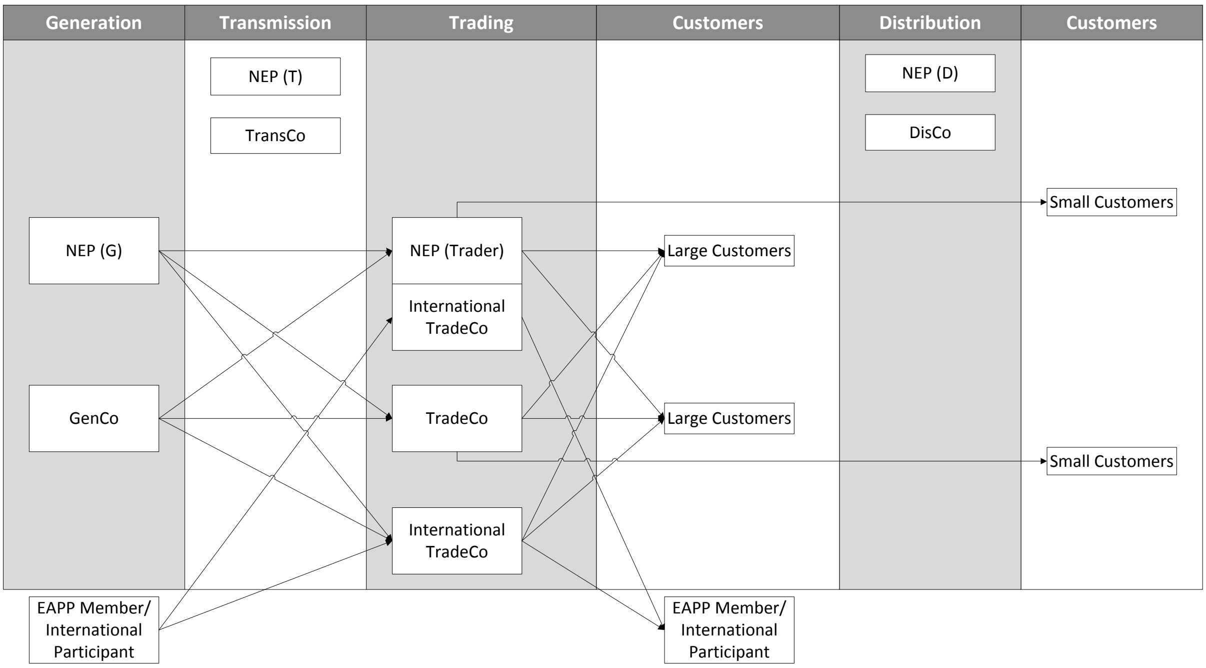


Figure 5: Intended functional Rwanda ESI structure for domestic and international transactions

(4) The new market structure places new demands on the *ESI* including:

(a) Appropriate and transparent technical and operational standards.

(b) Incorporation of bilateral trading arrangements.

(c) Energy wheeling across networks implying fair and non-discriminatory network access and prices.

(d) Network congestion management.

(e) Energy balancing services

(f) Ancillary services

(g) Independence/ring-fencing of the various NEP functions (*GenCo*, *TransCo*, *DisCo* and *SO/TSO*)

(5) Many of these issues can be addressed through suitable legislation including this *Grid Code* and other regulatory rules/standards.

3 Authority

3.1 Regulations

(1) The *Grid Code* derives its authority from the following regulations.

(a) Electricity license to produce (generate) electricity.

(b) Electricity license to transmit electricity.

(c) Electricity license to distribute electricity.

(d) Electricity license to trade (buy and sell) electricity both locally and internationally.

3.2 Legislation

(1) The various electricity licenses derive their legal authority from the following laws.

(a) Law N°21/2011 of 23/06/2011 Governing Electricity In Rwanda (*The Electricity Law*)

(b) Law Nº09/2013 of 01/03/2013 Establishing Rwanda Utilities Regulatory Authority (*RURA Law*)

(c) Applicable regulations and legislation released by *the Authority* from time to time

3.3 Applicability

(1) All *Licensees* are required to comply with the provisions of the *Electricity Law*, their respective granted *Licences* as well as the approved *Grid Code* and applicable legislation and regulations. Any breach could result in the sanctioning, suspension or withdrawal of the applicable *License*.

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 *IPS* in a manner that ensures reliable, efficient, economic, safe and on-going operation of the *IPS*.

4.2 Objectives

(1) The fundamental function of a *Grid Code* is to establish the rules and procedures that allow all *Participants* to use the *IPS* and to permit the *IPS* to be planned and operated:

(a) Safely,

(b) Reliably,

(c) Efficiently,

(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 *Participants*

(f) Specify minimum technical requirements for the *Transmission system*

(g) Specify minimum technical requirements for the *Distribution system*

(h) Ensure that the relevant *Information* is made available to all *Participants* as/when required

(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 Preamble;

(b) The Governance Code;

(c) The System Operations Code (including elements of Scheduling and Dispatch);

(d) The Network Code;

(e) The Metering Code;

(f) The Information Exchange Code;

(g) The Network Tariff Code

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

a. The **Preamble** provides the context for the *Grid Code* and its various sub-sections. It is also the single document in the *Grid Code* that contains detailed definitions and acronyms of all relevant terms and abbreviations used in the *Grid Code* documents.

b. 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*.

c. The **System Operations Code** sets out the responsibilities and roles of the *Grid Code Participants* as far as the operation of the *IPS* is concerned. It also sets out the responsibilities and roles of the *Grid Code Participants* as far as the scheduling and dispatch of the *IPS* is concerned. It addresses, amongst other things:

   i. Reliability, security and safety;
   ii. Field operation, maintenance and maintenance co-ordination / outage planning.
   iii. Operations planning;
   iv. Scheduling and dispatch operation actions;
   v. *Ancillary Services*;
   vi. Operational Authority
   vii. Operating procedures
   viii. Operation liaison
   ix. System frequency control
   x. Independent actions required and allowed by *Participants*;
   xi. Voltage control
   xii. Fault and incident reporting
   xiii. Commissioning responsibilities
   xiv. Risk of trip
   xv. Maintenance co-ordination and outage planning
   xvi. Communication of IPS operational conditions
   xvii. Telecontrol

d. The **Network Code** focuses on the technical requirements and standards of the *Interconnected Power System (IPS)*. It is broken down into sections defining:

   i. Off-grid conditions
   ii. Network connection processes

iii. General connection conditions (for *Generators (GenCos)*, *Embedded Generators (EGs)*, *Transmitters (TransCos)*, *DisCos* and *Customers*,

iv. Technical design requirements applicable to *TransCos* and *DisCos*,

v. Electrical protection requirements for *TransCos* and *DisCos*,

vi. Network planning and development,

vii. Other network services

viii. Network maintenance requirements.

e. The **Metering 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:

i. Application of the *Metering Code*

ii. Provisions of the *Metering Code*

iii. *Metering Point* responsibilities

iv. *Metering Installation* requirements

v. *Metering Apparatus* maintenance

vi. *Metering Apparatus* Access

vii. *Data validation and verification*

viii. The *Metering* database

ix. Testing of *Metering Installations*

x. *Metering* database inconsistencies

xi. Access to *Metering* Data

xii. Customer queries on *Metering* integrity and data

f. 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 *IPS* and the safe, reliable provision of *Transmission* and *Distribution* services. The Information Exchange Code contains the following:

i. *Information* exchange interface

ii. Planning *Information*,

iii. Operational *Information*, and

iv. Post-dispatch *Information*

v. Confidentiality of information.

g. The ***Network*** **Tariff Code** sets out the objectives and principles of *Transmission* and *Distribution* 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:

i. Authority of RURA to regulate tariffs/charges

ii. Applicability and objectives of the *Network* Tariff Code

iii. Principles for the regulation of income

iv. Approach to the determination of tariff structures and levels

v. Procedure for RURA Approval and Tariff Change Notifications

5 Definitions and Acronyms

(1) This 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 Rwandan market.

(2) All Definitions and Acronyms listed below apply to the complete set of *Grid Code* documents.

5.1 Definitions

(1) **Active Energy -** Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, and being the integral with respect to time of active power, measured in units of Watt-Hours or multiples thereof.

(2) **Active Power -** Instantaneous power derived from the product of voltage and current and the cosine of the voltage phase angle measured in units of Watts and multiples thereof.

(3) **Amendment –** A change to any part of the *Grid Code* approved by the Authority following the appropriate procedures outlined in the *Governance Code.*

(4) **Ancillary Services** - Services supplied to a *Transmission* company by *Generators*, *DisCos* and/or *end-use Customers* necessary for the reliable and secure transport of power from *Generators* to *DisCos* and *Customers*. Ancillary services maintain the short-term reliability of the IPS and include the various types of *reserves*, *black start*, *reactive power*, *unit islanding* etc.

(5) **Apparatus** - An item of equipment, in which electrical conductors are used, supported or of which they form a part and includes meters, lines, cables and appliances used or intended to be used for carrying electricity for the purpose of supplying or using electricity.

(6) **Area Control Error (ACE)** – The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including correction for metering error..

(7) **Authority –** See *Regulatory Authority*

(8) **Automatic *Generation* Control (AGC)** - Equipment that automatically adjusts a *Control Area's Generation* to maintain its interchange schedule plus its share of frequency regulation.

(9) **Automatic Load Shedding Scheme –** A load shedding scheme utilised by the *TSO* to prevent frequency collapse and to restore the balance between *Generation* output and *Demand*

(10) **Automatic Voltage Regulator (AVR)** - The continuously acting automatic equipment controlling the terminal voltage of a Synchronous Generating Unit by comparing the actual terminal voltage with a reference value and controlling by appropriate means the output of an Exciter (or source of the

electrical power providing the field current of a synchronous machine), depending on the deviations.

(11) **Auxiliary Supply** - Supply of electricity to auxiliary systems of a generating *unit* or substation equipment.

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

(a) Start without an outside electrical supply and

(a) 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 upon instruction of the *TSO*.

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

(14) **Co-*Generator* –** An entity who operates and/or owns a *Generating Unit* that as part of its core design utilises waste energy, produces other usable energy in addition to electricity and/or is renewable fuel based which is a co-product of an industrial production process. A Co-*Generator* typically connects to the *Distribution System* (an *Embedded Generator*) but can connect to the *Transmission System* in selected cases (a *Generator*).

(15) **Competition Authority** – An *Authority* setup to investigate, control and evaluate anti-competitive behaviour, restrictive business practices, abuse of dominant positions and mergers in various industries. In this instance, more specifically in the *ESI* in order to achieve equity and efficiency in the economy.

(16) **Connection Agreement** – A bilateral agreement made between a *Distribution Licensee*, *Transmission Licensee* or *TSO* and *a Participant* (domestic/international) setting out the terms and conditions relating to the use of a *Connection Point* and other specific provisions in relation to that connection, including inter alia the following:

(a) Active Power and/or Active Energy transfer

(b) *Reactive Power and/or Reactive Energy transfer*

(c) *Quality of Supply*

(d) *Ancillary* Services

(17) **Contingency** – An unexpected incident, failure or outage of an interconnected system component, such as a *Generating Unit*, *Transmission* line, circuit breaker, switch or other electrical element. A *Contingency* may also include multiple components, which are related by situations leading to simultaneous component outages.

(18) **Control Area** – An area comprised of an electric system or systems, bounded by interconnection metering, capable of regulating its *Generation* in order to maintain its interchange schedule with other electric systems or Control Areas and to contribute its frequency bias obligation as required. A *Control Area* adheres to the minimum requirements for a *Control Area* as defined in the Eastern Africa Power Pool (EAPP) Operating Rules.

(19) **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 import of energy between the states.

(20) ***Customer*** **–** See *End-use Customer*.

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

(22) **Data Terminal Equipment (DTE)** – A communication device that can control data flow and is capable of generating or terminating data.

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

(24) **Demand** – an instantaneous consumption of electric power from any *Participant*.

(25) **Demand Side Management (DSM) –** the ability of a *Consumer* to willing reduce consumption on instruction from the *System Operator* or via under frequency relays. This service may be compensated for as an *Ancillary Service*.

(26) **Derogation** – A waiver issued by the *Grid Code Review Panel* to suspend a *Participants* obligations to implement or comply with a provision or provisions of the Grid Code.

(27) **DisCo –** Refers to general (non-specific) *Distributor*

(28) **Dispatch Instruction –** An instruction to a *Generator* or *Consumer* to change the electrical output of the *Generator* or *Consumer*'s consumption.

(29) **Dispute** – Any difference controversy between the *Grid Code Review Panel* and a *Participant* in connection with or arising from the interpretation, implementation or breach of any provision in the *Grid Code*

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

(31) ***Distribution* area** – the area within which a *Distribution licensee* has the exclusive right to provide service to any *Customer* in the area that the *Distribution licensees licence* allows

(32) ***Distribution* Licensee** – a *licensee* authorised to undertake *Distribution* activities in accordance with the specific rights laid out in the issued licence

(33) ***Distribution* Metering Administrator** - A *Participant* that is responsible for all *Distribution* tariff metering installation, maintenance and operations e.g. *DisCo*.

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

(35) **Distributor** - A licensed entity that, subject to condition of its licence, owns operates and maintains a *Distribution system*.

(36) **EAPP Interconnected *Transmission* System –** The *Transmission* system in Eastern Africa consisting of two or more individual *National Systems* or *Control Areas* that normally operate in synchronism and are physically interconnected via *Transmission* facilities.

(37) **EAPP Interconnection Code** – The Code by which all *EAPP* member countries and EAPP member utilities are required to adhere to. It outlines the framework for the successful pooling of *Generation*, rules for coordinated system planning and operation, agreed principles and procedures for dispute settlements and arrangements for equitable sharing of benefits in the Eastern African region.

(38) **EAPP Sub-Committee on Planning –** the entity established under *EAPP* governance responsible for coordination of *Electricity Master Plans* and development programs of EAPP Members.

(39) **Economic regulation** – 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.

(40) **Electricity Law** – The Rwandan Electricity Law Nº 21/2011.

(41) **Electricity Master Plan –** 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.

(42) **Electricity Supply Industry (ESI)** – also referred to as *Electricity Industry* refers to the industry involving electricity *production* (*Generation)*, *Transmission*, *Distribution, trade*, *supply* and regulation.

(43) **Embedded Generator (EG)** – A legal entity operating licensed *Embedded Generating Units*.

(44) **Embedded Generating Unit (EGU)** - A type of *Generating Unit*, other than a *Co-Generator*, that is not directly connected to the *Transmission System*.

(45) **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.

(46) **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.

(47) **Emergency Transfer Capability** –the total amount of power above the net contracted purchases and sales which can be scheduled between two control areas 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:

a. All transmission loadings initially within long-term emergency ratings and voltages initially within acceptable limits;

b. *IPS* 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

c. 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).

(48) **End-use *Customer*** - Users of electricity above 1 kV (demand and/or supply). An *End-use Customer* can be a *Large Customer* and/or *Small Customer*.

(49) **Energy Management System (EMS)-** usually a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimise 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”.

(50) **Exemption –** A provision made by the *Authority* for a Participant who does not need to comply with a section/s of the *Grid Code.* The appropriate procedure outlined in the *Governance* Code should be followed before an *Exemption* is approved and granted.

(51) **Expert** - A well-qualified person with broad proven experience appointed by *RURA* or the *GCAC* to express his/her opinion or give advice on issues concerning the *Grid Code*.

(52) **Excluded services –** Services requested by *Customer*s that are excluded from the regulated activities and funded directly by the *Customer*

(53) **Force Majeure -** Causes beyond the reasonable control of and without the fault or negligence of the *Participant* claiming *Force Majeure*. It shall include failure or interruption of the delivery of electric power due to causes beyond that *Participants* control, including Acts of God, wars, sabotage, riots, actions of the elements, civil disturbances and strikes.

(54) **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 in accordance with the technical provisions laid out in the Grid Code.

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

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

(57) **GenCo –** Refers to general (non-specific) *Generator*

(58) ***Generation* licensee** – a *licensee* authorised to undertake electricity *Generation* services.

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

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

(61) ***Generator*** - A legal entity operating licensed *Generating Units*.

(62) **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*.

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

(64) **Grid Code** – the document (or set of documents) that legally establishes technical and other requirements for the connection to and use of the *IPS* by *participants* in a manner that ensures reliable, efficient, safe and ongoing operation of the *IPS* in line with the technical and procedural rules and standards issued by the *Authority.*

(65) **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.

(66) **Grid Code Advisory Committee (GCAC)** – The panel established by RURA in accordance with the *Governance Code* charged with the provision of expert technical advice on Grid Code matters as well as the review of the operation, consultative stakeholder process and revision of the *Grid Code.*

(67) **High Voltage (HV)** – AC or DC voltage of the amount equal or above seventy thousand volts plus or minus ten per cent.

(68) **Incident -** An event which is not part of the standard operation of the *Transmission System* or the *Distribution System* and which causes or may cause disruption to or a reduction in the quality of services or impact on people health or plant life and cost.

(69) **Incident Report –** A written document that describes the relevant facts and sequence of events that gave rise to in an *Incident*.

(70) **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.

(71) **Information Owner** - The responsible person acting on behalf of a *Participant* to whose system or installation the *Information* pertains.

(72) **Interconnected Power System (IPS) -** The *Transmission System, Distribution System* and any other connected system elements including *Customers*, *Power Stations* and *Interconnections*.

(73) **Interconnection(s) –** An electrical connection between Rwanda and an international *Participant e.g. EAPP member.*

(74) **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*.

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

(76) **Island –** See *Power Island*

(77) **Labour Law –** Rwandan Law No 13/2009, the Law regulating labour in Rwanda.

(78) **Large *Customer*** – See definition of *Large Scale Customer*.

(79) **Large Scale *Customer*** – any person connected to *MV* and/or *HV* networks who annually consumes an electricity quantity which is equal to or higher than the minimum quantity set by the relevant authority.

(80) **Licence –** a *licence* issued by the *Authority* pursuant to the *RURA Law*, relating to the electricity supply industry.

(81) **Licensed activity –** An activity requiring a *licence* as set out in the *Electricity Law*.

(82) **Licensee –** any person licensed to provide electricity market administration services as defined in the *Electricity Law*.

(83) **Low Voltage (LV) –** AC or DC voltage less or equal to four hundred volts plus or minus five percentages.

(84) **Losses -** The technical or resistive energy losses incurred on the *Transmission system* and/or *Distribution system*.

(85) **Manual load shedding -** The load reduction obtained by manually shedding load at convenient points on the *Transmission system* or *Distribution system* under emergency conditions as required by the *System Operator*.

(86) **Medium Voltage (MV) –** AC or DC voltage above four hundred volts plus or minus ten percent and less or equal to thirty three thousand volts plus or minus ten percent.

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

(88) **Metering -** All the *Apparatus* employed in measuring the *supply* and or use of electrical power/energy (active and reactive where applicable) together with the *Apparatus* directly associated with it.

(89) **Metering Installation -** An installation that comprises an electronic meter that can be locally or remotely interrogated, has an electronic communication link and is connected to the *TMA's* or *DMA's Metering* database.

(90) **Metering Point –** the position in the *IPS* at which a *Participant* measures the amount and direction of active and reactive use of electrical power.

(91) **Metering Service Provider –** A person, company or entity who undertakes *installation of Metering Installations,* maintenance or data reading tasks on behalf of a *Participant.*

(92) **Metering Threshold –** S ≥ 250 kVA (supplying or using)

(93) **Minister –** the Minister responsible for energy matters.

(94) **Ministry of Energy (MoE) –** The government entity responsible for policy on energy matters in Rwanda, currently known as the *Ministry of Infrastructure (MININFRA).*

(95) **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.

(96) **National Electro-technical Council (NECO)** – The technical national council made up of various stakeholders focusing on national standards development, direction and adoption. The NECO works closely with the *NSA*.

(97) **National Energy Provider (NEP) –** The state owned, commercial entity responsible for providing electrical power/energy in Rwanda.

(98) **National Grid Control Centre (NGCC)** - means a place from where the *System Operator* Control Centre is located. From here, controlling and/or directing the safe operation of the *Generation*, *Transmission* and *Distribution* of electrical power to *Customer*s is carried out.

(99) **National Standards Authority (NSA)** – The entity responsible for standards development, adoption and enforcement in Rwanda.

(100) **National System –** See *Transmission System*.

(101) **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 a station's auxiliaries and the losses in the transformers that are considered integral parts of the station.

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

(103) **Operating Reserves -** are the additional outputs from *Generating Units* or reduction in demand (from loads) 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:

(a) *Primary Response*

(b) *Secondary response*

(c) *Tertiary Response*

(104) **Other Network Services –** *Other Network Services* are services that may be competitive or provided by *TransCos/DisCos* as a monopoly service. These services are the mandatory services supplied/procured to ensure a standard of supply that meets *QoS*, reliability and safety standards.

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

(106) **Performance Agreement –** an enforceable agreement between a *licensee* and the *Authority* attached to the issued *licence* 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*.

(107) **Planned Interruption -** A *Planned Outage* that will interrupt *Customer* supply.

(108) **Planned Interruption -** A *Planned Outage* that will interrupt *Customer* supply.

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

(110) **Point of Common Coupling -** The electrical node, normally a *busbar*, in a *Transmission or Distribution substation* where different feeders are connected together for the first time.

(111) **Point of Connection (PoC) -** The electrical node in a *Transmission* or *Distribution Substation* where a *Participant* is physically connected to a *Transmission* or *Distribution* company assets.

(112) **Point of Delivery (PoD) -** See *Point of Supply*.

(113) **Point of Supply (PoS) -** A *Transmission or Distribution Substation* where energy can be delivered/supplied by/to *Generators/Embedded Generators*/*Customers*.

(114) **Power Balance Statement –** The forecast prepared by the *TSO* for the Rwandan *IPS* outlining the expected demand and *Generation* over the planning horizon as defined in the *EAPP Interconnection Code*

(115) **Power Factor –** refers to the ratio of the RMS of the active power to apparent power measured over the same integrating period

(116) **Power Island –** A balanced isolated group of *generating units* and/or *co-Generators* and/or *embedded Generators* with complementary local demand

(117) **Power Pool** – The interconnection to *SAPP* or *EAPP* and the rules associated with each *Power Pool*.

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

(119) **Power System Stabiliser (PSS) -** Equipment controlling the Exciter output via the voltage regulator in such a way that power oscillations of synchronous machines are dampened. Input variables may be speed, frequency, accelerating power or active power (or a combination of these).

(120) **Premium supply/connection –** See *Firm Supply*

(121) **Primary Response –** The automatic response from synchronised *Generating Units* to a rise or fall in frequency on the *IPS.*

(122) **Primary Substation Equipment -** Equipment installed at *substations* including inter alia transformers, busbars, circuit breakers, isolators, shunt devices, FACTS devices

(123) **Production** – See *Generation*

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

(125) **Quality of Supply –** the technical parameters that describe the electricity supplied to *Customer*s according to RBS standards and any other RURA prescribed documents

(126) **Reactive Power -** Instantaneous power derived from the product of voltage and current and the sine of the voltage-current phase angle which is measured in units of VArs and multiples thereof.

(127) **Regulatory Authority** – the Rwanda Utilities Regulatory Authority (RURA) established under the *RURA Law*

(128) **Regulatory Board –** Refers to the organ, that is properly constituted with the *RURA Law*, and that assumes legal responsibility for corporate activities and who oversees the management of the Regulatory Authority.

(129) **Related business –** 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*.

(130) **RURA Law –** The Rwanda Law N°09/2013 of 01/03/2013 establishing Rwanda Utilities Regulatory Authority .

(131) **Scheduling -** A process to determine which Unit or *Apparatus* will be in operation and at what loading level.

(132) **Secondary Response –** The centralised automatic control that adjusts the *Active Power* production of *Generating Units* to restore frequency and interchanges with other *Control Areas* to target values following a frequency deviation (using the *AGC*).

(133) **Secondary Substation Equipment -** Equipment installed at *substations* including inter alia protection, telecommunications and metering equipment

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

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

(a) *Generator*;

(b) *System Operator*;

(c) *TransCo*

(d) DisCo

(e) *TradeCo*

(f) *Large Customer*

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

(136) **Small *Customer* –**See definition of *Small Scale Customer*.

(137) **Small Scale *Customer*** – any person connected to *LV* and/or *MV* networks who annually consumes an electricity quantity which is lesser than the one set by the *Authority*.

(138) **Stakeholders -** The entities affected by or having a material interest in the *Grid Code*. This includes *Customer*s and other industry *participants*, for example the RURA.

(139) **Standard Supply –** is defined such that if a circuit is out for maintenance or on an unplanned outage, that either no supply will be available or supply is still available but not in accordance with the technical provisions laid out in *the Grid Code*.

(140) **Substation -** A site at which primary and secondary equipment is installed including inter alia electrical isolating/switching devices, transformation equipment, shunt and FACTs devices are installed.

(141) **Supply –** the sale of electricity to *Customer*s.

(142) **System Frequency -** The frequency of the fundamental AC voltage as measured at selected points by the *System Operator*. The scheduled (target) system frequency f is 50 Hz.

(143) **System Minutes -** The normalised performance indicator for interruptions, defined as:

(Energy interrupted (MWh)* 60) / (system peak demand (MW)).

(144) **System Operator –** The *TSO* licensed to provide *system operation* services.

(145) **System Tests -** Those tests which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *Transmission System*. In addition, they include commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out which may have a significant impact upon the *IPS* and/or a *Transmission system*.

(146) **Telecontrol –** The general term used to refer to *Supervisory Control and Data Acquisition (SCADA) Apparatus* installed in a power system (including local and remote areas) and the associated functionality provided by such *Apparatus* for power system data retrieval and control

(147) **Tertiary Reserves –** Changes in the dispatching and commitment of *Generating Units.* Tertiary reserves restore *Primary Reserves* and *Secondary Reserves*, to manage constraints and to bring frequency and interchanges with Control Areas back to their target when *Secondary Reserves* are depleted.

(148) **Trade –** Refers to the actions of a *TradeCo of* buying of electricity directly from *Generators* and/or *DisCo*s as well as the selling of electricity to *DisCos* and/or large/small *Customer*s

(149) **TradeCo –** Refer to *Trader*

(150) **Trader –** a legal entity that has been licenced to Trade electricity in the Rwandan electricity industry

(151) **TransCo -** Refers to general (non-specific) responsibility of *Transmission (*also referred to as a *Transmitter)*

(152) ***Transmission* –** 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.

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

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

(155) ***Transmission* licensee –** a *licensee* authorised to undertake *Transmission* activities in accordance with the specific rights laid out in the issued licence

(156) ***Transmission* Metering Administrator (TMA) -** A *Participant* that is responsible for all *Transmission* tariff metering installation, maintenance and operations e.g. *TransCo*.

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

(158) ***Transmission* system capability statement –** The assessment made by the *TSO* of the capability of the *IPS* to support the required energy flows across the Rwandan *IPS* and for cross-border *interconnections* as detailed in the *EAPP Interconnection Code*

(159) ***Transmission* System Operator (TSO) –** the entity responsible for overall co-ordination of the planning and operation of the *Transmission System* by the *Authority*.

(160) **Unit –** Refer to *Generating Unit*

(161) **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 *MCR* pre-trip conditions.

(162) **Unplanned Outage –** An outage that is not requested, negotiated, scheduled and confirmed 14 days before taking place. This is not a *forced outage* or *emergency outage*

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
ADC:	Analogue to Digital Conversion
AGC:	Automatic *Generation* Control
AMR:	Automated Meter Reading
ARC:	Auto Re-Close
AVR:	Automatic Voltage Regulator
COUE:	Cost of Unserved Energy
CT:	Current Transformer
DC:	Direct Current
DLC:	Dead Line Charge
DMA	*Distribution* Metering Administrator
DPI:	Dip Proofing Inverter
DS:	*Distribution* System
DSM:	Demand Side Management
DTE:	Data Terminal Equipment
EAPP:	Eastern African Power Pool
EAPP CC:	Eastern African Power Pool Coordination Centre
EEAR:	Expected Energy At Risk
EENS:	Expected Energy Not Served
E/F:	Earth Fault
EG:	Embedded Generator
EMS:	Energy Management System
ESI:	Electricity Supply Industry
FACTS:	Flexible AC *Transmission* Systems
FL:	Fault Level
GCAC:	Grid Code Advisory Committee
GCRP:	Grid Code Review Panel
GCS:	Grid Code Secretariat

GCR:	Grid Code Requirement
GOR:	Government of Rwanda
HP:	High Pressure
HV:	High Voltage
HVDC:	High Voltage Direct Current
Hz:	Hertz
IDMT:	Inverse Definite Minimum Time
IEC:	International Electro-technical Commission
IPS:	Interconnected Power System
IPP:	Independent Power Producer
ISO:	Independent System Operator
ITC:	Independent *Transmission* Company
LRMC:	Long Run Marginal Cost
MBU:	Marketing Business Unit
MCR:	Maximum Continuous Rating
MINICOM:	Ministry of Commerce, Industry, Investment Promotion and Cooperatives
MININFRA:	Ministry of Infrastructure
MINIRENA:	Ministry of Natural Resources
MoE:	Ministry of Energy (see *MININFRA*)
MUT:	Multiple-Unit Tripping
MV:	Medium Voltage
MVA:	Megavolt-Ampere
MW:	Megawatt
NECO:	National Electro-technical Council
NEC/R	Neutral Earthing Compensator with Resistor
NEP:	National Energy Provider
NSA:	National Standards Authority
NGCC	National Grid Control Centre
OLTC:	On-load tap changer:
OEM:	Original Equipment Manufacturer
O/C:	Over-Current
PCC:	Point of Common Coupling
PCLF:	Plant Capability Loss Factor
PoC:	Point Of Connection
PoD:	Point Of Delivery
PoS:	Point Of Supply

PPA:	Power Purchase Agreement
PS:	Power Station
PSS	Power System Stabiliser
p.u.:	Per Unit
QOS:	Quality of Supply
RAB:	Regulatory Asset Base
RAS:	Remedial Action Schemes
REMA:	Rwanda Environmental Management Authority
RMS	Root Mean Squared
ROCOF	Rate of Change of Frequency
ROR:	Rate of Return
RURA:	Rwanda Utility Utilities Regulatory Authority
RTU:	Remote Terminal Unit
SAIDI:	System Average Interruption Duration Index
SAIFI:	System Average Interruption Frequency Index
SAIRI:	System Average Interruption Restoration Index
SAPP:	Southern African Power Pool
SCADA:	Supervisory Control and Data Acquisition
SINELAC:	Societe International D'Electricite Des Pays Des Grands-Lacs
SPS:	Special Protection Schemes
SRMC:	Short Run Marginal Cost
SSR:	Sub-Synchronous Resonance
SVC:	Static VAR Compensator
TMA:	*Transmission* Metering Administrator
TRFR:	Transformer
TS:	*Transmission* System
TSO:	*Transmission* System Operator
UAGS:	Unplanned Automatic Grid Separations
UCLF:	Unit Capability Loss Factor
Um, Umax:	Maximum Rated Voltage
Un:	Nominal Voltage
VT:	Voltage Transformer
WACC:	Weighted Average Cost of Capital

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:

General Manager: *Transmission* (*NEP*)
Electricity, Water and Sanitation Authority (*NEP*)
P. O. Box 537 Kigali – Rwanda
E-Mail: To be provided by the NEP

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

Rwanda Utilities Regulatory Authority (RURA)
Director of Energy (RURA)
E-Mail: info@rura.gov.rw
P.O.Box: 7289 Kigali-Rwanda

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

General Manager: *Transmission* (*NEP*)
Electricity, Water and Sanitation Authority (*NEP*)
P. O. Box 537 Kigali – Rwanda
E-Mail: To be provided by the NEP

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

(a) 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;

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

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

(d) if successfully transmitted by Electronic Mail (E-Mail), 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 Rwanda, has drawn on regionally and internationally available grid codes and other documents where applicable. In particular the grid codes of EAPP, Kenya, Namibia, South Africa, Tanzania, Uganda, United Kingdom and Zambia were consulted.

RWANDA UTILITIES REGULATORY AUTHORITY

(*RURA*)

THE RWANDA GRID CODE

Governance Code

2 of 7 Code Documents

Version 1.0

RURA, Rwanda

TABLE OF CONTENTS

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 *Participants* (Generators (*GenCos)*, Transmitters (*TransCos), Distributors (DisCos)* and *Traders* (*TradeCos))*, and other operating codes/guidelines that relate to the *Electricity Supply Industry (ESI)*.

(2) The accountabilities of various entities in the governance of the *Grid Code* are set out in Table 1 below.

Table 1: *Grid Code* Accountabilities

Body	Function
The Authority	• *Grid Code* Development and Approval • *Grid Code* Governance and Compliance • *Grid Code* dispute mediation
Grid Code Advisory Committee	• Review of the operation and revision of the *Grid Code*
Experts	• *Expert* opinions and drafting in respect of *Grid Code*
Grid Code Secretariat	• Administration of the *Grid Code*
Grid Code Participants	• Implementation of and compliance with the *Grid Code*

2 *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 Preamble;

(b) The Governance Code;

(c) The System Operations Code (including elements of Scheduling and Dispatch);

(d) The Network Code;

(e) The Metering Code;

(f) The Information Exchange Code;

(g) The Network Tariff Code

(2) This document deals with the *Grid Code* governance arrangements. 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*.

(3) *The Preamble* document provides the policy and industry context for the *Grid Code*. It also sets out the legal and regulatory references from which the *Grid Code* derives its authority. Furthermore, the Preamble also contains a comprehensive list of definitions and acronyms for the various terms and abbreviations used in the suite of *Grid Code* documents.

3 Administrative Authority

(1) The *Rwanda Utility Regulatory Authority* (*RURA*) is the administrative authority for the *Grid Code* (*the Authority*). *The Authority* shall ensure that the *Grid Code* is compiled, approved and implemented for the benefit of the *ESI* in Rwanda.

4 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. Review and make recommendations to *the Authority* regarding proposals to amend the *Grid Code*,

b. Review and make recommendations to *the Authority* regarding proposals for *Exemption* to comply with the *Grid Code*,

c. Facilitate the provision of *Expert* technical advice to *the Authority* on matters related to the *Grid Code* and

d. Ensure a consultative stakeholder process is followed in the formulation and review of the *Grid Code*,

4.1 Constitution of the GCAC

(1) The GCAC shall be a stakeholder representative panel, representing *Participants* in the most equitable manner possible.

(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 *ESI*. The *Regulatory Authority* may decide to amend the composition of the GCAC as part of the membership review process in consultation with the GCAC. The *Regulatory Authority* shall ensure that members on the GCAC are able to make meaningful contributions towards the review process.

(4) The *Regulatory Authority* shall endeavour to balance the representation on the GCAC taking into account:

a. Public versus private

b. Service providers versus customers

c. Policy versus regulation versus implementation

(5) Following on from this it is recommended that the GCAC shall consist of at least the following:

a. One (1) member representing the *System Operator (SO)*,

b. One (1) member representing National energy Provider (*NEP) TransCo*,

c. One (1) member representing *NEP GenCo*

d. One (1) member representing *NEP DisCo*

e. One (1) member representing other GenCos

f. One (1) member representing *Large Customers*

g. One (1) member representing *Consumer protection Associations*

h. One (1) member representing the National Electro-technical Council *(NECO)*

i. One (1) member from the *Competition Authority*

j. One (1) members representing the *MININFRA*

k. Two (2) members from *the Authority*, including one to chair.

(6) 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.

(7) *The Authority* shall publish changes in membership within 14 days, on the *Authority's* website or other suitable communications medium.

(8) *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.

(9) Members shall nominate an alternative representative. Such nomination shall be made in writing to the *GCS*.

4.2 Functioning of the GCAC

(1) The GCAC shall review all proposals for amendment of or *Exemption*s 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's* website.

(4) A member from *the Authority* 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 GCAC. 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, the meeting shall make the necessary recommendation(s). Following this, the GCS shall circulate the recommendations 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 by the GCS 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.

(11) *The Authority* shall publish the *Grid Code* and amendments thereto in the Government Gazette after the approval thereof by the Minister.

(12) *The Authority* shall publish the latest revision of the *Grid Code* on its website.

4.3 The Grid Code Secretariat

(1) The *System Operator (SO)* representative will be 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* recommendations for submission to the *Regulatory Board* 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

(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 *Exemption*s within one week of receipt of its approval.

(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.

5 Registration and De-registration of *Grid Code Participant*

(1) The GCS shall be responsible for making entries in the register of *Grid Code Participants* upon receipt of notification from the *Regulatory Board* of licensed entities (*Licensees*).

(2) *Grid Code Participants* shall be registered in their respective licensed categories namely *Generation*, *Transmission*, *Distribution* and *Trading*.

(3) No licensed entity shall have access to the *Transmission System or the Distribution 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*.

6 *Grid Code* Amendment and *Exemption* Procedure

6.1 Changes to the Grid Code

(1) *The Authority* is the approval authority for the *Grid Code*. Only *the Authority* shall therefore approve any *Amendments* to or *Exemption*s from the *Grid Code* upon recommendation by the GCAC.

(2) Any *Grid Code Participant*, *Customer*, member of the GCAC or *the Authority* may propose amendments to or *Exemption*s from the *Grid Code*.

(3) Any *Grid Code Participant* or *Customer* 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) It may not be economically viable or technically necessary to upgrade existing equipment to the required *Grid Code* standards. Where this is the case *the Authority* will give consideration to a time bound *Exemption* for all or part of the *Grid Code*.

(b) To alleviate off-grid supply arrangements from complying with on-grid requirements.

(c) To facilitate transition through interim arrangements, and

(d) To facilitate temporary conditions necessitating *Exemption*.

(4) An application containing the details of a proposed change to the *Grid Code* shall be submitted to the GCS in accordance with the provisions set out in this Governance Code.

(5) The procedure for amendment to or *Exemption* from the *Grid Code* is set out in Figure 1.

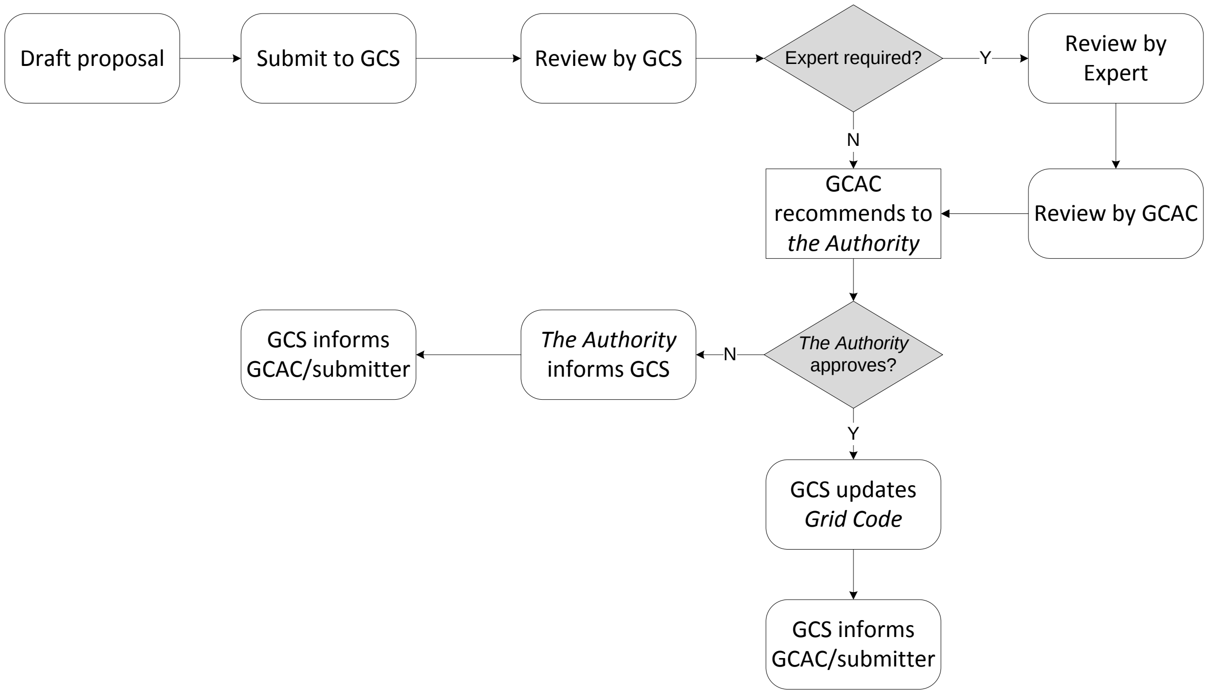


Figure 1: Grid Code amendment/Exemption procedure

6.2 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's* 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) A *Grid Code Participant* or *Customer* seeking *Exemption* from any provision in the *Grid Code* shall make a written request to the GCS containing the following information:

(a) Details of the applicant applying for *Exemption*;

(b) The clause against which the present or predicted non-compliance is identified;

(c) The specific reason for non-compliance with the provision;

(d) Identification of the *Apparatus* in respect of which an *Exemption* is being sought;

(e) Whether the *Exemption* sought is permanent or for a delay in achieving compliance,

(f) If a delay in achieving compliance is being sought, the date by which the non-compliance will be remedied.

(6) 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* for detailed assessment, clarification, reformulation and/or recommendation, and

(b) Lastly, forward the recommendation to *the Authority* for consideration once it has been finalised.

(7) 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.

(8) The GCS shall inform the applicant of the expected time frames for dealing with the submission.

(9) The applicant shall be allowed to make representation to the *Expert* team sessions and/or the GCAC prior to the formulation or finalisation of the GCAC recommendation to *the Authority*.

6.3 Recommendation to the Authority

(1) Once the GCAC has reviewed submissions, the GCS shall prepare the formal recommendation to the *Regulatory Board* on all proposed amendments and *Exemptions* to the *Grid Code*. The recommendation(s) to the *Regulatory Board* shall also include a clear expression of divergent views on such proposals, if any were received.

(2) Full or partial *Exemption* from complying with a certain provision of the *Grid Code* may be granted to *Grid Code Participants*.

(3) All *Exemption*s granted shall prevail over the relevant section of the *Grid Code*.

(4) Amendments and *Exemption*s shall have an implementation date stipulated by *the Authority* and shall, if applicable, include time bound provisions and conditions.

(5) *The Authority* shall give notice to the GCS of the decisions reached by the *Regulatory Board*. 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 *Exemption*s.

(7) *The Authority* shall keep a register of all *Exemption*s which have been granted, identifying the name of the *Grid Code Participant* and equipment in respect of which the *Exemption* has been granted, the relevant provision of the *Grid Code*, the period of *Exemption* and the extent of compliance with the provisions.

(8) Upon request from any *Grid Code Participant*, *the Authority* shall provide a copy of such register of *Exemption*s to such *Grid Code Participant*.

7 Dispute mediation, resolution and appeal mechanism

(1) In addition to the provisions of the *Electricity Law* that address dispute settlement, registered *Grid Code Participants* or *Customers* shall have access to a documented procedure for handling disputes arising under the *Grid Code*.

7.1 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 7.3.

7.2 Disputes Relating to decisions of the Regulatory Board

(1) Any objection to decisions by the *Regulatory Board* shall be made in writing to the *Regulatory Board*.

(2) Where the *Grid Code Participant* or Customer is not satisfied with decision of the *Regulatory Board* in respect of *Grid Code* compliance or *Grid Code* violations and sanctions, and after failure of the dispute, mediation and resolution mechanism set out in this Governance Code, the party may appeal before the competent court.

7.3 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 7.3.1 and 7.3.2.

(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.

7.3.1 *Incident Report*

(1) An *Incident Report* should be seen as formal communication of a problem.

(2) An effected party 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 Report*s received and a log of all *Incident Report*s communicated to *Customers*.

(5) *Incident Reports* are operational in nature and generally require action only by technical and *Customer* relations staff.

7.3.2 Non-Conformance Report

(1) A *Customer* may issue a *Non-Conformance Report* when it is suspected that:

(a) The *Participant* has failed to provide a reasonable explanation,

(b) The *Participant* has wilfully misrepresented the facts concerning an incident,

(c) The *Participant* has failed to implement the agreed preventative actions within the agreed time frame,

(d) The number of *Incident Report*s is excessive in relation to historical performance

(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 Report*s 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 *Non-Conformance Report*, recommended action shall be agreed upon. Both *Participants* shall implement these recommendations within an agreed time frame.

(5) *Participants* shall report annually to *the Authority* on the following aspects of the procedure:

(a) Number of non-conformance reports for each *Customer* category

(b) Number of closed out non-conformance reports for each *Customer* category

(c) Number of disputes resolved

(6) A dispute may be declared when the parties cannot agree on the *Non-Conformance Report* or the recommendations of the *Non-Conformance Report* or when the agreed recommendations are not implemented in the agreed time frame.

7.4 Submission of Disputes to the Authority

(1) Disputes are unresolved complaints between *Participants* that require intervention. Any *Participant* or *Customer* may submit a dispute to *the Authority* provided the required process of either Section 7.1 or Section 7.3 has been followed.

(2) When a dispute is raised with *the Authority*, parties shall provide the following information:

(a) Full history of relevant *Incident Report*s

(b) Detailed *Non-Conformance Report* and accompanying information that gave rise to the dispute

(c) Written report from each *Participant* detailing the reason for not being able to close out the *Non-Conformance Report*.

(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 may refer the matter for arbitration for final decision, alternative the aggrieved party may appeal the *Regulatory Board* decision before a competent court.

(7) In the event that the parties agree to refer the matter for arbitration, 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

(c) Primarily a technical matter, a person with suitable technical knowledge.

(8) The appointment of the arbitrator shall be agreed between the *Participants*, but failing agreement between them within a period of 14 days after the arbitration has been demanded, either of the *Participants* 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 as well as any sharing of costs of the arbitration and shall be final and binding on the parties.

8 Compliance

(1) All *Grid Code Participants* and *Customers* 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 7.3.2.

(3) *The Authority* may require a *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.

9 *Grid Code* Violations and Sanctions

(1) If a *Grid Code Participant* is in breach of any of the *Grid Code* requirements, *the Authority* shall impose administrative and financial penalties as provided in the applicable laws and regulations and in the provisions of present *License*.

10 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

(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*.

11 Contracting

(1) The *Grid Code* shall comprise one of the standard documents that form part of the contracting arrangements between *Participants* in the *ESI*. Other contractual documents and arrangements include inter alia:

(a) Connection Agreements

(b) Use of System Agreements

(c) Operating Agreements

(d) Power Purchase Agreements and/or Supply Agreements

(e) Ancillary Services Agreements

12 Version Control

(1) The *Grid Code* will evolve as the ESI in Rwanda evolves.

(2) Each of the sections and Codes that collectively form the Rwandan *Grid Code* shall have separate version control and approvals.

(3) The GCS shall be responsible for version control.

RWANDA UTILITIES REGULATORY AUTHORITY

(RURA)

THE RWANDA GRID CODE

System Operations Code

3 of 7 Code Documents

Version 1.0

RURA, Rwanda

TABLE OF CONTENTS

1 Introduction

(1) The *System Operations Code* sets out the responsibilities and roles of *Participants* as far as the operation of the *Interconnected Power System (IPS)* is concerned, and more specifically issues related to:

(a) Operational reliability, security and safety;

(b) Operations planning;

(c) *Ancillary Services*;

(d) Scheduling and dispatch of *Generation* and *Ancillary Services*;

(e) Independent actions required and allowed by *Participants*;

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

(g) Maintenance co-ordinations and outage planning

(h) Communication of system conditions, operational *Information; and*

(i) Telecontrol

2 Field operation, maintenance and maintenance co-ordination / outage planning.

3 Operation of the *IPS*

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

(2) The *SO* must be appropriately regulated by *the Authority* (via the relevant regulatory rules) to ensure transparent, safe, reliable, efficient and ongoing operation of the *IPS.*

(3) The *SO* shall operate the *IPS* in accordance with the provisions of this *Code*.

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

(5) The *SO* shall have ultimate authority and accountability for the operation of the *IPS*.

(6) *Power Pool* and other *Interconnection(s)* operations shall be governed by the *Power Pool* and related guidelines/agreements.

3.1 SO Obligations

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

3.1.1 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 and/or local loads, in order to facilitate system restoration.

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

(5) The *SO* 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 *Apparatus*.

(6) Should it become unsafe to operate *Units* in parallel with the *IPS* 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 operation.

(7) In the event of a system separation, the *SO* 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 *SO* may request that the *SO* takes any available action to increase or decrease the active energy transfer into or out of its system by the way of emergency assistance. Such requests shall be met by the *SO* providing it has the capability to do so.

3.1.2 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 single 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 *SO* is responsible for efficient restoration of the *Transmission System* (*TS*) after supply interruptions.

(3) The *SO* shall operate and maintain primary and emergency National Grid Control Centres (NGCCs) and facilities to ensure continuous operation of the *IPS*.

3.1.3 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 *Apparatus* ratings.

(3) The *SO* shall manage constraints on the *TS* through the determination of operational limits, scheduling of sufficient generation for the demand and *Ancillary Services* to relieve constraints.

(4) To achieve a high degree of service reliability, the *SO* shall ensure adequate and reliable communications between all *NGCCs*, *Generator(s)* and *Substations*. Communication facilities to be provided and maintained by various *Participants* (*Generators*, *Embedded Generators*, TransCos, DisCos, *Customers)* are specified in the *Information Exchange Code*.

(5) The *SO* shall be responsible for the determination of the *TS* protection philosophy (as contrasted and supplementary to *Apparatus Protection* philosophy) by means of applicable analytical studies.

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

4 Operations Planning

4.1 Operations Plans

4.1.1 Introduction

(1) *Generator(s)* and the *SO* 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 *SO,* is responsible for using available personnel and system *Apparatus* to implement these plans to assure that the *IPS* reliability is maintained.

4.1.2 Objectives

(1) The objectives of the Operations Plans are:

(a) To inform all *Generators*, TransCos, *DisCos* or Large *Customers* whose systems make up or are connected to the *TS*, of the procedures and responsibilities which are required to execute the operations plans;

(b) To enable the *SO* to co-ordinate operations and outages of centrally dispatched *Generating Units* taking into account *TransCos' TS* planned outages, so as to provide the maximum reliability of electric power delivery at the lowest cost.

4.1.3 Operations Plans Requirements

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

(a) **Normal Operations** - where each *Generator, TransCo*, *DisCo* or *Large Customer* (where applicable), working with the *SO*, shall plan its future operations so that normal interconnection operation proceeds in an orderly consistent manner and each *DisCo* or *Large Customer* shall provide its best estimate of demand to that the *SO* can develop the total demand forecast.

(b) **Emergency Operations** - A set of plans shall be developed, maintained and implemented, by each *Generator, TransCo*, *DisCo* or *Large Customer* (where applicable) and the *SO,* to cope with operating emergencies. These plans shall be conducted with other *Generators* and the *SO* as appropriate.

4.2 Annual Operations Plan

4.2.1 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 forecasted demand and energy requirements for the next year to 5 years ahead by the end of October in each calendar year.

(b) Verification that *Generation* and *Transmission* outages are planned to maximise resource utilisation and 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 *SO* and the *Generators*, TransCos, *DisCo/s* and *Large Customer* to produce and provide data;

(c) Definition of the work necessary for the *SO, Generators, TransCos*, *DisCo/s* and *Large Customers* to contribute towards the annual operations plan; and

(d) The lines of communication and interaction between the *Participants.*

4.2.2 Implementation Procedure for Annual Operations Plan

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

4.2.3 Data Requirements

(1) A list of response capability data required in connection with *Operating Reserve* for each *Generating Unit* shall be submitted to the *SO* 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 *TransCo*/*SO* and the *Generator*. The *SO* shall be informed promptly of any change in these parameters.

4.3 Transmission Operations Planning

4.3.1 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 an *IPS* when:

(a) *Transmission Apparatus* 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, *Apparatus* loading or voltage levels deviate from normal operating limits or are expected to exceed emergency limits following a contingency, and if reliability of the bulk power supply is threatened, the *SO* shall take immediate steps to relieve the conditions. These steps include notifying other systems (international/regional), adjusting *Generation*, changing *Scheduling* 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 (international/regional). This includes coordination of *Apparatus* outages, voltage levels, MW and MVAr flow monitoring and switching that affects two or more systems of transmission components.

4.3.2 *TS* Operations Planning Procedures

(1) In order to accomplish the needed level of coordination, the *SO* 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 coordinated.

4.3.3 *TS* Coordinating Studies

(1) Studies shall be made on a coordinated basis:

(a) to determine the facilities on each system which may affect the operation of the coordinated 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:

a. Thermal and stability limits

b. Short and long time loading limits

c. 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 *IPS* 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 *Emergency Outage* which may have a bearing on the reliability of the *TS* shall be communicated to all systems which may be affected.

4.3.4 Protection Coordination

(1) The satisfactory operation of the *TS*, especially under abnormal conditions, is greatly influenced by the relay *Apparatus* 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*, *DisCo/s* and *Large Customers* have an obligation to implement relay application, operation, and preventive maintenance criteria according to the *SO* requirements.

(3) The application of the relay systems of the *Generators*, *DisCo/s* and *Large Customers* shall be coordinated by the *SO* to enhance the system reliability and yet have the least adverse effect on the *TS*.

(4) Each protection device shall be recalibrated every five years. A review of the protection settings shall also be carried out whenever there is an expansion or change to the transmission or generation facilities.

4.3.5 Remedial Action Schemes

(1) *Remedial Action Schemes* (*RAS*), also known as *Special Protection Schemes (SPS)*, are designed to automatically perform system protection functions other than the isolation of an electrical fault. *RAS* are designed to trip, or remove from service, *Units* or *Transmission* facilities under a set of carefully defined conditions. *RAS* are normally used in order to increase *TS* Capability under specified conditions. They may also be used to permit higher loading levels on the Rwandan *IPS* in those instances where additional facilities cannot be built or have been delayed. Their application is specific to particular circumstances.

(2) *RAS* installed on the *EAPP Interconnected Transmission System* shall be subject to agreement between the Rwandan *SO* and the *EAPP CC*. *RAS* shall be subject to procedures detailing the operation and the conditions for switching into service of the scheme. The effects of the automatic actions arising from the operation of the *RAS* shall be subject to the specific agreement of all *Participants* involved.

(3) The *SO* shall monitor the status of all *RAS* and notify relevant *Participants* and *EAPP CC* of any change of status.

5 Scheduling & Dispatch of Generation & Ancillary Services

(1) The *SO* shall provide the scheduling and dispatch of *Generation (Generation Scheduler)*, demand forecast and *Ancillary Services* for the *IPS*.

(2) The scheduling of the operation of the *Generating Units* shall ensure reliable operating margins.

(3) The responsibility for executing the energy and *Ancillary Services* schedules shall lie with the *SO.*

(4) Rescheduling during unplanned events shall be undertaken by the *SO* on the basis of rules provided in *this Code*.

(5) International *Interconnection* operations shall be co-ordinated from the Rwandan side by the *SO* within the common *Power Pool* arrangements.

5.1 Weekly Operations Plan

(1) Each week by 10:00 hours on Thursday, the *SO* 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 *Units* that are on standby duty as *Tertiary Response*.

(2) By 09:00 hours on Friday, the *SO* shall prepare a *Weekly Operations Plan* that takes into account the *Units*' unavailability.

(3) By 10:00 on Friday the *SO* shall provide the weekly international interchange schedule to relevant neighbouring *TSO's* and *EAPP CC*.

(4) Each week the *SO* shall determine the allocation of reserve margin to each *Generator*, with due consideration to start-up prices, response characteristics of the *Units* on the *TS* (ramp rates), *TS* constraints, availability of *Units*, hydro dam levels and hydro reservoirs (dams/lakes etc) inflow rates in its *Weekly Operations Plan*.

(5) The *Weekly Operations Plan* shall state the amount of operating reserve to be utilised by the *SO* in the scheduling and dispatching process.

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

5.2 Daily Generation Scheduling

(1) Scheduling the operations of *Units* is a major component of operations planning. Scheduling of the *Units* depends upon the pattern of demand by the system, the order-of-merit operation of *Units*, the availability of *Units*, the flexibility of operation of *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 *Unit* to the *SO.*

(b) The submission of relevant *Generator* data by each *Generator* to the *SO.*

(c) The issue by the *SO* of a Generation schedule the *Day* before the schedule *Day*.

(d) Where an externally interconnected *Participant* outside the country is connected to the *IPS* for the purpose of system security enhancement and economic operation (e.g. sharing of *Operating Reserves*), the generation scheduling and hence, power transaction shall be governed by *Power Pool* Rules, Inter-Utility Joint Operation Agreements and/or any other Inter-Utility Agreements.

(e) *Generation* scheduling requires *Generator* data to enable the *SO* to prepare a *merit order* to be used in scheduling and dispatch and the preparation and issue of a *Generation* Schedule. Based on this data, the *SO* 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 reserves, while maintaining the integrity of the *IPS* and security and *Quality of Supply (QoS)*.

5.2.1 Scheduling Procedure

(1) The computation of the generation schedule shall require the following information from *Generators*:

(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 *SO* 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 *Information Exchange Code*.

(4) The *Generation* schedule shall be submitted by the *SO* to the relevant *Generators* by 15:00 hours

(5) The *SO* shall provide the next day's international interchange schedule to relevant neighbouring *TSO's* and *EAPP CC* by 15:00.

(6) Availability declaration:

(a) The availability declaration is to be expressed as 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.

(b) A revised availability declaration for a *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 *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 *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 *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 *Unit* is available at what wattage, expressed in a whole number of MW, for each such time period.

5.2.2 Generation Scheduling and Dispatch Parameters

(1) The generation scheduling and dispatch parameters shall reflect the true operating characteristics of *Units*. 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 *SO* as a statement of which *Units* may be required for the next following schedule *Day*:

(a) In compiling the generation schedule, the *SO* shall take account of and give due weight to the following factors:

i. *TS* constraints from time to time, as determined by the *SO* and as advised by *Generators*;

ii. for *Units*, their parameters registered as generation scheduling and dispatch parameters (including indications of *Unit* inflexibility);

iii. the requirements, as determined by the *SO* and as advised by *DisCo/s*, for voltage control and MVAR reserves;

iv. the need to provide *Operating Reserves*, by using the various categories of *Operating Reserves*, as determined by the *SO* ;

v. the requirements as determined by the *SO* for maintaining frequency control.

(b) The generation schedule shall be compiled by the *SO* to schedule such *Generating Units* taking into account the above factors and in accordance with offered availability as follows:

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 operations plan; 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 *SO* 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 *Units*, notified to the *SO* 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 Unit requirements within constrained groups, following notification to the *SO* of the changes in capability;

v. changes of *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 *SO* , would impose increased risk to the *IPS* and would therefore require the *SO* to increase operational reserve levels. Such conditions include:

1. unpredicted *Transmission Apparatus* outages which place more than the equivalent of one large *Unit* at risk to any fault;

2. unpredicted outage of *Generator's Apparatus* 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*;

5. impending strikes or political unrest posing a high risk to the *IPS* or parts thereof; and

6. limitations or deficiencies of the *SO* scheduling process computational algorithms.

(d) For the following situations, a written record of these adjustments shall be kept by the *SO* , for a period of at least 12 months:

i. adverse weather is anticipated;

ii. demand control has been instructed by the *SO* ; or

iii. a total or partial collapse exists.

(3) These factors may mean that a *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 *SO* including those responsible for the deviation. These reports shall be consolidated into a *Weekly Report* by the *SO* to the *Generators*, *DisCo*/s and *the Authority*.

(4) Content of Generation Schedule.

(a) The *Information* contained in the generation schedule shall indicate for a *Unit* or *Interconnection* power transaction, the period for which it is scheduled during the following *Day*. It shall also include *Units* or *Interconnection* power transaction running as a result of non-System reason (such as test purposes) and system requirements (such as *Reactive Power* reserve) and *Units* and *Interconnected Participants* assigned to a specific reserve role.

5.2.3 Special Actions

(1) The generation schedule may be followed by a list of special actions (either pre or post-fault) that the *SO* may request a *Generator* to take in respect of *Units*, or an *Interconnection*, in order to maintain the integrity of the *IPS*. For consumers directly connected to the *Transmission System* to which *Units* or *Consumers* are also connected, these special actions shall generally involve load transfer between the *Points of Supply* or arrangements for *Demand* reduction by manual or automatic means.

(2) For *Interconnections* these special actions shall generally involve an increase or decrease of net power flows across an *Interconnection* by manual or automatic means.

(3) These special actions shall be discussed and agreed upon with the *Generator*, *Interconnection*, *DisCo* or *Customer* concerned. If not agreed, *Generation* may be restricted or demand may be at risk.

5.2.4 Other Relevant Generation Data

(1) Other relevant generation data includes:

(a) details of any special factors which in the opinion of the *Generator* may have a material effect on the likely output of such *Units*;

(b) details of any *Unit's* commissioning or changes in the commissioning programs submitted earlier.

5.2.5 Distribution System Data

(1) By 10:00 hours each *Day*, *DisCo/s* shall submit to the *SO* in writing confirmation or notification of the following for the following availability declaration period:

(a) constraints on its *Distribution System* which the *SO* may need to take into account;

(b) the requirements of voltage control and MVAR reserves which the *SO* may need to take into account for system security reasons. The form of the submission shall be that of a *Unit* output (both MW and MVAR) required in relation to that *Distribution* system following availability declaration period.

5.2.6 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 *SO* prior to 15:00 hours on the *Day* prior to the relevant schedule *Day*, the *SO* 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 *SO* at or after 15:00 hours in each *Day* but before the end of the next following schedule *Day*, the *SO* 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.

5.2.7 Issues of Generation Schedule

(1) The generation schedule shall be issued to *Generators* and *Distributors* or otherwise to the *Generator* direct by 15:00 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 *SO* reserves the right to issue a revised generation schedule to the extent necessary as a result of such events.

(2) The *SO* 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 *SO*.

(4) The generation schedule received by each *Generator* shall contain only information relating to its *Units*.

5.3 Generation Dispatch

5.3.1 Merit Order Operation

(1) To meet the continuously changing demand on the *IPS* in the most economical manner, *Units* 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 Unit i.e. Short Run Marginal Cost (SRMC)*. Fixed costs are not taken into consideration. At any time, the *Unit* with the least operating costs is used to meet the demand with a satisfactory margin.

(2) For this purpose, *Units* are listed according to the lowest-to-highest operating costs for each *Unit* and such a list is known as an *"order-of-merit Schedule".*

(3) The *order-of-merit Schedule* for a hydro system is primarily based upon the annual energy plan for the hydro *Units*. The costs for hydro *Units* are be based upon:

a. Efficiency of the *Unit*

b. The reservoir/pond level

c. Run of river status

d. Long-Run Marginal Costs (LRMCs).

(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.

5.3.2 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 *Primary, Secondary* and *Tertiary Response Units*.

(3) *Units* which are required to run for security or inflexibility purposes are allocated first.

(4) *Units* which committed to bilateral agreements with *TradeCos* are allocated next.

(5) The remainder of the estimated demand for each operating period to be supplied through a given Day shall be dispatched according to the remaining *Units* available in the predefined *order-of-merit*.

(6) In cases where only partial loading of a *Unit* 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 cost curves and *Unit* technical data.

(7) 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.

(8) Scheduling shall also take into account the rates of loading and unloading of *Units* (ramp rates) and other station constraints such as the time intervals between synchronising or shutting down *Units* to each station.

5.4 *SO Roles and Responsibilities*

(1) In order to operate the *IPS*, the *SO* shall prepare *Units* operations schedules and issue unit *Dispatch Instructions*.

(2) The *Information* which the *SO* shall use in issuing *Dispatch Instructions* are as follows:

(a) The generation schedule used in dispatching the *Units* 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, system demand forecast, generation trading contracts and other relevant operational data.

(b) Commercial *Ancillary Services*.

5.4.1 Re-Optimization of Generation Schedule or Subsequent Schedules

(1) The *SO* 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 *Generators* always keep the *SO* informed of changes of availability declarations and dispatch parameters immediately as they occur.

(2) Indicative synchronising and de-synchronising times of *Units* in the re-optimised schedule shall be made available to the *Generators* who shall immediately acknowledge the times, together with their compliance of the synchronising instructions.

5.4.2 Generation Dispatch Instructions

(1) The *SO* shall issue *Dispatch Instructions* to all *Generators* 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 *SO.* A *Dispatch Instruction* may be subsequently cancelled or varied.

(3) *Units* declared available but not included in the generation schedule may be issued *Dispatch Instructions*.

(4) In addition to instructions relating to dispatch of active power, *Dispatch Instructions* may include:

(a) details of the *Operating Reserve* to be carried on each *Unit* including specification of the time scale in which that *Operating Reserve* may be transferable into increased generation output;

(b) an instruction for *Units* to provide *Ancillary Services*;

(c) Target (at instructed MW level) voltage levels or the individual reactive power output from generating *Units*. In the event of sudden change in system voltage, generating *Units* shall not take any action to override automatic MVAr response (AVR response)unless instructed otherwise by the *SO,* or unless immediate action is necessary to comply with stability limits. *Generators* may take such action as is necessary to maintain the integrity of their *Unit/s*;

(d) notice and change in notice to synchronise or desynchronise *Units* in a specific time-scale;

(e) an instruction for *Units* to operate in Synchronous Condenser mode; and

(f) an instruction to carry out tests as specified in the *Network Code*.

(5) The form of instructions and terms to be used by the *SO* in issuing instructions together with their meanings are to be mutually agreed by all relevant *Participants*.

5.4.3 Communication with *Generators* and *DisCo/s*

(1) System regulation shall be performed automatically using *Automatic Generation Control (AGC)* facilities by the *SO* 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 *Generators*. In the event that while carrying out Dispatch Instructions, an un-foreseen problem arises caused by safety reasons, the *SO* shall be notified without delay by telephone.

5.4.4 Action Required by *Generators*

(1) Each *Generator* shall comply with all *Dispatch Instructions* properly given by the *SO*. If an unforeseen problem arises which affects the safety of the *Apparatus* or personnel, the *Generator* shall disregard *Dispatch Instructions* and take necessary corrective actions after which the *SO* shall be notified immediately.

(2) De-synchronising may take place without the *SO's* prior agreement if it is done purely on safety grounds. Synchronisation or de-synchronisation as a result of inter-trip schemes or under-frequency relay operation shall be reported to the *SO* immediately.

(3) Each *Unit* shall be operated with AVRs and excitation limiters in-service unless released from this obligation by the *SO*.

(4) To preserve the *IPS* synchronously connected system integrity under emergency conditions, the *SO* 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 *Unit*. A refusal may only be given on safety grounds (relating to person or plant).

5.4.5 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 *SO* and *Generators*.

5.4.6 Generating Unit Changes

(1) *Generators* shall without delay notify the *SO* 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.

5.4.7 Instructions to *DisCo/s*

(1) The *SO* shall issue instructions directly to *DisCo/s* for special actions and *Demand Side Management (DSM)*. These instructions may include-

(a) a demand reduction, disconnection or restoration of load and load transfer; and

(b) a demand inter-trip.

6 Ancillary Services

(1) The *SO* shall be responsible for the technical specification and execution of all short term (daily) reliability services for the *IPS*. These include *IPS* restoration, the balancing of supply and demand (frequency regulation), the provision of quality voltages (reactive power requirements) and the management of the real-time technical risk (reliability, *Operating Reserves*). 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 *SO* shall be responsible for procuring the required *Ancillary Services* that are economically efficient and needed to provide the required reliability. As a result, there will be some form of *TradeCo* licence required for the *SO* to procure *Ancillary Services* from the relevant *Participants.* The costs associated with the procurement of *Ancillary Services* shall be determined using the guidelines presented in the *Network Tariff Code* for the *SO.*

(4) All *Generators* shall inform the *SO* 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*.

6.1 Operating Reserves

(1) *Operating Reserves* are required to ensure reliability of the *IPS* and secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of *Operating Reserves:*

a. *Primary Response*

b. *Secondary Response*

c. *Tertiary Response*.

6.1.1 Primary Response

(1) *Primary Response* is the automatic response by synchronised *Units* to a rise or fall in the frequency of the *IPS* requiring changes in the Generating Unit's *Active Power* output, to restore the frequency to within operational limits.

(2) When interconnected to the *EAPP*, the response to a change in system frequency shall be fully available within ten (10) seconds of the frequency change and be sustainable for a further twenty (20) seconds.

(3) When not interconnected to the *EAPP*, the requirement is to keep the frequency above 49.0 Hz following all credible single contingency losses. The capacity of the largest *Unit* connected to the system is the largest single contingency.

(4) The *Primary Response* requirement for the *IPS* shall be determined by the *SO* at least once a year. The requirement shall be made available to all *Participants*.

(5) *Demand Side Management* also participates in *Primary Response* through the self-regulating effect of frequency-sensitive loads such as induction motors or the action of under frequency relays that disconnect some demand at given frequency thresholds (not associated with automatic *Under-Frequency Load Shedding (UFLS)* schemes).

6.1.2 Secondary Response

(1) *Secondary Response* is a centralised control of *Active Power* on the *IPS* that adjusts the *Active Power* production of *Units* to restore the frequency and interchanges with other *Control Areas* to their target values following a frequency deviation. This response is centralised and can be automatic (via *Automatic Generation Control (AGC))* or *Dispatch Instruction* by telephone, voice links or by automatic logging devices and shall be formally acknowledged immediately by *Generators*. This reserve is used for second-by-second balancing of supply and demand. *Primary Response* limits and arrests frequency deviations whilst *Secondary Response* restores the frequency to its target value.

(2) *Secondary Response* is the automatic response to a frequency change which is fully available by thirty (30) seconds from the time of frequency change to take over from *Primary Response*, and which is sustainable for a period of at least thirty (30) minutes. *Secondary Response* is provided by *Units* already synchronised to the *IPS* and is normally controlled by the *SO* by *AGC (*where available) or *Dispatch Instruction* as detailed above in clause (1).

(3) *Secondary Response* replaces *Primary Response* within minutes. Once replaced, *Primary Response* is again available to cover any further incidents that cause frequency deviation from the *IPS* target frequency.

(4) Sufficient *Secondary Response* 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) Most stringent Power Pool requirements when interconnected to one or more Power Pools

(5) The *Secondary Response* requirement for the *IPS* shall be determined by the *SO* at least once a year. The requirement shall be made available to all *Participants*.

6.1.3 Tertiary Response

(1) *Tertiary Response* refers to *SO* instructed changes in the dispatching and commitment of *Units*. *Tertiary Response* is used to restore both *Primary* and *Secondary Response*, to manage constraints on the *IPS* and to bring the frequency and the interchanges back to their target value when the *Secondary Response* has been depleted.

(2) Where *Tertiary Response* is held on Generating *Units* not synchronised to the *IPS*, the *Units* shall be capable of being synchronised within a specified time generally between fifteen (15) minutes and one (1) hour. For example, non-synchronised *Tertiary Response* could consist of fast start hydro, gas turbine generators and steam turbine generators on hot-standby.

(3) The *Tertiary Response* requirement for the System shall be determined by the *SO* at least once a year. The requirement shall be made available to all *Participants*.

(4) *Demand Side Management* can participate in *Tertiary Response*. 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 *SO National Grid Control Centre (NGCC)*. These requirements are due to the need to take quick action when abnormal conditions prevail on the system.

6.2 Black Start

(1) *Units* capable of *Black Start* shall be certified by the *SO* and entitled to payment for the service.

(2) To ensure optimal operation of the *IPS*, the *SO* may deploy network islanding schemes on the network, e.g. an out-of-step tripping scheme.

(3) The *SO* shall determine the minimum requirements for each *Black Start* supplier and ensure that the contracted suppliers are capable of providing the service.

(4) *Black Start Units* shall perform appropriate tests and simulations on an annual basis to ensure *Black Start* facility is available. Such tests shall be witnessed and approved by the *SO* (as defined in the *Network Code*).

6.3 Reactive Power Compensation & 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 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 strategic *Units* 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 *Active Power*. The amount of *Reactive Power* shall be controlled by the *SO*. This may be done directly through the *Energy Management system (EMS)* 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 *SO* shall ensure there is sufficient *Reactive Power* and *Reactive Power* reserve (slow and fast acting) to maintain transmission voltages within prescribed limits for single contingencies.

(5) The *SO* shall ensure sufficient *Reactive Power* and *Reactive Power* reserve (slow and fast acting) to maintain *IPS* stability.

7 <u>Operational Authority</u>

(1) The *SO* shall have operational authority over the *TS* for other networks that 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 *Apparatus* of another *Participant* without the permission of the 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 3.1, *Participants* shall retain the right to safeguard the health of their *Apparatus*.

8 Operating Procedures

(1) The *SO* 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 *Apparatus* on the *TS* or connected to the *TS*.

(2) Each *Participant* shall be responsible for his own safety rules and procedures. The *SO* 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 *SO*.

(3) Power Pool operating agreements shall apply in the case of operational liaison with all international power systems connected to the *TS*.

9 Operational Liaison, Permission for Synchronisation

(1) The *SO* 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 *IPS*.

(3) A *Customer* shall enter into an operating agreement with the *SO*, 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 transfers.

10 <u>Emergency and Contingency Planning</u>

(1) The *SO* 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 (UFLS)*;

(b) Meeting disaster management requirements including the necessary minimum load requirements;

(c) Forced outages 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 *Participants*, without causing undue risk or undue cost. The costs of these tests shall be borne by the respective asset owners. The *SO* shall ensure the coordination of the tests in consultation with all affected *Participants*.

(5) The *SO* shall specify minimum emergency requirements for *Distributors*, *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 *SO*'s requirements for contingency and emergency plans.

(7) Automatic and *Manual Load Shedding* schemes shall be made available under the direction of the *SO*.

(8) The *SO* 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 *SO*, *DisCo/s* shall perform related load flow studies on their part of the network and make the results available to the *SO*.

11 System Frequency and *ACE* Control Under Abnormal Frequency or Interchange Imbalance Conditions

(1) The *SO* 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*.

11.1 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;

(b) the *Area Control Error (ACE)* deficit does not exceed the available reserves for longer than 15 minutes;

(c) the frequency is not less than 49.8 Hz for longer than 15 minutes;

(d) applicable Power Pool control performance criteria are not violated;

(e) The frequency is within the range 49,5 to 50,5 Hz;

(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.

11.2 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 *SO* on expected utilisation of any contingency resources.

(3) The *SO* 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 *SO*.

(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.

12 Independent Actions 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 *Apparatus*. Advance notice of such action shall be given where possible and no financial penalties shall apply for such action. Examples include inter alia hot connections, solid breakers, malfunctioning Protection.

(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 *Apparatus* 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.

13 Voltage Control

(1) The *SO* shall be responsible for the voltage control of the *TS*, at *Transmission* level voltages as well as at the interface between *TransCo*/s and its customers (DisCo/s and/or *Large 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 *SO* within 15 minutes of the event occurring.

(2) *DisCos* and *Customers* shall report the loss of major loads (larger than 5 MW) to the *SO* 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 affecting the Power Pool shall be reported to the relevant *Participants* within the times specified in the relevant Power Pool rules.

(4) Incidents on the *IPS* involving sabotage or suspected sabotage, as well as threats of sabotage shall be reported to the *SO*.

(5) Any major 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. The following procedure should be followed:

a. A preliminary incident report shall be available after three (3) working days.

b. A final report within three (3) months.

c. The *SO* shall initiate such an investigation, arrange for the writing of the report and involve all affected *Participants*.

d. All these *Participants* shall make all relevant required *Information* available to the *SO*. The confidentiality status of information is described in the *Information Exchange Code*.

(6) A major incident is defined as an incident where:

(a) More than 20 *System Minutes* of load was interrupted;

(b) A loss of demand/generation greater than 20 MW for more than 15 minutes from a single incident; or

(c) Severe damage to plant/*Apparatus* has occurred.

(7) 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.

(8) Incidents shall also be reported to *the Authority* as defined in the licence conditions.

(8) The *SO* shall be responsible for developing and maintaining an adequate system of fault statistics.

15 Commissioning

(1) The *SO* 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 *Apparatus* associated with the *Transmission* connection, or re-commissioning of such existing *Apparatus*, shall be agreed with the *SO* in writing before such commissioning starts.

(3) Aspects of commissioning 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 *Apparatus* at the *Connection Point*, the *TransCo* shall liaise with the affected *Customers*/*DisCos* on all aspects that could potentially affect the *Customers'* operation.

(6) *TransCos* and *Customers/DisCos* shall perform all commissioning tests required in order to confirm that the *TransCo* and the *Customers'/DisCos'* plant and *Apparatus* meet 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 Generator/*Customer* shall, as soon as possible, notify the *SO* 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 *SO*.

(2) *Participants* shall minimise the risk of tripping / loss of output on their own *Power Stations* and *Apparatus*, associated with their operations 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 *SO*.

(4) When a risk of trip of *Apparatus* 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 *SO* 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 Co-ordination/Outage Planning

(1) Optimal reliability of the *IPS* shall be achieved by co-ordinating scheduled outages of *Generation, Transmission, Distribution, Customer*, *Metering*, communication and control facilities affecting *IPS* operation.

(2) The maintenance coordination / outage planning responsibility shall be borne by the *SO* and shall be done in collaboration with the Generation Scheduler (at the *SO*).

17.1 Definition of Roles and Responsibilities

17.1.1 Generation Scheduler

(1) The person responsible for scheduling and dispatching *Generation* on the *IPS* as outlined in section 5 of *this Code.*

17.1.2 Outage Requester

(1) An outage requester is a person requesting an outage on plant/*Apparatus* 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 could be a *TransCo*, *DisCo*, *Generator*, *Customer* employee or agent, formally nominated.

17.1.3 *SO* Outage Scheduler

(1) The *SO* outage scheduler is a person appointed to assess the viability of a scheduled outage and either to confirm or to turn down the request. The *SO* 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/*Apparatus* that affects international *Customers*.

17.1.4 *SO* Shift Controller

(1) The *SO* Controller on shift at the time of the outage that is responsible for finally sanctioning (or alternatively refusing) the planned outage and ensuring that the relevant operating instructions are issued.

17.2 Outage Process

(1) The *SO* shall develop and maintain an electronic *TS* maintenance scheduling system for the coordination of all TS outages.

(2) *TransCo/s* shall inform all *Customers/DisCos* of the name and contact details of the *SO* Outage Scheduler(s) in the different geographic parts of the country (if more than one exists).

(3) The *SO* shall make available to *Customers/DisCos* an outage schedule of all Planned Outages 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.

(4) 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 (*TransCo, DisCo, Customer* or *Generator*) shall enter this request into the maintenance scheduling system if the Outage Requester has access to this system. If no access is available, the Outage Requester shall contact the relevant *SO Outage Scheduler* with the request.

(5) When the *SO* 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 *Participants,* the *SO* Outage Scheduler shall mark it as a scheduled outage.

(6) At this point the *SO* Outage Scheduler shall confirm the outage if it satisfies all the necessary requirements. If acceptable the *SO* Outage 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 by the *SO Outage Scheduler*.

(7) When it is time for the confirmed booking to be executed (the outage becoming effective), the status shall be changed to taken by the *SO* 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 *SO* Shift Controller, who shall enter this *Information* into the system. This allows for the progress of the outage to be monitored by those concerned.

(8) When the outage has been completed it shall be the responsibility of the *SO* Shift Controller receiving the hand back, to change the status of the outage to completed.

(9) 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.

(10) 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 *TransCo/s*.

(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 *SO* shall be responsible for identifying Risk-related Outages.

(b) The *SO* and *Customer* control centres shall be responsible for the Security-linking instructions in the said contingency plan.

(c) It shall be the responsibility of *TransCo/s* to supply the *Information* relating to returning the plant to service.

(d) *TransCo/s* shall develop by-pass schemes with assistance from the *SO* and the *Customer* control centre.

(e) The *SO* and *Customer* control centres shall be responsible for identification of the load at risk and load shedding in the said contingency plan.

(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 *Customer* 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 *SO* 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 *Participants*. *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) *TransCo/s* shall give *DisCo/s* and *Customers* at least 14 days' notice of Planned Interruptions.

17.4 Maintenance Planning Between TransCo/s and Generators

(1) Over and above the requirements mentioned above, all *Generators* shall provide the *SO* with the following documents in the pro-forma format specified in the *Information Exchange Code*, 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 *Unit*, looking five years ahead, showing the same information as above and issued by 31 October of each year.

(c) A monthly variance report, explaining the differences between the above two reports.

(2) Each *Generator* shall invite *TransCo/s* 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 *TransCo/s* 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 *SO*.

(5) The *SO* shall coordinate network outages affecting *Unit* output with related *Unit* outages to the maximum possible extent.

(6) The objectives to be used by the *SO* in this maintenance coordination are (in order of descending importance:

a. Maintaining adequate reserve levels at all times

b. Ensuring reliability where *TS* constraints exist

c. 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 *SO* cancelling the request owing to system conditions, the outage requesting *Participant* shall bear the cost of such cancellation.

18 Communication of System Conditions, Operational Information and *IPS* Performance

(1) The *SO* 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 *SO* 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 *SO* shall report on both technical and energy aspects of *IPS* performance monthly and annually. This shall include daily demands, energies, transmission losses, interruptions and *QoS* aspects as detailed in the *Information Exchange Code*. This *Information* shall be available to all *Participants* on request.

19 Telecontrol

(1) The nationally adopted standard used by the *SO* is the standard to be adopted by all *Participants*.

(2) Where tele-control facilities are shared between *Participants*, operating procedures shall be agreed.

RWANDA UTILITIES REGULATORY AUTHORITY

(RURA)

THE RWANDA GRID *CODE*

Network Code

4 of 7 *Code* Documents

Version 1.0

RURA, Rwanda

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1 Introduction

(1) *The Network Code* covers the *Transmission* and *Distribution* network requirements applicable to prospective connection applications, technical and protection requirements, the network planning and development process as well as network maintenance requirements.

(2) This *Code* details involves the following *Participants:*

a. Generators

b. Transmitters (TransCos)

c. Distributors (DisCos)

d. Embedded Generators (EGs)

e. Transmission System Operator (TSO)

f. System Operator (SO)

g. Customers

(3) If the relevant licence has been attained from *the Authority* (*Generation*, *Transmission*, *Distribution*) and appropriate processes followed in terms of technical connection conditions by any prospective *Participant (Generator, Transmitter, Distributor, Embedded Generator (EG)* or *Customer)*, *Transmission System (TS)* and *Distribution System (DS)* open access shall not be denied by any *DisCo* or *TransCo.*

2 Off-Grid conditions

(1) For *Off-Grid* networks, all *Grid Code* requirements shall be applied with the appropriate *Exemptions* granted by *the Authority as* agreed upon between the *Authority* and the *Participant(s)*.

(2) If an *Off-Grid* network is to be connected to the *IPS,* the *Participant(s)* shall endeavour to comply with all *Grid Code* requirements. Any *Exemptions* shall be agreed upon between the *Participant(s)* and *the Authority.*

(3) *Participants* will be instructed by *the Authority* to improve their networks to comply or approach compliance with *Grid Code* requirements within appropriate time limits.

3 Transmission and Distribution Network connection Process

(1) Any *Participant* (applicant) seeking a connection to a *TS/DS* or seeking modifications to an existing connection shall apply in writing to the respective *TransCo/DisCo* using the sample application form in Appendix C in addition to supplying the required *Information* as outlined in the *Information Exchange Code*. Each *TransCo/DisCo* can develop and publish its own application form for connecting *Generators*

(2) The relevant *TransCo/DisCo* shall provide a provisional quote for a new connection (or for upgrading of an existing connection) within the timeframes agreed upon. The applicant may request this provisional quote *Information* from the *TransCo/DisCo* which should be provided without commitment and without detailed studies.

(3) Once a provisional quote has been accepted by the applicant, the applicant can request a budget quote from the *TransCo/DisCo*. The *TransCo/DisCo* can charge for providing this budget quote according to the approved tariff methodology set out in the *Tariff Code* or as agreed upon between the applicant and the *TransCo/DisCo*. The cost for providing the budget quote should be in line with the costs involved in performing the relevant technical integration studies to ensure that the new/upgraded connection will not jeopardise the IPS in any way and is in compliance with the technical limit criteria set out in section 7 of *this Code*.

(4) Following commercial conditions being met (payment for the budget quote), the *TransCo/DisCo* shall provide the applicant with a budget quote. It should be noted that the budget quote can provide a number of options for connection to the *TS/DS.* The provision of this budget quote indicates that

that the applicant has provisionally been given a *Point of Connection* (a *Point of Connection* has been made available to the applicant).

(5) If the applicant wishes to pursue the connection to the *TS/DS*, following further negotiations with the respective *TransCo/DisCo* (to ensure all *Grid Code* technical and other requirements have been met and will be met during operation), the applicant can enter into a formalised *Connection Agreement* with the respective *TransCo/DisCo*. This constitutes the applicant becoming a Participant in the *Grid Code whether as a Distributor, Large Customer, Embedded Generator* or *Generator.*

(6) If the applicant and the *TransCo/DisCo* cannot reach an agreement on the proposed connection, a dispute as outlined in the *Governance Code* will need be lodged.

(7) Where there is *TS/DS* development or where the provision of access to one *Participant* will have a major cost impact on other *Participant/s*, the respective *TransCo/DisCo* shall notify the affected *Participant/s* well in advance. If a dispute arises regarding funding of the connection, the matter shall be referred to the *Authority* for a decision. The *Authority* shall decide on time frames as part of this decision-making process in consultation with the affected *Participants*.

(8) The connection charges to be levied by a Transco/DisCo on a Participant (applicant) for a connection shall relate only to the direct costs of connecting the applicant to the Nominated Point of Connection and shall not include any costs that will be incurred by the TransCo/DisCo in reinforcing the TransCo/DisCo’s network beyond this point as a result of the proposed connection.

4 <u>Connection conditions</u>

(1) This section on connection conditions specifies acceptable technical, design and operational criteria which must be complied with by any relevant *Participant* connected to or seeking connection to the *TS and DS* in relation to the part of the *TS* and *DS* where the connection will take place. The relevant *Participants* for this include:

a. *TransCos*

b. *DisCos*

c. *System Operator (SO)*

d. *Large/Small Customers*

e. *Generators*

f. *Embedded Generators (EGs)*

(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* and *DS* are similar for all *Participants* of an equivalent category and will enable *TransCos*, *DisCos* and the *SO* to comply with statutory and licence obligations. Since *QoS* and network integrity are shared responsibilities of each *TransCo*, *DisCo*, the *SO, Generators, EGs* and their *Customer*s, these conditions furthermore ensure adherence to sound engineering practice and *Codes* by all the *Participants*.

4.1 Generator connection conditions

(1) This section defines acceptable requirements for *Generator* connections.

(2) *Units* with *MCR* < 250 kVA do not need to comply with the connection conditions of this *Code.*

(3) The following guideline procedure (shown graphically in Figure 1) can be used by a prospective *Generator* when wanting to become a *Generator*:

a. A potential *Generator* should apply to *the Authority* for an *Interim/Temporary Generation Licence* before entering into any *Connection Agreement* with any *TransCo* or making an application to generate into the *IPS* (and attaining a *PPA*).

b. Once the potential Generator has been granted an *Interim/Temporary Generation Licence*, the *Generator* shall apply for a connection to the appropriate *TransCo* before connecting to the *TransCo's* network (via the procedure outlined in section 3 for a network connection). A sample application form required for a *Generator* is included in Appendix B. It should be noted that *Information* included in the sample *Generator* application form in Appendix B will be relevant in the process of checking whether a prospective *Generator* can connect to the relevant *TransCo's TS*.

c. A *TransCo* shall, subject to the necessary technical requirements being met (following the process in section 3), make available a *Point of Connection (PoC)* to the requesting *Generator*.

d. Once the *PoC* has been made available to the *Generator* by the *TransCo*, the *Generator* can make an application to the buyer of the electricity *(SO/Buyer/Trader*) unless an offtaker has already approached or been approached by the *Generator*. The *Generator* shall negotiate a conditional *Power Purchase Agreement (PPA)* with the relevant licensed entity *(SO/Buyer/Trader*). The reason for the conditional *PPA* is that the *Generator* does not yet have a *Generation Licence*.

e. If the Generator accepts the PoC made available, the *Generator* shall enter into a *Connection Agreement* with the relevant *TransCo.* It should be noted that this *Connection Agreement* will typically be signed on condition of the prospective *Generator* being granted a *Generation Licence by* the Authority.

f. Finally, the *Generator* should apply to *the Authority* for a *Generation Licence* with all the previously attained documents e.g. *Temporary/Interim Generation Licence*, *Connection Agreement, PPA* (taking into account confidentiality requirements).

g. Following *the Authority* granting a *Generation Licence* to the prospective Generator, the Generator can/shall commence construction based on the statutory requirements in the *Generation Licence*, *Connection Agreement, PPA* and any other relevant documentation.

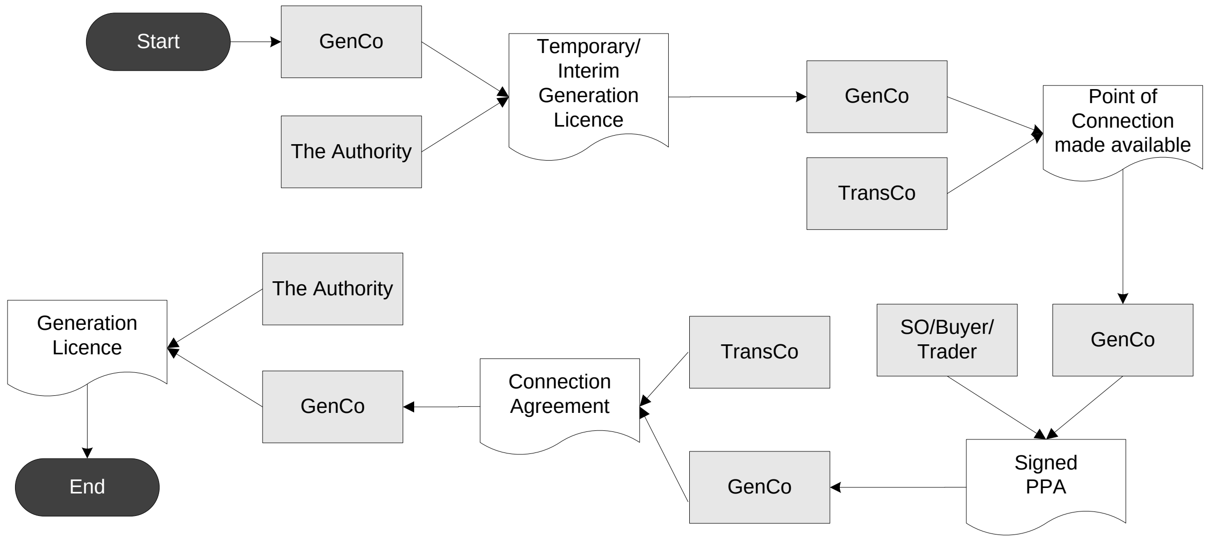

Figure 1 Guideline for connection process for a prospective *Generator*

(4) *Generating Units* shall comply with the connection conditions based on characteristics and rated capacity as specified in Table 8 and Table 9 in Appendix A.

(5) For new *Generating Units* with MCR > 3.5 MW and/or *Power Stations* with total MCR > 7 MW, special consideration shall be given to the impact of the risks on future operating costs e.g. *Ancillary Services*. The *SO* should quantify these expected costs. The special consideration may include obtaining *the Authority's* approval for including these costs in the tariff base or obliging the *Generator* to purchase reserves.

4.1.1 Protection

(1) A *Generating Unit's Generator* transformer, *Unit* transformer, busbar ducts and switchgear shall be equipped with well-maintained protection functions, to

rapidly disconnect appropriate sections of the *Power Station (PS)* should a fault occur within the relevant protection zones that may affect the overall *TS*.

(2) The following protection requirements shall be provided in order to protect the *IPS*:

a. **Backup impedance:** An impedance facility with a reach greater than the impedance of the generator transformer shall be used. This shall operate for phase faults in the *Unit*, in the *HV* yard or in the adjacent *Transmission* lines, with a suitable delay for cases when the corresponding main protection fails to operate.

b. **Loss of Excitation:** The *Generator* shall provide a facility to detect loss of excitation on a *Unit* and initiate a *Unit* trip. The type of facility to be implemented shall be agreed with the *SO*.

c. **Pole slipping facility:** Where agreed upon between the *Generator* and the *SO, Units* shall be fitted with a facility protecting against pole slipping.

d. **Reverse power:** This protection shall operate in the event of a *Unit* inadvertently importing active power from the *IPS*. The *Unit* shall be disconnected from the *IPS* under this condition. Settings for reverse power shall be as agreed upon between the *Generator* and the *TransCo* and/or *SO.*

e. ***Unit* transformer HV backup earth fault:** This is an *IDMT* facility that shall monitor the current in the *Generating Units'* transformer neutral connection. It can detect earth faults in the transformer *HV* side or in the adjacent network. The back-up earth fault facility shall trip the *HV* circuit breaker.

f. **HV breaker fail:** The "breaker fail" protection shall monitor the *HV* circuit breakers' 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 as agreed upon with the *SO* (maximum 150 ms), it shall trip the necessary adjacent circuit breakers.

g. **HV circuit breaker pole disagreement:** The pole disagreement protection shall operate in the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal. In cases where the three poles of a circuit breaker are MCRhanically coupled, pole disagreement protection is made redundant and is not required.

h. ***Unit* switch onto standstill:** 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 the protection and that used for the circuit breaker closing circuit shall be the same. This protection safeguards the *Generating Unit* against an unintended connection to the *TS* (back energisation) when at standstill, at low speed or when inadequately excited.

(3) Should system conditions dictate, the *SO* shall determine other capital protection requirements in consultation with the *Generator*. This *Apparatus* may be installed at the relevant *Generating Unit* or *PS*, and be maintained by the relevant *Generator*.

(4) Any dispute as to the allocation of costs for the *Apparatus* identified in clause (2)(3) above shall be decided in terms of the dispute resolution MCRhanism in the *Governance Code*.

(5) Required *HV* breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the *SO*. Guidelines for operating times are as follows:

a. 100 ms where the *PoC* is 70 kV or above.

b. 120 ms where the *PoC* is below 70 kV.

(6) Further downstream breaker tripping and fault clearing times (away from the *PoC*), including breaker operating time, shall not exceed 120 ms plus an additional 30 ms for DC offset decay.

(7) Where so designed, earth fault clearing times for high-resistance earthed systems may exceed the tripping times of clause (5) and (6) above.

(8) The *SO* shall co-ordinate and approve all protection interfaces between *Generators* and *TransCos*.

(9) The settings of all protection tripping functions on the *Unit* protection system of a *Generating Unit*, relevant to *TS* performance and as agreed with each *Generator* in writing, shall be agreed between the *SO* (in collaboration with the *TransCo*) and each *Generator*, and shall be documented and maintained by the *Generator*, with the reference copy, which reflects the actual *PS* status at all times, held by the *SO*. The *Generator* shall control all other copies.

(10) A *Generating Unit* may disconnect from the *TS* in response to conditions at the *PoC* that will result in *Unit* damage. Protection setting documents shall illustrate *PS* capabilities and protection operations where relevant.

(11) *Participants* shall ensure that competent persons shall carry out testing, commissioning and configuration of protection systems.

(12) Prototype and routine testing shall be carried out as defined in Appendix D section D-4.1.

(13) *Generators* shall communicate any work on the protection circuits interfacing with *Transmission* protection systems (e.g. bus zone) to the *SO* and relevant *TransCo* before commencing the work. This includes work done during a *Unit* outage.

4.1.2 Excitation system requirements

(1) A continuously-variable, continuously-acting automatic excitation control system i.e. an *Automatic Voltage Regulator (AVR*) shall be installed to provide terminal voltage control of the *Unit*, without instability, over the entire operating range of the *Unit* (Note: this does not include the possible influence of a *Power System Stabiliser (PSS)*). Excitation systems shall comply with the appropriate 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 IEC 60034-16-1.

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

(4) The settings of the excitation system shall be agreed between the *SO* (in collaboration with the relevant *TransCo*) and each *Generator*, and shall be documented, with the master copy held by the *SO*. The *Generators* shall control all other copies. The procedure for this is shown in Appendix D section D-4.2

(5) In addition, the *Unit* shall be capable of operating in the full range indicated in the generating *Unit*s' capability diagram supplied as part of the *Information Exchange Code* requirements. Test procedures are given in Appendix D section 0.

(6) The active power output under steady state conditions at the *PoC* of any *Unit* shall not be affected by voltage changes in the normal operating range of ±5% of nominal voltage at the *PoC.*

(7) The reactive power output of a *Unit* under steady state conditions must be fully available within the voltage range of ±10% of nominal voltage at the *PoC.*

(8) *PSSs* as described in IEC60034-16-1 should be applied if/when required for all new *Units* and for existing *Unit* retrofitting as may be required depending on *IPS* requirements. The requirement for a *PSS* and/or any other excitation control facilities and/or *AVR* refurbishment shall be determined in collaboration with the *SO* and the relevant *TransCo*.

(9) Routine and prototype response tests shall be carried out on excitation systems as indicated in Appendix D section D-4.2 ensuring compliance with IEC 60034-16-3.

4.1.3 Reactive power capabilities

(1) All new *Units* shall be capable of supplying rated active power output at any point between the limits 0.85 *PF* lagging and 0.95 *PF* 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 D section 0.

4.1.4 Multiple *Unit* Tripping (MUT) risks

(1) A *PS* 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 duration of time. This "short duration of time" timeframe should be defined by the *SO* in collaboration with *the Authority*.

4.1.5 Governing

(2) All *Units* equal to or bigger than MCR > 1 MVA shall have an operational governor capable of responding according to the minimum requirements set out in this section.

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

(4) Routine and prototype response tests shall be carried out on the governing systems as indicated in Appendix D.

4.1.5.1 System frequency deviations

(1) The nominal frequency of the *IPS* is 50 Hz and is normally controlled within the limits as defined in the *System Operations Code*. The system frequency could rise or fall in exceptional circumstances and *Units* must be capable of continuous normal operation for the operating frequency-voltage operating ranges indicated in and described in section 4.1.8.

(2) Considering future *interconnections* and power trading with surrounding countries (including *EAPP* and non-*EAPP* members), the *IPS* should align its frequency limits with that of *EAPP* in terms of the various defined system conditions as shown in Table 1 and described as follows:

a. **Normal operation**: Frequency shall be controlled between 49.5 Hz and 50.5 Hz (±1%) unless exceptional circumstances prevail.

b. **System disturbance**: Following a system disturbance such as the loss of the largest single *Unit* on the *IPS*, the frequency band is extended to between 49.0 Hz and 51.0 Hz (±2%).

c. **System fault:** If multiple *Generating Units* are tripped, major *Transmission Apparatus* fail or large loads are suddenly disconnected, the minimum and maximum frequency band is between 48.75 Hz and 51.25 Hz (±2.5%).

d. **Extreme:** If several of the contingencies mentioned previously occur simultaneously, the operating condition is labelled as extreme and the frequency can be below 47.5 Hz or above 51.5 Hz (-5%/+3%). This condition typically results in a system blackout as frequency recovery back to normal range is not possible.

Table 1 Frequency limits to be adhered to in Rwandan *IPS*

Operating Condition	Frequency (Hz)		Frequency variation (%)
	Lower	Upper	
Normal	49.50	50.50	± 1
System disturbance	49.00	51.00	± 2
System fault	48.75	51.25	± 2.5
Extreme system operation or fault	<47.50	>51.50	-5%/+3

(3) The design of *Generating Units* must enable continuous operation, at up to 100% MCR (excluding Gas Turbines) active power output when the system frequency is within the ranges specified in Table 1.

(4) Frequency sensitive relay settings installed on *Generating Units* i.e. tripping time, pick up frequency, *rate of change of frequency (ROCOF)* shall be as agreed with the *SO* (in collaboration with the *TransCo*). Sections 4.1.5.2 to 4.1.5.6 shall be used as guidelines for these tripping times.

(5) The time vs system frequency plot as shown in Figure 2 shows the minimum operating range of a non-hydro *Unit*.

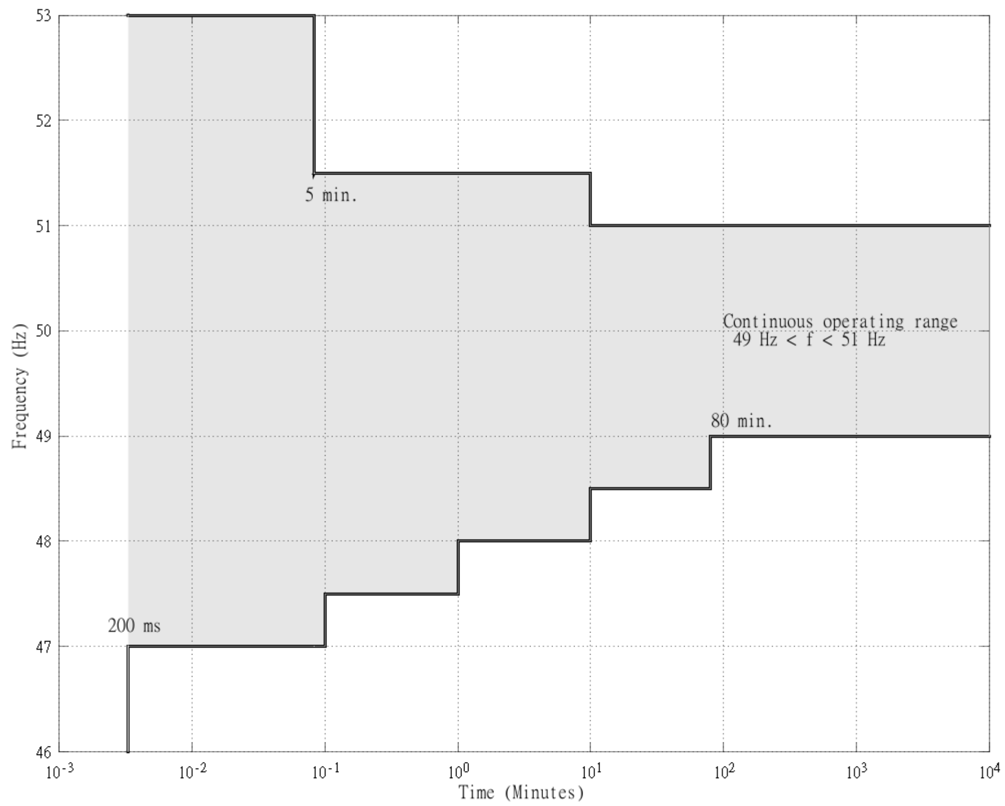

Figure 2 Time vs system frequency plot, minimum operating range of a non-hydro *Unit*

4.1.5.2 High Frequency Requirements for non-hydro *Units*

(1) All synchronised non-hydro *Units* shall respond by reducing active power to frequencies above 50 Hz incorporating the allowable dead band described in section 4.1.5.6. Speed governors shall be set to give a 4% governor droop characteristic (or as otherwise agreed by the *SO*). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(2) **51 Hz < f ≤ 51.5 Hz condition**:

a. When the frequency goes above 51 Hz but is less than 51.5 Hz the *Unit* shall be designed to run for at least 10 minutes over the life of the plant and for at least 5 consecutive minutes without tripping.

b. Exceeding the above limit shall prompt the *Generating Unit* to take all reasonable efforts to reduce the system frequency below 51.5 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 51.5 Hz for 5 minutes. The *Generator* will trip a *Unit*, and if the system frequency does not fall below 51.5 Hz, the other *Units* shall be tripped in staggered format over the next 5 minutes or until the system frequency is below 51.5 Hz. The *SO* shall approve this tripping philosophy and the settings.

(3) **f > 51.5 Hz condition:**

a. 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 and for at least 30 consecutive seconds without tripping.

b. 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 *SO* shall approve this tripping philosophy and the settings.

4.1.5.3 High Frequency Requirements for hydro *Units*

(1) All synchronised hydro *Units* shall respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in section 4.1.5.6. Speed governors shall be set to give a 4% governor droop characteristic (or as otherwise agreed by the *SO*). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(2) Currently, the *IPS* is not designed for (N-1) contingencies and as a result high over-frequency withstand capabilities of *Generating Units* will be required. If 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 *Unit* and for at least 4 consecutive 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 non-hydro *Generators*. Settings shall be agreed with the *SO*.

4.1.5.4 Low Frequency Requirements for non-hydro *Units*

(1) Low frequency response is defined as an *Ancillary Service* known as *Operating Reserves*. However, all *Units* shall be designed to be capable of having a 4% governor droop characteristic (or as otherwise agreed by the *SO*) with a minimum response of 3% of *MCR* within 10 seconds of a frequency incident. The response must be sustained for at least 15 minutes.

(2) **49.0 Hz > f ≥ 48.5 Hz condition**:

a. The *Unit* shall be designed to run for at least 80 minutes over the life of the plant if the frequency goes below 49.0 Hz but greater than 48.5 Hz.

b. No automatic tripping of *Generators* shall be allowed in this region.

(3) **48.5 Hz > f ≥ 48 Hz condition**:

a. The *Unit* shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes below 48.5 Hz but greater than 48.0 Hz. The *Unit* shall be able to operate for least 1 consecutive minute while the frequency is in this range.

b. If the system frequency is less than 48.5 Hz for 1 minute the *Unit* can be islanded or tripped to protect the *Unit*.

(4) **48 Hz > f ≥ 47.5 Hz condition**:

a. The *Unit* shall be designed to run for at least 1 minute over the life of the plant if the frequency goes below 48.0 Hz but is greater than 47.5 Hz. If the system frequency is less than 48.0 Hz but is greater than 47.5 Hz for 10 seconds the *Unit* can be islanded or tripped to protect the *Unit*.

(5) **f < 47.5 Hz condition**:

a. If the system frequency falls below 47.5 Hz for longer than 6 seconds the *Unit* can be islanded or tripped.

4.1.5.5 Low Frequency Requirements for hydro *Units*

(1) All reasonable efforts shall be made by the *Generator* to avoid tripping of hydro *Generating Units* for under frequency conditions provided that the system frequency is above or equal to 46 Hz.

(2) If the system frequency falls below 46 Hz for more than 1 second, the *Unit* can be tripped to protect itself.

4.1.5.6 Dead band

(1) The maximum allowable dead band shall be 0.20 Hz for governing. This means that no response is required from *Units* while 49.8 Hz ≤ f ≤ 50.2 Hz.

4.1.6 Restart after station blackout

4.1.6.1 Non-hydro *PSs*

(1) A *PS* 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 provided that the following is maintained at the *PoC* for the duration of the *Unit* start-up process:

a. A stable supply of at least 90% of nominal voltage for the *Unit* with *on-load tap changers (OLTCs)* on the generator *Generating Units'* transformers, and a stable supply of at least 95% nominal voltage for *Units* without OLTCs on the *Generating Units'* transformers.

b. An unbalance between phase voltages of no more than 3% negative phase sequence.

c. A frequency within the continuous operating range.

(2) For the purposes of this *Code*, examples of unreasonable delay in the restart of a *PS* are:

a. Restart of the first *Unit* that takes longer than 2 hours after restart initiation

b. Restart of the second *Unit* that takes longer than 1 hour after the synchronising of the first *Unit*.

c. Restarting of all other *Units* that takes longer than 30 minutes each after the synchronising of the second *Unit*.

d. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant *Generator*.

e. 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.

(3) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix D section 0.

4.1.6.2 Hydro *PS*s, Diesel and Gas engines and Gas Turbines

(1) A *PS* or 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 provided that the following is maintained at the *PoC* for the duration of the *Unit* start-up process:

a. A stable supply of at least 90% of nominal voltage for *Unit* with OLTCs on the generator transformers, and a stable supply of at least 95% nominal voltage for *Unit* without OLTCs on the generator transformers.

b. An unbalance between phase voltages of not more than 3% negative phase sequence.

c. A frequency within the continuous operating range.

(2) For the purposes of this *Code*, examples of unreasonable delay in the restart of a *PS* are:

a. Restart of the first *Unit* that takes longer than 30 minutes after restart initiation

b. Restarting of all other *Unit* that take longer than 30 minutes each after the synchronising of the first *Unit*.

c. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator.

d. 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.

(3) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix D section 0.

4.1.7 Black start capability

(1) *Black start capability* is defined as an *Ancillary Service* of which the relevant arrangements should be made by the *SO* in terms of the strategic type and location of *Black start capability.*

(2) The relevant arrangements made by the *SO* to procure *Black start capability* should strategically take into consideration *EAPP Black start* requirements and procedures in the *EAPP Interconnection Code*.

(3) *PSs* that have declared that they have *Black start capability* shall demonstrate this facility by test as described in Appendix D section 0.

4.1.8 External supply disturbance withstand capability

(1) Any *Unit* and any *PS Apparatus* shall be designed with anticipation of the following voltage conditions at the *PoC*:

a. A voltage deviation in the range of 90% to 110% of nominal voltage for extended periods.

b. A voltage drop:

i. to 0% for up to 0.2 s.

ii. to 75% for 2 s.

iii. to 85% for 60 .

iv. Provided that during the 3 minute period immediately following the end of the above voltage conditions the actual voltage remains in the range 90-110% of the nominal voltage.

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. Requirements to withstand the ARC cycle for faults on *Transmission* lines connected to *PSs* are as follows:

i. Single-phase faults:

1ph fault - 1ph trip - 1 second 1ph ARC dead time - 1ph ARC - 1ph fault - 3ph trip - 3 seconds 3ph ARC dead time - 3ph ARC - 1ph fault - 3ph trip - lock out.

Note: The above only applies where synchronism is maintained.

ii. Three-phase faults:

Currently it is not possible to withstand three phase faults on the *IPS* as a result of the radial nature of the *IPS* currently not designed for (N-1) operation.

(2) The frequency-voltage tolerances to be applied to *Generating Units* are as specified in Figure 3 as defined in IEC 600034-3.

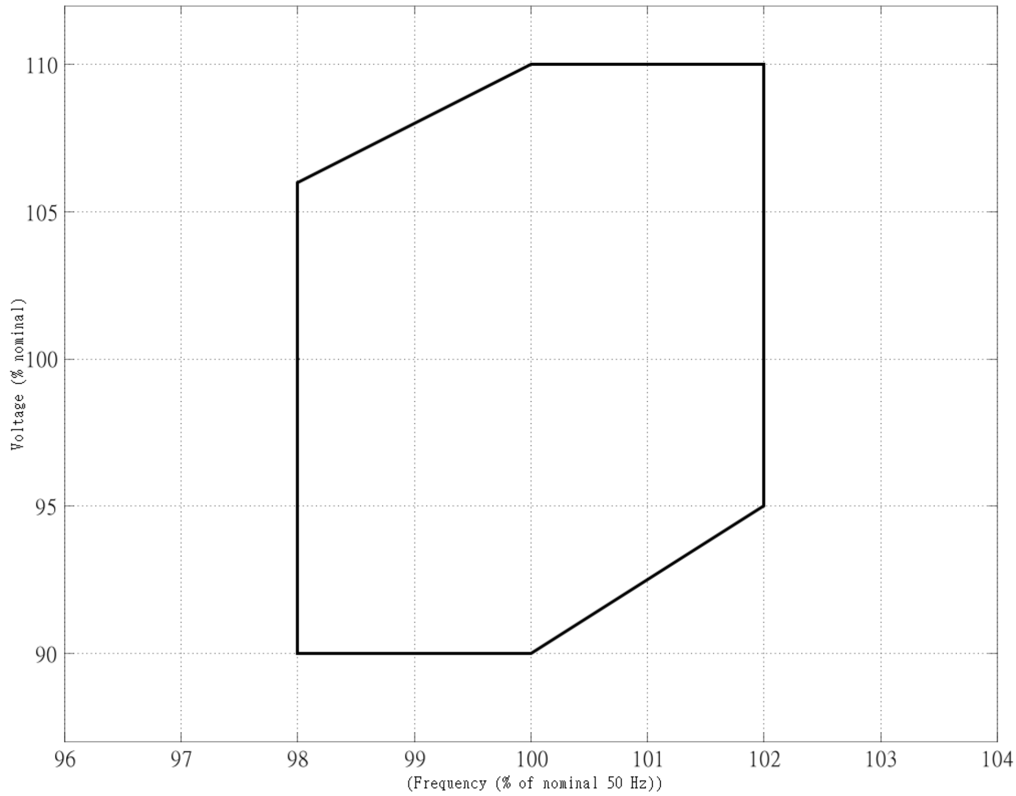

Figure 3 Frequency-voltage tolerances required from *Unit* at the *PoC.*

4.1.9 On-load tap changers (OLTCs)

(1) *Generating Unit* step-up transformers shall have on-load tap changers (OLTCs) which can be remotely controlled. The range shall be agreed upon between the *TransCo* and the *Generator*.

4.1.10 Emergency *Unit* capabilities

(1) All *Generators* shall specify their *Unit's* capabilities for providing emergency support above *MCR* under abnormal power system conditions, as detailed in the *System Operations Code*.

4.1.11 Facility for independent generator action

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

4.1.12 Automatic under-frequency starting

(1) It may be agreed with the *SO* that strategic *Units* are capable of automatically starting within 15 minutes which shall have automatic under-frequency starting capability. This starting shall be initiated by frequency-level facilities with settings in the range 49 Hz to 50 Hz as specified by the *SO*.

4.1.13 Synchronisation

(1) All *Units* shall have the appropriate relays installed to allow for synchronisation with the *IPS* only once the appropriate parameters (voltage, phase and frequency) are within the error limits agreed upon between the *Generator* and the *SO.*

4.1.14 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 *SO* 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 *SO*, compliance by the *PS* or each of that *Generator's Units* with every connection condition as specified in Appendix D.

(3) A *Generator* shall conduct tests or studies to demonstrate that each *PS* and each *Generating Unit* complies with each of the requirements of this *Code*. Tests shall be carried out on new *Unit*, after every outage where the integrity of any connection condition may have been compromised, to demonstrate the compliance of the *Unit* with the relevant connection conditions. The *Generator* shall continuously monitor its compliance in all material respects with all the connection conditions of the *Grid Code*.

(4) Each *Generator* shall submit to the *SO* 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 *PSs* are not complying in any material respect with one or more sections of this *Code*, then the *Generator* shall:

a. Promptly notify the *SO* of that fact.

b. Promptly advise the *SO* of the remedial steps it proposes to take to ensure that the relevant *Unit* or *PS* (as applicable) can comply with this *Code* and the proposed timetable for implementing those steps

c. Diligently take such remedial action as will ensure that the relevant *Unit* or *PS* (as applicable) can comply with this *Code*. The *Generator* shall regularly report in writing to the *SO* on its progress in implementing the remedial action.

d. After taking remedial action as described above, demonstrate to the reasonable satisfaction of the *SO* that the relevant *Unit* or *PS* (as applicable) is then complying with this *Code*.

(6) The *SO* may issue an instruction requiring a *Generator* to carry out a test to demonstrate that the relevant *PS* complies with *Grid Code* requirements. A *Generator* may not refuse such an instruction, provided it is issued timorously and there are reasonable grounds for suspecting non-compliance.

4.1.15 Suspected non-compliance

(1) If at any time the *SO* believes that a *Unit* or *PS* is not complying with a connection condition, the *SO* shall notify the relevant *Generator* of such non-compliance specifying the connection condition concerned and the basis for the *SO*'s belief.

(2) If the relevant *Generator* believes that the *Unit* or *PS* (as applicable) is complying with the *Code*, then the *SO* and the *Generator* must promptly meet to resolve their difference.

(3) If no resolution is found following meetings between the *SO* and *Generator*, the dispute resolution process defined in the *Governance Code* should be followed.

4.1.16 *Unit* modifications

4.1.16.1 Modification proposals

(1) If a *Generator* proposes to change or modify any of its *Unit* in a manner that could reasonably be expected to either adversely affect that *Unit*'s ability to inter alia comply with this *Code*, or changes the performance, information supplied and/or settings, then that *Generator* shall submit a proposal notice to the *SO* which shall:

a. Contain detailed plans of the proposed change or modification.

b. State when the *Generator* intends to make the proposed change or modification.

c. 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*.

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

(3) If no resolution is found following meetings between the *SO* and *Generator*, the dispute resolution process defined in the *Governance Code* should be followed.

4.1.16.2 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 *SO*.

(2) The *Generator* shall notify the *SO* promptly after an approved change or modification to a *Unit* has been implemented.

4.1.16.3 Testing of modifications

(1) The *Generator* shall confirm that a change or modification to any of its *Unit* 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 *SO* with a report in relation to that test (including test results, where appropriate).

4.1.17 Apparatus requirements

(1) Where a *Generator* needs to install *Apparatus* that connects directly with a *TransCo's Apparatus*, for example in the *HV* yard of the *TransCo*, such *Apparatus* shall adhere to the *TransCo's* design requirements.

(2) A *TransCo* may require *Generators* to provide documentary proof that their connection apparatus complies with all relevant standards, both by design and by testing.

4.2 Embedded Generator connection conditions

(1) This section defines acceptable requirements for *EG* connections.

(2) A similar procedure to that followed in section 4.1 for *Generator* connections is shown graphically in Figure 4 as a guideline for prospective *EG* connections.

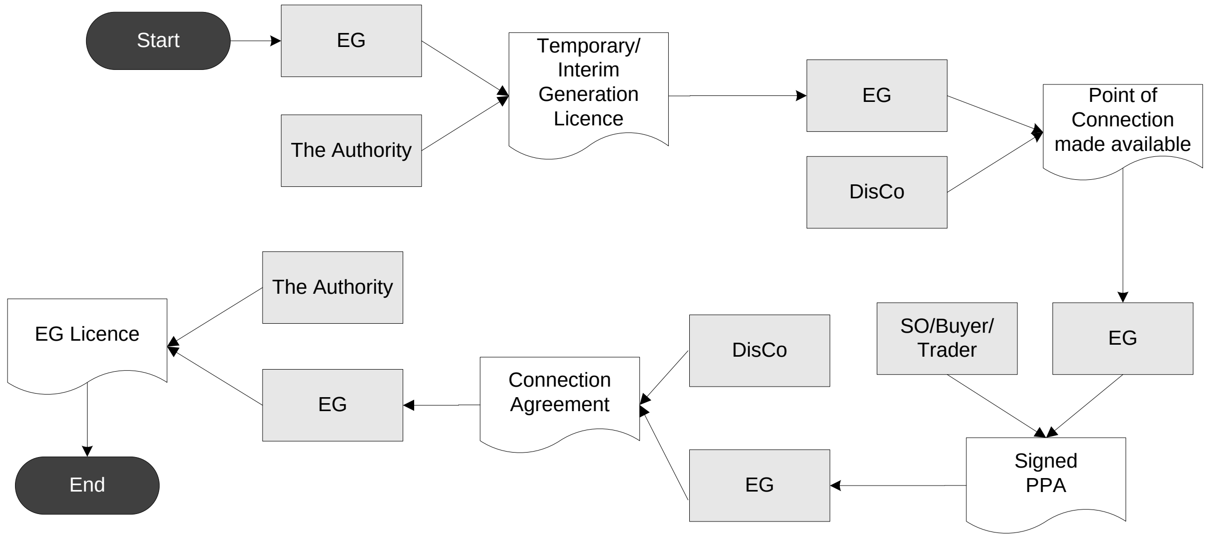

Figure 4 Guideline connection process for a prospective *Embedded Generator*

(3) The applicable lower limit for *Embedded Generation* requiring a licence as defined in the *Electricity Law* applies in this *Code.*

(4) The relevant adopted national standard shall apply for Embedded Generation e.g. IEEE 1547, IEC 63547

4.2.1 Responsibilities

4.2.1.1 Embedded Generators responsibilities

(1) The *EG* shall enter into a *Connection Agreement* with the relevant *DisCo* before connecting to the relevant *DS*.

(2) The *EG* shall ensure that the reliability and *Quality of Supply (QoS)* complies with the terms of the *Connection Agreement*.

(3) The *EG* shall comply with the *DisCo's* protection requirements detailed in this section as well as protection of own plant against abnormalities, which could arise on the *DS*.

(4) The *EG* shall be responsible for any dedicated connection costs incurred on the *DS* as a result of connection to the *DS* in compliance with the *Tariff Code*.

(5) The *EG* shall be responsible for synchronizing the *PS* to the *DS* within pre-agreed settings with the *DisCo*.

(6) *EGs* shall specify, with all relevant details, in their application for connection if the *PS* to be connected shall have black-start and / or self start capabilities.

4.2.1.2 Distributors responsibilities

(1) If requested by the *EG*, a *DisCo* shall provide information relating to inter alia their *DS* capacity, loading, short circuit levels, X/R ratio at the *PoC* and any other relevant information to enable the *EG* to identify and evaluate opportunities for connecting to the *DS*. The *DisCo* may charge the *EG* a reasonable fee for such information.

(2) The *DisCo* shall treat all applications for connection to the *DS* by potential *EGs* in an open and transparent manner that ensures equal treatment for all applicants.

(3) *DisCos* shall be responsible for the installation of bidirectional metering Apparatus between the *DisCo* and the *EG* to the standard defined in the *Metering Code*.

(4) *DisCos* shall develop detailed protection requirement guidelines for connecting *Embedded Generation* to the *DS* which complement *Embedded Generation* protection requirements in this *Code* to ensure safe and reliable operation of the *DS*.

4.2.2 *PoC* technical requirements

(1) The *EG* shall be responsible for the design, construction, maintenance and operation of the *Apparatus* on the *PS* side of the *PoC*.

(2) In the case of a dedicated *PoC*, the *EG* shall be responsible for the provision of the site required for the installation of the *DisCo's* Apparatus required for connecting the *PS*.

(3) The technical specifications of the Connection Agreement shall be agreed upon by the *Participants* based on *DS Impact Assessment Studies*.

(4) A circuit breaker and visible isolation shall be installed at the *PoC* to provide the means of electrically isolating the *DS* from the *Embedded Generation*.

(5) The *EG* shall be responsible for the circuit breaker to connect and disconnect the *Generating Unit* as well as the required protection functionality of the *PS.*

(6) The location of the circuit breaker and visible isolation shall be decided upon by the *Participants*.

4.2.3 Protection

4.2.3.1 General protection requirements

(1) The *EG's* protection systems shall comply with the requirements of this section complemented by detailed *DisCo* developed guidelines.

(2) *Embedded Generation* of MCR > 500 kVA shall in addition to the requirements of this section on *EGs*, comply with section 4.1 of this *Code* regarding protection requirements.

(3) Additional features including inter-tripping and *PS* status are to be agreed upon by the *Participants*.

(4) The protection schemes used by the *EG* shall incorporate adequate facilities for testing and maintenance.

(5) The protection schemes of the *EG* shall be coordinated with the relevant *DisCo's* protection systems.

(6) The protection schemes of the *EG* should be submitted by the *EG* for approval by the relevant *DisCo* and/or *SO* where applicable.

(7) Each protection operation shall be investigated for its correctness based on available *Information*. The *EG* shall provide a report to the *Distributor* and/or the *SO* when requested to do so.

4.2.3.2 Specific protection requirements

(1) **Phase and earth fault:** The protection system of the *EG* shall fully coordinate with the protective relays of the *DS*. Also, the *EG* shall be responsible for the installation and maintenance of all protection relays at the *PoC*.

(2) **Over-voltage and over-frequency:** The *EG* shall install over-voltage and over-frequency protection to disconnect the *PS* under abnormal network conditions as agreed between the *DisCo* and the *EG*.

(3) **Faults on Distribution System:** The *EG* shall be responsible for protecting its *PS* in the event of faults and other disturbances arising on the *DS*.

(4) **Islanding:**

a. The *DisCo* shall specify if/when the *EG* may remain connected if the section of the *DS* to which the *EG* is connected is isolated (islanded) from the rest of the network.

b. The *PS* shall be equipped with a dead-line detection protection system to prevent a *Unit* from being connected to a de-energised *DS*. The *DisCo* shall take reasonable steps to prevent closing circuit breakers onto an islanded network.

c. For unintentional network islanding, the *EG* and the *DisCo* shall agree on a methodology for disconnecting and connecting the *Embedded Generation*.

(5) **Reverse power:** Settings for reverse power shall be as agreed upon between the *EG* and the *DisCo* and/or *SO.* The recommended setting for reverse power is 10-20% of *MCR* of the *Unit* with a time delay of 10-30 seconds to prevent operation during power swings or when synchronising the *Unit* to the network.

(6) **DC Failure protection:** DC failure within the *EG's* facility is a serious safety risk and the appropriate alarms (non-urgent and urgent) should be provided to the *DisCo* via *Telecontrol* facilities. Upon the receipt of an urgent DC alarm by the *DisCo* from the *EG*, the *EG* should disconnect and/or be disconnected from the relevant network immediately.

(7) **Phase unbalance:** Negative phase sequence overcurrent shall be applied to the *EG*'s *PS* to protect *Embedded Generating Unit* from unbalanced loading conditions.

4.2.4 Excitation system

(1) *EGs* using synchronous generators as *Embedded Generating Units* shall be equipped with excitation controllers capable of connecting and operating on a network within statutory voltage limits operating in voltage control mode or *PF* control mode as agreed upon in the *Connection Agreement*.

(2) *EGs* using Induction (asynchronous) generators as *Embedded Generating Unit* will need to ensure that the *PS* is capable of operating in either *PF* control mode or voltage control mode within the statutory voltage or *PF* limits agreed upon in the *Connection Agreement*. This can be accomplished by an integrated *PS* controller via the combined use of inter alia step-up transformer tap-changers, shunt reactive devices (reactors/capacitors) and/or fast reactive power devices (SVCs, STATCOMs) as agreed upon with the *DisCo and/or SO* where appropriate.

(3) *EGs* using inverter type *Apparatus* as *Embedded Generating Units* shall be capable of operating in either *PF* control mode or voltage control mode operating within the statutory voltage or *PF* limits agreed upon in the *Connection Agreement.*

4.2.5 Governing

(1) The governing requirements of section 4.1.5 of this *Code* shall apply to *Embedded Generating Units* if MCR is greater than the limit defined in section 4.1.5.

(2) *Embedded Generating Units* with *MCR* lower than the limit defined in section 4.1.5 are not required to comply with governing and frequency requirements defined in this *Code*.

4.2.6 Synchronisation

(1) All *Embedded Generating Units* shall have the appropriate relays installed to allow for synchronisation with the *DisCo's* network only once the appropriate parameters (voltage, phase, frequency) are within the limits agreed upon between the *DisCo* and *EG* and possibly the *SO in selected cases.*

4.2.7 Telecontrol

(1) Each *EG's PS* should have an *RTU* (or appropriate *Data Terminal Equipment (DTE)*) in accordance with the relevant *DisCo's* standard to allow for the relevant *Information* to be exchanged.

4.2.8 Quality of Supply (QoS)

(1) **General QoS:** The *EG* shall comply with general *QoS* requirements as agreed upon between the *DisCo* and *EG.* Suggested *QoS* standards are the IEC 61000 suite or SABS 048.*QoS* parameters include inter alia the following:

i. Voltage regulation

ii. Frequency regulation

iii. Unbalance

iv. Harmonics and inter-harmonics

v. Flicker

vi. Voltage surges and switching disturbances

vii. Voltage dips

(2) **Frequency variations:** The *PS* shall remain synchronized to the *DS* while the network frequency remains within the agreed frequency limits defined in section 4.1 of this *Code* and shall respond to frequency variations if required to do so considering section 4.2.5 of this *Code*.

(3) **Power Factor:** The *PF* at the *PoC* shall be maintained within the limits agreed upon by the *Participants* in the *Connection Agreement.*

(4) **Fault Levels:**

a. The *EG* shall ensure that the agreed fault level contribution from the *EG's PS* (as agreed in the *Connection Agreement*) shall not be exceeded.

b. The *DisCo* shall ensure that the agreed fault level in the network at the *PoC* shall not be exceeded.

(5) **Telemetry:** The *EG* shall have the means to remotely report any status change of any critical function that may negatively impact on the *QoS* on the *DS* (via *RTU/DTE* as defined in section *4.2.7*).

4.3 DisCos and Customers

(1) This section describes connection conditions for *DisCos* and *Customers*.

(2) A *TransCo* shall, subject to the conditions in section **Error! Reference source not found.**, and in collaboration with the *TSO* offer to connect and, subsequent to the signing of the relevant agreements, make available a *PoC* to any requesting *DisCo* or *Customer*.

(3) A *DisCo* and/or *Customer* may request additional reinforcements to the *TS* over and above that which could be economically justified as described in section 7 of this *Code*. In this case, a *TransCo* shall provide such reinforcements if the *DisCo* and/or *Customer* agrees to bear the costs, which shall be priced according to the *Tariff Code*.

(4) Single phase system and interconnection requirements in rural areas

4.3.1 Power Factor

(5) *DisCos* and *Customers* shall take all reasonable steps to ensure that *PFs* at each respective *Point/s of Connection* from the respective *TransCo* are, unless otherwise agreed to in contracts between *Participants*:

a. PF = 0.90 importing or higher during periods of peak demand and during shoulder hours.

b. PF = 1.00 importing or lower during periods of minimum demand.

(6) The above *PF* requirement applies to each *PoC* individually for *DisCos* and/or *Customers* with more than one *PoC*.

(7) An exporting *PF* shall not be acceptable, unless specifically agreed to in the relevant agreements made between *Participants*.

(8) Aside from the typical kVA (power factor) charge levied in tariffs as detailed in the *Tariff Code,* technical requirements regarding *PFs* should be less than the agreed upon limit between *Participants* 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 economic cost solutions shall be sought.

(9) The required *PF* from an *EG* shall be in accordance with the required reactive power control and/or voltage control mode as agreed upon between the *EG* and the *DisCo.*

4.3.2 Protection

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

(2) All *Apparatus* connected directly to a *TS* or *DS Substation* shall comply with the *Grid Code* protection requirements described in section 6 of this *Code*. 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*.

(3) *DisCos* that have *Customers* connected directly to *Transmission Substation*s are responsible for ensuring that such *Customer*s comply with the relevant protection standards.

(4) A *DisCo's* protection system shall be appropriately designed and maintained to ensure optimal grading, coordination and discrimination to ensure safety and minimum interruptions to *EGs* and *Customers*.

(5) The *Customer* shall install and maintain protection, which is compatible with the existing *DS* protection. The *Customer's* protection settings shall ensure coordination with the *DisCo's* protection systems.

(6) The *Customer* shall, on request, provide the relevant *DisCo* with test certificates, prior to commissioning, of the protection system/s that are installed at the *PoS (PoS)* with the *DisCo*.

(7) The *DisCo* shall, on request, provide the relevant *TransCo* and the *SO* (where appropriate) with test certificates, prior to commissioning, of the protection system/s that are installed at the *PoS* with the relevant *TransCo*.

(8) Where *Apparatus* or protection schemes are shared, the *Participants* shall provide the necessary *Apparatus* and interactions between the *Apparatus* of the other party.

4.3.3 Fault levels

(1) Minimum fault levels at each *PoS* on the *TS* shall be maintained by *TransCos* under normal operating conditions to ensure compliance with the adopted *QoS* standards and to ensure correct operation of protection systems.

(2) *TransCos* shall annually provide the *SO* with minimum and maximum normal operating fault levels for each *PoS* on their respective *TS*.

(3) The *SO* shall annually, or when substantial deviations have taken place, publish updated minimum and maximum normal operating fault levels for each *PoS* on the *TS*.

(4) *Participants* shall ensure their *Apparatus* is capable of operating in these specified fault level ranges.

(5) If *Participants Apparatus* fault level ratings are or will be exceeded, they shall promptly notify the relevant *TransCo*. The *TransCo* shall seek overall lowest economic cost solutions to address fault level problems.

(6) Corrective action shall be for the cost of the relevant asset owner and per the implementation plan agreed to.

(7) Any dispute as to the allocation of costs for the equipment identified in clause (6) above shall be decided in terms of the dispute resolution MCRhanism in the *Governance Code*.

(8) *TransCos* and *DisCos* shall liaise with the relevant *Participants* as per the process defined in section 7 of this *Code*, on how fault levels are planned to change and on the best overall solutions when equipment ratings become inadequate. Overall lowest economic cost solutions shall be sought and a joint impact assessment shall be done covering all aspects. *Transco* and *DisCos* shall communicate the potential impact on safety of people when *Apparatus* ratings are exceeded.

4.3.4 Earthing requirements

(1) A *TransCo* or *DisCo* shall advise *Customers* about the neutral earthing methods used in their *TS or DS* respectively.

(2) The method of neutral earthing used on those portions of *Customer's* installations that are physically connected to the *TS* or *DS* shall comply with the nationally adopted earthing standards for *Customers* and for *EGs*.

(3) Protective earthing of *Apparatus* must be done in accordance with the applicable national standard , e.g. IEC 61936 or IEEE 142 or SABS 076.

(4) Designed lightning protection requirements shall be applied to the *TS* or *DS* and relevant switching yards.

(5) *Substation* earthing requirements shall be in accordance with IEC 61936 or IEEE 142 or SABS 076.

4.3.5 Network performance indices

(1) Network performance predominantly relates to *QoS* standards adopted by *the Authority*. These are a shared responsibility between *DisCos* and *Customer*s (*Large Customers, Small Customers* and *EGs*). Suggested *QoS* standards are the IEC 61000 suite or SABS 048

(2) *The Authority* shall be responsible for determining and setting of *DS* performance indices as well as the format in which these are reported. These performance indices predominantly relate to the nationally adopted *QoS* standards and as a guideline the following indices are included in this *Code*:

a. Interruption performance

b. Voltage regulation performance

c. Dip performance

d. Total harmonic distortion performance (harmonics and inter-harmonics)

e. Flicker performance

f. Unbalance performance

g. Voltage dip performance

h. Frequency

i. Voltage surges and switching disturbances

(1) Before the end of each year each *DisCo* and *Customer* (where applicable) shall publish and submit to *the Authority* its targets for performance for the following year.

(2) *The Authority* shall annually evaluate the *DS* performance indices to compare each *DisCo's* actual performance with the *DisCo's* unique targets set by *the Authority*. *The Authority* shall publish these comparative results.

(3) If a *DisCo's* or *Customer's* network performance falls below acceptable levels and affects the *QoS* to other *Participants* or causes damage (direct or indirect) to a *Participants Apparatus*, the *Participant* responsible for the deviation shall endeavour to find a solution to remedy the cause of damage as well as possible payment for the damaged *Apparatus*.

(4) Acceptable network performance shall be as follows:

a. Performance comparable to benchmarks for similar networks.

b. Performance that complies with a *TransCo's* operating and maintenance procedures at the relevant *Substation*.

c. Performance that complies with the minimum agreed standards of *QoS*.

(5) If *DisCos* or *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 problematic *Apparatus*, installing additional network *Apparatus*, changing operating procedures (by installing fault-limiting devices if the number of faults cannot be reduced). These changes should be effected in consultation with the relevant *Participant* on both the technical scope and time frame.

(6) Where *QoS* standards are transgressed, the relevant *Participants* shall co-operate and agree in determining the root causes and plans of action. If no solution is found or responsibility for damaged *Apparatus* taken, the process for dispute resolution process, as described in the *Governance Code*, shall be followed.

4.3.6 A TransCo's delivered *QoS*

(1) *QoS* is a shared responsibility between a *TransCo* and its *Customer*s (*Distributors*, *Large Customers* and *Generators*), and shall be based on nationally adopted *QoS* standards as agreed with all relevant *Participants* i.e. IEC 61000 suite or SABS 048.

(2) A *TransCo* shall agree in writing with its *Customer*s, for every *PoS*, at least on the following *QoS* parameters, taking local circumstances, historical performance and the relevant standards into account:

a. Interruption performance

b. Voltage regulation

c. Frequency regulation

d. Voltage unbalance on the *TS* should at least comply with the limits set in the *EAPP Interconnection Code* or better based on the nationally adopted standards.

e. Harmonics and inter-harmonics (EAPP limits use IEEE 519)

f. Voltage flicker on the *TS* should at least comply with the limits set in the *EAPP Interconnection Code* or better based on the nationally adopted standards.

g. Voltage surges and switching disturbances

h. Performance on the *TS* should be evaluated based on nationally adopted standards as no voltage dip performance criteria are set in the *EAPP Interconnection Code*.

(3) *A Participants* responsibilities in terms *QoS* to the *TransCo's TS* and *IPS* in general should also be included in the relevant agreements between *Participants*.

(4) 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 two years unless otherwise agreed. For harmonic voltages and voltage unbalance, performance can be monitored after one week of measurements is completed.

(5) Where a *TransCo* fails to meet the agreed *QoS* parameters, it shall take reasonable steps at own cost to overcome the shortcomings. These changes should be effected in consultation with the relevant *Participant* on both the technical scope and the time frame.

4.3.7 A *DisCo*'s *QoS*

(1) A *DisCo* shall agree in writing with its *Customer*s, for every *PoS*, at least on the following *QoS* parameters based on the nationally adopted *QoS* standard e.g. relevant parts of the IEC 61000 suite or SABS 048, taking local circumstances, historical performance and the relevant standards into account:

a. Interruption performance

b. Voltage regulation

c. Frequency regulation

d. Unbalance

e. Harmonics and inter-harmonics

f. Flicker

g. Voltage surges and switching disturbances

h. Voltage dips

(2) *A Participants'* (*EGs*, *Large Customer*s, *and Small Customers*) responsibilities in terms *QoS* to a *DisCo's DS* should also be included in the agreement.

(3) Where a *DisCo* fails to meet the agreed *QoS* parameters, it shall take reasonable steps at own cost to overcome the shortcomings. These changes should be effected in consultation with the relevant *Participant* on both the technical scope and the time frame.

4.3.8 Losses in the ***Distribution*** system

(1) Losses shall be classified into three categories:

a. Technical Losses.

b. Non-Technical Losses.

c. Administrative Losses.

5 Technical design requirements

(1) The connection requirements set out in this *Code* are based on minimum technical requirements laid out in the *EAPP Interconnection Code* to ensure the

IPS is compliant with regional requirements. This will ensure the possibility of future electrical power trading with EAPP members as a result of *EAPP* interconnection requirements being met.

5.1 Transmission system design requirements

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

5.1.1 Apparatus design standards

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

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

(3) *Participants* may require the *TransCo* to provide documentary proof that their connection *Apparatus* complies with all relevant standards, both by design and by testing.

5.1.2 Clearances

(1) Clearances for all electrical equipment shall at least comply with IEC 61936 and the applicable *Labour Law* in terms of occupational health and safety.

5.1.3 CT and VT ratios, accuracies and cores

(1) All *TransCos* shall adopt the same standards for *Current Transformer (CT)* and Voltage Transformer (*VT)* ratios, cores, transducers and *Analogue to Digital Conversion (ADC)* (in the form of *Remote Terminal Unit (RTUs)* or appropriate *DTE*) as defined in IEC 60044.

5.1.4 Standard busbar arrangements

(1) *Substations* on the *TS* shall be configured in accordance with the principles described in this section.

(2) The reliability and availability of the *TS* is not dependent only on *TS* lines, transformers, and other *Primary Substation Equipment* and *Secondary Substation Equipment*; 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 *TS* to *Participants* be prudently assessed when planning the *TS*.

(3) The standard *Substation* arrangement shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar. A *TransCo* shall, however, consider local conditions, type of *Apparatus* used, type of load supplied and other factors in the assessment of the required busbar redundancy.

(4) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability. Therefore, the following bypass arrangements are *Grid Code* requirements:

a. A bypass with single busbar selection shall be used at *HV* on single line radial feeds to provide continuity of supply when maintaining and/or testing the line breakers.

b. A bypass with double busbar selection shall be used on *HV* lines where justified.

c. *HV* busbar configuration at *PSs* shall be agreed upon with *Generators* and *TransCos*.

5.1.5 Motorised isolators

(1) All *TS Apparatus* isolators on the *TS* shall be motorised at new *Substations*.

5.1.6 Earthing and surge protection

(2) Each *TransCo* shall ensure adequacy of all earthing installations to provide for:

a. The safety of personnel and the public.

b. The correct operation of all protection systems.

c. Agreed design and performance levels.

(3) Earthing isolators shall be provided at new *Substation*s where the fault level is designed for *20 kA* and above.

(4) Each *TransCo* shall provide adequate protection to limit lightning surges and/or switching surges at the *PoC* to the standardised limits e.g. IEC 60071, using the best technology methods e.g. IEC 62305. Protection systems shall be adequate to protect *Apparatus* to the rating levels as outlined in Table 2 (220 kV and 400 kV included for future network expansion) to align with the *EAPP Interconnection Code* which are based on IEC 60071.

Table 2 Permissible transient voltages on Rwandan *TS* (based on IEC 60071)

Nominal Voltage (kV)	Highest operating voltage on equipment (kV)	Withstand voltage for lightning surge (kV), LIWL	Withstand voltage for switching surge (kV), SIWL	50 Hz, 1 min. withstand voltage (kV)
70	72.5	325	N/A	140
110	123	550	N/A	230
220	245	950	N/A	395
400	420	1050-1425	850/950/1050	N/A

5.1.7 Telecontrol

(1) All *Participants* shall be permitted to have *Telecontrol/SCADA* facilities in the *Substations*, yards and/or buildings of other *Participants*, to perform agreed monitoring and control. The asset owner shall provide access to such Apparatus.

(2) *TransCos* shall have reliable *Telecontrol*/*SCADA* facilities (including telecommunications, computers and *RTUs/DTE*) for the *TS*, to provide the necessary response where system conditions require by the *SO*. e.g. IEC 60870.

5.1.8 Transformer tap changers

(1) *TransCos* shall install remote tap changing facilities on all new transformers in their respective *TS* networks.

(2) Transformers used in the *TS* are normally not on automatic tap change. Transformers supplying *Customers* and/or *DisCos* are usually on automatic tap change. As a result, the voltage levels, sensitivity and time delay settings as well as on/off auto tap changing shall be determined by the *SO* in consultation with the *Customer and/or DisCo* and the *TransCo*.

5.1.9 ***Substation* drawings**

(1) The following set of engineering drawings shall be made available by the respective asset owners for all *Points of Connection* and *Points of Supply*, if required by other relevant *Participants* for the purposes of connection to the network:

a. Station Electric Diagram

b. Key Plan

c. Bay Layout Schedules

d. Foundation, Earth Mat 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

q. Any other engineering drawings required as agreed upon between *Participants.*

(2) All engineering drawings shall use the standard electrical symbol set used in IEC 60617.

5.1.10 Voltage

(1) Steady state voltage conditions at *TS* busses should be maintained within the following ranges unless otherwise agreed upon between *Participants*:

a. Under normal conditions: $0.95 \text{ p.u.} \leq V_{bus} < 1.05 \text{ p.u.}$

b. Under any single contingency: $0.90 \text{ p.u.} \leq V_{bus} < 1.10 \text{ p.u.}$

c. Multiple contingency: $0.85 \text{ p.u.} \leq V_{bus} < 1.20 \text{ p.u.}$

5.2 Distribution System design requirements

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

5.2.1 Apparatus design standards

(1) All *DisCo*s shall use the standards for Apparatus on the *DS* as defined in section 5.1.1

5.2.2 Clearances

(1) All clearances shall be as defined in section 5.1.2

5.2.3 CT and VT ratios, accuracies and cores

(1) All *DisCos* shall adopt the same standards outlined in section 5.1.3.

5.2.4 Standard busbar arrangements

(1) *Substations* on the *DS* shall be configured in accordance with the principles described in this section.

(2) For reliability and availability of the *DS,* it is important that the busbar layout and what it can do for the reliability and availability of the *DS* be assessed by the relevant *DisCo* when planning the *DS*.

(3) The standard *Substation* arrangement shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar. A *DisCo* shall, however, consider local conditions, type of *Apparatus* used, type of load supplied and other factors in the assessment of the required busbar redundancy. A *DisCo* shall also adhere to the system reliability criteria as described in section 7 of this *Code*.

(4) The bypass facilities to be provided at *DisCo Substations* shall be as follows:

a. A bypass with single busbar selection shall be used at *MV* voltage levels on single line radial feeds to provide continuity of supply when maintaining and/or testing the line breakers.

b. A bypass with double busbar selection shall be used at *MV* voltage levels where justified.

c. Busbar configuration at *PS*s (*EGs*) shall be agreed upon with *EG*s and/or co-generators.

5.2.5 Motorised isolators

(1) The provision of motorised isolators at new *Distribution Substations* is to be based on individual merit (importance ranking vs. cost vs. remoteness).

5.2.6 Earthing and surge protection

(1) Each *DisCo* shall ensure adequacy of all earthing installations to provide for:

a. The safety of personnel and the public.

b. The correct operation of all protection systems.

c. Agreed design and performance levels.

(2) Earthing isolators shall be provided at new *Substations* where the fault level is designed for 20 kA and above.

(3) Each *DisCo* shall provide adequate protection to limit lightning surges and/or switching surges at the *PoC* to the standardised limits (e.g. IEC 60071) using the best technology methods e.g. IEC 62305. The protection shall be adequate to protect the *Apparatus* to the rating levels as outlined in Table 2 (existing *DS* voltage levels included) which are based on IEC 60071.

Table 3 Permissible transient voltages on Rwandan *DS* (based on IEC 60071)

Nominal Voltage (kV)	Highest operating voltage on equipment (kV)	Withstand voltage for lightning surge (kV), LIWL	Withstand voltage for switching surge (kV), SIWL	50 Hz, 1 min. withstand voltage (kV)
6.6	7.2	40-60	N/A	20
11	12	60/75/95	N/A	28
15	17.5	75/95	N/A	38
30	36	145/170	N/A	70

5.2.7 Telecontrol

(1) All *Participants* shall be permitted to have *Telecontrol/SCADA* facilities in the *Substations*, yards and/or buildings of the other *Participants*, to perform agreed monitoring and control. The asset owner shall provide access to such *Apparatus*.

(2) *DisCos* shall have reliable *Telecontrol/SCADA* facilities (including telecommunications, computers and *RTUs/DTE*) for the *DS* connected

directly to the *TS*, to provide the necessary response where system conditions require by the *SO*. e.g. IEC 60870.

5.2.8 Transformer tap changers

(1) *DisCos* shall install automatic tap changing facilities on all new transformers in their respective networks.

(2) Transformers used in the *DS* should be on automatic tap change to ensure sufficient voltage regulation. The voltage levels, sensitivity and time delay settings as well as on/off auto tap changing shall be determined by the *DisCo* in consultation with the *Customer* where appropriate.

5.2.9 *Substation* drawings

(1) Engineering drawing requirements are as given in section 5.1.9.

5.2.10 Voltage

(2) Steady state voltage conditions at *DS* busses shall be maintained within the following ranges unless otherwise agreed upon between the *DisCo* and *Customer*:

a. Under normal conditions: $0.95 \text{ p.u.} \leq V_{bus} < 1.05 \text{ p.u.}$

b. Under any single contingency: $0.90 \text{ p.u.} \leq V_{bus} < 1.10 \text{ p.u.}$

c. Multiple contingency: 0.85 p.u. ≤ Vbus < 1.20 p.u.

5.2.11 Apparatus requirements

(1) *Apparatus* at the *PoC* with a *Customer*, *EG* and/or *TransCo* shall comply with the *DisCo's* standards as approved by *the Authority* and/or agreed upon in the *Distribution Licensee's licence* and/or any equivalent national standards.

(2) The *DisCo* shall provide a *Customer* and/or *EG* with the necessary information to enable the *Customer* and/or *EG* to install *Apparatus* with the required rating and capacity.

(3) *DisCos,* their *Customers* and/or *EGs* shall ensure that all *Apparatus* at the *PoC* is maintained at least in accordance with the manufacturers' specifications.

(4) *DisCos,* their *Customers* and/or *EGs* connected to at *MV* and *HV* levels shall retain test results and maintenance records relating to the *Apparatus* at the *PoC* and make this information available if requested by the *DisCo* and/or *Authority*.

6 Protection requirements

(1) This section specifies the minimum protection requirements for *DisCos* and *TransCos* as well as typical settings, to ensure adequate performance of the *TS and DS*.

(2) *TransCos* and *DisCos* shall at all times install and maintain protection installations that comply with the provisions of this section and other relevant sections of this *Code*.

(3) *TransCos* and *DisCos* shall conduct periodic testing of *Apparatus* and systems to ensure and demonstrate that these are performing to the design specifications. Test procedures shall be according to the manufacturers' specifications.

(4) *TransCos and DisCos* shall make available to *Customers*, *Generators* and *EGs* all results of tests performed on *Apparatus* for reasonable requests.

(5) Protection schemes for *TSs* and *DSs* are generally divided into:

a. Apparatus protection.

b. System protection.

6.1 Apparatus protection requirements

6.1.1 Feeders above 70 kV

6.1.1.1 Design standard

(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 in line with EAPP Interconnection *Code* requirements.

(3) Separately fused and monitored DC supplies should be used for Main 1 and Main 2 protections systems.

(4) The Main 1 and Main 2 protection systems should not be identical to avoid the risk of simultaneous protection system failure.

(5) An additional backup 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.

6.1.1.2 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 not set to provide overload tripping.

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

6.1.1.3 Automatic Re-closing

(1) *Automatic re-closing (ARC)* facilities shall be provided on all feeders. Single pole and three-pole tripping as well as high speed *ARC* facilities should be available.

(2) The *SO* shall decide on *ARC* selection based on real time system, environmental constraints and consultation with *Customer*s, with regard to *Apparatus* capabilities and in accordance with the *ARC* philosophy below. All *ARC* settings and methodology shall be implemented by *TransCos* and be made available to *Customer*s on request.

(3) ARC Cycles:

a. Either of the following two ARC cycles for single phase faults shall be used:

i. Double attempt ARC cycle for persistent fault:

1ph fault – 1ph trip – 1ph ARC – 3ph trip – 3ph ARC – 3ph trip – lockout

ii. Single attempt ARC cycle for persistent fault:

1ph fault – 1ph trip – 1ph ARC – 3ph trip – lockout

(4) On some lines the *ARC* should be 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 *Customer*s' request.

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

e. Predominantly radial networks

6.1.1.4 Single Phase ARC

(1) In most applications the dead time of single phase *ARC* is selected to one (1) second but may differ for different system requirements. The *SO* shall define the required single phase ARC switching times with the relevant *TransCos*. The closing of the circuit breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the incident.

6.1.1.5 Three Phase ARC

(1) **Fast ARC:** Fast *ARC* i.e. fast closing of the breaker without checking synchronism, should not be used on the *TS* to avoid stress to the rotating

machines at the *PSs* 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.

(2) **Slow ARC:**

a. The Dead Line Charging (DLC) end is selected in line with Table 4 based on Fault Level (FL) at the connected *Substation*s A and B.

Table 4 Selection of DLC end of the line

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

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

c. On the line between two *PSs* 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.

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

6.1.1.6 Power swing blocking

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

6.1.2 Feeders at 70 kV and below (at TransCo *Substation*s)

6.1.2.1 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 *ARC*. Synchronising relays shall be provided on feeders that operate in "ring supplies" and are equipped with line voltage transformers.

6.1.2.2 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* systems. In isolated applications where *SCADA* systems are not available, overload tripping will be provided. Where overload conditions are alarmed at the *National Grid Control Center (NGCC),* it is the *NGCC's* responsibility to reduce load to an acceptable level as quickly as possible.

6.1.2.3 Automatic re-closing

(1) The *DisCos in collaboration with Customers* shall determine *ARC* requirements. The *SO* may specify additional *ARC* requirements for system security reasons, which could extend beyond *TransCo Substations*.

6.1.2.4 Tele-protection requirements

(1) New distance protection systems shall be equipped with tele-protection facilities to enhance the speed of operation.

6.1.2.5 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 e.g. bushings

c. Overheating

d. Faults external to the transformer

(2) A *TransCo* and/or *DisCo* shall consider the application of the following relays in the design of the transformer/reactor protection system:

a. **Transformer IDMT E/F:** The MV E/F Protection is to discriminate with the feeder back-up E/F Protection for feeder faults

b. **Transformer HV/MV IDMT O/C:** The *SO* 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 between the *SO* and the relevant *TransCo* may be used.

c. **Transformer HV/MV Instantaneous O/C:** 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.

d. **Transformer LV (Tertiary) IDMT/Instantaneous O/C:** 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.

e. **Transformer Current Differential Protection:** 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.

f. **Transformer High Impedance Restricted E/F:** 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 unlikely to occur.

g. **Transformer Thermal Overload:** Winding temperature and oil temperature relays, supplied by the manufacturer are used to prevent *TRFR* damage or life time reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

6.1.2.6 TS busbar and bus-coupler 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.

(2) Bus-coupler and bus-section panels are to be equipped with O/C and E/F protection.

6.1.2.7 TS shunt capacitor protection

(3) All the new HV 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.

(4) 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

g. Ancillary functions as indicated in section 6.1.2.9.

6.1.2.8 Over-voltage protection

(1) Primary protection against high transient over-voltages of magnitudes above 140% of nominal (e.g. induced by lightning) shall be provided by means of surge arrestors.

(2) 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.

(3) Over-voltage protection on shunt capacitors should be set to disconnect capacitors at 110% of nominal voltage with a typical delay of 200 ms to avoid unnecessary operations during switching transients.

(4) Over-voltage protection on feeders should be set to trip the local circuit breaker at a voltage level of 120% of nominal voltage with a delay of one (1) to two (2) seconds.

6.1.2.9 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. A *TransCo* shall consider the following functions for all new protection system designs:

a. **Breaker fail / bus strip:** Each individual protection scheme shall be equipped with breaker fail/bus-strip functionality to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

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

c. **Breaker anti-pumping:** To prevent repetitive closing of the breaker in case of fault in closing circuits, standard protection schemes should provide a breaker anti pumping timer. Circuit breakers are often equipped with their own anti pumping devices. In such cases anti pumping function is not required to be duplicated.

d. **Pantograph isolator discrepancy:** The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarms.

e. **Master relay:** 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.

6.2 System protection requirements

6.2.1 Under-frequency Load Shedding (UFLS)

(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 (UFLS)* relays shall be strategically installed on the *IPS* as determined by the *SO* in consultation with *TransCos*, *DisCos* and *Customers*. The respective asset owners shall pay for the installation and maintenance of these relays.

(3) UFLS relays shall be tested periodically. TransCos, *DisCos* and *Customers* shall submit to the *SO* written reports of each such tests, 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.

6.2.2 Out of step tripping

(1) The purpose for the out-of-step tripping protection is to separate the *IPS* in a situation where a loss of synchronous operation takes place between a *Unit* or *Units* and the *IPS*. 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 *IPS*.

(2) The *SO* shall determine and specify the out-of step tripping functionality to be installed at selected locations by *TransCo*s.

(3) DisCos shall determine and specify the out-of step tripping functionality to be installed at selected locations on their *DSs*.

6.2.3 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 *SO* shall determine and specify the under-voltage load shedding functionality to be installed at selected locations by *TransCos*.

6.2.4 Sub-synchronous Resonance (SSR) protection

(1) Although not a considerable threat to the *IPS* at the moment (small *IPS* with short lines), the possibility of *SSR* in the near future with interconnections to *EAPP members* and other countries in the region could result in conditions where *SSR* may become a problem requiring consideration. The *SSR* condition may arise on a power system where a generator is connected to the *IPS* 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 when larger thermal *Units* are employed. The *SSR* condition is addressed either through protection or mitigation:

a. In the case of protection, a suitable relay shall be deployed as part of the Unit's 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.

b. 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 *Units* shall liaise with the relevant *TransCo* and *SO* regarding *SSR* protection studies. Least-cost solutions shall be determined by the relevant *TransCo* in collaboration with the prospective *Generator* and *SO* in accordance with the *TS* planning and development section of this *Code* (section 7), and implemented by the relevant asset owner.

6.2.5 Protection settings impact on network stability

(1) Minimum clearance times for protection in *TransCo*, *DisCo* or *Customer* networks will be determined on a case by case basis in order to ensure general system stability on the *TS* i.e. to maintain rotor angle, frequency and voltage stability.

(2) *The EAPP Interconnection Code* specifies the minimum fault clearance times on the *EAPP Interconnected TS* can be better than (but no longer than):

a. 80 ms for faults on 400 kV and 500 kV

b. 100 ms for faults at 230 kV and 220 kV

c. 120 ms for faults at 132 kV and below

6.3 Protection systems performance monitoring

(1) To maintain a high level of protection performance and long term sustainability, *TransCos* shall monitor protection performance.

(2) *The Authority* audits as/when required.

(3) Each protection operation shall be investigated for its correctness based on available *Information*. Each *TransCo* and *DisCo* shall provide a report to *Customers* affected by a protection operation and/or the *SO* when requested to do so.

(4) The reliability of protection systems on the *TS* should be at least 99.5% (in line with EAPP requirements for the *EAPP Interconnected TS).*

7 Network planning and development

7.1 Transmission System (TS) planning

(1) This section specifies the technical, design and financial/economic criteria and procedures to be applied by a *TransCo* in the planning and development of its *TS* and to be taken into account by *DisCos* and *Customers* in the planning and development of their own systems. It also specifies the co-ordinated planning responsibility that the *TSO* takes on. It specifies *Information* to be supplied by *Customers* to *TransCos*, and *Information* to be supplied by *TransCos* to Customers as well as Information to be supplied to the *TSO*.

(2) The *TSO* shall assume the central co-ordinated responsibility of planning and development of the *Transmission System*.

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

a. A development on a *Customer/DisCo* system already connected to a *TS*.

b. The integration of new *Generators.*

c. The introduction of a new *TS Substation* or *PoC* or the modification of an existing connection between a *Customer* and the *TS*.

d. The cumulative effect of a number of such developments referred to in clauses a, c and c above by one or more *Customers/DisCos*.

e. The need to reconfigure, decommission or optimise parts of the existing network.

f. Relief of network congestion.

(4) Accordingly, the development of a *TS* may involve work:

a. At a *Substation* where *Customer's/DisCo's Apparatus* is connected to the *TS*.

b. On *TS* lines or other *Apparatus* 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*.

(5) The time required for the planning and development of the *TS* will depend on:

a. The type and extent of the necessary reinforcement and/or extension work

b. The need or otherwise for statutory planning consent

c. The associated possibility of the need for public participation

d. The degree of complexity in undertaking the new work while maintaining satisfactory security and *QoS* on existing *TSs* and the overall *TS*.

7.1.1 Planning process

(1) For the development of a specific *TransCo*'s network, the *TransCo* 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 *QoS* standards.

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

e. Determining the preferred option.

f. Building a business case for the preferred option using acceptable justification criteria.

g. Requesting approval of the preferred option and initiating execution (*the Authority/TSO*).

7.1.2 Identifying the need for network investment

(1) A *TransCo* shall source relevant data from inter alia the following to establish the needs for network strengthening:

a. Integrated Development Plans e.g. National Integrated Resource Plan

b. *Customer/DisCo* information

c. System performance indices

d. *TS* network load forecast

e. Government development plans e.g. Electricity Development Strategy, National Energy Policy and Strategy, Electricity Master Plans

f. *Customer/DisCo* development plans.

7.1.3 Forecasting the demand

(1) A *TransCo* is responsible for producing a *TS* demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years for the relevant TransCos section of the overall *TS*.

(2) A TransCo's *TS* demand forecast shall be determined for each *PoS*. *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* on a *TransCo's* network, a *TransCo* shall use *DisCo* and *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 *DisCos* and *Customers* shall annually, by the end of October, supply their 5-year ahead load forecast data and an estimate for the ten (10) years ahead demand as detailed in the *Information Exchange Code*.

7.1.4 Technical limits and targets for planning process

(1) The limits and targets against which proposed options are checked by a *TransCo* in collaboration with the *TSO* and *SO* shall include technical and statutory limits which must be observed, and other targets, which indicate that the overall *TS* 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.

7.1.4.1 Voltage limits and targets

(1) Technical and statutory limits are stated in Table 5.

(2) For convenience, standard voltages (U_M and U_N) are in included in Table 6.

Table 5 Technical and statutory voltage limits

Description of parameter	Parameter symbol
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 U_m, the highest voltage used at sending-end busbars in planning studies should not exceed 0.98 U_M	**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…: At Maximum Fault Level At 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 *Connection Agreement*)	**0.10 U_N** **U_N ±10%**

Table 6 Standard voltages

U_N (kV)	U_M (kV)	$(U_M-U_N)/U_N$ (%)
400	420	5.00
220	245	11.36
110	123	11.81
66	72.5	9.85
33	36	9.09
11	12	9.09

(3) Target voltages for planning purposes are as in Table 9.

Table 7 Target voltages for planning purposes

Description of parameter	Parameter symbol
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:	**QoS standard**
Maximum negative sequence voltage caused by *Customer* at PCC:	**QoS standard**
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**

7.1.4.2 Other long-term planning targets

(1) ***TS* lines:** Thermal ratings of standard *TS* lines shall be determined and updated from time to time. The temperatures used to derive thermal ratings shall be 90ºC for aluminium conductor steel reinforced (ACSR) 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.

(2) **Transformers:** Standard transformer ratings shall be determined and updated from time to time using IEC specifications e.g. IEC 60076. 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 transformer strengthening, depending on the actual transformer and on load conditions.

(3) **Shunt reactive compensation:**

a. Shunt capacitors shall be able to operate at 30% above their nominal rated current at U_N to allow for harmonics and voltages up to U_M.

b. 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 overall *TS*, the *Participant* shall inform the *SO* before proceeding with the installation or modification.

c. Any *TransCo* wishing to install a new shunt device or series capacitor or modify the size of an existing shunt device or series capacitor, shall at his expense arrange for *SSR*, harmonic and protection coordination studies to be conducted to ensure that *SSR* will not be excited in any generator in the *IPS*.

(4) **Circuit breakers:**

a. 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:

i. Single-phase breaking current: **1.15** times 3 phase fault current

ii. Peak making current: **2.55** times 3 phase rms fault current

7.1.4.3 Reliability criteria

(1) A system cannot be made 100% reliable as planned and forced outages 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) All *TransCos* in collaboration with the *TSO* shall formulate long-term plans for expanding or strengthening the overall *TS* on the basis of the justifiable reliability and redundancy.

7.1.4.4 Contingency criteria

(1) A system meeting the N-1 contingency criterion must comply with all relevant technical limits outlined in section 7.1.4.1 of *this Code* (on voltage limits) and the applicable current limits, under all credible system conditions.

(2) For contingencies considered under various loading conditions it shall be assumed that the appropriate, normally-used, *Generating Units* are in service to meet the load and provide *Operating Reserves* as occurs during actual system operation i.e. appropriate generation pattern should be assumed. 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.

(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.

7.1.4.5 Integration of ***PS*s**

(1) When the integration of *PSs* is planned, the following network redundancy criteria shall apply:

a. ***PS*s of less than 25 MW**

i. With all connecting lines in service, it shall be possible to transmit the total output of the *PS* to the system for any system load condition. If the local area depends on the *PS* for voltage support, the connection shall be made with a minimum of two lines.

ii. Transient stability shall be maintained following a successfully cleared single-phase fault.

iii. If only a single line is used, it shall have the capability of being switched to alternative busbars and be able to go onto bypass at each end of the line.

b. ***PS*s of more than 25 MW**

i. With one connecting line out of service (N-1), it shall be possible to transmit the total output of the *PS* to the system for any system load condition.

ii. The smallest *Unit* installed at the *PS* shall only include *Units* that are directly connected to the *TS* and are centrally dispatched.

c. **Transient stability**

i. Transient stability shall be retained for the following conditions:

1. A three-phase line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous *PS* loading condition; or

2. A single-phase fault cleared in “bus-strip” times, with the system healthy and the most onerous *PS* loading condition; or

3. A single-phase fault, cleared in normal protection times, with any one line out of service and the *PS* loaded to average availability.

4. The above conditions will only apply to *PSs* larger than 25 MW. For *PSs* smaller than 25 MW, the conditions will only apply where it is economically justifiable.

5. The cost of ensuring transient stability shall be carried by the *Generator* if the optimum solution, as determined by the relevant *TransCo* in consultation with *TSO*, results in *Unit* or *PS Apparatus* being installed. In other cases, the relevant *TransCo* shall bear the costs and recover these as per the approved tariff methodology in the *Tariff Code*.

d. **Busbar arrangements**

i. Busbar layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass and not more than 25 MW of generation shall be connected to any bus section, even with one bus section out of service.

ii. The busbar layout shall ensure that no more than 25 MW of generation is lost as a result of a single contingency.

e. **Information**

i. To enable the relevant *TransCo* and *TSO* (via approval) to successfully integrate new *PSs*, detailed information is required per *Unit* and *PS*, as described in the *Information Exchange Code*.

7.1.5 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) A *TransCo* shall only invest in the *TS* when the required development meets the approved investment criteria specified in this section. However, it may be mutually agreed with affected *Customers/DisCos* to waive certain investments.

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

a. Assume a typical project life expectancy of 25 years except where otherwise dictated by plant life or project life expectancy.

b. The following key economic parameters shall have *the Authority* approved process of being established:

i. Discount rate (%)

ii. Cost of Unserved Energy (COUE)

7.1.5.1 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 *Apparatus* redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the Customer Interruption Cost, load shedding, network constraints, poor *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:

Value of improved *QoS* to *Customer*s > Cost 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 improve the *QoS*, the *TransCo* should not invest in the proposed project(s).

(4) The equation above can be stated differently as:

p.a. value (RWF/kWh) x Reduction in EENS (kWh)> p.a. cost (TransCo) reduce EENS (RWF)

(5) The reduction in *Expected Energy Not Served (EENS)* is calculated on a probabilistic basis based on the improvements derived from the investments.

(6) The *COUE* is a function of inter alia 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.

(7) Figure 5 shows a typical load profile, while Figure 6 indicates the EENS for the time period considered. This is in the event of a load growing to 125 MVA whereas the firm transformer rating is 100 MVA.

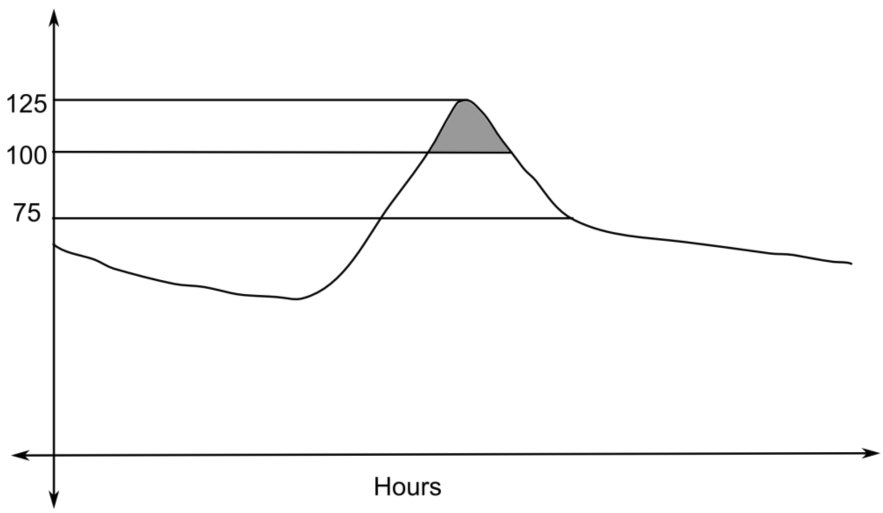

Figure 5 Example Load profile

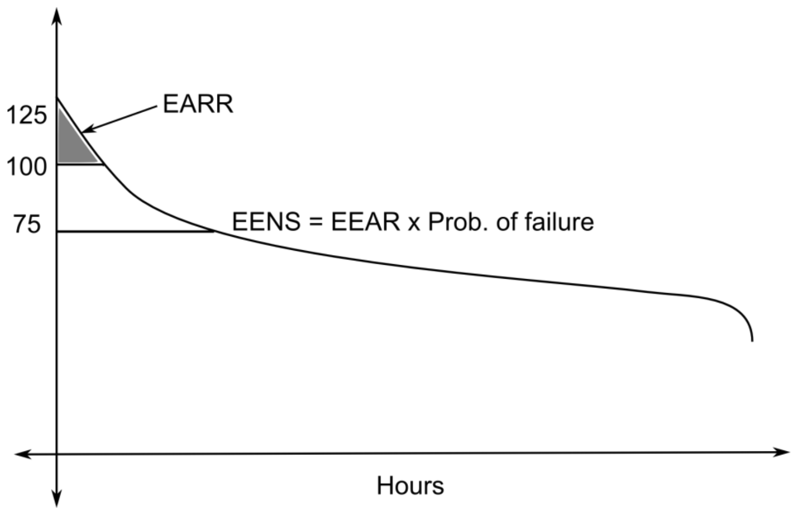

Figure 6 Example load duration curve

7.1.5.2 Cost reduction investments

(1) Proposed expenditure which is intended to reduce a *TransCo's* costs e.g. shunt capacitor installations, telecommunication projects and equipment replacement which reduces 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:

a. Calculate the *net-present value (NPV*) 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.

b. Perform a 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.

c. A resulting positive *NPV* indicates that the investment is justified over the expected life of the proposed new asset.

7.1.5.3 Statutory investments

(2) This category of projects include the following:

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

b. Increased connection with neighbouring countries in the region and *EAPP* requirements to allow the country's *ESI* access to other markets in turn possibly reducing the overall cost of electricity.

c. Projects necessary to meet environmental legislation.

d. Expenditure to satisfy the requirements of the *Labour Law* specifically regulations in terms of occupational health and safety. 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 not of economic benefit to the country.

7.1.6 Development Investigation Reports

(1) *TransCos* shall compile, before any development of the *TS* is approved, a detailed Development Investigation Report which should be submitted to *the Authority/TSO*. 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.

(2) The Development Investigation Report shall be approved in collaboration with the relevant *TransCo* and *TSO/the Authority* before any development commences.

7.1.7 Mitigation of network constraints

(1) *TransCos* have the obligation to resolve network constraints.

(2) Network constraints ("congestion") shall be regularly reviewed by *TransCos* in collaboration with the *TSO*. Economically optimal plans shall be put in place around each constraint, which may involve investment in the *TS*, the purchase of constrained *Generation*, *Ancillary Services* or other agreed upon solutions.

7.1.8 Special requirements for increased reliability

(1) Should a *Customer* require a more reliable or safer connection than the one provided for by a TransCo (a *Premium Supply*), and the *Customer* is willing to pay the total cost of providing the increased reliability in the form of an additional connection charge, the relevant *TransCo* shall meet the requirements at the lowest overall cost.

(2) The *Premium Supply* and the additional connection charges shall be approved in collaboration with the relevant *TransCo, Customer and the Authority/TSO* before any development commences.

7.1.9 Transmission System Development Plans

(1) All *TransCos* shall prepare *TS* development plans with a minimum window period of five (5) years indicating the major capital investments planned (but not yet necessarily approved). These *TS* Development Plans shall be reviewed at the least every 2 years by the *TSO*.

(2) The *TS* Development Plans shall be based on all *Customer* requests received at the time of preparing the plans, network load forecasting, as well as *TransCo* initiated projects.

(3) *TransCos* shall submit their *TS* development plans to the *TSO/the Authority* who will collaboratively approve them. This will allow for centralised co-

ordinated *TS* planning and development as well as a harmonised approach to regional *EAPP* interconnections.

(4) *TransCos* shall publish the latest approved TS Development Plans.

(5) *The TSO* shall submit a consolidated TS Development Plan to *the Authority* for approval

(6) The latest approved consolidated TS Development Plan shall be published by the *TSO*.

7.1.10 EAPP planning coordination

(1) The *TSO* shall be responsible for submitting the required *Power Balance Statement* and *TS Capability Statement* as outlined in the *EAPP Interconnection Code*.

(2) The T*SO* shall provide accurate and appropriate *Apparatus* characteristics and system data for modelling and simulation purposes as required in the *EAPP Interconnection Code*.

(3) The *Power Balance Statement* comprises a forecast of the expected demand and *Generation* over the planning horizon (10 years). This should be submitted by the *TSO* with the required information as detailed in the *EAPP Interconnection Code* timorously.

(4) The required *TS Capability Statement* outlines the capability of the *TS* to support the required energy flows across the Rwandan *TS* and for cross-border *interconnections.* The *TSO shall submit the TS Capability Statement* using data from the common *EAPP* database and shall ensure that the planning process is based on a common set of principles agreed upon beforehand.

(5) The *Power Balance Statement* and *TS Capability Statement* should be submitted in collaboration with the *EAPP Sub-Committee on Planning.*

7.2 Distribution System (DS) planning

(1) Similar to section 7.1 on *TS* planning and development, this section specifies the technical, design and economic criteria and procedures to be applied by a *DisCo* in the planning and development of its *DS* and the involvement of *the Authority* in general co-ordination and regulation of the overall *DS.*

7.2.1 Framework

(1) *DisCos* shall source/develop relevant data from various sources including inter alia the latest versions of the following to establish the need for network strengthening:

a. Integrated Development Plan

b. *Customer* information

c. System performance indices

d. Distribution network load forecast

e. Government development plans e.g. Electricity Development Strategy, National Energy Policy and Strategy, Electricity Master Plan

f. *Customer* development plans

(2) *DisCos* shall annually compile a 10-year load forecast for a *DisCo's* incoming *Points of Supply* including *DisCo's* cross-boundary connections to the relevant *TransCo's* network to which they are connected.

(3) *DisCos* shall be responsible for compiling network development plans with a minimum window period of five (5) years. These network development plans shall be reviewed at the least every 2 years by *the Authority*. 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 during the review process.

(4) The network development plans and post release changes shall be submitted to *the Authority*.

(5) All *DisCos* approved network development plans shall be published.

(6) *TransCos* and the *TSO* shall use the *Information* in approved *DisCo* development plans to perform their network planning responsibilities.

7.2.2 Network investment criteria

7.2.2.1 Introduction

(1) *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.

(2) *DisCos* shall invest in the *DS* when the required development meets the technical and investment criteria specified in this section.

(3) The need to invest must first be decided on technical grounds. All investments must be the least life-cycle cost technically acceptable solution, that is, it shall provide for *Standard Supply*:

a. Minimum QoS requirements defined in *this Code* and by *the Authority*.

b. Minimum reliability and operational requirements as determined by this *Code* and by *the Authority*.

(4) 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.

(5) Calculations to justify investment shall assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

(6) The following key economic and financial parameters shall be determined by *the Authority*:

a. Discount rate

b. *Customer* interruption cost i.e. *Cost of Unserved Energy (COUE)*.

c. Other *Authority* approved economic parameters.

7.2.2.2 General Investment Criteria

(1) Investments should be prudent (justified) as a least life-cycle cost solution after taking into account, where applicable, technical alternatives that consider the following:

a. The investment that will minimise the cost of the energy supplied and the *Customer* interruption cost i.e. *COUE*.

b. Current and projected demand on the network.

c. Reduction of life-cycle costs e.g. reduction of technical losses, operating and maintenance costs and telecommunication projects

d. Current condition of assets and refurbishment and maintenance requirements.

e. Demand and supply options.

f. Any associated risks.

(2) 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 *DisCos* and the *Customer*.

(3) Investments made by *DisCos* dedicated to a particular *Customer* shall be evaluated on a least life-cycle *DisCo* cost. *DisCo* cost will consider only the least-life cycle investment cost to the *DisCo*.

(4) *DisCos* shall evaluate investments in terms of the following categories:

a. Shared network investments.

b. Dedicated *Customer* connections.

c. Statutory investments.

d. International connections (cross-border connections)

7.2.2.3 Least economic cost criteria for shared network investments

(1) Shared network investments are:

a. Investments on shared infrastructure (not-dedicated) assets.

b. Investments required to provide adequate upstream network capacity.

c. Investments required to maintain or enhance supply to attain the relevant QoS and technical limits or targets applicable to *DisCo*s in this *Code*.

d. Refurbishment of existing standard dedicated connection assets.

(2) 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 minimise the cost to the electricity industry and not just to the *DisCo*.

7.2.2.4 Least life cycle cost criteria for standard dedicated *Customer* connections

(1) A standard connection (*Standard Supply*) is defined as the lowest life-cycle costs for a technically acceptable solution and will be charged for as described in the in the *Tariff Code*.

(2) Dedicated *Customer* connections are:

a. New connection assets created for the sole use of a *Customer* to meet the *Customer*'s technical specifications.

b. Dedicated assets are assets that are unlikely to be shared in the DisCo's planning horizon by any other *Customer*.

(3) All dedicated connection investments are to be justified on the technically acceptable least life-cycle costs.

(4) Where the investment meets the least life-cycle cost, the *Customer* shall be required to pay a standard connection charge as described in the *Tariff Code*.

(5) For certain *Customer* groupings, as approved by *the Authority*, the investments shall be justified collectively as per *Customer* grouping and not per *Customer*.

(6) The *DisCo* will refurbish / replace / reconfigure all *Apparatus* in terms of its standards to meet standard *QoS* and technical limits 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*.

7.2.2.5 Investment criteria for premium *Customer* connections

(1) The *DisCo* shall investigate the additional requirements for a premium connection (*Premium Supply*) and will provide a least life-cycle cost solution.

(2) 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 the *Tariff Code*. Such costs shall be appropriately pro-rated, if a

portion of the investment can be justified based on improved reliability or reduction of costs.

(3) The refurbishment of identified premium connection assets will occur when the equipment is no longer reliable or safe for operation. The *DisCo* 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*.

(4) At the time of refurbishment, should the *Customer* have any requirements that cannot be met in terms of clause (5) in section 7.2.2.4, any additional investment will be seen as a *Premium Connection*.

(5) Where the refurbishment of a supply in accordance with current technical standards will result in additional cost to the *Customer*, an engineering solution that minimises the sum of the *DisCo's* and the *Customer's* costs will be found. This least economic cost option will be implemented but any expenditure in excess of the *DisCo* least life-cycle cost solution (as per section 7.2.2.2 and 7.2.2.4) will be borne by the *Customer* through a new *Premium Connection* charge and shall not be recovered through use-of-system (network) charges.

7.2.2.6 Statutory or strategic investments

(1) *DisCos* will be obligated to make statutory investments in terms of clause (3) below.

(2) Statutory and strategic investments will be motivated on a least economic cost basis, as defined in section 7.2.2.3 of this *Code*.

(3) Strategic and statutory projects include the following:

a. Investments formally requested in terms of published government policy but not considered dedicated *Customer*s as under section 7.2.2.4.

b. Projects necessary to meet national environmental legislation.

c. Expenditure to satisfy the requirements on the *DisCo* to comply with appropriate Occupational Health and Safety legislation. This is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to the ESI.

d. Possible compulsory contractual commitments.

e. Servitude acquisition.

f. New *Embedded Generators (EGs)*.

7.2.2.7 Investment criteria for international connections

(1) The investment for international *Customer*s shall be in terms of the criteria set out for a dedicated connection, but the *DisCo* shall charge a connection charge that ensures that there is no cross border subsidies, as set out in the *Tariff Code.*

8 Other Network Services

(1) *Other Network Services* are those mandatory services to ensure a standard of supply that meets *QoS*, reliability and safety standards. *Other Network Services* may be competitive or provided by *TransCos/DisCos* as a monopoly service

(2) *Other Network Services* include the following:

a. Design and construction of dedicated *Customer* connections.

b. Recoverable works such as inspection and maintenance of non-*DisCo* and/or non-*Transmission* owned installations, line relocation and other requested recoverable works.

c. The construction and maintenance of public lighting assets.

(3) For *Other Network Services*, *Customers*, *Generators* and *EGs* shall be allowed to choose a contractor other than the *TransCo/DisCo* or a contractor

appointed by the *TransCo/DisCo*, provided that an agreement is mutually reached between the *TransCo/DisCo* and the *Customer*, *Generator* or *EG* prior to the project being undertaken. Conditions to be included in the agreement can include (amongst other conditions agreed upon):

a. The assets the *Customer*, *Generator* or *EG* is allowed to work on or not.

b. The terms and conditions for the approval of the network design.

c. The terms and conditions for the inspection and the work done prior to any agreement to take over and/or commission the connection.

d. The charges to be raised by the *TransCo/DisCo* for monopoly related services.

(4) The fees charged by the *TransCo/DisCo* for *Other Network* Services may be regulated by *the Authority*.

9 Network maintenance

(1) All *Participants* shall operate and maintain the *Apparatus* owned by them. The cost of such operations and maintenance shall be borne by the respective *Participants* unless such *Apparatus* 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. If no agreement can be found as to who damaged the *Apparatus* under consideration, the dispute resolution process outlined in the *Governance Code* shall be followed.

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

(3) Maintenance scheduling shall be done in accordance with the *System Operations Code*.

(4) *TransCos* and *DisCos* shall agree in writing with *Customers*, details of any special maintenance requirements as well as maintenance co-ordination

requirements per *Transmission Substation and Distribution Substation* respectively. *TransCos* and *DisCos* shall provide *Customers* with details of maintenance plans and practices upon request, if these affect the quality of a connection.

(5) *The Authority* can audit maintenance procedures as/when required.

Appendix A Generator Connection Conditions

Table 8 Summary of the requirements applicable to non-hydro generating *Unit*

Grid Code Requirement		Unit Size S_{MCR} (MVA rating)					
		S_{MCR} <1	1 to 20	20 to 40	40 to 60	60 to 100	$S_{MCR} \geq 100$
Plant availability		-	-	D	D	Yes	Yes
Plant reliability		-	-	D	D	Yes	Yes
Protection	Backup impedance	Yes	Yes	Yes	Yes	Yes	Yes
	Loss of field	-	-	D	D	D	Yes
	Pole slipping	-	-	D	D	D	Yes
	Trip to house load	-	-	-	D	D	Yes
	Generator TRFR backup E/F	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	-	-	D	Yes	Yes	Yes
	Main protection only	Yes	Yes	Yes	-	-	-
	Main protection (monitored) or main and main backup	-	-	-	D	-	-
	Main and backup protection (both monitored)	-	-	-	D	Yes	Yes
Excitation system requirements		Yes	Yes	Yes	Yes	Yes	Yes
	Power System Stabiliser	-	-	-	D	D	D
	Limiters	-	-	D			Yes

Grid Code Requirement		Unit Size S_{MCR} (MVA rating)					
		S_{MCR} <1	1 to 20	20 to 40	40 to 60	60 to 100	$S_{MCR} \geq 100$
Reactive power capabilities		D	D	D	Yes	Yes	Yes
Multiple Unit tripping		-	-	D	If PS > Largest single contingency		
Governing		-	Yes	Yes	Yes	Yes	Yes
Restart after station blackout		-	-	D	If PS > Largest single contingency		
Black start capability		-	-	A	A	A	A
External supply withstand capacity		D	D	If N_{Unit} at PS>5	If PS > Largest single contingency		
OLTC for step-up transformers		D	D	D	Yes	Yes	Yes
Emergency Unit capabilities		D	D	D	Yes	Yes	Yes
Independent action for control in system island		-	-	-	D	Yes	Yes
Automatic underfrequency starting		-	D	D	D	D	D

Key:

D - Depends on system requirements

A - If agreed upon

PS - *PS*

N_{Unit} -Number of *Unit* at a *PS*

Table 9 Summary of the requirements applicable to hydro generating *Unit*

Grid Code Requirement		Unit Size S_{MCR} (MVA rating)					
		S_{MCR} <1	1 to 20	20 to 40	40 to 60	60 to 100	$S_{MCR} \geq 100$
Plant availability		-	-	D	D	Yes	Yes
Plant reliability		-	-	D	D	Yes	Yes
Protection	Backup impedance	Yes	Yes	Yes	Yes	Yes	Yes
	Loss of field	-	-	D	D	D	Yes
	Pole slipping	-	-	D	D	D	Yes
	Trip to house load	-	-	-	D	D	Yes
	Generator TRFR backup E/F	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	-	-	D	Yes	Yes	Yes
	Main protection only	Yes	Yes	Yes	-	-	-
	Main protection (monitored) or main and main backup	-	-	-	D	-	-
	Main and backup protection (both monitored)	-	-	-	D	Yes	Yes
Excitation system requirements		Yes	Yes	Yes	Yes	Yes	Yes
	Power System Stabiliser	-	-	-	D	D	D

Grid Code Requirement		Unit Size S_{MCR} (MVA rating)					
		S_{MCR} <1	1 to 20	20 to 40	40 to 60	60 to 100	$S_{MCR} \geq 100$
	Limiters	-	-	D			Yes
Reactive power capabilities		D	D	D	Yes	Yes	Yes
Multiple Unit tripping		-	-	D	If PS > Largest single contingency		
Governing		-	Yes	Yes	Yes	Yes	Yes
Restart after station blackout		-	-	D	If PS > Largest single contingency		
Black start capability		-	-	A	A	A	A
External supply withstand capacity		D	D	If N*Unit* at PS>5	If PS > Largest single contingency		
OLTC for step-up transformers		D	D	D	Yes	Yes	Yes
Emergency Unit capabilities		D	D	D	Yes	Yes	Yes
Independent action for control in system island		-	-	-	D	Yes	Yes
Automatic underfrequency starting		-	D	D	D	D	D

Key:

D - Depends on system requirements

A - If agreed upon

PS - *PS*

N_{Unit} -Number of *Unit* at a *PS*

Appendix B Sample Generator / Embedded Generator Application Form

Note: This form (or a variant thereof as defined by each *TransCo* and/or *DisCo*) is to be completed in full by all prospective *Generators* or *Embedded Generators* and returned to the relevant *DisCo/TransCo* together with additional requested information for review.

Generator / Embedded Generator Application Form		
	Generator / Embedded Generator:	
	Name of TransCo/*DisCo* :	
1	**Date :**	
2	**Applicant Particulars:** Name of Applicant: Address: Telephone: Facsimile: Email:	
3	**Project Details:** Project Name: Project Location: Project Contact Name & Telephone Number: Facsimile: Project Type:	

4	**Construction Schedule:** Projected Start-up of Construction: Construction Power Requirements: Projected In-Service Date of Embedded Generator:	
5	**Site plan:** Please attach site plan to show inter alia scaled mapping of existing lot lines, road crossings, water services, electricity infrastructure	
6	**Preliminary design (please list as attached):** Design to show inter alia number and size of generators, transformer/s, proposed connection point/s, isolating devices, protection schemes	

7	**Generator specifications:** Manufacturer: Fuel type: Rated MVA: Rated MW: Rated Voltage: Rated Power Factor: Inertial Constant: Maximum MVAR Limit: Neutral to Earth Resistance in Ohms: Xd – Synchronous reactance in p.u: X'd - Direct Axis transient reactance in p.u: X"d – Direct axis sub-transient reactance in p.u: X2 – Negative sequence reactance in p.u: X0 – Zero sequence reactance in p.u	

8	**Generator and *Unit* transformer specifications:** Voltage and power ratings: Windings configuration: Neutral earth resistors or reactors: Positive and zero sequence impedances in p.u: R1: X1: RO: XO:	
9	**Expected Consumption in MWh per year** **(details to be clarified with the relevant *DisCo*/TransCo):**	
10	**Future Site Developments plans:**	
11	**Proposed Plant Design:** Operating characteristics	
12	**Any other additional relevant information (please list as attached):**	

I request the *Transmitter* /*DisCo* to proceed with a preliminary review of this *Embedded Generator/Generator* connection application and I agree to pay the cost associated with completing this review.

I further consent to the Transmitter/*DisCo* providing this *information* to other *Participants (TransCos, DisCos,* *the Authority, SO)* as required (with prior approval from myself).

Name:	____________________________	Signature:	______________________
Title:	____________________________	Date:	______________________

Appendix C   Transmission/Distribution service application form

Transmission/Distribution Service Application Form

Note: Where indicated, shaded areas are for completion by the Transmitter (*TransCo*)/Distributor (*DisCo*). Please provide any additional detail in the areas designated for notes.

Required Service:	
Transmission/Distribution)	

Applicant Contact Person 1:
Applicant's preferred form of address

Applicant Contact Person 1 Initials, Surname and Job Title:	
Initials:	
Surname:	
Job Title:	

Applicant Contact Person 2:
Applicant's preferred form of address

Applicant Contact Person 2 Initials, Surname and Job Title:	
Initials:	
Surname:	
Job Title:	

Company Name:
Officially registered company name

Co/CC Reg. Number:
Officially registered company number

Person 1 Telephone 1:	Person 2 Telephone 1:

Person 1 Telephone 2/Mobile:	Person 2 Telephone 2/Mobile:

Person 1 Fax	Person 2 Fax

Person 1 E-Mail:	Person 2 E-Mail:

Applicant's Physical Address:
*Customer*s physical location
Applicant's Postal Address:
*Customer*s physical location
Physical connection to the *Transmission* system (Y/N):
If not, indicate nature of business e.g. Trader :

Type of quote required (please tick)	Feasibility:		Firm:	

Notes:
Additional Applicant information

The following fields will be completed by the *TransCo/DisCo*

Applicant ID: Unique reference number			Applicant type: e.g. Individual, company, partnership, other	
Existing *Customer*: (Y/N)				

Application Date Initital application date	d d m m y y y y		Connection Voltage kV		Capacity of connection: MVA	
Requested completion date When applicant wants connection to network	d d m m y y y y		Estimated monthly consumption/generation: MWh			
Temporary connection: If temporary, num. of months for which connection is required	m m		Owner or tenant Applicant owns/rents property for this application			

Physical connection address (POS)

Geographical location of connection

Longitude		Latitude

Application category (please circle)				
Industrial	Commercial	Distribution	Generation	International
Other (please specify):				

Nearest existing *Transmission Substation*:
Substation closest to Physical connection address

Other Transmission System Connections:	Standard or premium connection:
Does *Customer* have other transmission connections/points of supply?	

Special instructions:

Cancellation Date	d d m m y y y y
Reason for cancellation:	

Note that further information may be required before a quote can be provided, as described in the Grid *Code*

The following fields will be completed by the *TransCo/DisCo*

Application ID: Unique no for current application		POS ID: Unique no applicable to point-of-supply	

Application Type ID:	NEW	INCR	DECR	CHANGE	LINES		Note: Only 1 application type ID per application
	New connection	Increase of connection to:	Decrease of connection to:	Change of *Customer* only	Existing lines to be moved		
	MVA	MVA	MVA	MVA	MVA	MVA	
	Size of required supply	Size of required supply	Size of required supply	Current supply	Current supply	Size of required supply	

Priority request indicator: Low / Normal / High		Priority request reason Motivation for high/low indicators	
Customer major activity:		Project ID:	
Grid Region:			

Application remarks:

Other Reference numbers: Other applicant applications and/or points of connection	

Quotation Date: Date on which application was completed	d d m m y y y y
Agreement Date:	d d m m y y y y

Date on which agreement was completed	
Connection fee amount (RWF)	
Connection fee reference number Unique number	
Connection fee payment date: Date on which receipt of connection payment	d d m m y y y y

Appendix D Surveying, monitoring and testing of generators

D-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 *PSs* with the *Grid Code*.

b. Provision by *PSs* of *Ancillary Services* which they are required or have agreed to provide.

D-2 Request for surveying, monitoring or testing

(1) The *SO* may at any time issue an instruction requiring a *PS* to carry out a test (although it may not do so more than twice in any calendar year in respect of any particular *PS* 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), at a time no sooner than 48 hours from the time that the instruction was issued, to demonstrate that the relevant *PS* complies with the *Grid Code* requirements.

D-3 Ongoing monitoring of a *Unit*'s performance

(2) *Generators* shall monitor each of their *Units* during normal service to confirm ongoing compliance with the applicable parts of this *Code*. Any material deviations detected must be reported to the *SO* within five working days.

(3) *Generators* shall keep records relating to the compliance by each of their *Generating Units* with each section of this *Code* applicable to that *Generating Unit*, setting out such information as the *SO* and/or *TransCo* reasonably requires for assessing power system performance (including actual *Unit* performance during abnormal conditions).

(4) Within one month after the end of June and December, *Generators* shall provide the *SO* with a report detailing the compliance or non-compliance in any material respect by each of their *Generating Units* with every section of

this *Code* during the previous six-month period. The template for this appears as an Appendix in the *Information Exchange Code*.

D-4 Procedures

D-4.1 Unit Protection System Grid Code Requirement

Parameter	**Reference**	
Protection function and setting integrity study	4.1.1	**APPLICABILITY AND FREQUENCY** **Prototype study:** All new *power stations* coming on line or *power stations* at which major refurbishment or upgrades of protection systems have taken place. **Routine review:** All *generators* to confirm compliance every six years. **PURPOSE** To ensure that the relevant protection functions in the *power station* are co-ordinated and aligned with the system requirements. **PROCEDURE** **Prototype:** *1.* Establish the system protection function and associated trip level requirements from the *System Operator.* 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 and stability calculations for each protection function.

		5. Convert protection tripping levels for each protection function into a per *unit* base. 6. Consolidate all settings in a 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 on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers' information into one document. 11. Submit to the *System Operator* for its acceptance and update. 12. Provide the *System Operator* with one original master copy and one working copy. **Review:** 1. Review Items 1 to 10 above. 2. Submit to the *System Operator* for its acceptance and update. 3. Provide the *System Operator* with one original master copy and one working copy. **ACCEPTANCE CRITERIA** All protection functions are set to meet the necessary protection requirements of the *transmission* and *power station* plant with a minimal margin, optimal fault clearing times and maximum plant availability. Submit a report to the *System Operator* one month after commissioning for a prototype study or six-yearly for routine tests.
Parameter	**Reference**	

Protection integrity tests	4.1.1	**APPLICABILITY** **Prototype test**: All new *power stations* coming on line and all other *power stations* after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified. **Routine test:/Reviews:** All *units* on: item 1 below: Review and confirm every 6 years item 2, and 3 below: at least every 12 years. . **PURPOSE** To confirm that the protection has been wired and functions according to the specifications. **PROCEDURE** 1. Apply final settings as per agreed documentation to all protection functions. 2. With the *unit* off load and de-energised, 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 *unit* at nominal speed, excite *unit* 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 are fully operational and operate to required levels within the relay *OEM* allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard. Submit a report to the *System Operator* one month after test.

D-4.2 Excitation System Grid Code Requirement

Parameter	**Reference**	
Excitation and setting integrity study	4.1.2	**APPLICABILITY AND FREQUENCY** **Prototype study:** All new *power stations* coming on line or *power stations* at which major refurbishment or upgrades of excitation systems have taken place. Also, where localised changes or modifications are done, only affected part or parts shall be covered. **Routine review:** All *power stations* to confirm compliance every six years. **PURPOSE** To ensure that the excitation system in the *power station* is co-ordinated and aligned with the system requirements. **PROCEDURE** **Prototype:** 1. Establish the excitation system performance requirements from the *System Operator*. 2. Derive a suitable model for the excitation system according to IEEE 421.5 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 the *System Operator* for their acceptance. 4. Derive excitation system settings that match the *power station* plant, *transmission* 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 and alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions.

		6. Document the details of the trip levels, stability calculations for each setting and function. 7. Convert the settings for each function into a 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 the signal source. 10. Document the tripping functions for each tripping on one tripping logic diagram. 11. Consolidate the detailed setting calculations, model, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers' information into one document. 12. Submit to the *System Operator* for its acceptance and update. 13. Provide the *System Operator* with one original master copy and one working copy. **Review:** Review items 1 to 10 above. Submit to the *System Operator* for its acceptance and update. Provide the *System Operator* with one original master copy and one working copy update if applicable. **ACCEPTANCE CRITERIA** The excitation system is set to meet the necessary control requirements in an optimised manner for the performance of the *transmission* and *power station* plant. The excitation system operates stable both internally and on the network. Submit a report to the *System Operator* one month after commissioning for a prototype study or five to six-yearly for routine tests, within one month after expiry of the due date.

Parameter	Reference	
Excitation response tests	4.1.2	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. Also, after localised modifications or works have been carried out to the plant that will affect this performance. **Routine test:** All *generators* to perform tests on each *unit* 6-yearly after a major overhaul of plant. **PURPOSE** To confirm that the excitation system performs as per the specifications. **PROCEDURE** • With the *unit* 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 *unit* in the open circuit mode, carry out the large signal performance testing as described in IEEE 421.2 of 1990. Determine time response, ceiling voltage and voltage response. • With the *unit* synchronised and loaded, carry out the small signal performance tests according to IEE 421.2 of 1990. Also carry out power system stabiliser tests and determine damping with and without power system stabiliser. • Document all responses. **ACCEPTANCE CRITERIA** The excitation system meets the necessary control requirements in an optimised manner for

		the performance of the *transmission* and *power station* plant as specified. The excitation system operates stably both internally and on the network. The power system stabilisers are set for optimised damping.

D-4.3 Unit Reactive Power Capability Grid Code Requirement

Parameter	**Reference**	
Reactive power capability	4.1.3	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the reactive power capability specified is met. **PROCEDURE** The *unit* will be required to regulate the voltage on the HV *busbar* to a set level. **ACCEPTANCE CRITERIA** The *unit* shall maintain the set voltage within ±5% of the capability registered with the *System Operator* for at least one hour. Submit a report to the *System Operator* one month after the test.

D-4.4 *PS* Multiple Unit Trip Grid Code Requirement

Parameter	**Reference**	
Multiple- unit tripping (MUT) tests, study and survey	4.1.4	**APPLICABILITY** **Prototype tests/study/survey:** New *power stations* coming on line: items 1 to 5 below. *Power stations* at which 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 stations*: item 5 below every 6 years **Routine testing**: All *power stations*. 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 the 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 *unit*, isolate the 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 a time. Where two supplies feed one common load, isolation of one supply at a time will be sufficient. Confirm 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 with 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 *unit* within the time zones specified in 3.1.5, isolate the *AC* supply to the *UPS* for a period of at least one 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 lightning 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 fuel power *stations* or penstock on hydro *power stations*) 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* that are likely to cause the tripping of more than one *unit* within the *MUT* categories specified in section 3.1.5. 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 as listed in 3.1.5 shall be present. Report to be submitted to the *System Operator* one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.

D-4.5 Governing System Grid Code Requirements

Parameter	**Reference**	
Governing response tests	4.1.5	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* 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*, acting reasonably but not more than 2-yearly. **PURPOSE** To prove that the *unit* is capable of the minimum requirements for governing. **PROCEDURE** *Frequency* or speed deviation to be injected on the *unit* for ten minutes. Real power output of the *unit* to be measured and recorded. **ACCEPTANCE CRITERIA** Minimum requirements of the *Grid Code* are met.

D-4.6 Unit Restart after Station Blackout Capability Grid Code Requirement

Parameter	**Reference**	
Restart after station blackout survey	4.1.6	**APPLICABILITY** **Prototype survey:** New *power stations* or *power stations* at which modifications have been carried out on plant critical to multiple-unit restarting. **PURPOSE** To confirm that a *power station* can restart *units* simultaneously, according to the criteria outlined in section 3.1.7, 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 3.1.7. Document 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 over the year, all stocks are above critical levels.

		Report to be submitted to the *System Operator* one month after commissioning. Routine survey reports to be submitted one month after expiry of the due date.

D-4.7 *PS* Black Start Capability Grid Code Requirement

Parameter	**Reference**	
***Black start*ing**	4.1.7	**APPLICABILITY** **Routine test:** *Power stations* that have contracted under the *ancillary services* to supply *black start* services. Once every three years for a *partial* test and once every six years for a *full* test. **PURPOSE** To demonstrate that a *black start power station* has such capability. **PROCEDURE** • The relevant *unit* of the *power station* shall be disconnected from the system and shut down. • All external auxiliary supplies to the relevant *unit* shall be disconnected. • In the case of a station *black start*, the designated *unit*, shall be started with the relevant *unit* board being energised from an independent *auxiliary supply* within the *power station*. This *auxiliary supply* has to be in shutdown mode until the *alternator* is at a standstill. • The *unit* shall be re-synchronised to the *IPS*. **ACCEPTANCE CRITERIA** The *unit* shall be able to re-synchronise to the *IPS* within 4 hours from the start of the test. A *partial* test shall involve: • Isolation of the *unit* • Starting up of the *unit* from an independent source and • Energizing a defined portion of the *transmission* / *distribution system*.

		A *full* test shall involve: • Isolation of the *unit* • Starting up of the *unit* from an independent source • Energizing a defined portion of the *transmission* / *distribution system* and • The subsequent loading of the unit to prove blackstart capability. Submit a report to the *System Operator* one month after the test. The *System Operator* may request a full re-test in the event of a failed test or to re-test functions that did not meet test requirements.

D-4.8 External Supply Disturbance Withstand Capability Grid Code Requirement

Parameter	**Reference**	
Voltage and *frequency* deviation	4.1.8	**APPLICABILITY** **Prototype survey/test:** New *power stations* coming on line or *power stations* in which major modifications have been made to plant that may be critical to system supply *frequency* or voltage magnitude deviations: item 2 for plants using dip proofing inverters (*DPI).* **Routine testing and survey:** All *power stations*: review items 1 to 3 every six years. Carry out item 3 every six years. **PURPOSE** To confirm that the *power station* and its *auxiliary supply* loads conform to the requirements of supply *frequency* and voltage magnitude deviations as specified in section 3.1.9. **SCOPE OF PLANT OR SYSTEMS** **Critical plant:** Equipment or systems that are likely to cause tripping of a *unit* or parts of a *unit* or that are 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 in section 3.1.6.

		A *unit* or *power station* shall not trip or unduly reduce load for system *frequency* changes in the range specified in section 3.1.6. **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 section 3.1.7. Document findings. Also consider protection and other tripping functions on critical plant. Document all findings. A *unit* or *power station* must not trip or unduly reduce load for system voltage changes in the range specified in section 3.1.7. 3. *Dip proofing inverter (DPI)* integrity testing: *DPIs* or / and any other equipment must be tested according to the *OEM* requirements. Document all results. Report to be submitted to the *System Operator* one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.

D-4.9 Unit Load and De-loading Rate Capability Grid Code Requirements

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** 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. 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.

RWANDA UTILITIES REGULATORY AUTHORITY

(RURA)

THE RWANDA GRID CODE

Metering Code

5 of 7 Code Documents

Version 1.0

RURA, Rwanda

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1 Introduction

(1) The *Metering Code* specifies *Transmission* and *Distribution* tariff and energy trading *Metering* requirements and clarifies responsibilities in terms of *Metering Installations*.

(2) The nationally adopted *Metering* standards e.g. SANS 474:2008, NRS 057:2011, IEC 62056, shall be used as the *Metering* requirements for this *Code*. This *Code* supplements some sections of the nationally adopted standards where these standards are inadequate.

(3) All sections written in this *Code* shall take precedence over the nationally adopted metering standards where disagreements and/or inadequacies exist.

2 Application of the *Metering* Code

(1) This *Code* shall apply to all *Participants* in respect of any *Metering Point* and applicable to:

a. Main *Metering Installations* and check *Metering Installations* used for the measurement of *Active Power/Energy* and *Reactive Power/Energy*

b. The design of the *Metering Installation*

c. The collection of *Metering Data*

d. The provision, installation and maintenance of *Metering Apparatus*

e. The accuracy of *Apparatus* used in the process of *Metering*

f. Testing procedures for *Metering Installations*

g. Storage requirements for *Metering Data*

h. Competencies and standards of performance of *Participants*

3 General Provisions

(1) The *Metering Point* shall be located at the point agreed upon between the *Participants* unless otherwise specified in this *Code.*

(2) *Participants* shall provide *TransCos* and/or *DisCos* (where applicable) with all *Information* reasonably required to enable optimal performance of their *Metering* duties.

4 Responsibility for *Metering* Installations

(1) The relevant *TransCo* or *DisCo* shall ensure that all points identified as *Metering Points* in accordance with Sections 2 and 3 above, have appropriate *Metering Installations*.

(2) The relevant *TransCo* or *DisCo* shall ensure that commissioning, maintenance, auditing and testing of *Metering Installations* are done in accordance with the nationally adopted standards.

(3) *W*here a *TransCo or DisCo* owns the *Substation* or the cable/line at the *Metering Point*, the respective *TransCo* or *DisCo* shall be responsible for providing the *Metering Installation* in accordance with this *Code*.

(4) Where the *Metering Installation* is between *TransCos*, the *TransCos* are to agree which *TransCo* is responsible for providing the *Metering Installation*.

(5) Where *Metering Installations* are between *Customers* (*Large* or *Small*) and *TransCos* or *DisCos* (where applicable), the *Metering Installation* should preferably be installed at the *Point of Supply* which defines the commercial boundary between the *TransCo or DisCo* and the *Customer*. Where this is not possible, the *Metering Point* shall be located at the point agreed between the *relevant TransCo* or *DisCo* and the *Customer*.

(6) Where a *Metering Installation* is between a *TransCo* or *DisCo* and a *Generator* or *Embedded Generator (EG)* (where applicable), the *TransCo* or *DisCo* shall be responsible for the *Metering Installation* whose location shall be agreed upon between the relevant *Participants.* If a *Generator or EG* would like to install an

additional *Metering Installation*, this is allowed. If the additional *Metering Installation* is at the same location as the above *Metering Installation*, the *DisCo* or *TransCo* shall allow access to the relevant location to allow for the installation of the additional *Metering Installation*. The cost of the additional *Metering Installation* shall be for the *Participant* installing the additional *Metering Installation.*

(7) *TransCos* shall be responsible for managing and collecting *Metering Information* on their respective *TSs* i.e. *TransCos* are the *Transmission Metering Administrators (TMAs)* for their respective *TSs.*

(8) *DisCos* shall be responsible for managing and collecting *Metering Information* on their respective *DSs* i.e. *DisCos* are the *Distribution Metering Administrators (TMAs)* for their respective *DSs.*

(9) Upon request from a *Customer, Generator* and/or *EG,* the relevant *TMA* or *DMA* shall provide applicable *Information* to the relevant *Participant* regarding *Metering Installations, Metering Information* and the *TMA* or *DMA Metering* database.

(10) A central co-ordinated database of all *Metering Installations* on the *IPS* shall be kept by the *SO.* It is the sole responsibility of the *SO* to ensure that this central co-ordinated database is kept up to date. The *SO* shall formulate the appropriate processes to ensure this occurs detailing timing of data collection from the *TMAs* and/or *DMAs*, procedures for this and general formatting as well as input fields of the database.

(11) The *SO* shall submit to an audit by the *Authority* when reasonably requested. The *SO* shall allow access by the *Authority* or an officially appointed sub-contractor appointed by the *Authority* to the central database for the audit.

(12) *TMAs* and/or *DMAs* shall submit to an audit by the *SO* and/or *the Authority* when reasonably requested. *TMAs* and/or *DMAs* shall allow access to all applicable *Information* for the audit to the *SO*, the *Authority* or an officially appointed sub-contractor appointed by the *SO* or the *Authority*.

5 ***Metering* installation requirements**

(1) The following requirements shall apply to all *Metering Installations*:

a. The type of *Metering Installation* at each *Metering Point* shall comply with the nationally adopted standard for *Metering* specifications as modified by this *Code* e.g. NRS 057.

b. Each *Metering Point* on the *TS* shall be installed with main *Metering*. There shall be at least one dedicated *Metering* Current Transformer (*CT)* and Voltage Transformer (*VT)* core. All *CTs* installed after the implementation of the *Grid Code* shall have separate main and check *CT* cores.

c. There shall be check metering installed at a Point of Connection (PoC) when agreed upon between *Participants.*

d. The accuracy of *Metering* and recorders shall be in accordance with the minimum requirements of the nationally adopted standard if applicable e.g. NRS 057.

e. Commissioning of the *Metering Installation* and *Metering Data* supporting systems shall take place in accordance with the requirements of the nationally adopted standard if applicable e.g. NRS 057.

f. Both active and reactive power/energy for *Participants* above the *Metering Threshold* shall be measurable without compromising any requirements of this *Code*.

g. Full four quadrant *Metering Installations* shall be installed for *Participants* when active and reactive energy flows in both directions.

h. Two quadrant *Metering Installations* shall be installed for *Participants* where active energy flows in both directions.

i. A *Metering Installation* above the *Metering Threshold* shall be configured to record and store *Metering Data* in half-hourly integration periods.

j. A *Metering Installation* above the *Metering Threshold* shall be able to store *Data* in memory for at least 40 days. *Data* stored in a *Metering Installation* shall be remotely and locally retrievable.

(2) The relevant *TransCo* or *DisCo* above the *Metering Threshold* shall connect a telecommunications medium to *Metering Installations* that will allow for remote downloading of *Metering Data*.

(3) The relevant *TransCo* or *DisCo* above the *Metering Threshold* shall remotely interrogate a *Metering Installation* daily or as mutually agreed upon between the affected *Participants* for appropriate storage and backup at a location other than the location of the *Metering Installation*.

(4) *Metering Installations* shall be visible and accessible, but the access to such shall be authorised by the relevant *TransCo* or *DisCo* unless the *Metering Installation* belongs to the *Participant* seeking access whereupon the *TransCo* or *DisCo* shall allow access upon request.

(5) *TransCos* and *DisCos* shall provide historical Metering *Data* for *Customers*, *Generators* and *EGs* on a secure server upon request.

(6) *TransCos* and *DisCos* shall provide, when required by *Customers*, Generators or *EGs*, real-time *Metering* impulses. The *Customers*, Generators or *EGs* shall bear the installation costs in such an event.

(7) The Metering *Data* retrieval process shall be a secure process whereby *Metering Installations* are directly interrogated to retrieve billing information from their systems. The protocols used to interrogate the *Metering Installations* shall be approved by the *Authority*/*NSA* or an agency acting on their behalf.

(8) In the event of a *Metering Installation* being used for purposes other than *Metering Data*, such use shall not in any way obstruct *Metering Data* collection and accuracy requirements.

(9) *TransCos* and *DisCos* shall communicate the secondary use of all *Metering Installations* to all *Participants* who may be affected by the secondary use of the *Metering Installation*.

(10) No secondary user shall interfere with *VT/CT* circuitry.

(11) Where own *Metering* staff or *Metering Service Providers* (as defined in the nationally adopted standard e.g. NRS 057) are contracted for any work related to *Metering*, the relevant *TransCo* or *DisCo* (where applicable) remains fully accountable to ensure compliance with the requirements of the *Metering Code*. The *TransCo or DisCo* shall thus only appoint own *Metering* staff or *Metering Service Providers* that have the necessary skills and authorisation to install *Metering Apparatus*. The skills requirements as specified in the nationally adopted standard shall be adhered to (NRS 057).

(12) All *Primary* and *Secondary Apparatus* shall be calibrated accordingly before installation as specified in the nationally adopted standard e.g. NRS 057.

6 *Metering Apparatus* maintenance

(1) All *Participants* (*TransCos, DisCos, Generators, EGs, Customers*) shall appoint own *Metering* staff or *Metering Service Providers* that have the necessary skills and authorisation to maintain *Metering Apparatus*. The skills requirements as specified in the nationally adopted standard shall be adhered to e.g. NRS057.

(2) *Metering Installations* shall be maintained according to the requirements and frequency in the nationally adopted standard e.g. NRS 057.

(3) For prepayment *Metering Installations*, the inspection procedure shall be followed as stated in the nationally adopted standard e.g. NRS057.

7 *Metering Apparatus* access

(1) *Metering Apparatus* owned by a *TransCo* or *DisCo* or a *Metering Service Provider* but installed on a *Customer's*, *Generator's* or *EG's* premises shall remain the property of the *TransCo*, *DisCo* or *Metering Service Provider*.

(2) Customers, *EGs* or *Generators* shall not tamper or permit tampering with *Metering Apparatus* owned by themselves, *TransCos*, *DisCos* or any *Metering Service Provider*.

(3) Except with written consent by the owner, access by *Customers*, *EGs*, *Generators* or representatives of these *Participants* to *Metering Installations*, Metering circuits and *Metering Data* shall be restricted to ensure that the integrity of the *Metering Installation* including *Metering* device, *Metering* installation and *Meter Data* are not at risk.

(4) *Customers*, *EGs*, *Generators* or representatives of these *Participants* shall not have direct access to *Metering Installations* owned by *TransCos* or *DisCos* to obtain any *Metering Information* unless in the company of the relevant *TransCo* or *DisCo* and vice versa. Direct access includes access gained by downloading the *Metering Information* from the *Metering Installation* directly through the digital communication interface, or remotely through any communication media, or any other means other than visual access. Requests from *Customers*, *EGs* and *Generators* to read their own *Metering Installations* shall not be unreasonably refused.

(5) Except with written consent by the owner of a *Metering Installation*, any *Customers*, *EGs*, *Generators* or representatives of these *Participants* shall not install any *Metering* Installation or other *Apparatus* integrated into a *TransCo's* or *DisCo's CT* and *VT* Metering circuits, test blocks, terminals, or any portion forming part of the electrical *Metering installation* or vice versa.

(6) *Customers*, *EGs*, *Generators* or representatives of these *Participants* shall provide reasonable access to the Metering *Apparatus* owned and operated by the *TransCo* or *DisCo*, *Metering Service Provider* but installed on the *Customer's*, *EG's* or *Generator's* premises provided an official identification is produced on request and vice versa.

(7) Where the *Metering Installation* is situated in a restricted area as defined in the appropriate legislation, procedure(s) as stated in the nationally adopted standard (NRS047), applicable legislation and/or as agreed between the *Participants* shall be followed to gain access to the *Apparatus*.

(8) Any changes that may affect a *Participant's* authorised and safe access to the *Metering Apparatus* shall be reported as soon as it is brought to either *Participant's* attention and rectified in the appropriate agreed upon timeframe.

8 *Metering Data* retrieval

(1) *TransCos* and *DisCos* shall ensure that the necessary *Data* retrieval *Apparatus* and processes are in place to achieve the Meter read frequency or regularity as required in the nationally adopted standard.

(2) The *Metering Data* retrieval process for *Automated Meter Reading (AMR)* typically on *Large Customers*, *Generators* and/or *EGs* shall be a secure process whereby *Metering Installations* are directly interrogated to retrieve billing *Information* from their memories. The retrieval process shall comply with the requirements in the nationally adopted standard e.g. NRS 071.

(3) Pre-payment *Metering Installations* are excluded from the requirements of this section.

9 *Data* validation and verification

9.1 Data validation

(1) *TransCos and DisCos* shall carry out *Data* validation in accordance with the nationally adopted standard e.g. NRS 057.

(2) Above the *Metering Threshold*, in the event of:

a. electronic access to the *Metering Installation* not being possible.

b. an emergency bypass or other scheme having no *Metering* system.

c. *Metering Data* not being available;

the *TransCo* or *DisCo* may resort to any of the following:

a. Manual *Metering Installation Data* downloading.

b. Estimation or substitution subject to mutual agreement between the affected *Participants.*

c. Profiling (based on among other parameters: geographical location, voltage level, sector specific customers).

d. Reading of the *Metering Installation* at scheduled intervals.

(3) In the event of an estimation having to be made, above the *Metering Threshold* the following shall apply:

a. The *TransCo* or *DisCo* shall produce a monthly report for all estimations made and shall submit this to the *Authority* upon request.

b. No estimation shall be made on three or more consecutive measurement periods, and if such estimation has to be made, the *TransCo* or *DisCo* shall ensure that the *Metering Installations* are downloaded for the billing cycle.

(4) Above the *Metering Threshold,* no more than three measurement periods may be estimated per *Metering Point* per *Month*. If such estimation has to be made, the *relevant TransCo or DisCo* shall ensure that the *Metering Installations* are downloaded for the billing cycle in lieu of the estimated *Data*.

9.2 Meter verification

(1) Above the *Metering Threshold*, in addition to the nationally adopted standard verification requirements e.g. NRS057, *TransCos and DisCos* shall compare Meter readings (advances) with their *Metering Database* at least once a year.

10 *Metering* Database

(1) As the relevant *TMAs* and *DMAs, TransCos and DisCos* respectively shall create, maintain and administer a *Metering Database* containing the following information:

a. Name and unique identifier of each *Metering Installation*

b. The date on which the *Metering Installation* was commissioned

c. The connecting *Participants* at the *Metering Installation*

d. Maintenance history for each *Metering Installation*

e. Telephone numbers used to retrieve *Information* from the *Metering Installation*

f. Type and form of the *Metering Installation* e.g. manufacturer, model

g. Fault history of a *Metering Installation*

h. Commissioning documents for *Metering Installations*

i. Calibration certificates for all *Metering Installations*

j. Information relating to raw and official values as indicated in the nationally adopted standard e.g. NRS 057-4

(2) *TransCos and DisCos* shall retain *Metering Information* for at least five years for audit trail purposes.

11 Testing of *Metering Installations*

(1) Any *Participant* may (upon request) test its *Metering Installation* by an independent accredited agent, in co-operation with the *TransCo or DisCo* concerned. The costs of such tests shall be for the account of the *TransCo or DisCo* concerned unless the *Metering Apparatus* is found to be within specification, in which event the cost shall be borne by the requesting *Participant*.

12 *Metering Data*base inconsistencies

(1) In the event of testing revealing that *Data* in the Metering database is inaccurate, the *TransCo* or *DisCo* shall inform all affected *Participants* and corrections shall be made to the official *Metering Data* and associated billing by mutual agreement between *Participants*.

13 Access to *Metering Data*

(1) Applicable official *Metering Data* shall be made available by *TransCos* and *DisCos* to all authorised *Participants* in a format agreed upon between *Participants*.

(2) *TransCos* and *DisCos* shall publish all formats in which it can provide *Data* to *Participants*. All new formats shall be negotiated between *TransCos and DisCos* and the affected *Participants*.

(3) Non-standard *Data* provision methods shall be provided by *TransCos* and *DisCos* at the expense of the requesting *Participant* as mutually agreed upon between *Participants*.

(4) *TransCos* and *DisCos* shall administer access to *Metering Data* from their own *Metering* database in line with the nationally adopted standard e.g. NRS 057-4.

(5) The *SO* shall administer access to the central database in a similar manner to the nationally adopted standard e.g. NRS 057-4.

(6) All security requirements for *Metering Data* shall be as specified in the nationally adopted standard e.g. NRS 057.

14 Confidentiality of *Metering Data*

(1) Metering *Data* for use in energy trading and/or billing is confidential *Information* and shall be treated in accordance with the *Information Exchange Code*.

15 Customer queries on *Metering* integrity and *Metering Data*

(1) Where *Customers, Generators* or *EGs* indicate they have a query or complaint related to *Metering*, the relevant *TransCo or DisCo* shall comply with the applicable requirements of the nationally adopted standard (NRS 047).

(2) Any *Customers, Generators* or *EGs* may request the *TransCo* or *DisCo* or *Metering Service Provider*, to test a *Metering Installation*. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of

the *TransCo* or *DisCo* unless the *Metering Installation* is found to be within specification, in which event the cost shall be borne by the requesting *Participant*.

(3) A *Customer, Generator* or *EG* may request an independent audit of *Metering Installations* done by an agent or *Metering Service Provider*. The appointed agent or *Metering Service Provider* shall be mutually agreed upon between the two *Participants*. The requesting *Participant* shall be responsible for any costs of the audit unless the *Metering Installations* are proved to be outside the defined standards.

(4) If errors are found with the *Metering* after testing or auditing, the *Customer's, Generator's* or *EG's* account will be adjusted according to the rectified *Data*.

(5) An audit result shall be submitted to the *TransCos* and/or *DisCos* and they shall respond to the *Customer, Generator* or *EG* within 30 calendar days on any account or *Metering* adjustments proposed in the audit report.

(6) *Customers, Generators* or *EGs* shall have the right to request an audit of the settlement process related to their account and the right to choose an independent agent qualified to perform the audit.

(7) Should no agreement be reached on account or *Metering* disputes between the *Customers, Generators* or *EGs* and the *TransCos or DisCos,* the dispute resolution procedure shall be followed as stipulated by in the *Governance Code*.

RWANDA UTILITIES REGULATORY AUTHORITY

(RURA)

THE RWANDA GRID CODE

Information Exchange Code

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Version 1.0

RURA, Rwanda

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1 Introduction

(1) The *Information Exchange Code* defines the reciprocal obligations of *Participants* with regard to the provision of *Information* for the implementation of the *Grid Code*. The *Information* requirements, as defined for all *Participants*, are necessary to ensure non-discriminatory access to the *Transmission System (TS)* and *Distribution System (DS)* and the safe, reliable provision of *Generation, Transmission* and *Distribution* services.

(2) The *Information* requirements are divided into:

a. Planning *Information*

b. Operational *Information*

c. 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.

(4) The appendices relevant to this *Code* are in a separate document and should be referred to as required.

2 *Information* Exchange interface

(1) The *Participants* shall identify the following for each type of *Information* exchange:

a. The name and contact details of the person(s) designated by the *Information Owner* to be responsible for provision of the *Information*.

b. The names, contact details of, and the *Participants* represented by persons requesting the *Information*.

c. The purpose for which the *Information* is required.

d. The *Participants* shall agree on appropriate procedures for the transfer of *Information*.

(2) With reference to the *Distribution System (DS)*, *Participants* with installed capacity of more than the *Metering Threshold* shall exchange *Information*, prior to commissioning, of new or altered *Apparatus* connected at the *Point of Connection* or changes to the operational regimes that could have an adverse effect on the *DS* to enable proper modifications to any affected *Participants* networks and related systems.

3 System planning *Information*

(1) *Large Customers, Embedded Generators (EGs)* and *GenCos* shall provide such *Information* as *TransCos* and *DisCos* (where appropriate) reasonably request on a regular basis for the purposes of planning and developing the *TS* and *DS*. *Large Customers, EGs* and *GenCos* shall submit the *Information* to the *TransCos* and *DisCos* without unreasonable delay. Such *Information* may be required so that *TransCos* and *DisCos* can plan and develop *TS* and *DS* systems accordingly, monitor current and future power system adequacy and performance as well as fulfil their statutory or regulatory obligations.

(2) *Small Customers,* selected *Large Customers* and *EGs* shall provide such *Information* as *DisCos* reasonably request on a regular basis .without unreasonable delay for the purposes of planning and developing the *DS* and as required to fulfil their statutory or regulatory obligations.

(3) *TransCos* and *DisCos* (where applicable) shall provide the above *Information* where appropriate to the *TSO* for purposes of system wide and coordinated modelling and studying of the behaviour of the *IPS*.

(4) *Participants* shall submit to the *TransCos and DisCos* the *Information* listed in Appendix 2 (for *DisCos* or *Customers*) or Appendix 3 and Appendix 9 (for *GenCos). TransCos and DisCos* may request additional *Information* when reasonably required.

(5) *TransCos* shall provide *GenCos* with *Information* about *Apparatus* and systems installed in HV yards as defined in Appendix 10.

(6) *DisCos* shall provide *EGs (EGs)* with *Information* about *Apparatus* and systems installed in *LV, MV and HV* yards as defined in Appendix 10.

(7) *TransCos* and *DisCos* shall keep an updated technical database of their *TSs* and *DSs* for purposes of modelling and studying the behaviour of their *TSs* and *DSs* respectively.

(8) The *TSO* shall keep an updated technical database of the *IPS* for purposes of modelling and studying the behaviour of the *IPS*. This database shall include appropriate data for surrounding international networks where interactions will have an effect on the *IPS*.

(9) As described in the *Network Code, TransCos* shall provide *Large Customers, GenCos* and *DisCos*, upon any reasonable request, with any relevant *Information* that they require to properly plan and design their own networks/installations or to comply with their obligations in terms of the *Grid Code*.

(10) As described in the *Network Code, DisCos* shall provide *Customers* and *EGs*, upon any reasonable request, with any relevant *Information* that they require to properly plan and design their own networks/installations or to comply with their obligations in terms of the *Grid Code.*

(11) *Customers*, *GenCos* and *EGs* shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *TransCos and/or DisCos* with *Information* relating to the data given in Table 1.

Table 1 Data required for commissioning a new/upgraded connection (TS or DS)

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 Code* and *Tariff Code* requirements)
Location map	Upgrades: Name of existing *PoC* 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 PoC to be specified
Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed PoC, and where applicable, the *Transmission/Distribution* line route from the facility boundary to the *PoC*, clearly marked
Electrical single-line diagram	Provide an electrical *Single Line Diagram (SLD)* of the *Customer* intake substation

(12) *TransCos and DisCos* may estimate any system planning *Information* not provided by a *GenCo*, *DisCo*, *EG* or *Customer*. *TransCos* and *DisCos* shall take all reasonable steps to reach agreement with *above Participants* on estimated *Data* items. *TransCos* and *DisCos* shall indicate to the relevant above *Participant* any *Data* items that have been estimated. The obligation to ensure the correctness of *Data* remains with the *Information owner* providing the *Information*.

(13) *GenCos* and *EGs* shall submit weekly to the relevant *TransCos* and/or *DisCos* as well as the *System Operator (SO)* (where applicable) all the maintenance planning *Information* detailed in Appendix 4 with regard to each *Unit* at each *Power Station (PS)*.

(14) *TransCos* and *DisCos* shall provide the approved monthly rolling maintenance schedule (approved by the *SO*) to *Customers*, *GenCos* and *EGs*

where appropriate for all planned work in *Substations* for a period of one year in advance.

(15) As required by the *EAPP Interconnection Code,* it is the *TSO's* responsibility to provide the relevant *Information* to *EAPP Sub-Committees* (*EAPP Sub-Committee on Planning* and/or *EAPP Sub-Committee on Operations).* Relevant *Information* includes the *Information* required for modelling and analysis of the steady-state and dynamic behaviour of the *EAPP Interconnected Transmission System.* More specifically, this *Data* includes*:*

a. Basic *Data*: Electrical characteristics and ratings of *Transmission Apparatus (Substations, Generating Units, AC Transmission* lines*,* HVDC *Transmission* lines*,* transformers, reactive compensation and interchange schedules) for each year up to ten (10) years ahead.

b. Study *Data*: Demand *Data* including the distribution of demand across individual *TS* nodes, generation patterns, evaluation of *Transmission* capacity, interchanges with *EAPP* and non-*EAPP* members, thermal ratings of *Transmission Apparatus,* timing *of new Apparatus* and outage schedules and a list of appropriate contingencies.

4 Operational *Information*

4.1 Pre-commissioning studies

(1) *Customers*, *Generators* and *EGs* shall meet all system planning *Information* requirements before the commissioning test date (this includes 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 *SO* in collaboration with the relevant *TransCo* or *DisCo* shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified *Apparatus* to the *TS* or *DS (including Customers, Generators* and *EGs)*, using supplied *Data* in accordance with section 3 of this *Code*, to verify that all control systems and *Apparatus* functions are correctly tuned and planning criteria have been satisfied.

(3) *The SO* in collaboration with the relevant *TransCo* or *DisCo* may request adjustments from the asset owner 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 *Apparatus*. *Information* shall be made available within a reasonable time on request from the *SO* and relevant *Participants* upon notification of such a request.

4.2 Commissioning and notification

(1) The relevant *Participants* shall ensure that exciter, turbine governor, *FACTS* and *HVDC* control system settings are implemented and are as finally recorded by the *SO* prior to commissioning.

(2) *Participants* shall give the *SO* notice, as defined in the *System Operations Code*, of the time at which the commissioning tests will be carried out. The *SO* and the *Participant* shall agree on the timely 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 *Apparatus* and shall be made available, within a reasonable time, to the *SO* upon notification of such a request.

(4) The asset owner shall communicate changes made during an outage to commissioned *Apparatus* to the *SO* and the relevant *TransCo or DisCo*, before the *Apparatus* is returned to service. The *TransCo or DisCo* shall keep commissioning records of operational *Data* as per Appendix 5 for the operational life of the *Apparatus* connected to the *TS* or *DS*.

4.3 General Information Data acquisition Information requirements

(1) Measurements and indications to be supplied by *TransCos, GenCos, DisCos, EGs* and *Large Customers* where appropriate to the *SO* 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 a *Participant* shall report this and restore or correct the signals and/or indications as soon as is reasonable as agreed with the *SO*.

(2) The *SO* shall notify a *Participant* (if applicable), where the *SO*, acting reasonably and in consultation with the *Participant*, determines that additional measurements and/or indications in relation to a *Participant's Apparatus* 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*. On receipt of such a notification from the *SO* the *Participant* shall promptly ensure that such measurements and/or indications are made available at the *Apparatus'* communications Gateway *Apparatus*.

(3) The *Data* formats to be used and the fields of *Information* to be supplied to the *SO* by various *Participants* are defined in Appendix 5.

(4) *TransCos and DisCos* shall provide periodic feedback to *GenCos, EGs* and *Customers* regarding the status of *Apparatus* and systems installed in *Substations* (where appropriate) where *GenCos, EGs* and *Customers* are connected to the relevant TransCo's *TS* or DisCo's *DS*. This feedback shall include results from tests, condition monitoring, inspections, audits, failure trends and calibration. The frequency of the feedback shall be determined in agreement between the *Participants*, but will not exceed one year. These status reports will also include contingency plans where applicable.

(5) The *SO* needs to inform *Customers* where out-of-step relays are installed and how the relays are expected to operate. Furthermore, the characteristics of the resultant islanded networks shall be provided by the *SO*, based on the most probable local network configuration at such a time.

(6) The cost of installation of *Data Terminal Equipment (DTE)* will be paid for by the relevant *Participant*.

(7) The *Participant* shall decide on the location of the *DTE*.

(8) The *Participant* will be responsible for the maintenance of communications links between *Generating Unit* Gateways and the *DTE*.

(9) The *SO* shall be responsible for the maintenance, upkeep and communication charges of the *DTE*.

4.4 *Unit scheduling*

(1) The *SO* shall create the *Data* defined in Appendix F for unit scheduling.

4.4.1 Schedules

(1) The *SO* shall define the next day's twenty-four (24) hour day-ahead energy schedule based on the principles defined in the *System Operations Code* and this shall be given to all relevant *Participants* before 15:00 on the day before dispatch.

(2) The *SO* shall define the daily twenty-four (24) hours day-ahead *Ancillary Service* schedule and this shall be given to all relevant *Participants* before 15:00 on the day before dispatch.

(3) All *Information Exchange* requirements for *Ancillary Services* that are contracted annually shall be included in the relevant contracts between *Participants*.

4.4.2 File transfers

(1) The format of the file used for *Data* transfer through file transfers shall be negotiated with the *SO*. The *Data* shall be made available in a common, electronically protected directory. All file transfer *Data* shall be fetched by the *SO*. File transfer requirements are briefly summarised in Table 2.

Table 2 File transfer requirements

File	Description	Trigger Event	Frequency
Dispatch schedule	The combined 24-hour day-ahead energy and ancillary services schedules. Hourly day-ahead contracts for different market categories that identify the unit with the next 24 hourly values for it	Generation dispatch schedule	Daily

4.5 Participants inter control centre communications

(1) Applicable *Customers, Generators*, *EGs*, *DisCos* and *TransCos* shall ensure that they provide the *SO* with network *Information* that is considered reasonable for the security and integrity of the *IPS* on request.

(2) The *SO* shall communicate network *Information* as requested to *Customers, Generators*, *EGs*, *DisCos* and *TransCos*, as required for safe and reliable operation of the *IPS*.

(3) The *Information* exchanged between *Participants* shall be electronic and/or paper-based, and within the time frame agreed upon between the *Participants*.

(4) The *Participants* shall optimise redundant communications where required for the safe operation and control of the *IPS*.

4.6 Communication facilities requirements

(1) The minimum communication facilities for voice and *Data* that are to be installed and maintained between the *SO* and *TransCos, Large Customers, GenCos and DisCos* shall comply with the applicable *IEC* standards for *SCADA* and communications *Apparatus*.

(2) The communication standards shall be set and documented by the *SO*, acting reasonably, in advance of design. Any changes to communication facility standards impacting on *GenCos*, EGs, *Customers* and/or *DisCos Apparatus* shall be designed in consultation with *GenCos*, EGs, *Customers* and/or *DisCos* and shall be informed by a reasonable business motivation.

4.6.1 Telecontrol

(1) The *Information* exchange between *Participant's Apparatus* shall support *Data* acquisition to and from a *Power Station's* Gateway. The *SO* shall be able to monitor the state of the *IPS* via telemetry from the *Gateway* connected to the *Participant's Power Station*.

(2) Signals and indications required by the *SO* are defined in Appendix 5, together with such other *Information* as the *SO* 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 *SO*. The provision and maintenance of the wiring and signalling from the *Participant's Apparatus* 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 *National Grid Control Centre (NGCC)* and, as reasonably required, to the emergency control centre of the *SO*. Any changes to telecontrol requirements impacting on *Participant Apparatus* shall be designed in consultation with *Participants* and shall be informed by a reasonable business motivation.

4.6.2 Telephone/facsimile

(1) Each *GenCo* and *EG* (where applicable) 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 *SO* 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 *SO* 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) *Participants* shall provide the *SO* 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 *SO.*

4.7 SCADA and communication infrastructure at Points of Connection

4.7.1 Access and security

(1) The *SO* shall agree with the relevant *Participants* the procedures governing security and access to the *Participants' SCADA*, computer and communications *Apparatus*. The procedures shall allow for adequate access to the *Apparatus* and *Information* by the *SO* or its nominated representative for purposes of maintenance, repair, testing and the taking of readings/measurements.

(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 *Participants*, and shall disclose that person's name and contact details to the *Authority*. A *Participant* 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 *SO* shall ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence across the *IPS*.

4.7.3 Integrity of installation

(1) Where electrical *Apparatus* does not belong to a *TransCo or DisCo*, the *TransCo* or DisCo shall enter into an agreement with a *Participant* for the provision of reliable and secure facilities for the housing and operation of *TransCo and DisCo Apparatus*. This includes access to, at no charge to the relevant *TransCo or DisCo*, 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 *Participants* 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 *Participants*.

(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 their 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) *Participants* 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) *Participants* shall store outage planning *Information* as defined in section 3 clause (13) and (14) electronically for at least five (5) years. Other system planning *Information* as defined in section 3 shall be retained for the life of the *Apparatus* concerned, whichever is the longer.

(7) The *SO* shall archive operational *Information*, in a historical repository sized for three (3) years of *Data*. This *Data* shall include:

a. *TS* time-tagged status *Information*, change of state alarms, and event messages.

b. Hourly scheduling and energy accounting *Information*.

c. *SO* 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 Common IPS information

(1) The *SO* shall provide all *Participants* with the following *Information* on a daily basis::

a. Hourly system total MW loading.

b. Hourly individual power station MW sent out.

c. Hourly system constraints and constrained generation.

d. Hourly international tie-line power flows.

e. Pre-determined system load flow *Data.*

5.1.1 Generation settlement

(1) The appropriate *TradeCos* (including *NEP (Trader)* as the *GenCo* of last resort i.e. balancing responsibility) shall settle generation with *GenCos* based on their bilateral agreements and on ex post *Information* from the *SO* or their appropriate *Metering Apparatus.*

(2) The above *Participants* shall make this *Information* available to the relevant *Participants*, within an agreed time period. Should this *Information* be classified as confidential, *Participants* shall treat it accordingly.

5.1.2 Ancillary Services settlement

(1) The *SO* has the sole responsibility for securing *Ancillary Services* and accordingly shall request all *Data* required for settlement of *Ancillary Services* from *TransCos, DisCos, Generators,* appropriate *EGs* and *Customers*. These *Participants* shall make this *Information* available, within an agreed time period to the *SO*. Should this *Information* be classified as confidential, *Participants* shall treat it accordingly.

5.1.3 Additional unit post dispatch Information

(1) The *SO* shall provide operational *Information* regarding *Unit* dispatch and overall dispatch performance as specified in Appendix 7.

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 *Participants* involved.

(2) *Participants* shall keep the agreed number of files for backup purposes so as to enable the recovery of *Information* in the case of communication failures.

(3) Typical file transfers between the *SO* and *Generators* are given in Table 3.

Table 3 Typical file transfers between *SO* and Generators

File	Description	Trigger Event	Frequency
Energy dispatch instructions	Record of Energy Dispatch Instructions sent to Generators from the SCADA system including AGC	Ongoing file appended at the end of the hour	Daily
Ancillary Service Dispatch Instructions	Record of Ancillary Service Dispatch Instructions sent to Generators from the SCADA system including AGC	Ongoing file appended at end of hour	Daily
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 *SO* 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 Customer performance

(1) *Where appropriate, EGs* shall provide sufficient *Information* to *DisCos* to ensure that DisCo's performance indices (as defined in the *Network Code)* are satisfactory.

(2) The performance measurements of all *DisCos* and relevant *Customers* shall be supplied to the *SO* in accordance with the operating agreement requirements as defined in the *Network Code*.

(3) *DisCos* and *TransCos* shall report periodic testing of *Under-Frequency Load Shedding (UFLS)* relays in the format given in Table 4.

Table 4 Under Frequency Load Shedding (UFLS) reporting and testing format

<table>
<tr><td colspan="5">TransCo/DisCo Name:
Date:
Substation Name:
Fed from which Transmission Substation (directly or indirectly):</td></tr>
<tr><td></td><td colspan="2">Activating frequency</td><td colspan="2">Timer setting</td></tr>
<tr><td></td><td>Required</td><td>As tested</td><td>Required</td><td>As tested</td></tr>
<tr><td>Stage 1</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Stage 2</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Stage 3</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Stage 4</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td colspan="2">Feeders selected (required)</td><td colspan="2">Feeders selected (as tested)</td></tr>
</table>

Stage 1		
Stage 2		
Stage 3		
Stage 4		

5.3.3 *TransCo* performance

(1) *TransCos* shall make the *TS* performance indicators *Information* given in Table 5 available monthly to the *SO, the Authority*, *DisCos*, *GenCos* and relevant *Customers*.

Table 5 TransCo performance information to be made available

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				
SAIDI				
SAIFI				
SAIRI				
TS losses				%

(2) *TransCos* shall provide *DisCos* and *Customers* with all performance indicators at each *Point of Supply* in accordance with section 4.3 of the *Network Code*.

5.3.4 System operational performance *Information*

(1) The following *IPS* operational *Information* shall be published by the *SO* to all *Participants*:

a. Daily:

i. The hourly actual demand of the previous day (MW)

ii. Hourly *Primary Response* reserve amounts of the previous day (MW)

b. Monthly:

i. Power (MW) generated

ii. Power (MW) imported

iii. Power (MW) exported

iv. Power (MW) available for distribution/sale

v. Overall *TS* losses.

vi. Each *Power Station's* availability

vii. *Secondary Response* reserve hours deficit over total hours

viii. Number of frequency excursions: $f > 51.0$ Hz or $f < 49.0$ Hz

ix. For each abnormal network condition the action taken by the *SO* to restore normal operations

x. Network constraints (details to be defined by the *Authority*)

c. Annually:

i. Annual *IPS* peak (MW), date and hour

ii. Annual *IPS* minimum (MW), date and hour

(2) *TransCos* shall make available all *Information* collected via recorders installed at *Substations*, to the *SO* for analysis. The *SO* shall make this *Information* available to affected *Participants* on request.

6 Confidentiality of *Information*

(1) *Information* exchanged between *Participants* governed by this *Code* shall not be confidential, unless otherwise stated.

(2) Confidential *Information* shall not be transferred to a third *Participant* without the written consent of the *Information Owner*. *Participants* shall observe the proprietary rights of third *Participants* for the purposes of this *Code.* Access to confidential *Information* within the organisations of *Participants* shall be provided as reasonably required.

(3) *Participants* 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, is provided. A sample Confidentiality Agreement is included in Appendix 1.

(5) *Participants* shall take all reasonable measures to control unauthorised access to confidential *Information* and to ensure secure *Information* exchange. *Participants* 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*).

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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 Customer data

Unless otherwise indicated, the following information shall be supplied to the *TransCos* (*System Operator*) 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 and probabilistic 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 switchbays 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 capacitors) 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_{Trans}
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_{Trans}
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_{Trans} % on rating MVA_{Trans} % on rating MVA_{Trans}
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 10 Mvar connected to or capable of being connected to a customer network, the customer shall inform the *TransCo* (or System Operator) and, if required, shall provide the *TransCo* (or System Operator) with the specific shunt capacitor or reactor data as well as network details necessary to perform primarily harmonic resonance studies. The customer shall inform the *TransCo* (or System Operator) of his intention to extend or modify this equipment.

If any participant finds that a capacitor bank of 10 Mvar or less is likely to cause harmonic resonance problems on the *TS*, he shall inform the *TransCo* (or System Operator). The 10 Mvar minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and the *TransCo* (or System Operator) 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 10 Mvar or less no longer cause harmonic resonance problems on the TS, the *TransCo* (or System Operator) 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	
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

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 STATCON (static condenser), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power 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, STATCON, 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 the *TransCo (or System Operator)* 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 multicircuit 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)	Ohmic 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 the *TRANSCO* 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)

	Units
Maximum continuous generation capacity:	MW
Maximum continuous sent out capacity	MW
Unit auxiliary active load	MW
Unit auxiliary reactive load	MVAr
EL1	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, 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 modelled 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: instantaneous reserve, regulating reserve, emergency reserve, ten (10) minute reserve and supplemental 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 Direct axis open-circuit sub-transient Quad axis open-circuit transient Quad axis open-circuit sub-transient Direct axis short-circuit transient Direct axis short-circuit sub-transient Quad axis short-circuit transient Quad axis short-circuit sub-transient	 Tdo' Tdo'' Tqo' Tqo'' Td' Td'' Tq' Tq''	 sec sec sec sec sec sec sec 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 the *TRANSCO* 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 the *TRANSCO* 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, the *TRANSCO* 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 *TRANSCO* 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

.

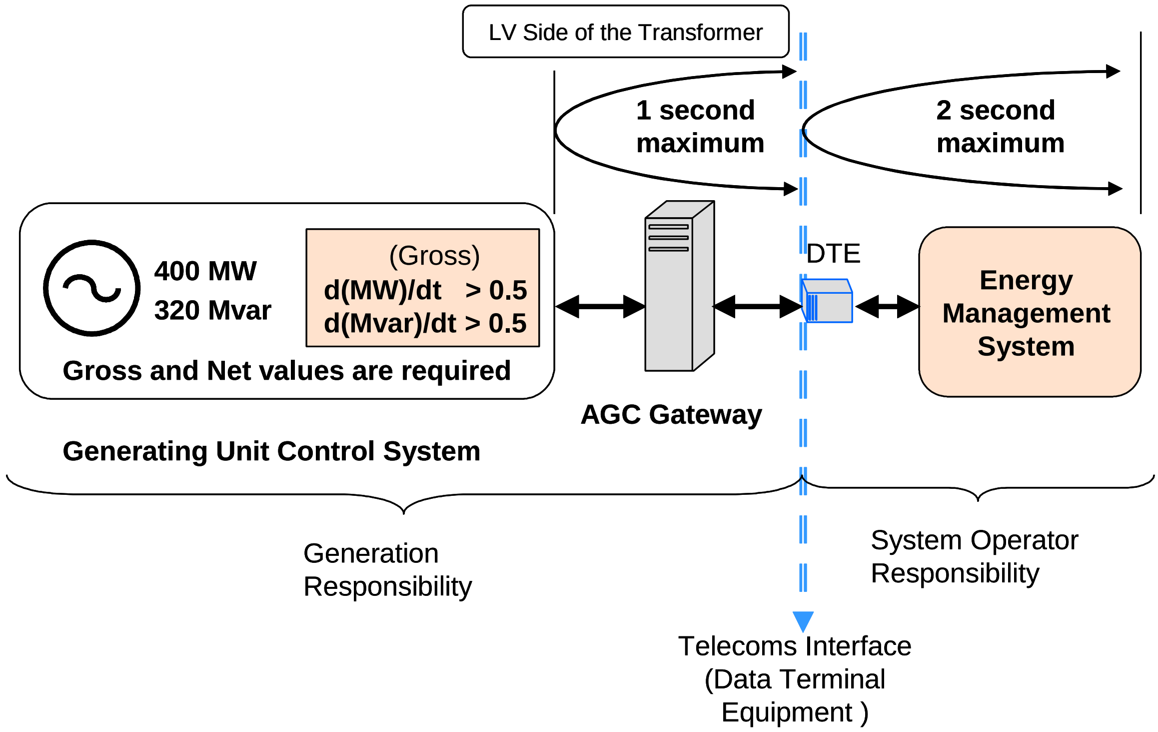


Figure 1 - Data collection time frame

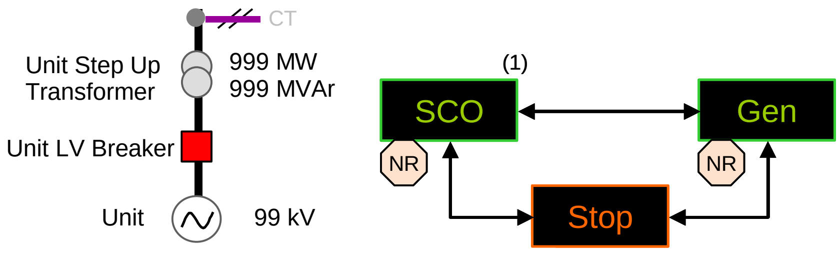
Data Acquisition

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



[1]

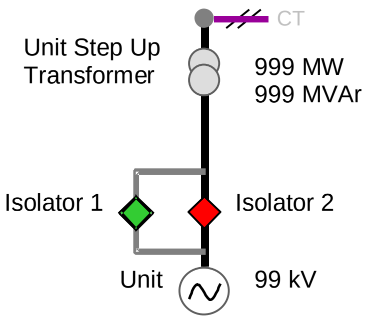
Unit Analogs			**Category**	**Type**	**Control**
Frequency			Info	Analog	
Gross MW			Info	Analog	
Gross Mvar			Info	Analog	
Net MW			Info	Analog	
Net Mvar			Info	Analog	
Rotor RPM			Info	Analog	
Stator kV			Info	Analog	

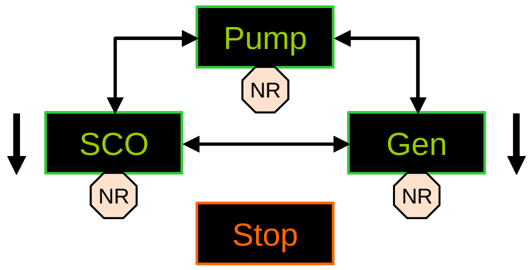
Unit Status Points	01_State	10_State	Category	Type	Control
Engine A	Ready	Not ready	Health	Single	
Engine B	Ready	Not ready	Health	Single	
GEN to SCO mode	Active	Off	Info	Single	True
SCO to GEN mode	Active	Off	Info	Single	True
Remote control	On	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	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

[1] Note that where modes or functions are not available, such as *SCO,* the associated signals are not required.

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]

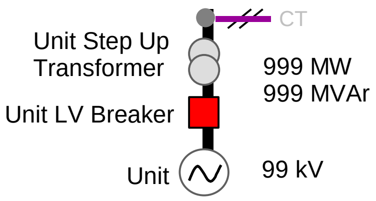
1.1 Unit Analogs			Category	Type	Control
Frequency			Info	Analog	
Gross MW			Info	Analog	
Gross Mvar			Info	Analog	
Net MW			Info	Analog	
Net Mvar			Info	Analog	
Stator kV			Info	Analog	
Rotor RPM			Info	Analog	

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	
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	

[2] Note that where modes or functions are not available, such as *SCO*, the associated signals are not required.

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	

(d) *System Operator* to and from *Power Station* signals

All manned *Power Stations* shall receive and provide the following signals to the *System Operator*:

System Operator to Power Station	01_State	10_State	Category	Type	Control
Reschedule	Initiate	Cancel	Info	Double	True
Emergency	Initiate	Cancel	Info	Double	True

Power Station to System Operator	01_State	10_State	Category	Type	Control
Reschedule Initiated	Acknowledge	No	Info	Double	
Emergency Initiate	Acknowledge	No	Info	Double	
Emergency Cancel	Acknowledge	No	Info	Double	

Signal Description

The *System Operator* staff initiates the action by activating the control function in the control room. The activation signal is sent via the BME to the *Generator* for action by the *Generator* staff. Note that once the *Emergency* signal has been sent to a *Generator*, and it has not been cancelled, the *Generator* should remain aware of the requirement to assist in delivering *Emergency* support.

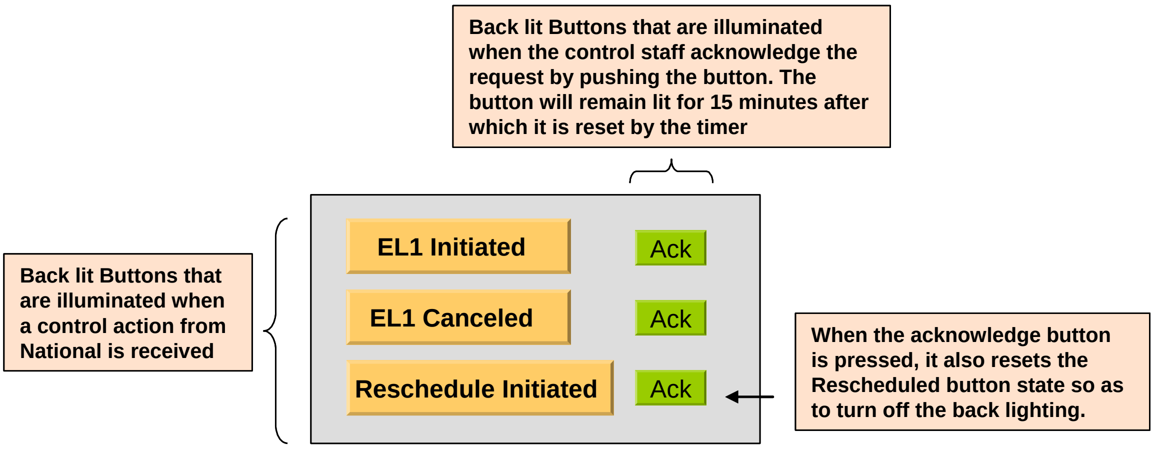


Figure 2 – Example *Emergency* and Reschedule indication.

Operation : ***Generator*** **functions:** *generators* can implement the functionality differently such as fast flashing indicting *Emergency Level 1* in force received, keeping the light lit solid whilst *EL1* in force and acknowledged, slow flashing to indicate *Emergency Level* 1 cancelled and off to indicate *Emergency Level* 1 cancelled and acknowledged.

An alternative is to have the logic implemented on a standard PC screen using an internet browser.

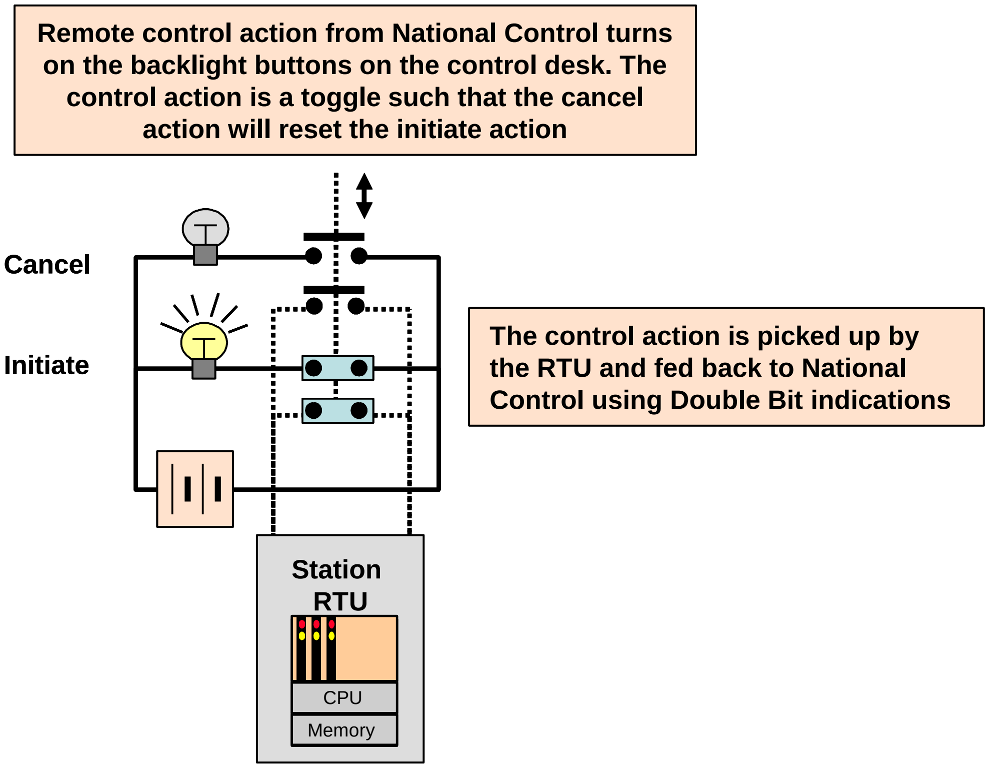


Figure 3 – Example *power station* relay action

Reschedule Initiated

The Reschedule function is sent by the *System Operator* to the generators via the BME and indicates that rescheduling took place that could result in a new generator schedule for the rest of the current day. There is no Cancel function for this action. When the *power station* staff acknowledge the request the requested state is reset.

***Emergency* Initiate**

The *Emergency* initiate request from the *System Operator* is an indication that maximum generation is required.

***Emergency* Cancel**

The *Emergency Cancel* indication from the *System Operator* is an indication that the *Emergency* assistance is no longer required.

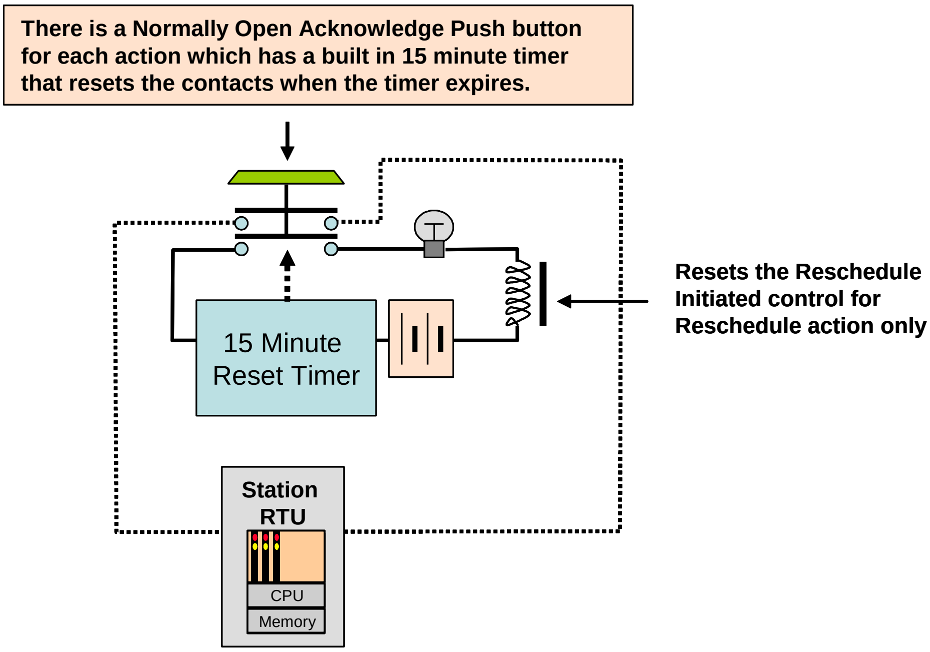


Figure 4 – Example acknowledge push button behaviour

Reschedule Initiate Acknowledge The Reschedule Acknowledged indication from the Station is an acknowledgement from the station that rescheduling took place. (This indication should have an automatic reset based on a 15 minute timer) See Figure 4.

***Emergency* Initiate/Cancel Acknowledged**

The ***Emergency* Initiate/Cancel** Acknowledged indication from the *generator* control room is an acknowledgement from the station that *Emergency* is in force or has be cancelled. (This indication could have an automatic reset based on a 15 minute timer).

(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 Raise Command	Raise pulse				True
AGC Lower Command		Lower pulse			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.

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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.

Raise/Lower Command

The Raise/Lower command consists of a message from the *System Operator*‘s *AGC* program instructing a particular unit to raise or lower its active power output by a predefined amount. The predefined amount is specified in terms of a rate of active power change (MW response per pulse received). The *unit* should be configured to interpret the amount and rate of active power change (MW) per pulse and the unit setpoint is adjusted appropriately.

(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[3]			Info	Analog	
Generator kV Setpoint[4]			Info	Analog	
Voltage or Q control mode[5]	V - Mode	Q - Mode	Info	Double	
Unit Controller status	Yes	No	Info	Double	
Unit Load Limit [6]			Info	Analog	
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 Raise	Raise pulse				True
Regulation High Limit Lower		Lower pulse			True
Regulation Low Limit Raise	Raise pulse				True
Regulation Low Limit Lower		Lower pulse			True
Generator MW Setpoint Raise	Raise pulse				True
Generator MW Setpoint Lower		Lower pulse			True
Generator Mvar Setpoint[7] Raise	Raise pulse				True
Generator Mvar Setpoint[8] Lower		Lower pulse			True
Generator kV Setpoint[9] Raise	Raise pulse				True
Generator kV Setpoint[10] Lower		Lower pulse			True
Voltage or Q control mode[11]	V - Mode	Q - Mode	Info		True
Primary Governing	On	Off	Info		True

[3] Only applicable to units running in SCO mode
[4] Only applicable to units running in SCO mode
[5] Only applicable to units running in SCO mode
[6] Maximum Load limit setting
[7] Only applicable to units running in SCO mode
[8] Only applicable to units running in SCO mode
[9] Only applicable to units running in SCO mode
[10] Only applicable to units running in SCO mode
[11] Only applicable to units running in SCO mode

A5.2 Distributor and end-use customer

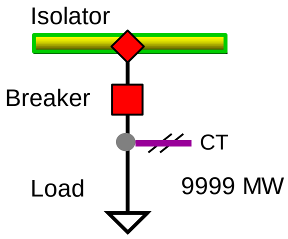
(a) Transmission equipment

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 market operator before the transfer to the System Operator.

APPENDIX 6: Operational schedules

(a) Energy schedules

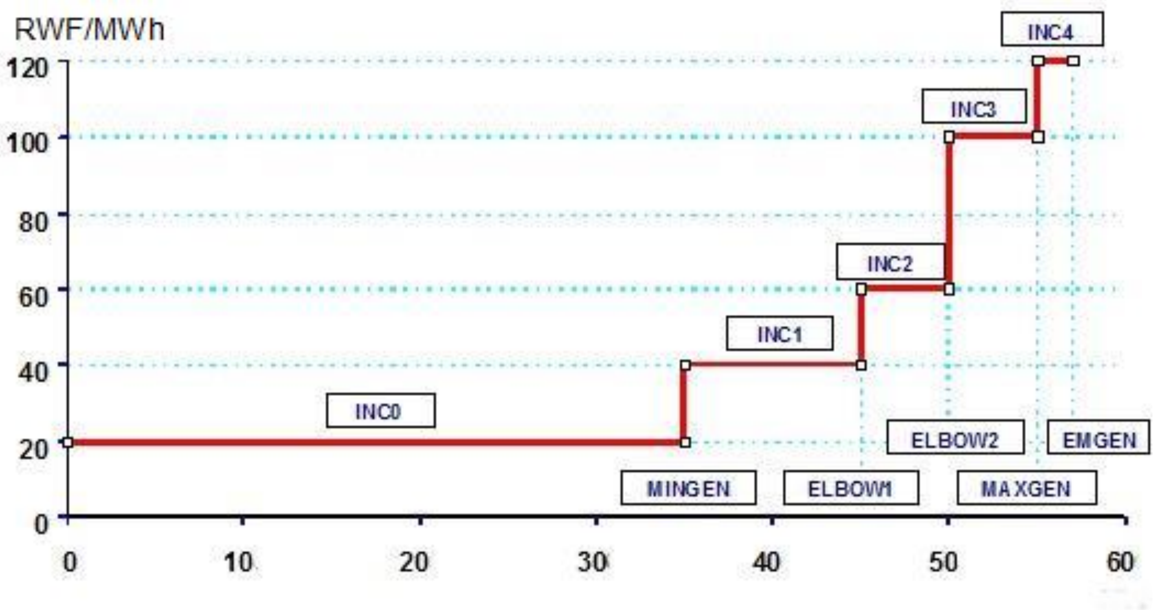
A *Generator's* bilateral contracted energy schedule (with any relevant *TradeCo, including NEP (TradeCo)*) shall be supplied to the *System Operator* in the format shown below:

No	Data description	Format	Size	Unit
1	The official abbreviation of the power station name as defined by the System Operator.	Characters	5	
2	The unit identification number.	Integer	0 - 99	
3	Contract hour	Integer	1-24	Hour
4	The contracted generation output per unit.	Integer	0 - 999	MWh

If not in a bilateral contract with a *TradeCo* (i.e. price sensitive *Information* is confidential and is not submitted to the *SO*), a *Generator* shall supply the *Short-Run Marginal Cost (SRMC)*, for *Generator* energy, to the *System Operator* for dispatch (if required, according to the *merit-order)*:

No	Data description	Format	Size	Unit
1	The official abbreviation of the power station name as defined by the System Operator.	Characters	5	
2	The unit identification number.	Integer	0 – 99	
3	Minimum generation capability of unit	Integer	999	MW
4	Price 1 = INC1	Real	999,99	RWF
5	Minus elbow 1 = Elbow 1 - 1MW			
6	Elbow 1	Integer	999	MW
7	Price 2 = INC1 + 0,02	Real	999,99	RWF
8	Minus elbow 2 = Elbow 2 - 1MW			
9	Elbow 2	Integer	999	MW
10	Price 3 = INC2	Real	999,99	RWF
11	Price 4 = INC2 + 0,03	Real	999,99	RWF
12	Price 5 = INC3	Real	999,99	RWF
13	Price 6 = INC3 + 0,04	Real	999,99	RWF
14	Max generation	Integer	999	MW

The offer prices are submitted in the form of price blocks where the price in RWF/MWh is specified against output in MW for each *Unit* at the *Power Station*. The price offer indicates the quantity of MWh per hour that the *Generator* is prepared to supply at the various price levels. An example price offer curve from a *Power Station* is given below.



The following parameters shall be specified:

- Unit Minimum Generation in MW (Mingen)
- Unit incremental prices (INC0 - INC4) in R/MWh
- Unit elbow points (Elbow 0 , Elbow 1, Elbow 2, Elbow 3) in MW (these are outputs at which the incremental price changes)
- Unit Maximum Continuous Rating in MW (MCR)
- Unit Price for Emergency Generation in R/MWh (treated as the last incremental price INC4) also referred to as Emergency Bid Price (EMBP).

The price curve shall, further comply with the following:

- The number of elbow points (E) shall not exceed four.
- The number of incremental prices shall be one more than the number of elbow points.
- Each incremental price shall be greater than or equal to (but not less than) the preceding one, excluding INC0 which can be set independent of the other incremental prices.
- All incremental prices shall be positive.

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 CER/BLO	Character	3	
4	Unit AGC status AUT/OFF/MAN	Character	3	
5	Unit set-point	Real	99,99	MW
6	AGC pulse	Real	9,9	
7	Unit sent out	Real	999,99	MW
8	Unit auxiliary	Real	999,99	MW
9	Unit contract	Integer	999	MW
10	Unit spinning	Integer	999	
11	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	Cross Border tie-line A	Integer	99999	MW
23	Cross Border tie-line B	Integer	99999	MW
24	Cross Border tie-line C	Integer	99999	MW
26	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: The parameter “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.

The following indicators are still under development:

- Protection management
- Ability to island
- Excitation system management
- Reactive capabilities
- Multiple-unit trip risks
- Governing requirements

- Restart after station blackout capability
- Black start capability
- Intermediate load capability
- External supply disturbance withstand capability
- Loading rates

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 with: MCR > Metering Threshold (kVA)

Generator	Tx substation name at closest connection point	Operating power factor	Installed capacity	Plant type	On-site usage		Net sent out		Generation net sent out contribution at peak									
			(MW)		Normal	Peak	Normal	Peak	Y 1	Y 2	Y 3	Y 4	Y 5	Y 6	Y 7	Y 8	Y 9	Y 10

APPENDIX 10: Generator HV yard information

TransCos shall provide the following information to *Generators* about equipment and systems installed in HV yards from the *TransCo*. The *TransCo* shall provide 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; the *TRANSCO* shall review the fault levels and impedance to network centre from HV yard, annually