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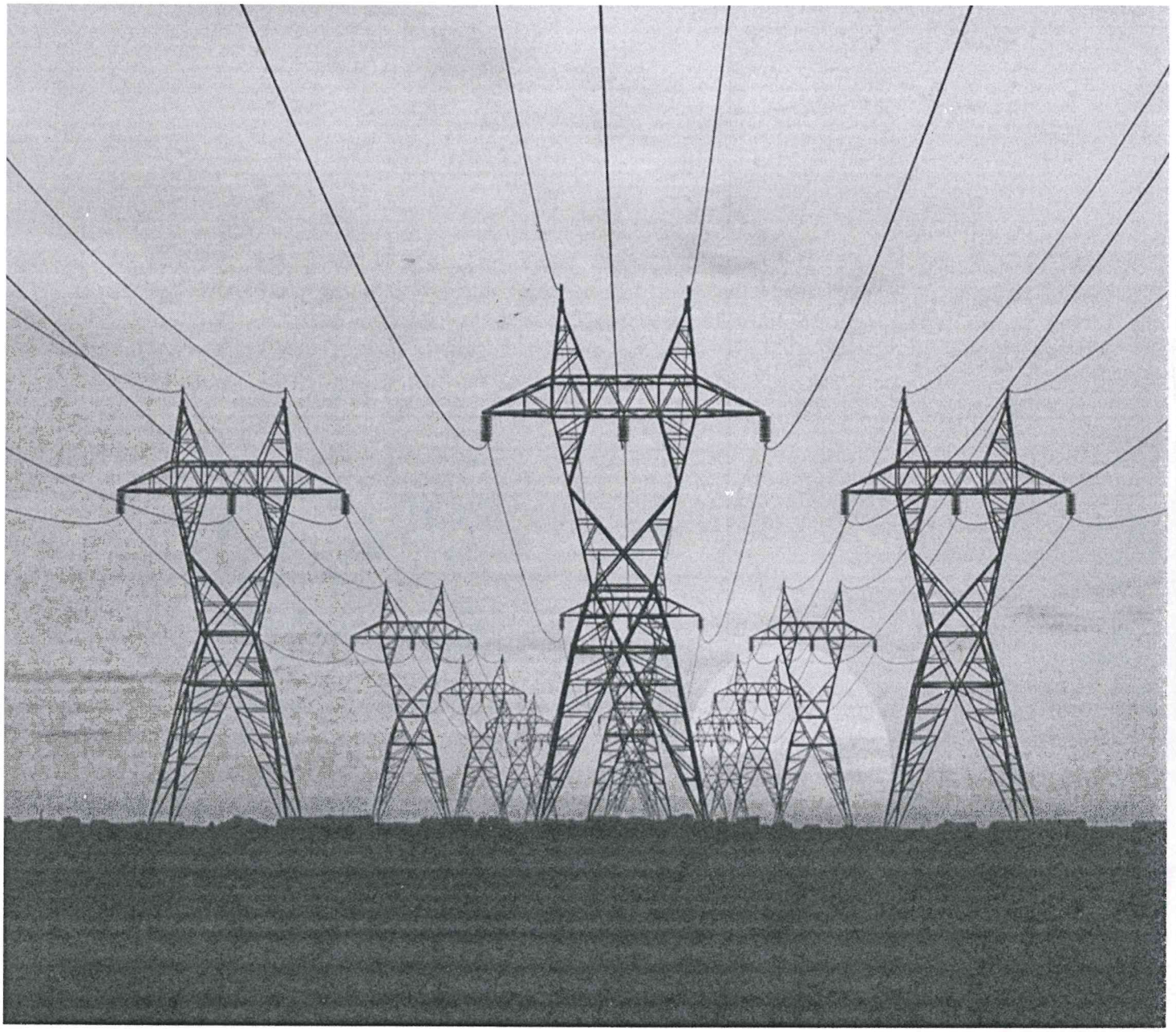
EEA
ETHIOPIAN ENERGY AUTHORITY



ETHIOPIAN NATIONAL TRANSMISSION GRID CODE

(Directive No. 865/2022)

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1 PREAMBLE

1.1 INTRODUCTION

The Grid Code, comprised of a document or a set of documents, specifies the rules and responsibilities for all entities related to electrical power system planning and operations. Its purpose is to legally establish technical and other requirements for the connection to and use of an electrical power system by parties in a manner that will ensure reliable, efficient, and safe operation.

Ethiopia has, for the first time in its history, opened up its electricity generation and distribution sector to private investors. Privately owned power companies can now invest in the electric power industry and compete with the state owned utility. The Ethiopian power system, however, lacks a formal Grid Code document that will ensure reliability, safety, and security of the electric power system operation. This Preamble provides the rationale for the development of an *Ethiopia National Transmission Grid Code (ENTGC)* with a summary of provisions. The *ENTGC* has gone through a rigorous approval process as required by the appropriate local authorities.

The objective of the *ENTGC* is to improve the ability to plan and operate Ethiopia's power system safely, reliably, efficiently, and economically, in a transparent and non-discriminatory manner, while multiple independent parties use the power system. The independent parties must operate within a framework of rules and regulations, and coordinate with each other and the operators of the electric system, and the *ENTGC* will provide this. The *ENTGC* is intended to establish the reciprocal obligations of *Users* of the *Ethiopia National Transmission System* (*ENTS*) and operation of the East African Power Pool.

The *ENTGC* is based partially on the *Eastern Africa Power Pool (EAPP)* and *East African Community Interconnection Code (EAPP IC*). Furthermore, the *EAPP IC* imposes certain minimum requirements on the Member Countries of the *EAPP*. Thus, the *EAPP IC* plays an important role in the development of the *ENTGC*. This *ENTGC* follows to the extent possible the organisation and formatting of the *EAPP IC*.

Other national grid codes were considered and reviewed in addition to the EAPP IC, including the South African Grid Code (2012), the South African Grid Connection Code for Renewable Power Plants (2012), the Namibian Grid Code (2005), the Indian Electricity Grid Code (2010), the Zambian Grid Code (2006), and the Rwanda Grid Code (2012), the *Ethiopian Electricity Agency (EEA)*'s Draft Interface Codes for Generation/Interconnection/ Distribution, and the Kenyan Grid Code recently developed and finalized by Nexant (2015).

In addition, The Final Interim Report Module 1B for "EAPP/EAC Regional Power System Master Plan (PSMP) & Grid Code Study" (2010) was also reviewed for relevant information.

Addressing exclusively wind power, the Australian Energy Market Operator (AEMO) report "Wind Integration: International Experience WP2: Review of Grid Codes 2nd October 2011" provided a review of Grid Codes from the United Kingdom, Germany, Denmark, Spain, Texas, Alberta, Hydro Quebec, Ontario Independent Electricity System Operator (IESO), and the European Network of Transmission System Operators for Electricity (*ENTSO-E*). This review was helpful in preparing the *Renewable Power Plant (RPP)* Chapter, one of the Chapters in the *ENTGC*.

1.2 STRUCTURE OF THE ENTGC

The *EAPP IC* and the *ENTGC* each place obligations on the *Regulatory Authority*, the *Ethiopia National TSO (ENTSO)*, and *Users*. In the chapters of the *ENTGC*, the *EAPP* requirements are listed first, followed by requirements specific to the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold. The *ENTGC* is applicable to the Generation, Transmission system of the *ENTS*. The *ENTGC* consists of the following Chapters:

1.2.1 Preamble

This Preamble and summarizes the provisions of the *ENTGC*.

This Preamble is available to all participants and prospective participants in the *ENTS* for information only and does not constitute part of the *ENTGC*.

1.2.2 Glossary and Definitions

The Glossary and Definitions (GD) contains a glossary of terms and a list of abbreviations and units used in the *ENTGC*. Defined terms are italicised and capitalised throughout the *ENTGC* and hold the meanings as defined. However, if a term is not capitalised or italicised, it shall still hold the definition as provided in the Glossary.

1.2.3 General Conditions

The General Conditions (GC) set out the over-riding principles to be used in the operation of the *ENTS* and form the basis for the decisions of a reasonable and prudent operator should specific events not be covered by the relevant Chapter. The GC describes the provisions necessary for the overall administration and review of the various aspects of the *ENTGC*. The GC also deals with those aspects of the *ENTGC* not covered in other Chapters, including the resolution of disputes, bilateral agreements, confidentiality, non-compliance and the revision of the *ENTGC* through the *Ethiopia National Transmission Grid Code Review Committee (ENTGCRC)*.

1.2.4 Governance Chapter

This Governance Chapter summarizes the main documents and organizations that provide the authority governing the planning, construction, and operation of the *ENTS*.

1.2.5 Planning Chapter

The Planning Chapter (PC) specifies the minimum technical and design criteria, principles, and procedures:

(a) To be used within Ethiopia in the planning and in the medium and long term development of the *ENTS*;

(b) To be taken into account by *Member Utilities* on a coordinated basis, and

(c) To specify the planning data required to be exchanged by *Member Utilities* and *EAPP* Sub-Committee on Planning to enable the *EAPP Interconnected Transmission System* to be planned in accordance with the planning standards.

1.2.6 Connections Chapter

The Connections Chapter (CC) specifies the minimum design, technical, and operational criteria of *Plant* and Apparatus, which must be complied with, by both *Users* and the *ENTSO* at the Connection Point in order to maintain secure and stable operation of the *ENTS*.

1.2.7 Renewable Power Plant Chapter

The *Renewable Power Plant (RPP)* Chapter sets out the requirements for *RPPs* so that they will be able to contribute to the stability of the *ENTS*.

1.2.8 Operations Chapters

The Operations Chapters (OC) set out the data exchange between and responsibilities of the *ENTSO*, the other *TSOs,* and the EAPP in operating the *EAPP Interconnected Transmission System*. The six OCs (OC 1 through OC 6) deal with the criteria and procedures which will be required to facilitate efficient, safe, reliable and coordinated system operation of the *ENTS,* other *Electric Systems,* and the *EAPP Interconnected Transmission System*. They include Chapters addressing Operational Planning, Operational Security, Emergency Operations, Incident Reporting, Demand Control, and System Tests.

1.2.8.1 Operational Planning

Also known as, OC 1, this Chapter summarizes Outage requirements for generation and transmission facilities and other factors likely to affect the operation of the *ENTS*, which shall be coordinated between the *ENTSO*, other *TSO*s, and the *EAPP Coordination Centre (EAPP CC)* for period of three (3) years ahead down to real time. In accordance with the terms of Chapter 5 (Planning Chapter, or the PC), the Introduction also requires the *ENTSO*, other *TSOs,* and the *EAPP Sub-Committee on Planning* to produce a *Power Balance Statement* and a *Transmission System Capability Statement* on an annual basis for the succeeding ten (10) years. It also sets out refinements of the planning process to account for nearer-term characteristics.

1.2.8.2 Operational Security

Also known as, OC 2, this Chapter specifies the technical requirements and standards for the operational security of the *ENTS*, the Electric Systems of other Member Countries, and the *EAPP Interconnected Transmission System* as they relate to the following issues:

(a) N-1 *Contingency* criterion;

(b) Interchange scheduling;

(c) Operating reserves for control of system frequency and interchange with other *Control Areas* or *External Systems*;

(d) Voltage control;

(e) Fault level control;

(f) Protection coordination, and

(g) *Remedial Action Schemes (RAS)*.

1.2.8.3 Emergency Operations

Also known as, OC 3, this Chapter's objectives are to ensure that the *ENTSO,* other *TSOs*, and the *EAPP CC*:

(a) Are able to identify insecure operating conditions on the *EAPP Interconnected Transmission System*;

(b) Have procedures and plans in place to manage emergency conditions;

(c) Have comprehensive contingency plans in place for the restoration of supplies in the shortest possible time using the most effective means.

1.2.8.4 Incident Reporting

Also known as, OC 4, this Chapter sets out the requirements for reporting significant incidents that have caused, or could have caused, damage to system equipment or operation of the Ethiopia and other Electric Systems, and or the *EAPP Interconnected Transmission System* outside the Operational Security Standards.

This Chapter also sets out the procedure for the joint investigation of significant incidents and for the technical audit of the *ENTSO* and other *TSOs* procedures and *Plant* and Apparatus connected to, or forming part of, the *EAPP Interconnected Transmission System*.

1.2.8.5 Demand Control

Also known as, OC 5, this Chapter sets out the provisions to be made by the ENTSO in cooperation with the EAPP CC, to permit reductions in demand in the event of insufficient generation capacity being available to meet demand or in the event of breakdown or thermal over loading of any part of the ENTS or the EAPP Interconnected Transmission System leading to the possibility of unacceptable frequency or voltage conditions.

The Ethiopia and other *TSOs* shall, after taking all other remedial actions, disconnect customer demand rather than risk an uncontrolled failure of *Plant* and or *Apparatus* or cascading *Outages* of the *EAPP Interconnected Transmission System*.

1.2.8.6 System Tests

Also known as, OC 6, this Chapter sets out the arrangements, data exchange, and procedures across the *EAPP Interconnected Transmission System* for *System Tests* or operational tests including *Black Start* tests and Power Island tests. *System Tests* are those tests, which involve either a simulated or a controlled application of irregular, unusual, or extreme conditions on the *EAPP Interconnected Transmission System*. In addition, they include commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out by a *User* and which may have a significant impact upon the *EAPP Interconnected Transmission System*.

1.2.9 Interchange Scheduling and Balancing Chapters

The Interchange Scheduling and Balancing Chapters (ISBC) set out the procedures for the scheduling, coordination and balancing of power transfers across the *EAPP Interconnected Transmission System*. The ISBC is divided into Chapters 14, 15, and 16 of the ENTGC: ISBC 1 Interchange Scheduling, ISBC 2 Balancing and Frequency Control, and ISBC 3 Ancillary Services.

1.2.9.1 Interchange Scheduling

Also known as, ISBC 1, this Chapter notes that the term Interchange Scheduling specifically refers to the intended delivery of *Active Power* and *Active Energy* from one *Control Area* to another *Control Area* within the *EAPP Interconnected Transmission System* or to be imported from or exported to *External Systems*.

ISBC 1 deals with the following aspects of the scheduling process:

(a) Determination of the Net Transmission Capability (*NTC*) between *Neighbouring Control Areas* and or *External Systems* over the Operational Planning timescales;

(b) Publication of *NTC* values to enable the *ENTSO*, other *TSOs*, and *Users* to evaluate possible energy interchanges;

(c) Allocation of *NTC* to the *ENTSO*, other *TSOs*, and or External Systems in accordance with pre-determined rules and the issue of Interchange Schedules.

1.2.9.2 Balancing and Frequency Control

Also known as, ISBC 2, this Chapter notes that in the *EAPP Interconnected Transmission System*, power balancing is necessary to control system frequency and the power exchange between Control Areas and with External Systems. In order to achieve this balance, the *ENTSO and* other *TSOs* shall ensure it has sufficient reserve capacity in order to maintain scheduled power exchanges within the *EAPP Interconnected Transmission System* and with External Systems and to control system frequency to meet the minimum standard under both normal and emergency conditions.

ISBC 2 sets out the procedure, which the *ENTSO* and other *TSOs* will use to direct frequency control. The frequency of the *EAPP Interconnected Transmission System* will be controlled by:

(a) Automatic response from synchronised *Generating Units*;

(b) The dispatch of *Generating Plants* including *Automatic Generation Control (AGC)*;

(c) Response from interconnections with *External Systems*, and

(d) Demand control.

1.2.9.3 Ancillary Services

Also known as, ISBC 3, this Chapter defines Ancillary Services as those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the EAPP Interconnected Transmission System in accordance with Prudent Utility Practice. These Ancillary Services are required to ensure that the *ENTSO* and other *TSOs* meet the obligations and responsibilities under the *EAPP IC* for a safe, secure, and reliable operation of the *EAPP* Interconnected Transmission System.

The operation of the *ENTS*, other National Systems, and the *EAPP Interconnected Transmission System* requires the provision by the *ENTSO* and other *TSOs* of the following *Ancillary Services* grouped into three major categories:

(a) Frequency Control;

(b) Network Control, and

(c) System Restart Capability.

The above *Ancillary Services* are the traditional mechanisms to provide the required capability in relation to:

(a) Operating Reserves;

(b) Demand Control;

(c) Voltage Control;

(d) Power flow control;

(e) Stability control, and

(f) Black-Start.

1.2.10Ethiopia Metering Chapter

The Ethiopia Metering Chapter (EMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each *Connection Point* of a User with the *ENTS*. The EMC also specifies the associated data collection equipment and the related metering procedures required for the operation of the *ENTS*.

1.2.11 Interconnection Metering Chapter

The Interconnection Metering Chapter (IMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each point of interchange of energy between *Control Areas*. The metering at the Interchange Point is required for real-time operation of *AGC* systems and for the accounting of *Inadvertent Deviations* in accordance with the Balancing and Frequency Control Chapter. The IMC also specifies the associated Data Collection and the related metering procedures required for the operation of the *EAPP Interconnected Transmission System*.

The IMC is not concerned with:

(a) Metering of *Connection Points* between *Users* and *National Systems,* and

(b) Metering for commercial purposes.

These metering systems are subject to the *ENTGC*, other National Grid Codes or Regulations, and or Power Purchase Agreements.

1.2.12 Data Exchange Chapter

The Data Exchange Chapter (DEC) defines the data to be exchanged between the *ENTSO*, other TSOs, and the *EAPP* Sub-Committees on Planning and Operations for the purpose of the modeling and analysis of steady-state and dynamic conditions for the *EAPP Interconnected Transmission System.* The DEC sets out the information flows required between the *ENTSO and* other *TSOs,* and the *EAPP Sub-Committees on Planning and Operations* to produce *EAPP* system models for the various processes that require system studies to be undertaken. These processes include those associated with System Planning as set out in Chapter 5 (Planning Chapter, or the PC), including the preparation of the *Transmission System Capability Statement*, and with Operational Planning as set out in OC 1.

1.2.13 Information Exchange Chapter

The Information Exchange Chapter defines the reciprocal obligations of parties with regard to the provision of information for the implementation of *ENTGC*. The information requirements, as defined for the *TNSP*, the *ENTSO*, the *Regulatory Authority*, and *Users*, are necessary to ensure non-discriminatory access to the *ENTS* and the safe, reliable provision of transmission services. The information requirements are divided into planning information, operational information and post-dispatch information.

1.2.14 Cyber Security Chapter

Cyber Security can be defined as the protection required to ensure confidentiality, integrity, and availability of the electronic communication system. With the two-way flow of electricity and information, the management and protection of the electrical communication system that includes information technology and telecommunication infrastructure has become critical to the electric utility industry. With the increase in dependence on modern communication technology (e.g.,

wireless, cloud computing, etc.), power systems are vulnerable to cyber-attacks and hackers. In Ethiopia, the growth in the field of information, communication, and technology (*ICT*) makes it imperative to develop a sound cyber security strategy that will ensure confidentiality, integrity, and availability of public and private sector information across Ethiopia's *ICT* infrastructure.

Ethiopia has initiated the effort to define its cyber security strategy as demonstrated in its National Cyber Security Master Plan draft that has been awaiting implementation. The Cyber Security Chapter addresses: (i) development of information security management controls and procedures; (ii) cyber security systems with identity; (iii) access management systems; and (iv) building defense against threats through training, awareness and monitoring.

1.2.15 System Operator Training Chapter

The *System Operator Training Chapter (SOTC)* states that it sets out the responsibilities and the minimum acceptable requirements for the development and implementation of System Operator Training and Authorisation programmes. This Chapter shall ensure that System Operators within Ethiopia and throughout *EAPP* and *EAC* are provided with continuous and coordinated operational training in order to promote the reliability and security of the *EAPP Interconnected Transmission System.*

1.3 SCOPE OF THE ENTGC

The *ENTGC* establishes the technical aspects of the planning, connection, operation, and use of the *ENTS* and the relationships between the *ENTSO*, *TNSPs*, *Generation Licensees*, and other Users of the *ENTS*.

The *ENTGC* shall be read in conjunction with the relevant legislation, including the Proclamation 810/2013, all applicable Energy Operation Regulations and any applicable amendments related to the administrative authority for the *ENTGC*. These legislative policies shall be used in conjunction with the Licences issued to *Users* and the applicable codes and regulations adopted by the *Regulatory Authority* and the Ministry of Water and Irrigation and Energy (MOWIE). All Licences issued after enactment of the *ENTGC* shall include the obligation of Parties to comply with the *ENTGC* requirements.

2 GLOSSARY AND DEFINITIONS

2.1 INTRODUCTION

The Glossary and Definitions Chapter contains a glossary of terms, a list of abbreviations, and units used in the Ethiopia *ENTGC*.

2.2 GLOSSARY

Table 2-1 provides a summary of the terms and definitions used in the *ENTGC*.

Table 2-1 Glossary and Definitions

WORD or PHRASE	DEFINITION
Active Energy	A measure of electrical energy flow during a time interval. It is measured in units of Watt- Hours or multiples thereof. It is the time integral of the product of voltage and the in phase component of current flow across a connection point
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
Active Power Control	The automatic change in Active Power output from a Wind Turbine Generating Plant in response to an Active Power Control Set-point received from the Transmission Licensee or Distribution Licensee
Active Power Control Set-point	The maximum amount of Active Power in MW, set by the Transmission Licensee or Distribution Licensee, that the Wind or Solar Turbine Generating Plant is permitted to export
Active Power Curtailment Set-point	The limit set by the ENTSO for the amount of active power that the RPP is permitted to generate. This instruction may be issued manually or automatically via a telecontrol facility. The manner of applying the limitation shall be agreed between the parties
Ancillary Services	Services provided by the licensees or customers not directly related to the generation and supply of electricity but to ensure stable and secure operation of an electrical power system and its recovery from emergency situations. Ancillary services include frequency regulation or control, spinning reserve, voltage and reactive power support, black start and load shedding facilities as defined in the "Council of Ministers Regulation to Provide for the Regulation of Energy Operations"
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

Approving Authority	Ethiopian Energy Authority is the Approving Authority for the purpose of revisions to the Ethiopia Electric Transmission Grid Code and the granting of Derogations
Area Control Error	The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including correction for metering error
Authority	The Ethiopian Energy Authority established by the regulation of the Council of Ministers as defined in the Energy Proclamation 810/2013
Automatic Generation Control	Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation
Automatic Load Shedding Scheme	A load-shedding scheme utilised by the Ethiopia National Transmission System Operator (TSO) or another TSO to prevent frequency collapse and to restore the balance between generation output and demand
Automatic Voltage Regulator	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
Availability Factor	Available generation capacity as a percentage of installed generation capacity
Biomass	Non-fossilised and biodegradable organic material originating from plants, animals and micro-organism and includes bio-ethanol, bio-diesel, biogas, charcoal, fuel wood, and agro waste
Black Start	The procedure necessary for recovery of the Ethiopia National Transmission System from Total Shutdown or Partial Shutdown
Black Start Capability	Ability of a Generating Plant, for at least one of its Generating Units, to Start-Up from Shutdown without an external electrical power supply and to energise a part of the Ethiopia Electric Transmission System and be Synchronised to the System upon instruction from the Transmission Licensee or Distribution Licensee
Board	The Ethiopian Energy Authority's Board as defined in the Energy Proclamation 810/2013
Capacity Factor	The ratio of total energy dispatched to installed generation capacity
Certificate of Competency	A document issued by the Authority that certify the competency of any person to engage in electrical works as defined in the Energy Proclamation 810/2013
Chairperson	The person duly appointed by the *Regulatory Authority* to be Chairperson of the Ethiopia National Transmission Grid Code Review Committee, or the person appointed by the Chairperson to be his alternate, or the person appointed to act as Chairperson of a meeting of the Ethiopia National Transmission Grid Code Review Committee

	the absence of the Chairperson or his alternate
Check Meter	A Meter nominated to provide electrical energy measurements at a Defined Metering Point or substitution of the Main Meter for verification purposes
Conductor	A material that allows the flow of electrical current in one or more directions
Confidential Information	Information which is or has been provided under or, in connection with the Ethiopia National Distribution Grid Code and which is stated under the Ethiopia National Distribution Grid Code or by the Ethiopian Energy Authority to be confidential information
Connection	Physical link to or through a transmission/distribution network that will allow the supply of electricity between electrical systems
Connection Agreement	A bilateral agreement made between the Ethiopia National TSO or a TNSP and a User setting out the terms and conditions relating to the use of the Connection Point and other specific provisions in relation to that connection
Connection Point	The physical point at which a User is connected to the Ethiopia Electric Transmission System
Constraint	A limitation on the capability of a network, load or a generator such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed
Consumer	A person or entity obtaining services from a Distribution Licensee
Contingency	An unexpected incident, failure or Outage of an interconnected system component, such as a Generating Plant, 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
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 to the Ethiopia Electric Transmission System.
Control Area Operator	The Ethiopia System Operator or another TSO responsible for operating, monitoring, and ensuring interchange scheduling of its Control Area
Control Center	A physical location from which a TSO exercises control over its transmission area
Current Transformer	An instrument transformer which performs the function of supplying the protective relays and measuring devices with currents of magnitude proportional to those of power circuit but sufficiently reduced in magnitude. It also serves the purpose of isolating the measuring instruments from high voltage circuits

Customer	A person obtaining electricity services from a licensee as defined in the Energy Proclamation 810/2013
Cut-out Wind Speed	The wind speed at which a wind turbine shuts down for protection against damage
Data Collection System	A computer based system that collects or receives data on a routine basis from Metering Equipment
Day	Day means calendar day wherever referred to in this document
Defined Metering Point	The DMP is and means The physical location at the Interchange Point within a Control Area where overall accuracy requirements are to be met. Each single circuit interconnection between Control Areas will have two DMPs, one in each Control Area
Derogation	A waiver to suspend a Transmission Licensee or Distribution Licensee's obligations to implement or comply with a provision or provisions of the ENTGC
Disconnection	The operation of switching equipment or other action so as to prevent the flow of electricity at a connection point
Dispatch	The process of precisely matching generation with load in real time
Dispatchable Resource	(1) A generating plant that can be turned on or off or can be adjusted upon request , or, (2) A customer participating as a demand side resource that can comply with the TSO instructions to reduce electricity usage
Dispute	Any difference between the Ethiopian Energy Authority and any Transmission Licensee or Distribution Licensee or User in connection with, or arising out of, the interpretation, implementation or breach of any provision of the ENTGC
Dispute Notice	A written notice issued by either Party to a Dispute outlining the matter of such Dispute
Distribution	The supply of electricity services to customers through medium and low voltage lines as defined in the Energy Proclamation 810/2013
Distribution Licence	A license granted by the Ethiopian Energy Authority to distribute and sell electricity as defined in the "Council of Ministers Regulation to Provide for the Regulation of Energy Operations"
Distribution Licensee	An entity granted a licence by the Ethiopian Energy Authority to distribute and sell electricity as defined in the "Council of Ministers Regulation to Provide for the Regulation of Energy Operations"
Distribution System	A distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system
EAPP Coordination Centre	Body established under the guidance of the EAPP Sub-Committee on Operation responsible for the collection of technical and commercial information
EAPP Independent Regulatory Board	Board consisting of nominees of national regulatory boards in the EAPP countries that is the regulatory body governing the EAPP IC

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
EAPP Sub-committee on Planning	EAPP body under the direction of EAPP Steering Committee responsible for the coordination of Master Plans and development programs of EAPP Member utilities
Eastern Africa Power Pool	Eastern Africa Power Pool (EAPP) is a regional intergovernmental body based in Addis Ababa, Ethiopia. Its mission is the pooling of electrical energy resources in a coordinated and optimized manner to provide an affordable, sustainable and reliable electricity in the region
Eastern Africa Power Pool Interconnection Code	The Interconnection Code that sets down the technical rules for the coordinated planning and operation of the EAPP.
Electrical Energy	Energy involving the use of electric current which may be produced either by mechanical, chemical, hydroelectric, wind, photovoltaic or any other sources as defined in the Energy Proclamation 810/2013.
Electrical Installation	Any electrical equipment that is fixed (or to be fixed) in, on, under or over a Customer's premises.
Electrical Plant	Any plant, equipment, apparatus or appliance (other than electrical supply line, meter, or electrical appliance belonging to a customer) used for, or for purposes connected with the import, export, generation, transmission, distribution and supply of electricity.
Electrical Work	Work of electrical design, installation, maintenance, testing, inspection, contracting, or consultancy, electro mechanical activity or any other electric related business as per the Energy Proclamation 810/2013
End-use User	A Customer of the ENTS that contracts for purchase of electrical energy for his/her own use, not for delivery or supply to another person
Energy Audit	A systematic procedure: (a) to obtain adequate knowledge of the existing energy consumption profile of a customer; (b) to identify and quantify cost effective energy saving opportunities; and (c) to report the findings as defined in the Energy Proclamation 810/2013.
Energy Conservation	Reduction in the amount of energy consumed in a process or system through elimination of waste and economical rational use as defined in the Energy Proclamation 810/2013
Energy Efficiency	Ability to provide the same or higher level of products or services at lower level of energy consumption as defined in the Energy Proclamation 810/2013
Ethiopia National Transmission Grid Code	Specifies technical requirements for connection to, and use of, the National Electricity Transmission System
Ethiopia National	The Committee established in accordance with section 4.5.1 of

Transmission Grid Code Review Committee	Chapter 4 (Governance) and charged with the review of the operation, and revision of the Ethiopia Grid Code. The Ethiopia Electric Transmission Grid Code Review Committee shall be governed by the Constitution and Rules set out in Section 4.5.of the ENTGC
Ethiopia National Transmission System	The electricity transmission system of Ethiopia including all Users connected to that system
Ethiopia National Transmission System Operator	The Committee established in accordance with Chapter 4 (Governance) of the Ethiopia National Transmission Grid Code and charged with providing recommendations to the Ethiopian Energy Authority on the review and revision of the ENTGC. The Ethiopia National Transmission Grid Code Review Committee shall be governed by the provisions set out in Section 4.5 of the ENTGC
Expected Un-served Energy	The expected amount of energy that cannot supplied by the power generating system during the period of observation, due to capacity deficiency
External System	Any electric system outside EAPP that interconnects to the EAPP Interconnected Transmission System
Fiscal Year	Ethiopian fiscal year that starts on July 8th of a year and ends on July 7th of the following year
Force Majeure	Causes beyond the reasonable control of and without the fault or negligence of the Party claiming Force Majeure. It shall include failure or interruption of the delivery of electric power due to causes beyond that Party's control, including Acts of God, wars, sabotage, riots, hurricanes and other actions of the elements, civil disturbances and strikes as set out in Section 3.7 of Chapter 3 (General Condition)
Forced Outage Factor	Percentage of forced withdrawal of generating plant/unit for service for upgrade, maintenance and associated reasons from the total capacity
Generating Plant	A facility for the generation of electric power comprised of one or more generating units which are likely to be individually controllable
Generating Unit	A specific unit within a Generating Plant that generates electric power from other sources of energy
Generation License	A licence authorising an entity to generate electrical energy
Generation Licensee	An entity licensed to operate and maintain generation assets and generate electricity within the Ethiopia National Transmission System
Generator	A device that converts mechanical energy to electrical energy for use in an external circuit
Governor	Automatic control system which maintains the desired system frequency by adjusting the mechanical power output of the turbine of a Generating Plant
Grid	The network of transmission and distribution systems and connection points for the movement and supply of electrical energy from Generating Plants to Customers
Grid Code Revision	A Register of all revisions to the Ethiopia Grid Code as set out in

Register	Section 4.10.4 of Chapter 4 (Governance)
High Voltage	A voltage level above 33,000 volts in accordance with Proclamation 810/2013
Inadvertent Deviation	Difference between net actual energy flow and net scheduled energy flow into or out of the Control Area
Independent Expert	A well-qualified person with broad proven experience who provides advice to the Ethiopia National Transmission Grid Code Review Committee on issues concerning the Grid Code
Independent Power Producer	Any entity that owns generation plant and sells bulk electricity to the national grid through power purchase agreement
Induction Generator	A type of alternating current (asynchronous) generator operating on the induction principle to produce electric power
Induction Motor	AC electric motor in which the electric current in the rotor needed to produce torque is obtained by electromagnetic induction from the magnetic field of the stator winding
Installation	Includes wiring , equipment, fittings and other materials used or intended to be used to convey electricity beyond the point of supply to the point of consumption as defined in the Energy Proclamation 810/2013
Interchange Point	A location where power flows from one Control Area to another Control Area
Interconnection Agreement	An agreement made between the System Operator and a Transmission System Operator of another EAPP Member Country, relating to the transfer of power and or Active and or Reactive Energy and or Ancillary Services between their respective electric systems
Inter-Governmental Memorandum of Understanding	A binding agreement that enabled the establishment of EAPP. The document covers issues such as the members, obligations, organizational structure, resources, arbitration, and enforcement of EAPP
Inter-Utility Memorandum of Understanding	A binding agreement between utilities of Member Countries of EAPP which defines the fundamental principles for the management and operation of the EAPP
Licence	A license as defined in the Proclamation 810/2013
Licensee	Holder of a licence under the Proclamation 810/2013
Low Voltage	A voltage level up to 400 volts in accordance with Proclamation 810/2013
Main Meter	The Meter nominated to provide electrical energy measurements at a Defined Metering Point
Maintenance Plan	Coordinated list of all planned transmission and generation Outages.
Maintenance Outage	Scheduled removal from service, in whole or in part of a Generating Plant or transmission facility in order to perform necessary repairs on specific components of the facility
Medium Voltage	A voltage level between 400 volts and 33,000 volts in accordance with

	Proclamation 810/2013
Member Country	An eastern Africa country whose government has signed the IG-MOU
Meter	A device, including associated equipment, complying with Ethiopian Standards which measures and records the production or consumption of electrical energy
Meter Information Register	A system which uniquely identifies the Meter and Users associated with the Meter and contain pertinent data relating to the Meter
Metering Equipment	Meters, time-switches, measurement transformers, metering protection and isolation equipment, circuitry and their associated data storage and data communications equipment and wiring which are part of the Active Energy and Reactive Energy measuring equipment at or relating to the Defined Metering Point
National System	The electricity transmission system of an EAPP Member Country including all Users connected to that system. For the purposes of the ENTGC, refers to the Ethiopia National Transmission System
National Load Dispatch Centre	The facility that houses the control system to monitor and control real time power system data to ensure security and reliability of the power system optimally
Neighboring System	Any system or Control Area either directly interconnected with or electrically close to the EAPP Interconnected Transmission System so as to be significantly affected by it
Network Service	Transmission/Distribution service associated with the conveyance and controlling the conveyance, of electricity through the Network
Network Service Provider	A legal entity that engages in the activity of owning, controlling, or operating a transmission system and who holds or is deemed to hold a licence or has been exempted from the requirement to obtain a licence from the Ethiopian Energy Authority
Operating Margins	Generating capability in MW above firm System Demand available to provide for regulation, load-forecasting error, equipment forced and scheduled outage
Operational Effect	An effect which causes the Ethiopia Electric Transmission System to operate (or be at a materially increased risk of operating) differently to the way in which it would or may have normally operated in the absence of such effect
Operational Plan	The plan issued each day containing details of all Outages of Generating Plants and Transmission equipment, details of anticipated transfers, transmission constraints, Contingency plans and any other relevant information
Outage	Disconnection or separation, planned or unplanned of one or more elements of the Ethiopia Electric Transmission System
Partial Shutdown	The same as a Total Shutdown except that all generation has ceased in a separate part of the Ethiopia Electric Transmission System and there is no supply from External Systems or other parts of the Ethiopia Electric Transmission System and therefore that part of the

	interconnected system is Shutdown
Party	Any person or entity with the specific meaning ascribed in the related provision of the Grid Code
Person	A natural or juridical person
Photovoltaic Solar Plant	Generate electricity directly from sunlight via an electronic process that occurs naturally in semiconductors
Planned Outage:	An Outage for which at least ten (10) days' notice has been given to allow the Outage to be planned in accordance with Outage Planning Process as described in Chapter 8 (Operations Planning)
Plant	Fixed and movable equipment used in the generation and/or supply and/or transmission of electricity other than Apparatus
Power Balance Statement	Forecast produced by TSOs for each National System of their expected demand and generation over the planning horizon as set out in Chapter 5 (Planning)
Power Island	An area cut off from the power grid, described in Chapter 10 (Emergency Operations)
Power System Security	Safe scheduling, operation and control of the power system on a continuous basis
Power System Stabiliser	Equipment controlling the Exciter output via the voltage regulator in such a way that power oscillations of the synchronous machines are dampened. Input variables may be speed, frequency or power (or a combination of these)
Power Transfer	Instantaneous rate at which active energy is transferred between connection points
Primary Response	The immediate automatic proportional increase or decrease of real power outputs by synchronised Generating Plants and other devices due to a fall or rise in frequency requiring changes in the Generating Plants Active Power output to restore the frequency to within operational limits as defined in Chapter 15 (Balancing and Frequency Control)
Prudent Utility Practice	The practices generally accepted and followed by electric utility industry of a Region conforming to the design, construction, operation, maintenance, safety and legal requirements which are attained by exercising that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from skilled and experienced operatives engaged in the same type of undertaking under the same or similar conditions
Quality of Service to Customers	Deals with the relationship between Licenses and Customers
Technical Quality of Electric Supply	Refers to technical aspects of power supply and covers such issues as voltage waveforms, service interruptions and outages
Ramp Rate	Rate of change of electricity produced from a Generating Plant
Rated Wind Speed	Average wind speed at which a wind power plant achieves its rated

	power. It is calculated as the average value of renewable speeds measured at hub height over a period of 10 minute
Reactive Energy	A measure, in varhours (varh) of the alternating exchange of stored energy in inductors and capacitors, which is the time- integral of the product of voltage and the out of phase component of current flow across a connection point
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 var and multiples thereof
Reactive Power Capability	Maximum rate at which reactive energy may be transferred from a Generating Plant to a Connection Point as specified in the connection agreement
Regional Control Center	A control centre responsible for the operation of the Distribution Network
Regulatory Authority	Ethiopian Energy Authority established by the Proclamation 810/2013 and the Council of Ministers Regulation No. 308/2014 replacing Ethiopian Energy Agency to issue licenses for generation, transmission and distribution, sale, and import/export of electric energy in Ethiopia
Remaining Capacity	The difference between available generating capacity and demand at the reference dates and calculated under normal climatic conditions as stated in Chapter 5 (Planning)
Remedial Action Scheme (RAS)	Also referred to as Special Protection System, RAS means a protection system that automatically initiates one or more control actions following electrical disturbances. Typical examples include tripping Generating Plants or loads and switching of series capacitors, shunt capacitors, or shunt reactors
Renewable Power Plant (RPP)	A Generating Plant whose primary energy source is a form of renewable energy, including but not limited to solar energy (for photovoltaic and concentrated solar plants), small hydro, geothermal, landfill gas, biomass, biogas, and wind, and whose generation output is variable in nature
Reserve	A measure of available capacity over and above the capacity needed to meet normal peak demand levels. In case of a Generating Plant, it is the capacity to generate more or less energy than the system normally requires. For a transmission company, it is the capacity to handle additional energy transport if demand levels rise beyond expected peak levels
Reserve, Regulating	A generation reserve that is under central AGC and can respond within ten seconds and be fully active within ten minutes of activation. This reserve is used for second-by-second balancing of supply and demand. This reserve is also used to restore instantaneous reserve within ten minutes of the disturbance. The provision of Regulating Reserves is a Secondary Response. Regulation reserve can be up or down
Reserve, Responsive	An ancillary service provided by on line generation resources that can

	respond to frequency deviations caused by a generating unit trip
Reserve, Spinning	Extra generating capacity that is available by increasing the power output of Generating Plants that are already connected to the power system. Spinning reserve is generally used for containing the frequency at acceptable limits following a contingency, such as a unit trip or a sudden surge in load
Reserve, Non-spin	Off-line generation capacity that can be ramped to capacity and synchronized to the grid within a pre-specified time (typically 10 to 30 minutes) of a dispatch instruction by the TSO, and that is capable of maintaining that output for at least for two hours
Response	The provision of a reserve
Response, Primary	Refer to Primary Response
Secondary Response	Refer to Secondary Response
Rota Disconnection	A planned and properly authorised temporary disconnection of electricity to Customers for a set duration on a rotational basis at times of a severe shortfall in electricity production
RSA ID	RSA ID is a two-factor authentication technology that is used to protect network resources. The two factors typically are: (i) a password or PIN; and (ii) an authenticator, could be a hardware token (such as a USB token, smart card or key fob). The software token is the RSA Authentication Manager Software that provides the security engine used to verify authentication requests
System Average Interruption Duration Index	SAIDI indicates average minutes of service interruption per customer. It is the sum total of customer minutes interrupted divided by the total number of customers served. SAIDI is considered as one of the best indicators of system stress
System Average Interruption Frequency Index	The sum total of number of interruptions divided by the total number of customers
Secondary Response	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 Generating Plants already synchronised to the ENTS and is normally controlled by the Ethiopia National TSO by AGC
Secretary, Ethiopia National Transmission Grid Code Review Committee	The person appointed by the Ethiopian Energy Authority to the Ethiopian National Grid Code Review Committee and named as such
Significant Incident	An event which has caused or could have caused injury to persons, damage to system equipment or operation of the Ethiopia Electric Transmission System outside the operational security standards
Solar Power Generating Plant	A Generating Plant deriving its source of energy from the sun and for which its generation is variable in nature)

Special Protection Scheme	Refer to Remedial Action Scheme
Steering Committee	The body established by EAPP in accordance with the Inter-Government Memorandum of Understanding and responsible for the Governance of EAPP
Sub-committee on Planning	EAPP body under the direction of EAPP Steering Committee responsible for the coordination of Master Plans and development programs of EAPP Member utilities
Switchyard	Connection point of a Generating Plant into the electrical power transmission grid
Synchronous Generator	Alternating current generators of most thermal and hydro (water) driven power turbines which operate at the equivalent speed of frequency of the power system in its satisfactory operating state
System Operation	Performance of generation scheduling, commitment and dispatch, scheduling of transmission and ancillary services, and generation outage coordination, transmission congestion management and coordination, and such other activities as may be required for the reliable and efficient operation of the grid
System Operator	The entity responsible for the overall coordination of the planning and operation of the Ethiopia Electric Transmission System, including the scheduling and dispatch of Generating Plants connected to it
System Tests	Those tests that involve either a simulated or a controlled application of irregular, unusual, or extreme conditions on the Interconnected Transmission System. In addition, they include commissioning and or acceptance tests on Plant and Apparatus to be carried out by a User that may have a significant impact upon the Ethiopia Electric Transmission System and or another National System
Tariff	A list of charges for electricity services as defined in the Energy Proclamation 810/2013
Tertiary Reserve	Refers to TSO instructed changes in the dispatching and commitment of Generating Plants. Tertiary Reserve is used for restoring both Primary and Secondary Response, to manage constraints on the ENTS and to bring the frequency to target values when the Secondary Response has been depleted. Where Tertiary Reserve is held on Generating Plants not synchronised to the ENTS, the Generating Plants shall be capable of being synchronised within a specified time generally between fifteen (15) minutes and one (1) hour
Test Proposal	Outline provided in writing of the actions proposed to be carried out as part of tests involving Plant and Apparatus forming part of the EAPP Interconnected Transmission System
Test Proposer	The Party proposing System Tests
Total Shutdown	The situation existing when all generation has ceased within the Ethiopia Electric Transmission System and there is no supply from

	External Systems and, therefore, the Ethiopia Electric Transmission System has shutdown.
Transmission	The operation, management or control of facilities, consisting of high voltage electric supply lines for movement of electrical energy in bulk between Generating Plants and transmission substations for the purposes of enabling supply to Customer.
Transmission Line	An electric conductor that is part of a transmission network
Transmission Licence	As defined in Proclamation810/2013
Transmission Licensee	Any entity licensed to operate, and maintain transmission assets within the Ethiopia Electric Transmission System in accordance with Proclamation 810/2013 and Council of Ministers Energy Regulations document
Transmission Metering Administrator (TMA)	The entity responsible for transmission metering installation, maintenance, and operation
Transmission Network	Infrastructure that supports the transportation of electricity from the point of generation to the distribution with the ultimate objective of bringing to the end users or consumers
Transmission Network Service Provider (TNSP)	An legal entity that operates and is licensed to own and maintain a transmission network on the ENTS under the Energy Proclamation 810/2013
Transmission System Capability Statement	Assessment by EAPP Sub-committee on Planning and TSOs of the capability of the EAPP Interconnected Transmission System to support the required energy flows across both Systems and cross-border connections as set out in Chapter 5 (Planning)
Transmission System Operator	The entity responsible for the overall coordination of the planning and operation of the Transmission System, including the scheduling and dispatch of Generating Plants connected to it
Unplanned Outage	Any Outage, which was not planned with ten (10) days' notice.
User	Any person or entity, connected to or making use of the Ethiopia Electric System as a Generation Licensee, Transmission Licensee, a Distribution Licensee, or End-use User
User System	The system of a Transmission Licensee or a Distribution Licensee, or a system owned or operated by a User comprising Generating Plants and/or Apparatus connecting Generating Plants and/or End-use Users' equipment
Voltage Dip	Brief reduction in voltage typically caused by factors such as: (i) starting of a motor, (ii) excessive current drawn by fault or short circuit, (iii) faults on distant circuit that can be automatically switched and removed by reclosers
Voltage Droop	Voltage change (p.u.) caused by a change in reactive power (p.u.).
Voltage Flicker	Fluctuation of light intensity caused by large and rapid changes in industrial load such as electric arc furnaces that deteriorates power

	quality
Voltage Transformer	Voltage Transformers are necessary for isolating the protection, control and measurement equipment from the high voltages of a power system, and for supplying the equipment with the appropriate values voltage
Wind Turbine Generator	A Generating Plant that converts kinetic energy from the wind into electric power
Works	(a) electric supply lines, machinery, lands, buildings, structures, earth works and water works, and includes any apparatus or things of whatsoever description, required for the importation, exportation, generation, transmission, distribution supply and use of electrical energy; or (b) pipelines, machinery, lands, buildings, structures, earth works and water works, and includes any apparatus or things of whatsoever description, required for the importation, exportation, storage, refining, transportation, dispensing and supply of petroleum; or (c) machinery, lands, buildings, structures, earth works and water works, and includes any apparatus or things of whatsoever description, required for the importation, exportation, storage, production, transportation, distribution and supply of any other energy form

2.3 LIST OF ABBREVIATIONS

The list below provides a summary of the abbreviations used in the ENTGC.

Table 2-2: Abbreviations used in the ENTGC

Abbreviation	Description
AC	Alternating Current
ACE	Area Control Error
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
AS	Ancillary Services
AVR	Automatic Voltage Regulator
CC	Connections Chapter
CDs	Compact Disks
CEO	Chief Executive Officer
COUE	Cost of Un-served Energy
CD	Compact Disc
CT	Current Transformer
DC	Direct Current
DCF	Discounted Cash Flow
DEC	Data Exchange Chapter
DNSP	Distribution Network System Provider
DR	Demand Response
DTE	Data Terminal Equipment
DVDs	Digital Video Disks
EAC	East African Community
EAPP	Eastern Africa Power Pool
EAPP CC	Eastern Africa Power Pool Communication Center
EAPP IC	Eastern Africa Power Pool and East African Community Interconnection Code
EEA	Ethiopian Energy Authority

EENS	Expected Energy Not Served
EEP	Ethiopia Electric Power
EEU	Ethiopian Electric Utility
EHV	Extra High Voltage
EMC	Ethiopia Metering Code
EMS	Energy Management System
ENDGC	Ethiopia National Distribution System Grid Code
ENDGCRC	Ethiopia National Distribution System Grid Code Review Committee
ENDS	Ethiopia National Distribution System
ENTGC	Ethiopia National Transmission System Grid Code
ENTGCRC	Ethiopia National Transmission System Grid Code Review Committee
ENTGCRR	Ethiopia National Transmission System Grid Code Revision Register
ENTS	Ethiopia National Transmission System
ENTSO	Ethiopia National Transmission System Operator
ENTSO-E	European Network of Transmission System Operators for Electricity
ESP	Electronic Security Perimeter
EUE	Expected Un-served Energy
FACTS	Flexible Alternating Current Transmission System
FTP	File Transfer Protocol
FY	Fiscal Year
GC	General Conditions
GCR	Grid Code Requirement
GD	Glossary and Definitions
GoE	Government of Ethiopia
GPS	Global Position System
GTP	Growth and Transformation Plan
HV	High Voltage

HVDC	High Voltage Direct Current
IANA	Internet Assigned Names Authority
ICCP	Inter-Control Centre Communications Protocol
ICS	Interconnected System
ICT	Information, Communication, and Technology
IEC	International Electro-technical Commission
IG-MoU	Inter-Governmental Memorandum of Understanding
IMC	Interchange Metering Chapter
IPP	Independent Power Producer
IPSec	Internet Protocol Security
ISBC	Interchange Scheduling and Balancing Chapters
IU-MoU	Inter-Utility Memorandum of Understanding
MCR	Maximum Continuous Rating
MIR	Metering Information Register
MTBF	Meantime Between Failure
MTTR	Meantime To Repair
NCC	National Control Center
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NTC	Net Transmission Capability
OC	Operations Chapters
PC	Planning Chapter
PCC	Point of Common Coupling
POC	Point of Connection
PPA	Purchase Power Agreement
PSS	Power System Stabilizer
PV	Photo Voltaic
QOS	Quality of Service
RAS	Remedial Action System

RCC	Regional Control Center
RPP	Renewable Power Plant
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SAIDI	System Average Interruption Duration Index
SIWL	Switching Impulse Withstand Level
SMTP	Simple Mail Transfer Protocol
SOTC	System Operator Training Chapter
SPS	Special Protection Scheme
SVC	Static VAR Compensator
TCP/IP	Transmission Control Protocol/Internet Protocol
TMA	Transmission Metering Administrator
TNSP	Transmission Network System Provider
TSO	Transmission System Operator
UM	Voltage Maximum
UN	Voltage Nominal
VT	Voltage Transformer
WAN	Wide Area Network

2.4 LIST OF UNITS

The table below provides a summary of the units used in one or more of the chapters in ENTGC.

Table 2-3: List of Units

Symbol	Unit
Amp	Ampere
GW	Gigawatt (1,000,000,000 W)
GWh	Gigawatt-hour

h, Hr, hrs	Hour
Hz	Hertz
Kbps	Kilobits per second
kV	Kilovolt
kVA	Kilovolt-ampere
kvar	Kilovars
kW	Kilowatt
kWh	Kilowatt-hour
Mbps	Megabits per second
mHz	Milli-hertz (1/1000 Hz)
Min	Minute
Ms	Milli-second (1/1000 s)
MVA	Megavolt-ampere
Mvar	Megavars
Mvarh	Megavar-hour
MW	Megawatt
MWh	Megawatt-hour
s, sec	Second
TW	Terawatt (1,000,000,000,000 W)
V	Volt
W	Watt

3 GENERAL CONDITIONS

3.1 INTRODUCTION

The General Conditions (GC) set out the over-riding principles to be used in the operation of the *ENTS* and form the basis for the decisions of a reasonable and prudent operator should specific events not be covered by the relevant code. The GC describes the provisions necessary for the overall administration and review of the various aspects of the *ENTGC*. The GC also deal with those aspects of *ENTGC* not covered in other Chapters, including the resolution of *Disputes*, bilateral agreements, confidentiality, non-compliance and the revision of the *ENTGC* through the *ENTGCRC*.

3.2 SCOPE

These General Conditions apply to the *Regulatory Authority*, *ENTSO*, Transmission Licensees, Distribution Licensees, and *Users* of the *ENTS*.

3.3 OBJECTIVE

The Generation Conditions contain provisions, which are of a general nature and apply to all Chapters of the *ENTGC*. The objectives of the GC are to ensure, to the extent possible, that the various Chapters of the *ENTGC* work together and work in practice for the benefit of the *ENTSO*, *Transmission Licensees, Distribution Licensees,* and *Users*.

3.4 IMPLEMENTATION AND ENFORCEMENT

The *Regulatory Authority* is responsible for the implementation and enforcement of the *ENTGC*.

For the above purposes, the *Regulatory Authority* may, in certain cases, need access to services and facilities of *Users* or *Transmission Licensees and Distribution Licensees*, or to issue instructions to *Users* or *Transmission Licensees and Distribution Licensees* to implement and enforce the *ENTGC*. Accordingly, all *Users* and *Transmission Licensees and Distribution Licensees* are required not only to abide by the letter and spirit of the *ENTGC*, but also to provide the *Regulatory Authority* with such rights of access, services and facilities and to comply with any instructions of the *Regulatory Authority*.

Each *Party* shall, at all times, in its dealings with other *Parties* to the *ENTGC* act in good faith and in accordance with *Prudent Utility Practice*.

3.5 SAFETY AND ENVIRONMENT

For the avoidance of doubt, nothing in or pursuant to this *ENTGC* shall be taken to require a *Party* to do anything which could or would be unsafe or contrary to the *Party's* environmental obligations nor shall prevent a *Party* from doing anything which could or would be unsafe or contrary to that *Party's* environmental obligations to omit to do.

3.6 UNFORESEEN CIRCUMSTANCES

If circumstances arise, which are not contemplated by the provisions of the *ENTGC*, the *Regulatory Authority* shall, to the extent reasonably practicable in the circumstances, consult promptly with all affected *Users* and *Transmission Licensees and Distribution Licensees* in an effort to reach agreement as to what should be done. If agreement between the *Regulatory Authority* and such *Users* and *Transmission Licensees and Distribution Licensees* cannot be reached in a reasonable time, the *Regulatory Authority* shall determine the best course of action in accordance with *Prudent Utility Practice*.

Each *User* and *Transmission Licensee* or *Distribution Licensee* shall comply with all instructions given to it by the *Regulatory Authority* following such a determination provided the instructions are consistent with the then current technical parameters of the *Transmission Licensee* or *Distribution Licensee's National System*. The *Regulatory Authority* shall, as soon as reasonably practicable following the unforeseen circumstances, notify all relevant details to the *ENTGCRC* for consideration and recommendations in accordance with Chapter 4 (Governance).

3.7 FORCE MAJEURE

In situations of *Force Majeure,* the provisions of the *ENTGC* may be suspended in whole, or in part, pursuant to any directions given by the *Regulatory Authority* being the custodian of the *ENTGC*.

Neither *Party* shall be held to have defaulted in respect of any obligation under the *ENTGC* if prevented or delayed from performing that obligation, in whole or in part, because of a *Force Majeure* event. If a *Force Majeure* event prevents or delays a *Party* from performing any of its obligations under the *ENTGC*, that *Party* shall:

(a) Promptly notify any other Party involved, the *Regulatory Authority* of the Force Majeure event and its assessment in good faith of the nature and the effect that the event will have on its ability to perform any of its obligations and the measures that the Party proposes to take to alleviate the impact of the Force Majeure event. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable. The notice shall be posted on the *ENTSO* Website

(b) Not be entitled to suspend performance of any of its obligations under the *ENTGC* to any greater extent or for any longer time than the Force Majeure event requires it to do

(c) Use its best efforts to mitigate the effects of the Force Majeure event, remedy its inability to perform, and resume full performance of its obligations

(d) Keep the other Party continually informed of its efforts, and

(e) Provide written notice to the other Party when it resumes performance of any obligations affected by the Force Majeure event. The notice shall be published on the *ENTSO* Website

3.8 COMPLIANCE

(a) All parties shall comply with the *ENTGC* as updated via *Regulatory Authority* decisions from time to time.

(b) Certification of safety compliance by a licensed electrical inspector shall be a pre-requisite for energizing an electrical installation from the supply line of the licensee

(c) Participants shall inform the *Regulatory Authority* of any non-compliance report of a material nature that has been submitted to another participant without delay, but no later than 30 days after becoming aware of the item unless there is significant risk to the *ENTS*, which then must be reported immediately

(d) Failure to comply with the requirements, conditions, or obligations of Certificate of Competency as stated in Proclamation 810/2013 is punishable with simple imprisonment of up to three years, or with a fine not more than Birr 15,000 or with both

(e) The *Regulatory Authority* may require a participant to provide the *Regulatory Authority* with information that it deems necessary for the proper administration of the *ENTGC*. This information shall be treated as confidential

(f) Upon a report or suspicion of non-compliance the *Regulatory Authority* may seek to resolve the issue through negotiation

1. Take action in terms of the procedures for handling licensing contraventions
2. Consider an application for amendment
3. Consider an application for exemption

(g) Application for exemption or suspension of obligations under the *ENTGC* is treated under Section 3.9 Non-Compliance below

3.9 NON-COMPLIANCE

If a Transmission Licensee or *TNSP* or *User* finds that it is, or will be unable to comply with any provision of this *ENTGC*, then that party shall without delay, but not later than 30 days after discovery, report such non-compliance to the *Regulatory Authority*.

3.9.1 Non-Compliance Situations

If the Transmission Licensee or *TNSP* or *User* fails to fulfill all the provisions established in this *ENTGC*, it shall be considered a Non Compliance situation.

A Non- Compliance situation will include, but is not limited to:

(a) Failure to provide the *Regulatory Authority*, on time, all of the information established in this Performance Standards

(b) Providing the *Regulatory Authority* incomplete or inaccurate data or reports, in particular inaccuracies or other problems verified by the audits of the *Regulatory Authority*

(c) Failure to implement in time the procedures and information systems required in the *ENTGC* established in this Performance Standard.

(d) Failure or unsuitable delays in the execution of the approved remedial actions and plans to comply with *ENTGC* provisions following the approval of a Derogation and mitigation plan

3.9.2 Penalties

If the *Regulatory Authority* determines that the *User* is in a non-compliance situation for which *Derogation* has not been filed, or is in the process of being filed, or for which a *Derogation* has not been approved by the *Regulatory Authority*, or is in violation of the terms of an approved *Derogation*, the *Regulatory Authority*will determine and apply a penalty for the non-compliance situation. The *Regulatory Authority* shall also consider that the *Transmission Licensee* is in non-compliance with its licence conditions, and may suspend or revoke the licence. The *Regulatory Authority* shall use directives under Item No. 144 (Penalty) under the "Final English Draft Energy Operation Regulation – Version (2)", as appropriate, while issuing a penalty.

Generation, transmission, distribution, sales, import, export of electricity for commercial purposes; performing electrical work, energy audit, *Energy Efficiency* and *Energy Conservation* contracting or consultancy service without valid license are punishable as per the Energy Proclamation 810/2013.

The *Regulatory Authority* shall also consider the following factors while imposing penalties:

(a) Severity of the non-compliance and any environmental, health, and safety impacts
(b) Instances of repeated and deliberate non-compliance
(c) Penalties shall be comparable to those specified in other laws, regulations, and applicable contracts
(d) Penalties shall be set at a level such that non-compliance will not be economically preferable to compliance

3.10 DEROGATION

The *Regulatory Authority* may issue *Derogations* suspending a *Transmission Licensee's or Distribution Licensee*'s or a *User*'s obligations to implement or comply with the *ENTGC* to such an extent as may be specified in the *Derogations.*

If a *User* finds that it is, or will be, unable to comply with any provision of the *ENTGC*, then they shall, without delay, report such non-compliance to the *Regulatory Authority*. The applicant may request an exemption from the *ENTGC* requirement, or request additional time to correct the non-compliance item.

A *Party* seeking *Derogations* from any provision in the *ENTGC* shall make a written request to the *Regulatory Authority* containing the following information. Refer also to the sample Request for *Derogation* form in Appendix A.

(a) Name of the *Party* applying for *Derogation*

(b) Contact information, name and signature of CEO or other corporate officer delegated by the CEO

(c) The specific provision of *ENTGC* (section number and title) against which the present or predicted non-compliance is identified

(d) The reason for non-compliance

(e) The nature and extent of the non-compliance

(f) The date of non-compliance discovery and reporting of the non-compliance

(g) Identification and description of the system, facility, equipment, process, procedure or specific connection point in respect of which *Derogation* is sought

(h) Whether the *Derogation* sought is permanent exemption or for a delay in achieving compliance, and If a delay in achieving compliance is being sought, the date by which the non-compliance will be remedied

(i) A description of any health and safety implications and the associated risk management measures

(j) A description of the proposal for restoring compliance (where applicable) including details of actions to:

1. Mitigate risks to customers or other authorized electricity operators
2. Restore compliance (including timetable of works)

(k) A description of the reasonable alternative actions that have been considered

(l) A statement of the expected duration of the non-compliance

(The *User* is required to justify the *Derogation* request in terms of both the specific circumstances and the expected duration. Licensees are advised to give as much notice as possible when making *Derogation* requests since Derogation will not be granted unless the *Regulatory Authority* is satisfied that the request is justified.)

3.10.1 Derogation Review

Upon receipt of any request for *Derogation*, the *Regulatory Authority* shall promptly consider such a request provided that the *Regulatory Authority* considers that the grounds for the *Derogation* are reasonable. In its consideration of a *Derogation* request, the *Regulatory Authority* may contact the relevant *User* to obtain clarifications, request additional information or to discuss changes to the request, and review possible remedial actions to achieve compliance as soon as reasonably practicable.

The *Regulatory Authority* may initiate at its own initiative a review of any existing *Derogations*, and any *Derogations* under consideration where a relevant and material change in circumstance has occurred.

The *Regulatory Authority* may also seek the views and advice of an *Independent Expert* on the proposed *Derogation*, as set out in section 3.11 in this chapter.

It may be the case that not all *Plant* and *Apparatus* in use as at the date of adoption of this *ENTGC* will be able to meet the requirements of the *ENTGC*. In some cases, it may not be economically or technically necessary to upgrade such existing *Plant* and *Apparatus* to the required *ENTGC* standards. Where this is the case the *Regulatory Authority* will give consideration to a time bound *Derogation* for all or part of the *ENTS*.

In the event that *Derogation* is granted, the *Transmission Licensee or Distribution Licensee* or *User* shall take all necessary action to ensure full compliance with the obligation for which the *Derogation* has been granted.

Where a material change in circumstances has occurred, a review of any existing *Derogation* and any *Derogation* under consideration may be initiated by the *Regulatory Authority*.

3.10.2 Derogation Register

The *Regulatory Authority* shall keep a register of all *Derogations, which* have been granted, identifying the name of the *Transmission Licensee or Distribution Licensee* or *User* and *Plant* and *Apparatus* in respect of which the *Derogation* has been granted, the relevant provision of the *ENTGC*, the period of *Derogation* and the extent of compliance with the provisions. The register of *Derogations* shall be published on the *ENTSO Website*.

Upon request from any *Transmission Licensee or Distribution Licensee* or *User*, the *Regulatory Authority* shall provide a copy of such register of *Derogations* to such *Transmission Licensee or Distribution Licensee* or *User*.

3.10.3 Transitional Provisions

Transitional Provisions are intended to facilitate compliance and reduce the need for *Derogation* requests to suspend obligations under *ENTGC* provisions.

Transitional Provisions are provisions of the *ENTGC* approved by the *Regulatory Authority* that shall not apply either in whole or in part to some or all *User*s. They differ from Derogation *i*n that:

(a) They cover potentially many *Users*

(b) They can be sought by a group of *User*s with similar needs to suspend obligations

(c) In appropriate circumstances, the *Regulatory Authority* can initiate a Transitional Provision

Situations, which might require the use of Transitional Provisions, include (but are not limited to):

(a) The effective date of the *ENTGC* and its impact on requirements, such as multiple old *Generating Plants* that need equipment upgrade in order to reach compliance

(b) Discovery of a common-mode problem with equipment

Transitional Provisions may require a plan of how the affected *Users* are going to reach compliance, or reasons why they should be permanently exempt.

3.11 DISPUTE RESOLUTION

3.11.1 Mutual Discussion

If a *Dispute* between *the Regulatory Authority* and any *Transmission Licensee or Distribution Licensee* or *User* or between *Users* in connection with, or arising out of, the interpretation, implementation or breach of any provision in this *ENTGC*, any *Party* may issue to the other *Party* a written notice (the "*Dispute Notice*") outlining the matter in *Dispute*. Following issue of a *Dispute Notice* both *Parties* shall discuss in good faith and attempt to settle the *Dispute* between them.

Dispute resolution may include a request to the *Regulatory Authority* to refer the matter to the *ENTGCRC* to consider the disputed *ENTGC* provisions and offer recommendations on resolution of the *Dispute*.

Settlement of Dispute shall be handled as described in PART SEVEN SETTLEMENT OF DISPUTE, "COUNCIL OF MINISTERS REGULATION TO PROVIDE FOR THE REGULATION OF ENERGY OPERATIONS".

3.11.2 Determination by the Regulatory Authority

If the *Dispute* cannot be settled within thirty (30) business days after issue of the *Dispute Notice*, either *Party* shall have the right to refer the *Dispute* to the *Regulatory Authority* for arbitration. Proclamation 810/2013, Part Eight (Miscellaneous Provisions), Section 38 (Settlement of Disputes) shall be consulted as appropriate. The general guideline for the procedure will be as follows:

(a) The request for referral shall be made in writing to the *Regulatory Authority* and a dated copy of the original *Dispute Notice* between the *Parties* shall be attached

(b) Upon receipt of a request for referral, the *Regulatory Authority* shall write to the Parties acknowledging that the *Dispute* has been referred to the *Regulatory Authority* for determination

(c) Following receipt of *Regulatory Authority* acknowledgment, each Party shall have five (5) business days to submit their reason(s) as to the cause of the *Dispute* in writing to the *Regulatory Authority* and

(d) No later than ten (10) business days after the *Regulatory Authority* has received each Party's reason(s) as to the causes of the *Dispute* in writing, the *Regulatory Authority* shall write to each Party setting out the manner in which it intends to resolve the *Dispute* and indicate a date by which a determination may be expected which in any case shall not exceed three (3) months. The *Regulatory Authority* may also seek the views and advice of an Independent Expert on settlement of the *Dispute* as set out in section 3.11 in this chapter (General Conditions)

The determination by the *Regulatory Authority* shall be legally binding on all *Parties*.

Determinations by the *Regulatory Authority* are subject to appeal before the Energy Tribunal as provided under the "COUNCIL OF MINISTERS REGULATION TO PROVIDE FOR THE REGULATION OF ENERGY OPERATIONS".

3.12 INDEPENDENT EXPERT OPINION

If any matter is referred to an independent expert in accordance with the description in Chapter 4 (Governance), the *Independent Expert* shall be appointed by the *Regulatory Authority* as appropriate. Such person shall be an expert with specialized skills in the matter under consideration and must not have any material relationship with any of the *Parties* to the matter. When referring a matter to an *Independent Expert* a written brief shall be prepared containing:

(a) A description of the *Derogation* requested or the matter on which the *Independent Expert* is required to express an opinion or give advice;

(b) All the relevant documentation;

(c) All the relevant correspondence between Parties, and

(d) A request that the Independent Expert drafts an opinion setting out a possible solution to the issue.

The *Independent Expert* shall not act as an arbitrator. Provisions of any arbitration legislation shall not apply and the *Regulatory Authority* will undertake to treat his determination as binding and conclusive upon them.

The *Independent Expert* shall determine the procedure to be followed for preparing an opinion. The venue for the *Independent Expert's* inquiries will be agreed between the *Parties* to the matter under consideration. Modern technologies such as videoconferencing may be used to ensure that the process is as cost efficient and equitable as possible.

The *Independent Expert* must within fifteen (15) business days of his appointment accept submissions from the *Parties* in *Dispute* and must state his determination of those matters within sixty (60) business days of his appointment.

Responsibility for the entire cost of the Independent Expert shall be:

(a) In the case of referral pursuant to section 3.9.4 in this chapter, the Party or Parties seeking revision of the *ENTGC* shall equally divide the entire cost

(b) In the case of referral pursuant to section 3.10.2 in this chapter, the Party or Parties seeking *Derogation* pursuant to section 3.10.1 in this chapter shall equally divide the entire cost

(c) In the case of referral pursuant to section 3.11 in this chapter, the disputing Parties shall equally divide the entire cost

3.13 ENTGC INTERPRETATION

In the event that any *Transmission Licensee, Distribution Licensee, or User* requires additional interpretation of the wording or application of any provision of the *ENTGC*, they make a request to the *Regulatory Authority* for such interpretation. If the request is reasonable, the *Regulatory Authority* shall provide the *Transmission Licensee, Distribution Licensee* or *User* with an interpretation of the relevant provision. In the event that a *Transmission Licensee, Distribution Licensee,* or *User*, acting reasonably, deems that an interpretation provided by the *Regulatory Authority* is unreasonable or inappropriate, the matter is resolved as provided in Section 3.11 Dispute Resolution of the *ENTGC*.

3.14 HIERARCHY

In the event of any conflict between the provisions of the *ENTGC* and any contract, bilateral agreement or arrangement between a *Transmission Licensee, Distribution Licensee,* or a *User*, the provisions of the *ENTGC* shall prevail unless the *ENTGC* expressly provides otherwise.

3.15 CONFIDENTIALITY

All data exchanged relating to connection to, planning, operation and maintenance of the *ENTS* shall be treated by all *Parties* as confidential.

Confidential information does not include:

(a) Information that is in the public domain provided that specific items of information shall not be considered as in the public domain merely because more general information is in the public domain and provided that the information is not in the public domain as a result of a breach of confidence by the Party seeking to disclose the information or a Party to whom it has disclosed the information

(b) Information required to be published or information required to be disclosed in any Chapter of the *ENTGC*, and

(c) Information that must be disclosed in compliance with a judicial or governmental order or other legal process

All data relating to and exchanged among Parties concerning the *ENTS* shall be considered to be *Confidential Information*. The *Regulatory Authority* shall consult with the *ENTSO* and *Users* concerning the publication of any of the data exchanged. Aggregate data may be made available by the *ENTSO,* when requested by a *User*. These data shall be used only for the purpose specified in the request and shall be treated by the *User* as confidential. All such disclosure of *Confidential Information* shall be subject to a written Confidentiality Agreement duly signed by the *ENTSO* and *User*. Such *Confidential Information* shall not be disclosed to other parties without the express written consent of the parties to the Confidentiality Agreement.

3.15.1Confidential Information

(a) Each *Party* shall use all reasonable endeavours to keep confidential any *Confidential Information* which comes into the possession or control of that *Party* or of which the *Party* becomes aware. The information owner may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, is provided.

(b) A Party:

1. Shall not disclose *Confidential Information* to any person except as permitted by the *ENTGC*;
2. Shall only use or reproduce *Confidential Information* for the purpose for which it was disclosed or another purpose contemplated by the *ENTGC*;
3. Shall not permit unauthorised persons to have access to *Confidential Information*

(c) Each Party shall use all reasonable endeavours:

1. To prevent unauthorised access to confidential information which is in the possession or control of that Party; and
2. To ensure that any person to whom he discloses *Confidential Information* observes the provisions of this Section 3.15.1 in relation to that information
3. To control unauthorised access to confidential information and to ensure secure information exchange. Parties shall report any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak, and shall provide the information owner with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the information owner)

3.15.2Exceptions

This Section does not prevent:

(a) The disclosure, use or reproduction of information if the relevant information is at the time generally and publicly available other than as a result of breach of confidence by the *Party* who wishes to disclose, use or reproduce the information or any person to whom the *Party* has disclosed the information

(b) The disclosure, use or reproduction of information to the extent required by law or by a lawful requirement of:

1. Any government or governmental body, authority or agency having jurisdiction over a *Party* or his related bodies corporate; or

(c) The disclosure, use, or reproduction of information if required in connection with legal proceedings

3.15.3Application of Confidentiality to the Regulatory Authority

For the purpose of Section 3.15, other than Section 3.15.4, "*Party*" includes the *Regulatory Authority* and any council, Committee or other body established by the *Regulatory Authority* under the *ENTGC*.

3.15.4 Indemnity to the Regulatory Authority

Each *Party* indemnifies the *Regulatory Authority* against any claim, action, damage, loss, liability, expense or outgoing which the *Regulatory Authority* pays, suffers, incurs, or is liable for in respect of any breach by that *Party* or any officer, *agent* or employee of that *Party* of this Section 3.15.4 of the *ENTGC*.

3.15.5 Party Information

Each Party shall develop and, to the extent practicable, implement a policy to protect information that is acquired pursuant to the various functions from use or access, which is contrary to the provisions of the *ENTGC*.

3.15.6 Information on Ethiopia National Transmission Grid Code Bodies

The *Regulatory Authority* shall develop and implement policies concerning:

(a) The protection of information which *ENTGC* Bodies acquire pursuant to their various functions from use or access by *Parties* or *ENTGC* Bodies which is contrary to the provisions of the *ENTGC*; and

(b) The dissemination of such information where appropriate to *Parties* and other interested parties

3.16 CONSTRUCTION OF REFERENCES

3.16.1 Preamble, Table of Contents and Headings

The Preamble, table of contents, and headings are inserted for information and convenience only and shall not be used in construing the provisions of the *ENTGC*.

3.16.2 Cross References

A cross-reference to another document or part of the *ENTGC* shall not of itself impose any additional or further or co-existent obligation or confer any additional or further or co-existent right in the part of the text where such cross-reference is contained.

3.16.3 Definitions

(a) Terms and expressions printed in italics are listed in the Glossary and Definitions Chapter and shall, unless the context otherwise requires or is not consistent therewith, bear the respective meaning set out therein

(b) Terms not herein defined shall have the meaning ascribed thereto in the Oxford English Dictionary.

(c) Where the Glossary and Definitions refers to any word or term which is more particularly defined in a part of the *ENTGC*, the definition in that part of the *ENTGC* will prevail over the definition in the Glossary and Definitions in the event of any inconsistency

3.16.4 Figures

Figures are provided in some Chapters of the *ENTGC* for convenience and to illustrate a process. In case of any discrepancy between the text and figures regarding any provision of the *ENTGC*, the text shall prevail.

3.16.5 Gender, Singular and Plural

Unless the context otherwise requires, the singular shall include the plural and vice versa, and references to any gender shall include the other gender.

3.16.6 Include and Including

References to the words "include" or "including" are to be construed without limitation to the generality of the preceding words.

3.16.7 Mandatory Provisions

The word "shall" refers to a rule, procedure, requirement, or any other provision of the *ENTGC* that requires mandatory compliance.

3.16.8 Person or Entity

References to a person or entity shall include any individual and any other entity, in each case whether or not having a separate legal personality.

3.16.9 References

References to clauses, provisions or to a particular paragraph, sub-paragraph, or Appendix are, unless the context otherwise requires, references to that clause, provision, paragraph, sub-paragraph, or Appendix in or to that part of the *ENTGC* in which the reference is made.

3.16.10 Written and In Writing

Any references to "in writing" or "written" include typewriting, printing, lithography, and other modes of reproducing words in a legible and non-transitory form.

3.17 LANGUAGE

This *ENTGC* is written in English. In case of any discrepancies between the English version and a version translated into any other language, the English version shall prevail.

4 GOVERNANCE

4.1 INTRODUCTION AND OBJECTIVE

The objective of this Governance Chapter is to describe the provisions necessary for the overall administration and review of the various aspects of the *ENTGC*. This chapter also summarizes the main documents and organizations that provide the authority governing the planning, construction, and operation of the *ENTS*.

This *ENTGC* shall be read in conjunction with the relevant legislation including the Proclamation 810/2013 and any applicable amendments related to the administrative authority for the *ENTGC*. The *ENTGC* requirements shall also be applied in conjunction with the licences issued to Generation Licensees, Transmission companies, TNSPs, and regulations that relate to the *ENTS* adopted by the *Regulatory Authority* and the MOWIE. All Transmission Licences and agreements concluded after implementation of the *ENDGC* shall include the obligation of parties to comply with *ENTGC* requirements.

This chapter also describes the methodology that will be used to:

a. Ensure that *Users* are represented in reviewing and making recommendations to the development and revision of the *ENTGC* requirements

b. Facilitate the monitoring and auditing of compliance with the *ENTG*

c. Specify the processes used for the settlement of disputes

4.2 GOVERNANCE DOCUMENTS

The primary laws defining governance are Ethiopia's Proclamation 810/2013, and Council of Ministers Regulation NO. 308/2014 that established the *Regulatory Authority*.

The functions of the *Regulatory Authority* under the Proclamation include but are not limited to issuing competency certification in the areas of inspection, maintenance, testing, design, consultancy, contracting and electro mechanical activities together with electrical installation work. The *Regulatory Authority* functions also include establishing regional regulation framework guiding the operational arrangements, and practices of electrical works in power generation, transmission, interconnection, and distribution with well- defined structure that addresses roles and responsibilities of relevant stakeholders.

The organisations with governance functions include the *Regulatory Authority,* and the *MOWIE*, which oversees the activities of the *Regulatory Authority*.

4.3 THE ETHIOPIA NATIONAL TRANSMISSION GRID CODE REVIEW COMMITTEE (ENTGCRC)

The *Regulatory Authority* shall establish and maintain, as a standing committee, the *ENTGCRC*, which shall be governed by the provisions of the *ENTGCRC* set out in Section 4.3.4 in this chapter. The *Regulatory Authority* is responsible for the review of the operations and revision of the *ENTGC*. The *ENTGCRC* shall not have a decision-making authority and the *Regulatory Authority* shall not be bound by its deliberations or recommendations.

4.3.1 Role of the ENTGCRC

The *ENTGCRC* shall:

(a) Keep the *ENTGC* and its working under review;

(b) Ensure that the *ENTGC* is consistent in its approach and is developed to reflect changes in *Prudent Utility Practice* and technology

(c) Review and discuss all proposals for amendments to the *ENTGC* which the *Regulatory Authority , ENTSO, and/*or *Users* submit to the *ENTGCRC* for consideration from time to time

(d) Review anything referred to it by the *Regulatory Authority and* consider whether the actions taken by the *ENTSO* were justified and what changes, if any, are necessary to the *ENTGC*

(e) Present recommendations to the *Regulatory Authority* as to amendments to the *ENTGC* that the *ENTGCRC* considers warranted and the reason for such changes

(f) Publish such recommendations and the reasons for them on the *Regulatory Authority* Website

(g) Review existing standards relevant to the operation of the *ENTS* and make modifications or proposals for new standards in relation to the operation of the *Ethiopia Electric Transmission System*, and

(h) Issue guidance in relation to the *ENTGC* and its implementation, performance and interpretation

4.3.2 Composition of the ENTGCRC

The *ENTGCRC* shall consist of the following Members:

(a) A Chairperson appointed by the *Regulatory Authority*

(b) One person representing the *Regulatory Authority*

(c) One person representing the *ENTSO*

(d) One person representing public *Transmission Licensees* and one person representing private *Transmission Licensees*

(e) One person representing public *Distribution Licensee* and one person representing private *Distribution Licensees*

(f) One person representing public *Generation Licensees* and one person representing private *Generation Licensee*

In the case that any of the above categories include more than one entity, the constituents shall form a caucus and appoint a representative. All appointments are subject to approval by the *Regulatory Authority* with regard to required minimum qualifications for Members provided in Section 4.3.5.

4.3.3 Conduct of Business

The *ENTGCRC* shall establish and comply at all times with its own rules and procedures governing the conduct of its business as approved by the *Regulatory Authority*.

If the *ENTGCRC* is unable to reach unanimous or consensus agreement on any matter presented before it, it shall report the cause of disagreement and the views held by the respective *Members* of the *ENTGCRC* to the *Regulatory Authority*.

4.3.4 Rules of the ENTGCRC

4.3.4.1 Committee Name

The Committee charged with making recommendations to the *Regulatory Authority* on the review of the operation and revision of the *ENTGC* shall be called the *Ethiopia National Transmission Grid Code Review Committee (ENTGCRC)* and shall be governed by the provisions set out in this section of the *ENTGC*.

4.3.5 ENTGCRC Member Qualifications

Due to the technical nature of many of the duties and responsibilities of the *ENTGCRC* Members, any person that is being considered as an *ENTGCRC* Member must meet the following minimum experience and qualifications;

4.3.5.1 Chairperson

(a) Minimum of ten (10) years of electric industry experience in a technical capacity

(b) Minimum of seven (7) years of energy sector regulatory compliance oversight experience

4.3.5.2 Committee Member

(a) Minimum of seven (7) years of electric industry experience in a technical capacity

(b) Minimum of three (3) years of experience in regulatory compliance responsibilities for an electric utility, *Regulatory Authority* or independent power producer

4.3.6 Term of Office

The term of office of a Member shall be three (3) years from the date of his or her appointment. A Member may resign, be reappointed replaced or removed in accordance with the provisions set

forth for the governance of the *ENTGCRC*.

The *Regulatory Authority* has the right to modify the term of office during the initial formation of the *ENTGCRC* to assure that incumbent member's terms do not expire at the same time. This will assure that the Committee has a consistent mix of incumbents and new *Members*.

4.3.7 Appointment by Regulatory Authority

If at any time any person entitled to appoint a *Member* or *Members* has not made an appointment and/or is in disagreement as to whom to appoint and as a result no *Member* represents that entity, the *Chairperson* shall notify the *Regulatory Authority* . The *Regulatory Authority shall* have the right, until the relevant entity has made an appointment, to appoint a *Member* on behalf of that entity. The appointed *Member* must be from an entity from the corresponding category as described in Section 4.3.2. In the event that the *Regulatory Authority* does not exercise this right, the *ENTGCRC* shall be regarded as complete in the absence of that *Member*.

4.3.8 Nature of Member

No person other than an individual shall be appointed a Member or his alternate.

4.3.9 Retirement of Members

If a *Member* chooses to retire before the end of their term, written notification shall immediately be given to the *Chairperson*. The *Chairperson* shall notify the *Party* that appointed the retiring *Member*, and by notice in writing to the *Chairperson*, the said *Party* shall indicate its wish to appoint a new *Member*. Should the position of a *Member* become vacant, the *Party* appointing him must appoint a replacement within twenty-five (25) calendar days.

Such notifications for re-appointment or appointment must be delivered to the *Chairperson* at least twenty one (21) days in advance of the meeting of *the ENTGCRC* from the person or group of persons represented by each Member.

4.3.10 Alternates

Each entity shall have the power to appoint any individual to be an *Alternate* to the *Member*, and may at its discretion, remove an alternate Member so appointed. An entity shall not appoint another *Member* as an *Alternate*. Any appointment or removal of an alternate *Member* shall, unless the Chairperson otherwise agrees, be effected by notice in writing executed by the appointer and delivered to the Secretary or tendered at a meeting of the *ENTGCRC*. If his appointer so requests, an alternate *Member* shall be entitled to receive notice of all meetings of the *ENTGCRC* or of sub-committees or working groups of which his appointer is a *Member*. He shall also be entitled to attend and vote as a *Member* at any such meeting at which the *Member* appointing him is not personally present and at the meeting to exercise and discharge all the functions, powers and duties of his appointer as a *Member*. For the purpose of the proceedings at such meetings, the provisions of this Constitution shall apply as if the alternate appointed were a *Member*. An alternate shall have

all the rights and obligations of a *Member* including voting rights

4.3.11 Ceasing to Act

An alternate *Member* shall cease to be an alternate *Member* if his appointer ceases for any reason to be a *Member*.

4.3.12 References Include Alternates

References to a *Member* shall, unless the context otherwise requires, include his duly appointed alternate.

4.3.13 Representation and Voting

4.3.13.1 Representation

The *Chairperson* and every *Member* shall be entitled to attend and participate at every meeting of the *ENTGCRC*. One adviser (or such greater number as the *Chairperson* shall permit) shall be entitled to attend any meeting of the *ENTGCRC* with each *Member*.

4.3.13.2 Voting

The *ENTGCRC* will seek to achieve a unanimous consensus agreement among all voting *Members*. If the *Committee* is unable to reach unanimous consensus on an item, a simple majority voting method will be used. If there is a tie after voting, the *Chairperson* will be allowed to cast a tie-breaking vote. Otherwise, the *Chairperson* shall not cast a vote.

4.3.14 Removal

Any person or persons entitled to appoint a *Member*, including the *Chairperson*, may at any time replace that *Member* or the *Chairperson*, as the case may be, from office and appoint another person in his place. A person or persons will only have the right to remove from the *Committee* the person that it or they have appointed, and will have no right to remove from office the *Chairperson* or any other *Member*, as the case may be, appointed by another person. In the event of disagreement amongst persons entitled to appoint a *Member*, the relevant provisions of 4.3.7 "Appointment by the *Regulatory Authority*" shall apply with any necessary changes. Whenever any individual *Member* or the *Chairperson* changes, the person or group of persons entitled to appoint that *Member* or the *Chairperson*, shall notify the Secretary in writing within seven (7) days of the change taking effect.

4.4 THE CHAIRPERSON POSITION

4.4.1 Appointment/Removal

The *Regulatory Authority* may, at any time replace the *Chairperson*. Upon retirement or

replacement by the *Regulatory Authority* of the first and each successive *Chairperson*, the *Regulatory Authority* shall appoint a person to act as *Chairperson*.

4.4.2 Alternate Chairperson

The *Chairperson* shall preside at every meeting of *the ENTGCRC* at which he is present. If the *Chairperson* is unable to be present at a meeting, but has appointed an alternate, such alternate shall act as *Chairperson*. If neither the *Chairperson* nor his alternate is present within half an hour after the time appointed for holding the meeting, the *Members* present may appoint one of their number to act as *Chairperson* of the meeting; such appointee shall not be treated as the *Chairperson*'s alternate and shall not be entitled to cast the *Chairperson*'s vote.

4.5 THE SECRETARY POSITION

4.5.1 Appointment

The *Regulatory Authority* shall have power to appoint and dismiss a Secretary and such other staff for the *ENTGCRC* as it may deem necessary. The *Regulatory Authority* shall notify each Member of the identity and address for correspondence of the Secretary as soon as reasonably practicable after the appointment of the first Secretary and, subsequently after the appointment of any new Secretary. The Secretary may, but need not, be a Member but shall not be a Member by virtue only of being Secretary. The Secretary shall have the right to speak at meetings but, unless they are a Member, they have no right to cast a vote at any meeting.

4.5.2 Duties

The Secretary's duties shall be to attend to the day-to-day operation of the *ENTGCRC* and, in particular, to:

(a) Attend to the requisition of meetings and to serve all requisite notices;

(b) Maintain a register of names and addresses of Members and their alternates as appointed from time to time; and

(c) Keep minutes of all meetings.

4.5.3 Registers

The Secretary shall make available the registers of names and addresses and minutes for inspection by the *Regulatory Authority*, Members, and Member Transmission and Transmission Licensees.

4.5.4 Group Representative's Addresses

Each Member shall provide all contact information (e.g., address, email address, office and mobile number). In addition, each member shall be responsible for communicating any change of contact information to the Secretary. Notices sent to the latest address provided shall be considered as having been duly given.

4.6 MEETINGS

4.6.1 Date and Venue

The *ENTGCRC* shall hold meetings quarterly at regular scheduled times as the Committee may decide.

4.6.2 Further Meetings

The Chairperson or any other Member may request the *Secretary* to requisition meetings by giving a twenty-one (21) day notice to the Secretary. The notice shall be in writing and contain a summary of the agenda of the business that is proposed to be conducted. The Secretary shall proceed to convene a meeting of the *ENTGCRC* within seven (7) days of the date of expiry of such notice.

4.6.3 Notice of Meetings

4.6.3.1 Notice by Chairperson

All meetings shall be called by the *Chairperson* on at least fourteen (14) days written notice (exclusive of the day on which it is served and of the day for which it is given), or by shorter notice if so agreed in writing by all Members. The *Chairperson* shall provide notice of the meeting to Consumer organizations, to allow their representatives to observe the meeting.

4.6.3.2 Details in Notice

The notice of each meeting shall contain the time, date and venue of the meeting, an agenda.

4.6.3.3 Failure to Give Notice

The accidental omission to give notice of a meeting or the non-receipt of notice of a meeting by a person entitled to receive notice shall not invalidate the proceedings at that meeting.

4.6.3.4 Proposal for Agenda

By notice to the Secretary, any Member can request additional matters to be considered at the meeting. Provided such notice is given at least ten (10) days (exclusive of the day on which it is served and of the day for which it is given) before the date of the meeting, those matters will be included in a revised agenda for the meeting. The Secretary shall circulate the revised agenda to each Member as soon as practicable.

4.6.4 Proceedings at Meetings

4.6.4.1 Quorum

Fifty percent (50%) plus one (1) Member present in person, or by their alternates, shall constitute a quorum.

4.6.4.2 Inquorate Meetings

If, within half an hour from the time appointed for holding any meeting of the *ENTGCRC*, a quorum is not present, the meeting shall be adjourned to such day, time and place as the Secretary may notify to *Members* within three (3) days of the adjournment.

The adjourned meeting shall not be called upon to take place within one week of the adjournment but may be called on less than fourteen (14) day notice.

4.6.5 Agenda

Only matters identified in the agenda shall be resolved upon at a meeting. However, this shall not prevent matters raised under the heading "Any Other Business" from being discussed, and if the Chairperson thinks fit, be resolved.

4.6.6 Validity of Acts

All acts done by any meeting of the *ENTGCRC* that there was some defect in the appointment of a Member, be as valid as if such person had been duly appointed.

4.6.7 Meeting Attendance

Members shall attend meetings in person. In special circumstances as approved by the *Chairperson*, meetings may consist of a conference between *Members* who are not all in one place but who are able directly or by teleconference to speak to each of the others and to be heard by each of the others simultaneously. The word "meeting" shall be construed accordingly.

4.6.8 Minutes

4.6.8.1 Circulation

The *Secretary* shall circulate copies of the minutes of each meeting of the *ENTGCRC* to each *Member* as soon as practicable and in any event within ten (10) business days after the meeting has been held.

4.6.8.2 Approval of Minutes

Each *Member* shall notify the Secretary of his approval or disapproval of the minutes of each meeting within ten (10) business days of receipt of the minutes. A *Member,* who fails to do so, will be deemed to have approved the minutes. The approval or disapproval of the minutes aforesaid will

not affect the validity of decisions taken by the *ENTGCRC* at the meeting to which the minutes relate.

4.6.8.3 Amendments

If the Secretary receives any comments on the minutes, he shall then include those aspects of the minutes upon which there is disagreement into the agenda for the next following meeting of the *ENTGCRC* as the first item for resolution.

4.6.9 Guidance from the ENTGCRC

The *ENTGCRC* may at any time, and from time to time, issue guidance in relation to the *ENTGC* and its implementation, performance and interpretation, and it may establish sub-committees and working groups to carry out such work.

4.6.10 Sub-Committees and Working Groups

4.6.10.1 Sub-Committees

The *ENTGCRC* may establish and may co-opt such sub- committees from time to time consisting of such persons as it considers desirable, whether *Members* or not. Each sub-committee shall be subject to such written terms of reference and shall be subject to such procedures as the *ENTGCRC* may determine. The meetings of sub-committees shall so far as possible be arranged so that the minutes of such meetings can be presented to the *Members* in sufficient time for consideration before the next following meeting of the *ENTGCRC*.

4.6.10.2 Working Groups

The *ENTGCRC* may further establish working groups to advise it on any matter from time to time. Such working groups may consist of Members and/or others as the *ENTGCRC* may determine for the purpose.

4.6.10.3 Resolutions

Resolutions of sub-committees and working groups shall not have binding effect unless approved by resolution of the *ENTGCRC*.

4.7 VACATION OF OFFICE

The office of a Member shall be vacated if:

(a) they resign office by notice delivered to the Secretary; or

(b) they become bankrupt or compounds with their creditors generally; or

(c) they become of unsound mind or a patient for any purpose of any statute relating to mental health; or

(d) they or their alternate fails to attend more than three (3) consecutive meetings of the *ENTGCRC* without submitting an explanation to the Chairperson which is reasonably

acceptable to the Chairperson.

4.8 MEMBER'S RESPONSIBILITIES AND PROTECTIONS

4.8.1 Responsibilities

In the exercise of its powers and the performance of its duties and responsibilities, the *ENTGCRC* shall have due regard for the need to promote the attainment of the principal duties of the *ENTGCRC*.

4.8.2 Representation

In the exercise of its powers and the performance of its duties and responsibilities as a Member, a Member shall represent the interests of the institution or entity by whom he was appointed, provided that such obligation of representation shall at all times be subordinate to the obligations of the Member as a Member of the *ENTGCRC*.

4.8.3 Reliance on Documentation

The *ENTGCRC*, each Member and the Secretary shall be entitled to rely upon any communication or document reasonably believed by it or him to be genuine and correct and to have been communicated or signed by the person by whom it purports to be communicated or signed.

4.9 REVISIONS TO THE ENTGC

Any *User*, *ENTGCRC* Member, the *ENTSO*, and the *Regulatory Authority* may propose revisions to the *ENTGC*. The *Regulatory Authority* as the custodian of *ENTGC* shall have the sole authority to make revisions to the *ENTGC*. Before approving any proposed revisions to *ENTGC*, the *Regulatory Authority* shall be guided by the *ENTGCRC* recommendations on the matter and any representations made by Parties. In considering the proposed revisions, the *Regulatory Authority* may also seek the opinion of an Independent Expert.

The *Regulatory Authority* shall, as required, prepare and issue amended versions of the *ENTGC* containing such revisions, as have been approved by the *Regulatory Authority*. All revisions to the *ENTGC* shall be recorded in the *ENTGCRR*, which shall indicate the date, Chapter amended and the reason for the change. An up to date *ENTGC* including all approved revisions shall be published on the *Regulatory Authority* website along with the *ENTGC* Revision Register. The revised version of the *ENTGC* shall take effect from the date on which it is published on the *Regulatory Authority* website, or such other later date as specified by the *Regulatory Authority*.

4.10 ENTGC AUDITS

4.10.1 Customer Request

A customer may request from the *TNSP*, or a *TNSP* may request from a customer, any material in the possession or control of that participant relating to compliance with a Section of the *ENTGC*. The requesting participant may not request such information in relation to a particular section of the *ENTGC* within six (6) months of a previous request made under this Section in relation to the relevant Section.

4.10.2 Information Requirements

A request under this Section 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

4.10.3 Withholding of Information

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.

4.11 CONTRACTING

The *ENTGC* shall comprise one of the standard documents that form part of the contract between *TNSP* and each of their customers. *TNSP* shall contract with customers for any services specified in the *ENTGC*.

4.12 REGISTRATION OF LICENSEES

4.12.1 Users

TNSP shall ensure that transmission agreements between *TNSP* and *end-use customers* after the implementation of the *ENTGC* shall include an obligation on customers to comply with *ENTGC* requirements.

4.12.2 Licensed Entities

The *Regulatory Authority* shall ensure that all licensees comply with *ENTGC* requirements.

4.12.3 Registration of ENTGC Licensees

No entity shall have access to the *ENTS* before obtaining a license from the *Regulatory Authority as defined in the Council of Ministers Energy Regulations document*. The *Regulatory Authority* shall be responsible for creating and maintaining a register of licensees as described in the Council of Ministers Energy Regulations document. Service-providers shall ensure that Users are registered as licensees before entering into a contract for services with such customers.

A *User* who no longer holds a license from the *Regulatory Authority* shall be removed from the register of licensees.

4.13 NOTICES

4.13.1 Service of Notices under the ENTGC

A notice is properly given under the *ENTGC* to a person if:

(a) It is personally served; or

(b) A letter containing the notice is prepaid and posted to the person at an address (if any) supplied by the person to the sender for service of notices or, where the person is a *User*, an address shown for that person in the register of *Users* to whom licenses have been issued under Proclamation 810/2013 maintained by the *Regulatory Authority* or, where the addressee is the *Regulatory Authority*, the registered office of the *Regulatory Authority* or

(c) It is sent to the person by facsimile or electronic mail to a number or reference which corresponds with the address referred to in Section 4.14.1(b) in this chapter or which is supplied by the person to the *Regulatory Authority* for service of notices; or

(d) It is published in a newspaper with wide circulation in the area where the person is resident or in a daily newspaper circulated generally

(e) It is communicated verbally to the person and that communication is recorded or thereafter confirmed in writing; or

(f) The person receives the notice

4.13.2 Time of Service

A notice is treated as being given to a person by the sender:

(a) Where sent by post in accordance with Section 4.13.1(a) in central Addis Ababa, on the second business day after the day on which it is posted
(b) Where sent by post in accordance with Section 4.13.1(b) to any other address, on the third business day after the day on which it is posted
(c) Where sent by facsimile in accordance with Section 4.13.1(c) and a complete and correct transmission report is received
(d) Where the notice is of the type in relation to which the addressee is obliged under the *ENTGC* to monitor the receipt by facsimile outside of, as well as during, business hours, on the day of transmission; and

(e) In all other cases, on the day of transmission if a business day or, if the transmission is on a day which is not a business day or is after 16h00 Hr (addressee's time), at 9h00 Hr on the following business day
(f) Where sent by electronic mail in accordance with Section 4.13.1(c)
(g) Where the notice is of a type in relation to which the addressee is obliged under the *ENTGC* to monitor receipt by electronic mail outside of, as well as during, business hours, on the day when the notice is recorded as having been first received at the electronic mail destination; and
(h) In all other cases, on the day when the notice is recorded as having been first received at the electronic mail destination, if a business day or if that time is after 16h00 Hr (addressee's time), or the day is not a business day, at 9h00 Hr on the following business day; or
(i) Where published in a newspaper in accordance with Section 4.13.1(d), on the next day after the date of publication of the notice
(j) In any other case, when the person actually receives the notice

4.13.3 Counting of Days

Where a specified period (including, without limitation, a particular number of *days*) shall elapse or expire from or after the giving of a notice before an action may be taken neither the *day* on which the notice is given nor the *day* on which the action is to be taken may be counted in reckoning the period.

4.13.4 Reference to Addressee

In this Section, a reference to an addressee includes a reference to an addressee's officers, *agents*, or employees or any person reasonably believed by the sender to be an officer, *agent* or employee of the addressee.

4.14 ENFORCEMENT

4.14.1 Investigations

(a) A *User* shall, if requested by the *Regulatory Authority*, supply it with information relating to any matter concerning the *ENTGC* in such form, covering such matters and within such reasonable time as the *Regulatory Authority* may request

(b) If a *User* fails to comply with a request by the *Regulatory Authority* for information as described in Section 4.15.1(a) in this chapter, the *Regulatory Authority* may appoint a person to investigate the matter and to prepare a report or such other documentation as the *Regulatory Authority* may require. A *User* shall assist the person to undertake the investigation and to prepare the report or other documentation. In addition, a *User* shall, at the request of the person appointed, direct third parties to make available such information as the person may reasonably require

(c) The cost of the investigation and of preparing the report or other documentation prepared by the person appointed shall be met by the *User* directed to supply the information under Section 4.15.1(a) in this chapter unless the *Regulatory Authority* otherwise determines

(d) Any report or other documentation referred to in this Section 4.14.1 in this chapter may be used in any proceeding involving the *Regulatory Authority* under the *Act* or for the purpose of commencing any such proceeding

(e) The *Regulatory Authority* shall develop and implement guidelines in accordance with the *ENTGC* consultation procedures governing the exercise of the powers conferred on it by this Section 4.14.1.

(f) The guidelines referred to in Section 4.14.1(e) in this chapter shall set out the circumstances that a *User* will be required to bear the cost of providing the information sought by the *Regulatory Authority* under this Section 4.14.1, including where no breach of the *ENTGC* by the relevant *User* has occurred

4.14.2 Entry and Inspection

The *Regulatory Authority* and its authorised officers and representatives shall have such rights of entry to premises and installations as may be granted under the *Proclamation 810/2013*

4.14.3 Functions of the Regulatory Authority

The functions of the *Regulatory Authority* are set out in the *Proclamation 810/2013.*

4.14.4 Alleged Breaches of the ENTGC

(a) If a *User* considers that another *User* or *consumer* may have breached or may be breaching this *ENTGC* or any provision in their C*onnection Agreement,* the aggrieved *User* may, in accordance with this *ENTGC* or the terms of their C*onnection Agreement*:

1. Give notice to the person in breach to immediately take steps to remedy and/or stop the breach, as the case may be
2. Subject to Section 4.14.4 in the chapter, impose any sanctions on the person in breach as provided in this *ENTGC* or their C*onnection Agreement* and
3. Without limitation to his powers, use reasonable endeavours to give effect to any sanctions so imposed

(b) If the *Regulatory Authority* considers that:

1. A *User* may have breached or may be breaching the *ENTGC*; and
2. Given the circumstances of the breach is established, it would be appropriate that a sanction or sanctions be imposed on that User, the *Regulatory Authority* shall notify the User of the alleged breach and details of the sanctions, which may be imposed if the breach is established

(c) If the *Regulatory Authority* receives written information from a *User* or any other person which alleges a breach of the *ENTGC* by a *User*, the *Regulatory Authority* shall within five (5) *business days* of receipt of the information determine whether, based on that information, there would appear prima facie to be a breach of the *ENTGC*

(d) If the *Regulatory Authority* considers that a *User* may be the subject of a *disconnection* order it shall:

1. Promptly notify the *Users* which the *Regulatory Authority* considers may be affected; and
2. Without limitation to its powers, use reasonable endeavours to give effect to any arrangements notified to the *Regulatory Authority A* by the *Users* for ensuring the continuation of *supply* to the relevant purchasers of electricity

4.14.5 Sanctions

The nature of sanctions that may be imposed under the *ENTGC* and the circumstances, in which a *User* or the *Regulatory Authority* may implement any sanction that has been imposed, shall be set out in regulations approved or issued by the *Regulatory Authority*.

4.14.6 Regulatory Authority Action

(a) The *Regulatory Authority* may direct a *User* or any person to do or refrain from doing anything that the *Regulatory Authority* thinks necessary or desirable to give effect or assist in giving effect to any of its orders

(b) Without limiting the generality of Section 4.14.6(a), the *Regulatory Authority* may direct a *TNSP* to *disconnect* a *User* or any *consumer* from any *transmission system* or *distribution system* in order to assist in giving effect to any of its orders

(c) A *User, consumer* or any person shall comply with a direction given under Section 4.14.6(a)

4.14.7 User Actions

If any partner, *agent*, officer, or employee of a *User* does any act or refrains from doing any act which if done or not done (as the case may be) by a *User* would constitute a breach of the *ENTGC* such act or omission shall be deemed for the purposes of this Section 4.14.7 to be the act or omission of the *User* concerned.

4.14.8 Publications

(a) The *Regulatory Authority* shall publish a report at least once every six (6) months setting out a summary for the period covered by the report of:

1. Matters which have been referred to it
2. All its findings during that period; and
3. Any sanctions it applied under the *Proclamation 810/2013*

(b) In considering the circulation of a report under Section 4.14.8(a), the *Regulatory Authority* shall have regard to *ENTGC* objectives

(c) In addition to the regular publication described in Section 4.14.8(a), the *Regulatory Authority* may publish a report on any one or more matters that have been referred to it, its findings in relation to those matters and any sanctions imposed in relation to those matters. A decision by the *Regulatory Authority* to publish a report under this Section 4.14.8(c) is a reviewable decision

(d) No *User*, or former *User* is entitled to make any claim against the *Regulatory Authority* for any loss or damage incurred by the *User* or former *User* from the publication of any

information pursuant to Section 4.14.8(a) Or (c) if the publication was done in good faith. No action or other proceeding will be maintainable by the person or *User* referred to in the publication against the *Regulatory Authority* or any person publishing or circulating the publication on behalf of the *Regulatory Authority* and this Section operates as leave for any such publication except where the publication was not done in good faith

4.14.9 System Security Directions

(a) Notwithstanding any other provisions of the *ENTGC*, a *User* shall follow any direction issued by or on behalf of the *TSO*, which the *TSO* is entitled to issue in exercising his powers under the Operations Chapter of the *ENTGC* relevant to maintaining or restoring *power system security*

(b) Any event or action required to be performed pursuant to a direction issued under the Operations Chapters of the *ENTGC* on or by a stipulated *day* is required by the *ENTGC* to occur on or by that *day*, whether or not a *business day*

(c) Any failure to observe such a direction will be deemed to be a breach of the *ENTGC*

(d) Any *User* who is aware of any such failure or who believes any such failure has taken place shall refer the allegation to the *Regulatory Authority* in accordance with the procedures contained in Section 4.14.4

4.15 MONITORING AND REPORTING

4.15.1 Monitoring Objectives

(a) The *Regulatory Authority* is responsible for monitoring compliance with and shall use its reasonable endeavours to ensure the effectiveness of the *ENTGC* in accordance with its objectives

(b) The *Regulatory Authority* shall undertake such monitoring as it considers necessary:

1. To determine whether *Users* are complying with the *ENTGC*
2. To assess whether the *Dispute* resolution, *ENTGC* enforcement, *ENTGC* change and other mechanisms are working effectively in the manner intended
3. To determine whether in its operation, the Code is adequately giving effect to objectives specified in the *ENTGC*; and
4. To collect, analyse, and disseminate information relevant and sufficient to enable the *Regulatory Authority* to comply with its reporting and other obligations and powers under the *ENTGC*

(c) The *Regulatory Authority* shall ensure that, to the extent practicable in light of the objectives set out in Section 4.15.1(b), the monitoring processes which it implements under this Section 4.15:

1. Are consistent over time
2. Do not discriminate unnecessarily between *Users*
3. Are cost effective to both the *Regulatory Authority* and all *Users*; and
4. Are publicised or information relating thereto is available to any person, subject to any requirements as a result of the confidentiality obligations

4.15.2 Reporting Requirements and Monitoring Standards

(a) The *Regulatory Authority* shall establish:

1. Reporting requirements for *Users* in relation to matters relevant to the *ENTGC*; and
2. Procedures and standards applicable to the *Regulatory Authority* and *Users* relating to information and data received by or from *Users* in relation to matters relevant to the *ENTGC*

(b) Prior to establishing requirements or standards and procedures referred to in Section 4.15.2(a), the *Regulatory Authority* shall consult with such *Users* as the *Regulatory Authority* considers appropriate. In formulating requirements or procedures and standards, the *Regulatory Authority* shall take into consideration the monitoring objectives set out in Section 4.15.1. The reporting requirements, standards, and procedures established by the *Regulatory Authority* are reviewable decisions

(c) Subject to Section 4.15.2(d), the *Regulatory Authority* shall notify to all *Users* particulars of the requirements, procedures, and standards that it establishes under this Section 4.15.2

(d) If the *Regulatory Authority* establishes additional or more onerous requirements or procedures and standards, which do not apply to all Users, and the *Regulatory Authority* considers that notification of those matters to all *Users* would contravene the confidentiality provisions in Section 3.15, the *Regulatory Authority* shall notify only those *Users* to whom the requirements or procedures and standards apply

(e) Each *User* shall comply with all requirements, procedures and standards established by the *Regulatory Authority* under this Section 4.15.2 to the extent that they are applicable to him within the time period specified for the requirement, procedure or standard or, if no such time period is specified, within a reasonable time. Each *User* shall bear his own costs associated with complying with these requirements, procedures, and standards

(f) In complying with his obligations or pursuing his rights under the *ENTGC*, a *User* shall not recklessly or knowingly provide, or permit any other person to provide on behalf of that *User*, misleading or deceptive data, or information to any other *User* or to the *Regulatory Authority*

(g) Any *User* may ask the *Regulatory Authority* to impose additional requirements, procedures, or standards under this Section 4.15.2 on another *User* in order to monitor or assess compliance with the *ENTGC* by that *User*. When such a request is made, the *Regulatory Authority* may but is not required to impose the additional requirements, procedures, or standards. A decision by the *Regulatory Authority* to impose additional requirement procedures or standards is a reviewable decision. If the *Regulatory Authority* decides to impose additional requirements, procedures, or standards, the *Regulatory Authority* may determine the allocation of costs of any additional compliance monitoring undertaken between the relevant *Users*. *Users* shall pay such costs as allocated. In the absence of such allocation, the *User* subject to the additional requirements, procedures, or standards will bear his own costs of compliance

(h) The *Regulatory Authority* shall develop and implement guidelines in accordance with the *ENTGC* consultation procedures governing the exercise of the powers conferred on it by Section 4.15.2(g) which guidelines shall set out the matters to which the *Regulatory*

Authority shall have regard prior to deciding the allocation of costs of any additional requirements, procedures or standards imposed pursuant to Section 4.15.2(g) between the relevant *Users*

4.15.3 Use of Information

(a) Subject to confidentiality obligations set out in the Confidentiality Sections of the *ENTGC*, the *Regulatory Authority* is entitled to use any data or information obtained as a result of any monitoring requirements imposed under Section 4.15.2 in pursuance of any of the *Regulatory Authority*'s powers or functions under the *ENTGC*. Without limitation, the *Regulatory Authority* may use any such information in connection with or to initiate:

1. A process to change or revise the *ENTGC*; or
2. An investigation under the *ENTGC*

(b) A *User* may claim that the information provided to the *Regulatory Authority* is confidential in nature to the *User* or that the *User* is under an obligation to another person to maintain the confidentiality of all or part of the information. Notwithstanding that the *Regulatory Authority* may consider the claim by the *User* to be reasonable, if the *Regulatory Authority* considers that its reporting obligations set out in the *ENTGC* make the disclosure of the information necessary or desirable, the *Regulatory Authority Regulatory Authority* may disclose the information. In doing so, the *Regulatory Authority* shall use all reasonable endeavours to ensure the information is disclosed only in a manner and to the extent that, as far as practicable, protects the confidential nature of the information and in no way is the *Regulatory Authority* to be liable for publishing or disclosing any information under this Section 4.16.3

(c) Prior to disclosing in accordance with Section 4.15.3(b) information which a *User* claims is confidential, the *Regulatory Authority* shall first notify that *User* as soon as practicable after the *Regulatory Authority* has made the decision to disclose the information

(d) Any decision by the *Regulatory Authority* under Section 4.15.3(b) to disclose information that is claimed by a User to be confidential is a reviewable decision and the *Regulatory Authority* shall not disclose the information until twenty-eight (28) *days* after it has provided written notice to the relevant *User* that it intends to disclose the information

4.15.4 Reporting

(a) Not later than the last day in each calendar year, the *Regulatory Authority* shall prepare and give an annual report for the previous *fiscal* year to all *Users* and interested parties. The annual report shall include:

1. The *Regulatory Authority*'s assessment of the extent to which the operation of the *ENTGC* during that period met the *ENTGC* objectives and of the strategic development of the *ENTGC* to meet industry objectives
2. The *Regulatory Authority*'s audited accounts for the period covered by the report
3. A report on the matters set out in the Operations Chapter concerning the *System Operator*'s use of powers of direction in relation to *power system security* granted to him under the Operations Chapter
4. A summary of, and reasons for, any *changes* to the *ENTGC*

5. A summary of identified material breaches of the *ENTGC* and the actions taken in response, including particulars of any sanctions imposed
6. A summary of any *Dispute* involving the *Regulatory Authority* and their resolutions
7. A summary of material matters in relation to the *Dispute* resolution under the *ENTGC* (without identifying the parties); and
8. The *Regulatory Authority* 's assessment of the matters set out in Section 4.15.1(b), which it is required to monitor

(b) In addition to the annual report described in Section 4.15.4(a), the *Regulatory Authority* may, if it considers it appropriate, provide an interim report to *Users* and interested parties on any one or more of the matters that should be contained in the annual report

4.15.5 Recovery of Reporting Costs

Where, under the *ENTGC*, the *Regulatory Authority* is entitled or required to publish or give information, notices or reports to any *User* or any other person, unless the context otherwise requires, the *Regulatory Authority* (as the case may be) shall charge those persons a fee at cost for providing them with a copy of the information or report.

5 PLANNING

5.1 EAPP IC REQUIREMENTS

5.1.1 Introduction

The Planning Chapter (PC) specifies the minimum technical and design criteria, principles and procedures:

(a) To be used within *EAPP* in the planning and in the medium and long-term development of the *EAPP Interconnected Transmission System*

(b) To be taken into account by Member Utilities on a coordinated basis, and

(c) To specify the planning data required to be exchanged by Member Utilities and the *EAPP Sub-Committee on Planning* to enable the *EAPP Interconnected Transmission System* to be planned in accordance with the planning standards

The PC specifies the requirements for the interchange of information between *EAPP Sub-Committee on Planning* and individual *TSOs*. This information is required to enable *EAPP Sub-Committee on Planning* and *TSOs* to take due account of developments, new connection sites or the modification of existing connection sites in a *National System* or new, or the modification of, connections with *External Systems*, including changes in factors such as demand, generation, new technology, reliability and environmental requirements that may also have an impact on the planning and operation of the *EAPP Interconnected Transmission System*.

All parts of the *EAPP Interconnected Transmission System* shall be designed so that the demand for electricity can be met reliably at the lowest cost. This means that the *EAPP Interconnected Transmission System* shall be planned, built, and operated so that sufficient transmission capacity will be available to utilise the generation capacity and to meet the needs of customers in an economic way.

The long-term economic design of the *EAPP Interconnected Transmission System* aims at a balance between investments and the cost of maintenance, operation, and supply interruptions, taking into account environmental and other limitations. Flexible solutions, which take into, account future uncertainties, such as generation limitations, new generation technologies, uncertain load development and technical development, should be selected.

5.1.2 Objectives

The objectives of the PC are to provide for:

(a) Coordination by the *EAPP Sub-Committee on Planning* of any proposed development or reinforcement of a *National System* or construction of new or modification of interconnections with *External Systems* to ensure that the reliability and security of the *EAPP Interconnected Transmission System* is not compromised

(b) Cooperation between the *TSOs* in the planning and procurement of new generation capacity at lowest overall cost, taking into account environmental considerations, and

(c) Submission of sufficient information to enable a *TSO* to optimise the planning and development of its *National System* including the use of available transmission capacity on the *EAPP Interconnected Transmission System*

5.1.3 Scope

The PC applies to the *EAPP Sub-committee on Planning* and to the *TSOs*. The *TSOs* are responsible for the collection of information from all *Users* connected to their *National System* and for providing any relevant information required by the PC to the *EAPP Sub-committee on Planning*.

Those *TSOs* with connections to *External Systems* shall ensure that the supply of data required under the PC should be contemplated in the *Interconnection Agreement* with the *External System* seeking a new or modified interconnection.

5.1.4 Principles of the Planning Chapter

These principles apply to the overall planning of the *EAPP Interconnected Transmission System*. The planning principles are concerned with planning of the interconnection between *National Systems,* connections with *External Systems* and with those facilities within *National Systems, which* have, or could have, an impact on the reliability of the *EAPP Interconnected Transmission System*.

The principles should also be applied in the planning of *National Systems* to ensure that the reliability criteria can be met. The principles, however, do not apply to local supply reliability and other local considerations, which are the subject of National Grid Codes or equivalent documents.

The reliability level for the *EAPP Interconnected Transmission System* is defined by a set of minimum criteria in the PC together with the performance characteristics and requirements set out in the Connection Chapter, which must both be met when designing developments, expansions, and reinforcements of both *EAPP Interconnected Transmission System* and *National Systems*. The criteria are based on a balance between the probability of contingencies and their consequences.

Reliable transmission capacity can be achieved by specifying standards for primary, protection, and auxiliary equipment as well as by reserve capacity and other operational resources as set out in the Operations Chapters.

5.1.5 Reliability Criteria

All *Plant* and *Apparatus* of the *EAPP Interconnected Transmission System* shall operate within normal capacity ratings, thermal loading and voltage limits under steady-state conditions as set out in Connection Chapter. The *EAPP Interconnected Transmission System* shall be able to supply all loads within the emergency limits for bus voltages and *Plant* and *Apparatus* loadings during the *Outage* of any line or transformer (N-1 criteria).

The security and reliability of the *EAPP Interconnected Transmission System* shall not be compromised by the loss of any single power system element such as *Generating Unit*, transmission circuit, and section of busbar, transformer or reactive compensation equipment.

The loss of a single element shall not cause:

(a) Any violation of the normal operational limits such as voltage, frequency or *Plant* and *Apparatus* loading which would jeopardise the safety and reliability of the *EAPP Interconnected Transmission System* or would cause overloading of *Plant* or *Apparatus*

(b) Islanding of any part of the *EAPP Interconnected Transmission System*

(c) Loss of stability of the *EAPP Interconnected Transmission System*; or

(d) Cascading *Outages* of other elements because of exceeding operational security limits as set out Chapter 9 (Operational Security or OC2)

These criteria are not applicable to areas connected by radial lines to a *National System* where loss of load and any local generation may be acceptable.

The N-1 criterion may be assured in a *National System* with the support of another interconnected *National System*, subject to the prior agreement of the respective *TSOs*.

The planning criteria for dynamic security are defined such that the *EAPP Interconnected Transmission System* shall remain stable following a single *Contingency*. The *EAPP Interconnected Transmission System* is able to remain stable in some cases following a fault without the outage of any transmission element by a successful auto-reclosing. If the attempt of auto-reclosing fails, the fault shall be cleared by tripping the faulted element.

5.1.6 Planning Process

The horizon for the planning of the *EAPP Interconnected Transmission System* extends over ten (10) years. The process has two elements:

(a) A forecast, the *Power Balance Statement*, by *TSOs* for each *National System* of their expected demand and generation over the planning horizon. This forecast will define the requirements for generation support from the *EAPP Interconnected Transmission System* for individual *National Systems*, and

(b) An assessment, the *Transmission System Capability Statement* by *EAPP Sub-committee on Planning* and *TSOs* of the capability of the *EAPP Interconnected Transmission System* to support the require energy flows across both *National Systems* and cross-border interconnections

5.1.6.1 Power Balance Statement

TSOs will prepare and submit to the *EAPP Sub-committee on Planning* the *Power Balance Statement*. This report will be submitted by 30 September annually showing in respect of the ten (10) succeeding calendar years:

(a) The projection of the seasonal maximum and minimum demand for electricity in each *National System* and the corresponding energy requirements for each year across the study period. These forecasts will correspond to certain reference dates to be defined by the *EAPP Sub-committee on Planning*

(b) The amount and nature of generation capacity currently available to meet the demand and any anticipated restrictions in the production of energy

(c) The amount of generation capacity it expects will be required to ensure that *Operating Margins* are achieved

(d) Details of plans for building additional *Generating Units* including upgrades of existing generation capacity

(e) The amount and nature of demand to be met by other *EAPP Member Countries* using transmission capacity available on the *EAPP Interconnected Transmission System*, and

(f) The power transfers anticipated with *External Systems*

The difference between available generating capacity and demand at the reference dates is called the *Remaining Capacity* and is calculated under normal climatic conditions. This *Remaining Capacity* represents the reserves available, which can be used to cover demand above forecast or *Generating Unit Outages* greater than expected. The *Remaining Capacity* can be positive with export potential or negative where the lack of capacity signals a need for imports.

The EAPP Sub-committee on Planning shall produce a Power Balance Statement for the EAPP Interconnected Transmission System based on the individual *TSOs*' Power Balance Statements.

5.1.6.2 Transmission System Capability Statement

Once the *Power Balance Statement* has identified the ability of each *TSO* to cover its internal demand with the available national generation capacity, a transmission adequacy assessment shall be carried out by each *TSO* in conjunction with the *EAPP Sub-committee on Planning.* This assessment will determine the capability of the *National System* to support the required energy flows across both the *National System* and cross-border connections.

Based on the transmission adequacy assessment carried out by each *TSO*, the *EAPP Subcommittee on Planning* will produce a *Transmission System Capability Statement* for the *EAPP Interconnected Transmission System*. This *Transmission System Capability Statement* is focused on the cross-border connections and those *TSO's National Systems, which* have a direct effect on the cross-border exchanges.

In producing the *Transmission System Capability Statement,* the *EAPP Sub-committee on Planning* shall consider various scenarios for interchanges, demands and generation. Sensitivity analysis shall be carried out taking into account such parameters as hydrological conditions and fuel price variations.

The *EAPP Sub-committee on Planning* may also consider the use of *Remedial Action Schemes (RAS),* in which automatic control equipment disconnects or otherwise controls generation, demand, or network elements other than for faults. Such *RAS* are used to enhance transmission capacity at the

expense of reliability and may only be used following specific agreement between the *EAPP Steering Committee* and the affected *TSO*.

The *EAPP Sub-committee on Planning* will determine the form and content of the *Transmission System Capability Statement* to be issued each year and shall publish it on the *EAPP* Website.

5.1.7 EAPP Power System Modeling

In order to produce the *EAPP Transmission System Capability Statement,* it will be necessary to carry out system analysis, including steady state and dynamic simulations of the *EAPP Interconnected Transmission System*. This system analysis is required in order to assess the reliability of the *EAPP Interconnected Transmission System* to meet the forecast demand and determine the need for system enhancements or reinforcements.

These system studies will be carried out by both the *EAPP Sub-committee on Planning* and the *TSOs* and shall be performed using a common set of principles and a common database. To achieve this, the *EAPP Sub-committee on Planning* shall establish a set of common objectives for the development and submission of system data for *EAPP* power system modelling. The data shall include sufficient detail to ensure that system contingencies, steady state, transient and dynamic analyses can be simulated. The data required for system studies is set out in the Data Exchange Chapter.

5.1.8 Responsibilities

EAPP Sub-committee on Planning in conjunction with the *TSOs* shall identify the scope and specify the data required for reliability analyses and the procedures for data reporting. These requirements and procedures should be periodically reviewed, documented, and published for the *EAPP Interconnected Transmission System* at least every five (5) years.

Each *TSO* shall provide accurate and appropriate equipment characteristics and power system data for modelling and simulation purposes as required by the *EAPP Sub-committee on Planning*.

5.1.9 Planning Data Confidentiality

System planning data shall be treated as non-confidential when the *EAPP Sub-Committees on Planning and Operations* and *TSOs* use such data:

(a) In the preparation of forecasts, Power Balance Statements and Transmission System Capability Statements

(b) For the planning of the *EAPP* Interconnected Transmission System

(c) To consider a Connection Application or provide advice to a *User*

(d) Under the terms of an Interconnection Agreement with an External System

5.2 ENTGC REQUIREMENTS

All the requirements presented in Section 5.1 EAPP IC Requirements shall apply in this Section 5.2 and in all other places in this Planning Chapter.

5.2.1 Introduction

Section 5.2 specifies the criteria and procedures to be applied by Ethiopia's *Planning and Development organization(*s) in the planning and development of the *ENTS*. It furthermore provides for accountability for *ENTS* planning and development and sets the required standards and targets. It also specifies the reciprocal obligations and interactions between *Users*.

5.2.2 Transmission System Planning and Development

(a) The *ENTS* planning and development shall be in accordance with the prevailing *Regulatory Authority* regulatory framework, as being implemented from time to time

(b) The development and update of the *ENTS* planning may occur for a number of reasons, including but not limited to:

1. Changes to customer requirements or networks
2. The introduction of a new transmission substation or Connection Point or the modification of an existing connection between a customer and the *ENTS*
3. The cumulative effect of a number of developments as referred to above
4. The need to reconfigure, decommission or optimise parts of the existing network

(c) The development of the *ENTS* may include work involving transformer, breaker, switches and other equipment connecting to the *ENTS*

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

5.2.2.1 Planning Process

(a) Ethiopia's *Planning and Development organization(*s) shall follow a planning process divided into major activities as follows:

1. Identification of the problem
2. Formulation of alternative options to meet this need
3. Study of these options to ensure compliance with agreed technical limits and justifiable reliability and quality of supply standards
4. Costing of these options on the basis of approved procedures
5. Determination of the preferred option
6. Building of a business case for the preferred option using the approved justification criteria
7. Request for approval of the preferred option and initiation of execution

5.2.2.2 Identification of Need for Transmission System Development

(a) The *ENTSO* shall review data from all relevant sources, including specific customer information, system performance statistics, *ENTS* load forecast, and government and customer development plans to establish the need for network strengthening

(b) The needs shall be determined through the modeling of the *ENTS* over at least a ten-year term, utilizing reasonable load and generation forecasts and equipment performance scenarios. Studies for purposes of determining connection charges payable by customers may cover a shorter period if appropriate

(c) The *ENTSO* shall annually conduct a planning review with parties to co-ordinate the *ENTS* and *ENDS*

5.2.3 Demand Forecast

(a) The *ENTSO* in consultation with the *TNSP*s and *DNSP*s, shall annually produce *ENTS* demand forecast for the next ten (10) years by end September of each year

(b) The *ENTS* demand forecast shall be determined for each point of demand. Generation and import/export capacity plans shall be used to obtain the annual generation patterns

(c) To forecast the maximum demand (MW) for each transmission substation, the *ENTSO* shall use *Distribution Licensees* and *end-use customer* load forecasts

(d) The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to bring it into line with the higher-level data

(e) All *Distribution Licensees* and *end-use customers* shall supply their ten (10)-year-ahead load forecast data to the *ENTSO* as detailed in the Information Exchange Chapter annually, by the end of July. All customers shall inform their *TNSP* of any changes in excess of fifty (50) *MW* to this forecast when this information becomes available

5.2.4 Transmission System Development Plan

(a) The *ENTSO* shall annually publish a minimum ten (10)-year-ahead *ENTS* development plan before the end of a fiscal year, indicating the major capital investments planned (but not necessarily approved). The plan shall include at least:

1. The acquisition of servitudes for strategic purposes
2. A list of planned investments including costs
3. Diagrams displaying the planned changes to the *ENTS*
4. An indication of the impact on customers in terms of service quality and cost
5. Any other information as specified by the *Regulatory Authority* from time to time

(b) The *ENTS* development plan shall be based on all customer requests received at that time, as well as the *TNSP* initiated projects based on load forecasts and changes in generation and transmission

(c) The *ENTSO* shall engage in a consultative process with customers and the *Regulatory Authority* on the *ENTS* development plan. The consultation process shall include:

1. An annual public forum to disseminate the intended *ENTS* development plan

2. Regular interfacing and joint planning with *Users* regarding the *ENTS* development

(d) *Dispute* s arising from the above process shall be decided in terms of the *Dispute* resolution mechanism in Chapter 4 (Governance)

(e) The *ENTSO* shall provide a five (5)-year statement of opportunities to render ancillary services for the mitigation of network constraints

(f) Transmission Asset Management/Service Plan shall be submitted to the *Regulatory Authority as* per the following guidelines:

1. The first Transmission Asset Management/Service Plan shall be submitted after six month of completion of construction work in case of newly constructed transmission line or after six months of issuance of license in case of already established transmission lines

2. The Transmission Asset Management/Service Plan shall be re-submitted as and when there are any upgrades/ major construction in the transmission infrastructure or any part thereof. The deadline for the resubmission of the plan for the Ethiopian fiscal year following it shall be Ginbot thirty (30) of each year

5.2.4.1 Development Investigation Reports

(a) Before any development of the network proceeds in terms of limits and targets, the *ENTSO* shall compile a detailed development investigation report. The report shall be used as the basis for the investment decision and shall as a minimum contain the following elements:

1. A description of the problem/request and the objectives to be achieved
2. Alternatives considered (including non-transmission or capital) and an evaluation of the long-term costs/benefits of each alternative
3. Detailed techno-economic justification of the alternative selected in accordance with the approved investment criteria, with consideration of relevant scenarios and appropriate risk analysis
4. Diagrams, sketches and relevant technical study results
5. Clear statement and analysis of the assumptions used

The report shall be submitted to the *Regulatory Authority*.

5.2.5 Technical Limits and Targets for Long Term Planning Purposes

(a) The planning limits, targets and criteria form the basis for evaluation of options for the long-term development of the *ENTS*

(b) The limits and targets against which proposed options are checked by the *ENTSO* shall include technical and statutory limits that must be observed and other targets that indicate that the system is reaching a point where power transfer problems may occur. If planning limits are not attained, alternative options shall be evaluated

5.2.5.1 Voltage Limits and Targets

(a) Technical and statutory limits are presented in Table 5-1

(b) Standard voltage levels are given in Table 5-2

(c) Table 5-3 has target voltages for planning purposes at transmission voltages

Table 5-1 Voltage Limits for Planning Purposes

Nominal continuous operating voltage on any bus for which equipment is designed	Un
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed Um, the highest voltage used at sending end busbars in planning studies should not exceed 0.98 Um	Um
Minimum voltage on Point of Common Coupling during motor starting	0.85 Un
Maximum voltage change when switching, capacitors, reactors, etc. (system healthy)	0.03 Un (healthy)
Statutory voltage on bus supplying customer for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	Un plus or minus 5%

Table 5-2 Standard Voltage Levels

Un (kV)	Um (kV)	(Um-Un)/Un, %
500	525	5.00
400	420	5.00
230	245	11.36
132	145	9.85

Table 5-3 Target Voltages for Planning Purposes at Transmission Voltages

Minimum steady state voltage at bus supplying customer load unless otherwise specified in the customer's supply agreement	0.95 Un1
Minimum and maximum steady state voltage on any controlled bus, unless otherwise specified in the customer supply agreement:	
System healthy: After designed contingency (before control actions): After control actions:	0.95 – 1.05Un 0.90 Un – 0.98 Um2 0.95 – 1.05 Un
Maximum steady state voltage at bus supplying customer load unless otherwise specified in the customer supply agreement	1.05 Un
Maximum harmonic voltage caused by customer at the PCC: Individual harmonic: Total (square root of sum of squares):	 0.01 Un 0.03 Un
Maximum negative sequence voltage caused by customer at PCC: Continuous single-phase load connected phase-to-phase: Multiple, continuously varying, single-phase loads:	 0.01 Un 0.015 Un
Harmonic voltage limits:	As defined in IEC 61000
Maximum voltage change owing to load varying N times per hour:	(4.5 log10n)% of Un
Maximum voltage decrease for a 5% (MW) load increase at receiving end of system (without adjustment):	0.05 Un

[1]Nominal voltage
[2]Maximum voltage

5.2.5.2 Other Targets for Long-term Planning Purposes

Transmission Lines

The *ENTSO* shall determine thermal ratings of standard transmission lines and update these from time to time. 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.

Transformers

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

Series Capacitors

The *ENTSO* shall assure that the maximum steady state current should not exceed the rated current of the series capacitor. The internationally accepted standard's cyclic overload capabilities are for operational use only, to allow time to reduce loading to within the rated current without damaging the series capacitor.

Shunt Reactive Compensation

The *ENTSO* shall assure that shunt capacitors shall be able to operate at thirty percent (30%) above their nominal rated current at Un to allow for harmonics and voltages up to Um.

Circuit Breakers

The *TNSP* shall specify and install circuit breakers as directed by the *ENTSO* that meet system fault levels and other conditions considered important for the safe and secure operation of the *ENTS*. Ratings are to be according to international circuit breaker standards such as those of the *IEC*.

5.2.5.3 Reliability Criteria for Long-term Planning Process

(a) The *ENTSO* shall formulate long-term plans for development of the *ENTS* on the basis of the justifiable redundancy. With one line, transformer, or reactive compensation device out of service (N-1), it shall be possible to supply the entire load under all credible system operating conditions. The loss of a single element shall not cause:

1. Any violation of the normal operational limits such as voltage, frequency or *Plant* and Apparatus loading which would jeopardise the safety and reliability of the *ENTS* or would cause overloading of *Plant* or Apparatus
2. Islanding of any part of the *ENTS*
3. Loss of stability of the *ENTS*; or
4. Cascading outages of other elements as a result of exceeding operational security limits as set out in Chapter 9 (Operational Security or OC2)

(b) Investment in the *ENTS* to satisfy the minimum (N-1) redundancy requirement shall be on a deterministic basis, with no financial justification required

(c) An unfirm transmission infeed to an underlying *Distribution Network* is acceptable, as long as the underlying *Distribution Network* can supply the entire load without load shedding or load curtailment and without violating the technical planning limits on either the transmission or Distribution systems on loss of the transmission infeed

(d) A system cannot be made one hundred percent (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. However, reliability is ensured to the extent possible employing the following process:

1. The Generation and Transmission entities shall provide the *ENTSO* their proposed outage programmes (Identifying each generating unit/line/*ICT*, the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date) in writing for the next *fiscal* year
2. *TSO* shall conducts system studies with these inputs and available resources to ensure adequate balance between generation and load requirement in an optimal manner while maintaining system security standards. Outcome of this analysis is a draft outage plan for the next *fiscal* year, which may have been rescheduled, if deemed necessary, based on the studies
3. The outage plan shall be finalized by *ENTSO* in consultation with the concerned Generation/Transmission entities. The detailed generation and transmission outage programmes shall be based on the latest annual outage plan (with all up-to-date adjustment). Each Utility shall obtain the final approval from *ENTSO*, just prior to availing an outage
4. The above annual outage plan shall be reviewed by *ENTSO* on quarterly basis in coordination with all parties concerned, and adjustments made wherever found necessary
5. In case of a system emergency (e.g., loss of generation, breakdown of transmission line affecting the system, grid disturbances, system isolation), the *ENTSO* may conduct studies again before clearance of the planned outage
6. *The ENTSO* is authorized to defer the planned outage in case of any of the followings based on an analysing on its criticality: (i) grid disturbances; (ii) System isolation; (iii) Partial Black out; (iv) Any other event in the system that may have an adverse impact on the system security by the proposed outage

(e) The *ENTSO* shall ,in planning the *ENTS*, minimise as far as practicable the risk of common cause failure of two (2) or more items of *Plant* (e.g. loss of two (2) or more lines in a common servitude or on a double circuit or multicircuit structure), and insofar as such risk is unavoidable, shall take reasonable measures to mitigate such risk

(f) Additional equipment shall be provided if it can be justified to be included in the rate base in terms of the Least Economic Cost and/or Cost Reduction Investment or the cost is recoverable from a customer or group of customers in accordance with the descriptions under Strategic Investments in this chapter

5.2.5.4 Contingency Criteria for Long-term Planning Process

(a) A system meeting the (N-1) or (N-2) *Contingency* criterion must comply with all relevant limits outlined Tables 5-1, 5-2, and 5-3 (voltage limits) and the applicable current limits, under all credible system conditions

(b) For *Contingencies* under various loading conditions it shall be assumed that appropriate, normally used *Generating Plant* is in service to meet the load and provide spinning reserve. For the more probable (N-1) network *Contingency*, the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable (N-2) network *Contingency* an average pattern shall be used. Refer to the load and generation assumptions for load flow studies in Transmission System Development Plan in this chapter

(c) The generation assumptions for the (N-) and (N-2) network *Contingencies* do not affect the final justification to proceed with investments, but merely define what is meant by the statement that the system has been designed to meet an (N-1) or (N-2) *Contingency*

5.2.6 Integration of Generating Plants

When the integration of *Generating Plants* is planned, the following network redundancy criteria shall apply:

(a) *Generating Plants* of less than 100 MW:

1. With all connecting lines in service, it shall be possible to transmit the total output of the *Generating Plant* to the system for any system load condition. If the local area depends on the *Generating Plant* for voltage support, the connection shall be made with a minimum of two lines
2. Transient stability shall be maintained following a successfully cleared single-phase fault
3. 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) *Generating Plants* of more than 100 MW:

1. With one connecting line out of service (N-1), it shall be possible to transmit the total output of the *Generating Plant* to the system for any system load condition
2. With the two most onerous line outages (N-2), it shall be possible to transmit the total output of the *Generating Plant* less its smallest unit to the system
3. Smallest unit installed at the *Generating Plant* shall only include units that are directly connected to the transmission system and are centrally dispatched

(c) 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 *Generating Plant* loading condition; or
2. A single-phase fault cleared in "bus strip" times, with the system healthy and the most onerous *Generating Plant* loading condition; or
3. A single-phase fault, cleared in normal protection times, with any one line out of service and the *Generating Plant* loaded to average availability

(d) The cost of ensuring transient stability shall be carried by the *Generation Licensee* if the optimum solution, as determined by the *ENTSO*, results in unit or *Generating Plant* equipment being installed. In other cases, the *TNSP* shall bear the costs and recover these as per the approved *Tariff* methodology

(e) Busbar layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass

(f) The busbar layout shall ensure that not more than 100 *MW* of generation is lost as a result of a single *Contingency*

(g) To enable the *ENTSO* to successfully integrate new *Generating Plant*, detailed information is required for each *Generating Plant*, as described in the Information Exchange Chapter 20.

5.2.7 Criteria for Network Investments

(a) The *TNSP* shall invest in the *ENTS* when the required development meets the technical and investment criteria specified in this section, or if the investment is in response to a customer request for transmission service and the cost is recoverable from the customer or group of customers concerned in accordance with the *Regulatory Authority* approved connection charges guidelines

(b) The *TNSP* shall communicate all impacts timeously such that provision can be made for budgeting and implementation of related changes at the customer installation

(c) Any one of the investment criteria below, each applicable under different circumstances, can be applied

(d) Calculations will assume a typical project life expectancy of 25 years, except where otherwise dictated by *Plant* life or project life expectancy

(e) The following key economic parameters shall have an *Regulatory Authority* -approved process of establishment:

1. Discount rate
2. *Cost of unserved energy (COUE)*
3. Other parameters as specified by the *Regulatory Authority* from time to time

5.2.7.1 Least Economic Cost Criteria

(a) These criteria shall apply under the following circumstances:

1. When new customers are to be connected
2. When investments are made in terms of improved supply reliability and/or quality to attain the limits or targets determined in Technical Limits and Targets for Long Term Planning Purposes in this chapter.
3. To determine and/or verify the desired level of network or equipment redundancy

(b) The methodology for determining the value of load or generation in neighbouring countries shall be approved by *Regulatory Authority*

(c) The methodology requires the cost of poor Transmission Network Services to be determined. These include the cost of

1. Interruptions
2. Load shedding
3. Network constraints
4. Voltage dip, surge, flicker, and harmonic distortion

(d) The least-cost investment criterion equation to be satisfied can be expressed as follows: "Value of improved Quality of Service (*QOS*) to customers > cost to the *TNSP* to provide improved *QOS*"

(e) From this equation, it is evident that if the value of the improved *QOS* to the customer is less than the cost to the *TNSP*, then the *TNSP* should not invest in the proposed project(s). The investment decision shall then be delayed such that optimised economic benefit can be derived

(f) This implies that for the criteria to be satisfied: "*COUE* annual value (B/kWh) x annual reduction in *Expected Unserved Energy (EUE)* to consumers (kWh) > annual cost to the *TNSP* to reduce *EUE*"

(g) The reduction in *EUE* shall be calculated on a probabilistic basis based on a methodology approved by *Regulatory Authority*

(h) The Cost of Unserved Energy (*COUE*) is a function of the types of loads, the proportion of the total load contributed by each different 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 customers, the availability of customer backup generation and many other factors

5.2.7.2 Cost Reduction Investment

(a) Proposed expenditure that is intended to reduce *TNSPs*' costs (e.g. shunt capacitor installations, telecommunication projects and equipment replacement that reduce costs, external telephone service expenses and maintenance costs respectively) or the cost of losses or other ancillary services should be evaluated in the following manner:

1. First, it is necessary to calculate the *Net Present Value (NPV)* of the proposed investment *using Discounted Cash Flow (DCF)* methods. This shall be done by considering all cost reductions (e.g. savings in system losses) as positive cash flows, offsetting the required capital expenditure. Once again, sensitivity analysis with respect to the amount of capital expenditure (estimated contingency amount), the Annual Average Incremental Cost of Generation (when appropriate) and future load growth scenarios is required. As before, a resulting positive *NPV* indicates that the investment is justified over the expected life of the proposed new asset
2. However, a positive *NPV* does not always indicate the optimal timing for the investment. For this reason, the second portion of the cost reduction analysis is necessary – ascertaining whether the annual extra costs incurred by the *TNSP* for owning (levelised) and operating the proposed asset is less than all cost reductions resulting from the new asset in the first year that it is in commission

5.2.7.3 Statutory Investments

(a) This category of projects comprises investments that the *TNSP* is legally required to make, irrespective of whether any economic benefit is likely to accrue, including the following:

1. Investments formally requested in terms of published government policy
2. Projects necessary to meet environmental legislation
3. Expenditure to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission and the safety of the general public
4. Expenditure required to comply with other applicable legislation
5. Expenditure required to comply with court orders
6. Possible compulsory contractual commitments

(b) The results of the least economic cost and/or cost reduction analyses should still be documented to demonstrate the financial impact on the business

5.2.7.4 Strategic Investments

(a) This category of investments comprises discretionary investments made by the *TNSP* to ensure the long-term sustainability of the *TNSP*, including:

1. Site and servitude acquisition
2. Expenditure, except for network expansion, required to ensure the longer-term sustainability of the *TNSP* which cannot be justified in terms of the Least Economic Cost and Cost Reduction Investment Criteria or recovered from a customer or group of customers as a connection charge or Strategic Investment of this Chapter. In this case, the motivation as to why the investment is genuinely needed to ensure the longer-term sustainability of the *TNSP* must be clearly stated, and the results of the least economic cost and/or cost reduction analyses must be documented, or reasons given why such analysis is not possible or practical. These shall include purchasing of capital spares to minimise outage duration following major *Plant* failure, purchase of specialised vehicles and equipment to transport transformers and reactors, or implementation of industry restructuring
3. Asset replacements forming part of an asset lifecycle management plan compiled in accordance with asset management practices approved by the *Regulatory Authority*.
4. Network expansion projects which cannot be justified in terms of N-1 redundancy or cannot be recovered from a customer or group of customers as a connection charge or Strategic Investment of this code, but will provide flexibility, and avoid network redundancy in the future
5. Any other investments considered by the *TNSP* to be justified as strategic on grounds other than those covered in this section are to be submitted to the *Regulatory Authority* for consideration on a case by case basis prior to commitment to expenditure. The results of the least economic cost and/or cost

reduction analyses should still be documented to demonstrate the financial impact on the business

5.2.8 Mitigation of Network Constraints

(a) The *TNSP*, at the direction of the *ENTSO*, has obligation to resolve network constraints

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

5.2.8.1 Special Customer Requirements for Increased Reliability

Should a customer require a more reliable or safer connection than the one provided for by the *TNSP*, and the customer is willing to pay the total cost of providing the increased reliability in the form of an additional connection charge, The *TNSP,* under the direction of the *ENTSO*, shall meet the requirements at the lowest overall cost.

6 CONNECTIONS

This chapter contains requirements specific to both the EAPP IC and the ENTGC. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

6.1 EAPP IC REQUIREMENTS

6.1.1 Introduction

The Connections Chapter (CC) specifies the minimum technical, design, and operational criteria of *Plant* and *Apparatus,* which must be complied with by the *TSOs* and *Users* at the *Connection Point*, in order to maintain secure and stable operation of the *EAPP Interconnected Transmission System.*

Respective National legislation and codes may lay down local requirements. These local requirements should observe the minimum standards in this CC to avoid adverse effects on the *EAPP Interconnected Transmission System,* which may affect power interconnection security and quality of supply to other *Parties* or increase fault levels beyond the capabilities of existing *Connection Points*.

The provisions of the CC shall apply to all connections to the *EAPP Interconnected Transmission System:*

(a) Existing at the date when this Chapter comes into effect, or

(b) As established or modified thereafter

6.1.2 Objective

The CC is designed to ensure:

(a) That a new or modified connection shall not impose adverse effects upon the *EAPP Interconnected Transmission System* nor will it be subject itself to unacceptable effects by its connection to the *EAPP Interconnected Transmission System*

(b) That the basic rules for connection treat all *TSOs* and *Users* in a nondiscriminatory manner, and

(c) Ongoing compliance with the technical and operational requirements of the Interconnection Code to facilitate operational management of the *EAPP Interconnected Transmission System*

6.1.3 Scope

The CC applies to *TSOs* and to all *Users* connected or seeking connection to the *EAPP Interconnected Transmission System*.

6.1.4 Transmission System Performance Characteristics

Important considerations for the operation of transmission lines and their performance requirements are as follows:

6.1.4.1 Frequency

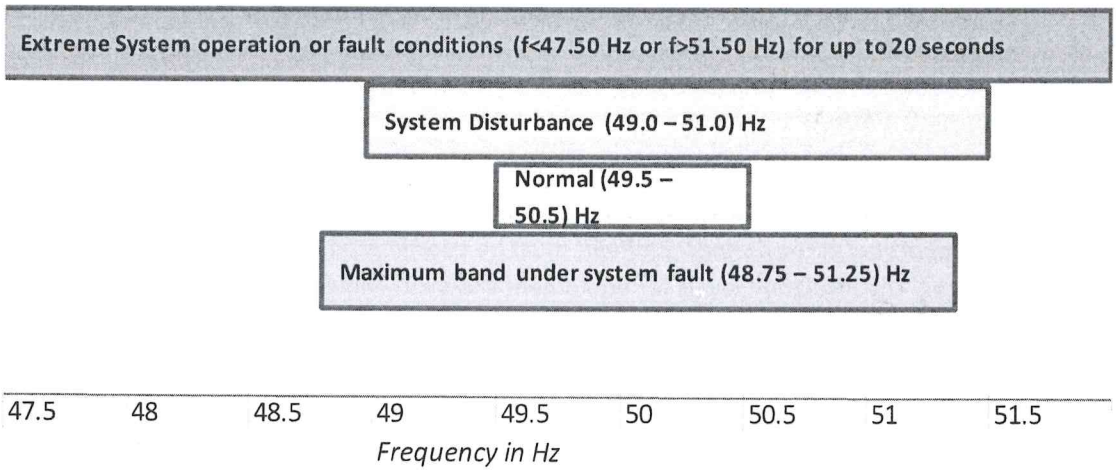
Frequency is the one parameter common to all members of a synchronous electric power system, and an accepted indicator of that system's ability to balance resources and demand as well as to manage disturbances.

Under normal operation, the frequency of the *EAPP Interconnected Transmission System* shall be nominally 50 Hz (±1%) and shall be controlled between 49.5 Hz and 50.5 Hz unless exceptional circumstances prevail. Following a system disturbance such as a load variation, the frequency band is extended to 49.0–51.0 Hz (±2%). If a major *Generating Unit* is tripped, a major transmission element fails or large loads are suddenly disconnected, the maximum frequency band becomes 48.75–51.25 Hz (±2.5%). If several of the contingencies mentioned previously occur simultaneously, the operating condition is labeled as extreme and the frequency can be below 47.5 Hz or above 51.5 Hz (-5%/+3%) for up to 20 seconds, and then extreme measures should be taken to restore the system. These figures are summarized in Table 6-1 and graphically represented in Figure 6-1.

Table 6-1: Frequency Limits in the EAPP Interconnected Transmission System

Operating Conditions	Frequency Limits
Under Normal Operation	49.50Hz to 50.50Hz
Under System Disturbance	49.00 Hz to 51.00 Hz
Maximum band under system fault	48.75 Hz to 51.25 Hz
Under extreme System operation or fault conditions	f<47.50 Hz or f>51.50 Hz for up to 20 seconds

Figure 6-1: Frequency Limits in the EAPP Interconnected Transmission System



6.1.4.2 Voltage

Requirements for voltage characteristics are defined below:

Steady State Voltage

Voltage conditions in a high voltage grid are directly related to the *Reactive Power* balance at the system nodes. Unlike *Active Power*, *Reactive Power* cannot be transmitted over long distances, since the transmission of *Reactive Power* generates an additional demand for *Reactive Power* in the system components, thereby causing voltage drops. In order to obtain an acceptable voltage level, *Reactive Power* generation and consumption have to be situated as close to each other as possible to avoid excessive *Reactive Power* transmission.

The voltages on the *EAPP Interconnected Transmission System* shall normally be maintained within the limits set out below:

1. Operating voltage range of 0.95 to 1.05 per unit in steady state normal conditions for nominal voltages used in the *EAPP Interconnected Transmission System* namely 500 kV, 400 kV, 230 KV, 220 kV, 132 kV, 110 kV and 66 kV,
2. Operating voltage range of 0.90 to 1.10 per unit after any single *Contingency*, and
3. Operating voltage range of 0.85 to 1.20 per unit after any multiple *Contingency* or severe system stress as indicated in Table 6-2 below.

Table 6-2: Steady State Voltage Limits

Operating Conditions	Voltage Limits
Normal	0.95 - 1.05
Contingency (N-1)	0.90 – 1.10
Multiple Contingency	0.85 – 1.20

The *TSOs* shall ensure that during periods of minimum demand, *Users* comply with a unity or lagging power factor, and a power factor of 0.95 lagging or higher during periods of peak and shoulder hours.

Transient Voltage

Transient over-voltages can occur on the *EAPP Interconnected Transmission System* as a result of lightning surges or the switching of long transmission lines or cables. The insulation level of all *Plant* and *Apparatus* at the *Connection Point* must be coordinated to take account of these transient over-voltages. The insulation levels for equipment shown in Table 6-3 below are based on *IEC* 60071-1:

Table 6-3: Permissible Transient Voltages

Nominal Voltage Or Rated Voltage	Used for Transmission in Countries	Highest Operating Voltage On Equipment	Withstand Voltage for Lightning Surge (LIWL)	Withstand Voltage For Switching Surge (SIWL)	50 Hz, 1 Min Withstand Voltage (Kv)
66 kV	Ethiopia, Sudan, Tanzania, Kenya	72.5 kV	325	N/A	140
110 kV	Burundi, DRC, Rwanda, Sudan	123 kV	550	N/A	230
132 kV	Ethiopia, Kenya,	145 kV	650	N/A	275

	Tanzania				
220 kV	Egypt, Kenya, Sudan, Tanzania	245 kV	950	N/A	395
230 kV	Ethiopia	245 kV	1050	N/A	N/A
400 kV	Ethiopia	420 kV	1050 – 1425	850 / 950 / 1050	N/A
500 kV	Egypt	550 kV	1175 – 1550	950 / 1050 / 1175	N/A

The lowest operating voltages at each voltage level depend on the local conditions. The lowest values are reached during operational disturbances and are usually not lower than 0.9 per unit.

Voltage Dips

A voltage reduction with duration of 10 ms to 1 minute and a voltage drop of more than 10 % of the existing value is known as a *voltage dip*. There are no standard requirements for the severity or extent of *voltage dips* since they are highly dependent on the system configuration. The duration of *a voltage dip* is highly dependent on the type of fault concerned and on which relay protection methods are used locally.

Most *voltage dips* are caused by earth faults. Whether or not such *voltage dips* are transferred to lower voltages depends on which earthing methods are used and on the transformer connections. The *voltage dips* may often become deeper and may spread to other parts of the system if faults occur in more than one phase, but this is relatively rare.

Voltage Flicker

Voltage Flicker is an increase or decrease in voltage over a short period of time, normally associated with a fluctuating load. The characteristics of the particular *Voltage Flicker* problem depend on the characteristics of the load change.

Voltage Flicker may arise during the start-up of an *Induction Generator*, motor, energisation of a transformer or other equipment as the large starting or inrush current may cause the voltage to drop considerably.

TSOs and *Users* are required to minimise the occurrence of *Voltage Flicker* on the *EAPP Interconnected Transmission System* as measured at the *Connection Point*. The *Voltage Flicker* limits are contained in the following *IEC* standards:

(a) *IEC*/TR3 61000-3-7 (1996) "Assessment of emission limits for fluctuating loads in *MV* and *HV* power systems"

(b) *IEC* 868/Engineering Recommendation P28 (page 17) "Limits on voltage flicker short term and long term severity values"

(c) In general, the total Voltage Flicker at a Connection Point shall not exceed:
   1. ± one (1) percent (%) of the steady state voltage level, when these occur repetitively; or
   2. ± three (3) percent (%) of the steady state voltage level, when these occur infrequently

6.1.4.3 Harmonics

Harmonics can cause telecommunication interference and thermal heating in transformers; they can disable solid-state equipment and create resonant over-voltages. In order to protect such equipment harmonics must be managed and mitigated. Harmonics are normally produced by *Plant* and *Apparatus* generating waveforms that distort the fundamental 50 Hz wave. Options to attenuate harmonics have advantages and disadvantages as well as cost implications. The best solution will depend on the total loading, the supply to site, and the standing distortions. Typical solutions include:

(a) *Improve filtering (add AC or DC chokes)*

(b) *Use passive filtering (tuned LC filter, requires reactive power to compensate*

(c) *Use multi-pulse rectifier (more economical when used with step down transformers to avoid oversizing of LV system and losses, minimum size limitations)*

(d) *Use electronic solution (Integrated in inverter with active rectifier; integrated into LV system)*

The following Table 6-4, based on IEEE 519-92, shows the permitted harmonic distortion levels on the *EAPP Interconnected Transmission System.* The acceptable distortion levels are the same as *the ones described in* Table 4-1 Standards for Voltage Harmonics in the EEA QoS Code.

Table 6-4: Acceptable Harmonic Distortion

Voltage Level	Acceptable Harmonic Distortion Levels
230 kV - 500 kV	Total Harmonic Distortion not exceeding 1.5% with no individual harmonic greater than 1%
110 kV - 132 kV	Total Harmonic Distortion not exceeding 2.5% with no individual harmonic greater than 1.5%
66 kV	Total Harmonic Distortion not exceeding 5% with no individual harmonic greater than 3.0%

6.1.4.4 Phase Unbalance

Under normal operation, the maximum negative phase sequence component of the phase voltage on the *EAPP Interconnected Transmission System* shall remain below one (1) percent (%). Under planned outage conditions, infrequent short duration peaks with a maximum value of two (2) percent (%) are permitted for phase unbalance, subject to the prior agreement of the *TSO*.

6.1.5 Technical Standards for Plant and Apparatus

All *Plant* and *Apparatus* connected to or proposed for connection to the *EAPP Interconnected Transmission System* shall meet certain minimum technical standards as detailed below, in the following order of preference:

(a) Relevant current international and African Standards, such as *IEC, ISO,* EN

(b) Relevant current national standards

Furthermore, *Plant* and *Apparatus* shall be designed, manufactured and tested in accordance with the quality assurance ISO 9000 family.

6.1.6 High Voltage Direct Current

Any HVDC interconnection shall be designed so that it has no negative effect on existing equipment connected to the *EAPP Interconnected Transmission System*. Each HVDC interconnection must ensure that they do not cause any sub-synchronous resonance, undamped oscillations, rapid voltage variations, harmonic voltages and interference with telecommunications.

The conditions specified in this Chapter of the CC apply to *HVDC* interconnections connecting to or within the *EAPP Interconnected Transmission System*. Each *HVDC* Interconnection shall have the following minimum capabilities:

(a) Operate continuously at its declared *MW* Output at frequencies in the range 49.5 Hz to 50.5 Hz

(b) Operate and remain connected to the *EAPP Interconnected Transmission System* at frequencies within the range 48.75 Hz to 51.25 Hz

(c) Remain connected to the *EAPP Interconnected Transmission System* at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds on each occasion that the frequency is below 47.5 Hz

(d) Remain synchronised to the *EAPP Interconnected Transmission System* during a rate of change of frequency of values up to and including 1 Hz per second

(e) Remain connected to the *EAPP Interconnected Transmission System* at declared *MW* Output at voltages within the ranges specified in Section 6.1.4 (Connection). Transmission System Performance Characteristics (Voltage) for step changes in voltage of up to 10%

(f) Remain connected during and following *voltage dips* at the HV terminals of the *HVDC* Interconnection Transformer of 95% of nominal voltage for a duration of 0.2 seconds and *voltage dips* of 50% of nominal voltage for a duration of 0.6 seconds. Following fault clearance the *HVDC* Interconnection should return to pre-fault conditions subject to normal frequency control and *Automatic Voltage Regulator* responses

(g) Operate within all normal operating characteristics at a minimum short circuit level at the *Connection Point* of 1000 MVA

(h) Remain connected to the *EAPP Interconnected Transmission System* during a negative phase sequence load unbalance in accordance with *IEC* 60034-1

(i) In an emergency be capable of reversing the power flow on the *HVDC* Interconnection at a rate which shall be no less than the *HVDC* Interconnection registered capacity within five (5) seconds, up to ten (10) times during the life of the *Plant* and no more than two (2) times in any given twelve (12) months

6.1.7 Protection Criteria

EAPP system protection criteria are defined below:

6.1.7.1 General

Protection system design shall be based on simplicity, safety to persons, mitigation, and limitation of equipment damage and control of the spread of any disturbance. The speedy operation of protection systems to clear faults in the *EAPP Interconnected Transmission System* is a pre-requisite to avoid instability and cascade tripping.

The protection systems to be applied to the *User's Plant* and *Apparatus* at the *Connection Point* shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the *EAPP Interconnected Transmission System*.

6.1.7.2 Fault Clearance Times

The clearance times for a fault on the *EAPP Interconnected Transmission System* or for a fault on the *User* system at the *Connection Point* shall not be longer than:

(a) Eighty (80) ms for faults at 400 kV and 500 kV

(b) One hundred (100) ms for faults at 230 kV

(c) One hundred twenty (120) ms for faults at 132 kV and below

Nothing shall prevent a *TSO* or *User* utilising faster fault clearance times. Total fault clearance time shall be from fault inception until arc extinction, which therefore includes relay operation, circuit breaker operation and telecommunications signaling times.

6.1.7.3 Circuit Breaker Fail Protection

When a circuit breaker is provided at the *Connection Point* to interrupt fault currents at any side of the *Connection Point*, a circuit breaker fail protection shall also be provided. The circuit breaker fail protection shall be designed to initiate the tripping of all the necessary electrically adjacent circuit breakers and to interrupt the fault current within the next 250 ms, in the event that the primary protection system fails to interrupt the fault current within the prescribed Fault Clearance Time as detailed in Section 6.1.7 (Connection – Protection Criteria).

6.1.7.4 Reliability of Protection Systems

The reliability of the protection system to initiate the successful tripping of the circuit breakers that are associated with the faulty *Plant* and *Apparatus* shall be not less than 99.5%.

6.1.7.5 Protection of Transmission Facilities

All transmission facilities on the *EAPP Interconnected Transmission System* shall be provided with two fully redundant main protection systems. The two protection systems shall be supplied from separate secondary windings on one *Voltage Transformer* or potential device and from separate *Current Transformer* secondary windings (using two *Current Transformer* s– one *Current Transformer* for each protection system). Separately fused and monitored DC supplies shall be used with the two protection systems. Each main protection shall be capable of operating in standalone mode in parallel with the other main protection in a 'one out of two' tripping scheme. To avoid the risk of simultaneous failure of both protection systems due to design deficiencies or equipment

problems, the use of two identical protection systems is not appropriate. In addition to the two main protections a separate back-up protection, normally an overcurrent protection, shall be provided.

6.1.7.6 Transmission Circuit Reclosure

Automatic reclosing is appropriate to support continuity of service and to maintain stability of the *EAPP Interconnected Transmission System*. All transmission lines shall be equipped with single pole and three pole tripping as well as high speed automatic reclose facilities. The impact on any generating or transmission facility of such automatic reclosure schemes requires careful consideration so that the reliability of the transmission system is not reduced or compromised.

6.1.8 Technical Requirements for Generating Units

6.1.8.1 Performance Requirements

It is necessary to define the performance requirements of *Generating Units, which* have or could have an impact on the reliability, security and adequacy of supply of the *EAPP Interconnected Transmission System*. In the initial stages of the interconnection only *Generating Units* directly connected to the *EAPP Interconnected Transmission System* and with a registered output of greater than thirty (30) *MW* shall meet the following requirements:

(a) Each *Generating Unit* shall be capable of supplying rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the *Generating Unit* terminals. The short circuit ratio of *Generating Units* shall not be less than 0.5

(b) Each *Generating Unit* must be capable of continuously supplying its registered output within the frequency range given in Section 6.1.4 (Connection -Transmission Performance Characteristics)

(c) The output voltage limits of *Generating Units* must not cause voltage variations in excess of ± 10% of nominal. Any necessary voltage regulating equipment shall be installed by the *Generation Licensee* to maintain the output voltage level of its *Generating Units*

(d) The *Active Power* output under steady state conditions of any *Generating Unit* directly connected to the *EAPP Interconnected Transmission System* shall not be affected by voltage changes in the normal operating range

(e) The *Reactive Power* output of a *Generating Unit* under steady state conditions must be fully available within the voltage range of ± 10% of nominal voltage at the *Connection Point*

6.1.8.2 Turbine Control System

The speed governor of each *Generating Unit* must be capable of operating to the standards approved by *EAPP Steering Committee* and the *TSO*. Each *Generating Unit* shall be fitted with a fast acting Turbine Controller to provide power and frequency control under normal operational conditions in accordance with the Interchange Scheduling and Balancing Chapters. The turbine speed control principle shall be that the *Generating Unit* output shall vary with rotational speed according to a proportional droop characteristic (*Primary Response*) between 2% and 5%. Superimposed load control loops shall have no negative impact on the steady state and transient performance of the turbine's rotational speed control.

The Turbine Controller shall be sufficiently damped for both isolated and interconnected operation modes. Under all operating conditions, the damping coefficient of the Turbine Speed Control shall be above 3% for gas turbines and 5% for steam turbines.

Under all system operating conditions, the *Generating Unit* speed shall not exceed 103% corresponding to 51.5 Hz for more than 20 seconds in the *EAPP Interconnected Transmission System* (refer to Frequency Sensitive Relays in this chapter *in this context).*

The Turbine Speed Controller and any other superimposed control loop such as load control or gas turbine temperature limiting control shall contribute to the *Primary Response* to maintain the unit within the *Generating Unit* capability limits.

The *Primary Response* characteristics shall be maintained under all operational conditions. Additionally, in the event that a *Generating Unit* becomes isolated from the system but is still supplying demand the *Generating Unit* must be able to provide *Primary Response* to maintain the frequency.

6.1.8.3 Automatic Voltage Regulator

A *continuous Automatic Voltage Regulator (AVR)* acting on the excitation system is required to provide constant terminal voltage of the *Generating Unit* without instability over the entire operating range of the *Generating Unit*. Control performance of the voltage control loop shall be such that under isolated operating conditions the damping coefficient shall be above 0.25 for the entire operating range.

The *AVR* shall have no negative impact on *Generating Unit* oscillation damping. If required by the *TSO*, in consultation with *EAPP Sub-Committees on Planning and Operation*, a *Power System Stabiliser* (PSS) shall be provided. Control principle, parameter setting and switch on/off logic shall be coordinated with the *TSO* and *EAPP Sub-Committees on Planning and Operation* and specified by the *TSO* in the *Connection Agreement*.

6.1.8.4 Frequency Sensitive Relays

The *EAPP Interconnected Transmission System* frequency could rise to 51.5 Hz or fall to 47.5 Hz and *Generating Unit*s must continue to operate within these respective frequency ranges unless *EAPP Sub-Committees on Planning and Operation* or the *TSO* has agreed to any frequency-level relays and/or rate-of-change-of-frequency relays which shall trip such *Generating Unit*s within this frequency range. Such tripping arrangements shall be set out by the *TSO* in the *Connection Agreement*.

6.1.8.5 Protection Arrangements

Protection of *Generating Unit*s and their connections to the *EAPP Interconnected Transmission System* shall meet the minimum requirements given in Section 6.1.4.

6.1.8.6 Loss of Excitation

The *Generation Licensee* shall provide the necessary protection device to detect loss of excitation on a *Generating Unit* and initiate a *Generating Unit* trip.

6.1.8.7 Pole Slipping Protection

Where system requirements dictate, the *TSO* shall specify in the *Connection Agreement* a requirement for *Generation Licensees* to fit pole-slipping protection on their *Generating Units*.

6.1.8.8 Black Start Capability

Some *Generating Units* shall be designated to have *Black Start Capability* primarily considering their type and location on the system as set out in Section 10.1.7 (Emergency Operations). This capability shall enable *Generation Licensee s* to restart their facilities without an incoming supply from the *EAPP Interconnected Transmission System*. *EAPP Sub-Committees on Planning and Operations* in consultation with *TSOs* shall nominate *Black Start Generating Units* at a number of strategic locations across the Region. The requirement for a *Black Start Capability* shall be incorporated into the *Connection Agreement* by the relevant *TSO*.

Black Start facilities shall be routinely tested by the *Generation Licensee* to ensure satisfactory operation. The *TSO* shall have the right to require the *Generation Licensee* to demonstrate the *Black Start Capability*.

6.1.9 Technical Requirements for the Interconnected Parties

Protection measures are required to be taken by *EAPP* and *TSOs* to isolate a *National System* or part of such system from the *EAPP Interconnected Transmission System* in case of uncleared faults or the malfunctioning of *Plant* or *Apparatus, which* could lead to a System Emergency condition.

Each *TSO* shall make the necessary arrangements to disconnect its *National System* from the *EAPP Interconnected Transmission System* under the circumstances stated below.

6.1.9.1 Area Separation by Frequency Deviation

The cross-border connections to *Neighbouring Systems* shall be tripped when frequency measured at the border falls below 48.75 Hz for more than thirty (30) seconds.

6.1.9.2 Area Separation by Abnormal Transient Conditions

The cross-border connections to *Neighbouring Systems* shall be tripped when an Out of Step pole slipping condition or when sustained inter-area oscillations with amplitudes exceeding an agreed limit are observed.

6.1.9.3 Area Separation by Transmission Line Overloading

The cross-border connections to *Neighbouring Systems* shall be tripped when overloading of the connections occurs. The overload values for the connections shall be agreed between the respective *TSOs* and *EAPP Sub-Committee on Operations*

6.1.10Ancillary Services

The CC contains requirements for the minimum capability for certain *Ancillary Services* as set out in further detail in ISBC 3. These *Ancillary Services* are required in order to maintain the *EAPP Interconnected Transmission System* in a safe, secure and reliable operating state.

In the case of *Generating Units,* these *Ancillary Services* include *Primary* and *Secondary Response,* voltage and load flow control and *Black Start Capability*. *TSOs* may enter into *Ancillary Services* Agreements with *Generation Licensee s* for the provision of these capabilities. The *Ancillary Services* Agreements may also contain commercial arrangements in relation to the provision of these capabilities or of more enhanced capabilities. *Tertiary Reserve* of a *Generating Unit* (fast start hydro, gas turbine, and steam turbine on hot standby) is an *Ancillary Service* that is being delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO.*

For transmission facilities the *Ancillary Services* provision is related to voltage control equipment such as shunt capacitors, flow control devices such as Phase Shifting Transformers and to special control systems such as *RAS*. The provision of such *Ancillary Services* would be subject to an agreement between the transmission provider and the *TSO*.

6.1.11Technical Criteria for Communications Equipment

6.1.11.1 General

The Control Centre of each *TSO* shall be equipped with adequate and reliable telecommunication facilities internally and with the Control Centres of other *TSOs* and the *EAPP Coordination Centre* to ensure the exchange of information necessary to maintain the security and reliability of the *EAPP Interconnected Transmission System*. Redundant facilities using alternate routes and different transmission media shall be provided. Each *TSO* is responsible for building, operating and maintaining that part of the telecommunications network located within its *National System* and shall bear all costs associated with the investment, operation, maintenance, and improvement.

Each *TSO* shall take appropriate measures to protect the telecommunications network against risks related to the disruption of operation, data corruption or disclosure of confidential information.

6.1.11.2 Telecommunication System

Dedicated telecommunication channels shall be provided between a Control Centre and the Control Centre of each *Neighbouring System*. All dedicated telecommunication channels shall not require intermediate switching to establish communication.

Alternate and physically independent telecommunication channels shall be provided for emergency use to back up the circuits used for critical data and voice communications.

6.1.11.3 Telecommunication Availability

The reliability calculation is based on the *MTBF/(MTBF+MTTR)* of each component between two gateways including the backup links. The target availability is 99.8%.

Restoration services on critical telecommunications channels shall be available twenty-four (24) hours per day, every day of the year. Each Control Centre operator should be able to take control of any telecommunication channel for its own use when necessary.

6.1.11.4 Reliability of Telecommunications Facilities

Vital telecommunications facilities shall be managed tested and actively monitored. Special attention shall be given to back up and emergency telecommunications facilities and equipment not used for routine communications.

6.1.11.5 Telecommunication Performance

Under normal conditions, the transmission delay, for a given data volume of mutually agreed real-time data exchange, between gateways should not exceed two (2) seconds. The system shall have sufficient bandwidth for a given data volume to meet the required performance. A speed of at least two (2) Mbps is recommended for the interconnected telecommunication channels and a minimum speed of sixty four (64) kbps is required. A lower speed than two (2) Mbps shall only be used as an interim solution.

6.1.11.6 Global Positioning System

All SCADA systems shall be synchronised to the *GPS* for accurate time keeping.

6.1.11.7 Expansions of Telecommunications Services

Expansions and modifications to the telecommunications network and minimum technical standard of components shall be agreed by the *EAPP Steering Committee.*

6.1.11.8 Standards

The following Standards shall be used for telecommunications services:

(a) The Wide Area Network (WAN) shall be based on *TCP/IP* protocol

(b) Communication between Control Centres shall be harmonised and based on *ICCP* protocol or as agreed between *TSOs* and *EAPP CC*

(c) Tele-control real-time information shall be based on *IEC* 870-6 TASE.2 protocol

(d) Non real-time services such as file transfer for exchange of transmission schedules, network model, planning data or statistics shall be based on the *FTP* protocol; and

(e) E-mail for special applications shall be based on *SMTP*

6.1.11.9 Voice Recorder

A recording system shall ensure permanent recording of all telephone conversations between the *TSO* Control Centres and the *EAPP Coordination Centre* and shall be located in the Control Centres and in the *EAPP Coordination Centre*.

The recording system shall be capable of playing back directly up to one-month telephone conversations. Archival storage shall be done on *CDs* or *DVDs* or any appropriate medium. Archives shall be stored for at least one (1) year.

6.1.12 Regional System Monitoring

Monitoring equipment shall be provided on the *EAPP Interconnected Transmission System* to enable the *EAPP Coordination Centre* and individual *TSOs* to monitor the *EAPP Interconnected Transmission System* operation and dynamic performance.

Additionally, the *TSO* shall be required to monitor Governor selection mode, and *AVR* selection mode for all power generation plants (with total plant capacity above 30 MW) connected to the national grid as indicated in Table 6-5 below. Table 6-5 also sets out the minimum telemetered data required by the *EAPP CC.*

Table 6-5: EAPP CC Minimum Requirements for Telemetering

Type of Connection	Telemetering Required	Telemetered Status Indicators
Interconnected Transmission System Node	*MW, Mvar, kV*, pf *MWh, Mvarh, Amps*	All circuit breakers on Interconnected Transmission System
Generating Unit connected directly to Interconnected Transmission System	*MW, Mvar, kV*, pf *MWh, Mvarh*	Generating Unit main circuit breakers
Generating Unit > 30 *MW* not directly connected to Interconnected Transmission System	*MW, Mvar, kV*, pf	Generating Unit main circuit breakers

The *EAPP Coordination Centre* shall define any further system parameters it requires to monitor.

6.1.13 Maintenance Standards

All *TSO's* and *User's Plant* and *Apparatus* connected to or forming part of the *EAPP Interconnected Transmission System* shall be maintained adequately for the purpose for which it is intended and to

ensure that it does not pose a threat to the safety of any person or other system facilities. The *EAPP Independent Regulatory Board* through the national Regulatory Body shall have the right to access and inspect the test results and maintenance records relating to such *Plant* and *Apparatus* at any time.

TSOs and *Users* shall ensure that *Plant* and *Apparatus*, including protection systems, are tested and maintained and remain rated for the duty required. *TSOs* shall ensure that a copy of the Annual *Transmission System Capability Statement* including the update of system fault levels is made available.

6.2 ENTGC REQUIREMENTS

6.2.1 Connection Conditions

This section defines acceptable requirements for *Generating Plant* connections. Note that some of the sections below refer to *ENTGC* requirement, with acronym *GCR* (*Generating Plant* Connection Requirements) for brevity and later reference.

Compliance with the *GCR* shall be read in conjunction with the *Generating Plant* characteristics and sizes as specified in Tables 6-6 and Table 6-7 in Section 6.3 of this chapter, which summarize requirements for *Generating Plant* connections.

The organization(s) responsible for the planning and development of the *ENTS* shall offer to connect and, subject to the signing of the necessary agreements, make available a *Connection Point* to any requesting G*eneration Licensee* to generate electricity.

For new units special consideration shall be given to the impact of the risks on future operating costs, e.g. for ancillary services. The *ENTSO* is to quantify these expected costs. The special consideration may include obtaining *Regulatory Authority* approval for including these costs in the *Tariff* base or obliging the G*eneration Licensee* to purchase reserves.

6.2.2 Plant Availability (GCR1a)

Generating Plants shall use Energy Availability Factor (EAF) to measure plant availability. EAF is defined as the ratio of the hours a generating unit is available to generate in a given period of time (Available Hours, or AH) over the total hours in the same period of time (Period Hour, or PH), expressed as a percentage.

6.2.3 Plant Availability (GCR1b)

Generating Plants shall also use EAF adjusted for planned maintenance (EAFPM) to measure plant availability. EAF adjusted for planned maintenance (EAFPM)" is defined as Available Hours/ (Period Hours – Planned maintenance Hours). In the case of Period Hours = Planned Maintenance Hours, EAFPM = 100%

6.2.4 Plant Reliability (GCR2)

Generating Plant reliability is expressed in terms of its availability when called upon to operate. Measures of *Generating Plants* reliability are based upon the *Generating Plant's* actual ability to generate power when it is considered available and upon starting failures and unplanned (or forced) outages. Achieving this reliability requires adequate levels of equipment availability, plant

maintainability with scheduled maintenance outages, fuel and water availability, and resistance to natural hazards.

6.2.5 Protection (GCR3)

A *Generating Plant*, unit step-up transformer, unit auxiliary transformer, associated busbar ducts and switchgear (including circuit breakers, load break switches, and disconnect switches) shall be equipped with well-maintained protection functions, in line with international best practices, to rapidly disconnect appropriate *Plant* sections should a fault occur within the relevant protection zones which fault may reflect into the *ENTS*. The following protection functions shall be provided as defined to protect the *ENTS*.

6.2.5.1 Backup Impedance

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

6.2.5.2 Loss of Field

All *Generating Plants* shall be fitted with a loss of field facility that matches the system requirements. The type of facility to be implemented shall be agreed with the organization(s) responsible for the planning and development of the *ENTS*.

6.2.5.3 Pole Slipping

Generating Plants shall be fitted with a facility protecting against pole slipping that matches the system requirements, where the *ENTSO* determines that it is required.

6.2.5.4 Trip to House Load

This protection shall operate in the event of a complete loss of load. For example if all the feeder breakers open at a *Generating Plant*, power flow into the system is cut off and the *Generating Plant* will accelerate. At 50.5 Hz the over-frequency facility shall pick up to start the house loading process. At this stage the *HV* breakers will still be closed. There will be power swings between the units and as soon as a unit has a reverse power condition the protection shall open the HV breaker. The units shall island feeding their own auxiliaries. When system conditions have been restored then the islanded units can be resynchronised to the system

6.2.5.5 Generator Transformer HV Back-up Earth Fault Protection

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

6.2.5.6 HV Breaker Fail Protection

The "breaker fail" protection shall monitor the HV circuit breaker's operation for protection trip signals, i.e. fault conditions. If a circuit breaker fails to open and the fault is still present after a specific time delay (maximum 150 ms), it shall trip the necessary adjacent circuit breakers.

6.2.5.7 HV Pole Disagreement Protection

The pole disagreement protection shall cover the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal. In cases where the three poles of a circuit breaker are mechanically coupled, pole disagreement protection is made redundant and shall not be provided.

6.2.5.8 Unit Switch onto Standstill Protection

This protection shall be installed in the *HV* yard substation or in the unit protection panels. If this protection is installed in the unit protection panels then the DC supply for this protection and that used for the circuit-breaker closing circuit shall be the same. This protection safeguards the *Generating Plant* against an unintended connection to the *ENTS* (back energisation) when at standstill or at low speed or when inadequately excited.

6.2.5.9 Main Protection

This protection shall be installed in the HV yard substation or in the unit protection panels. If this protection is installed in the unit protection panels then the DC supply for this protection and that used for control circuits shall be at least separately fused.

6.2.5.10 Protection Setting Management and Additional Requirements

(a) In addition, should system conditions dictate, other protection requirements shall be determined by the *ENTSO* in consultation with the *Generation Licensee* and these should be provided and maintained by the relevant *Generation Licensee* at its own cost

(b) Required HV breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the organization(s) responsible for the planning and development of the *ENTS*. Guidelines for operating times are:

1. 80 ms where the Connection Point is 400kV or above
2. 80 ms where the Connection Point is 230 kV
3. 100 ms where the *Connection Point* is 132 kV and below

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

1. 120 ms plus additional 30 ms for *DC* offset decay or
2. 100 ms plus additional 40 ms for *DC* offset decay

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

(e) All protections with the organization(s) responsible for the planning and development of the *ENTS* shall be coordinated between the *User*s

(f) The settings of all the protection tripping functions on the unit protection system of a unit, relevant to *ENTS* performance and as agreed with each *Generation Licensee* in writing, shall be co-ordinated with the transmission protection settings. These settings shall be agreed between the organization(s) responsible for the planning and development of the *ENTS* and each *Generation Licensee*, and shall be documented and maintained by the *Generation Licensee*, with the reference copy, which reflects the actual *Plant* status at all

time, held by the organization(s) responsible for the planning and development of the *ENTS*. The *Generation Licensee* shall control all other copies

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

(h) Any work on the protection circuits interfacing with transmission protection systems (e.g. bus zone) must be communicated to the *ENTSO* before commencing with the works. This includes work done during a unit outage

6.2.6 Ability of Units to Island (GCR4)

(a) Every unit that does not have black start or self- start capabilities of less than one hour without power from the ENTS shall be capable of unit islanding

(b) Islanding testing shall be contracted as an ancillary service

6.2.7 Excitation System Requirements (GCR5)

(a) A *Generating Plant* shall have a continuously acting *Automatic Voltage Regulator (AVR)*. The *AVR* shall provide constant terminal voltage control of the unit over the entire operating range of the unit. This does not include the possible influence of a power system stabiliser. Excitation control systems shall comply with the requirements specified in IEC 60034, IEEE 421 or any other standard agreed to by the *ENTSO*.

(b) The excitation system of each *Generating unit* shall normally be operated under the control of a continuously acting *AVR*, which shall be set to maintain a constant terminal voltage. The *Generating unit* may not disable or restrict the operation of the *AVR*, unless the *ENTSO* is informed.

(c) The *ENTSO* shall determine the settings of the excitation system in consultation with each generator. These settings shall be documented, with the controlled copy held by the *ENTSO*. The *Generation Licensee* shall control all other copies.

(d) The *Generating unit* shall be able to operate anywhere within its effective capability diagram as agreed by the *ENTSO*.

(e) *Generating unit* shall be capable of delivering constant active power output under steady state conditions for voltage changes in the normal operating range.

(f) *Generating unit* shall carry out routine and prototype response tests on excitation systems in accordance with IEC60034-16-3.

6.2.7.1 Power System Stabilizer

Generating Plants shall remain transiently stable and connected to the *ENTS* when subject to Voltage disturbances characterised by a large voltage dip of short duration or a smaller voltage dip of longer duration. Fault clearance time and recovery voltage levels shall be specified in the connection agreement based on system studies.

Generating Plants built after the implementation of the *ENTGC* shall be equipped with power system stabilisers as defined in IEC 60034, IEEE421 or any other standard agreed to by the *ENTSO*. The

requirements for other excitation control facilities and AVR refurbishment shall be determined in conjunction with the *ENTSO*.

6.2.7.2 Limiter

(a) The excitation control system shall be equipped with a load angle limiter and flux limiter except for installed *AVR* equipment up to and including analogue electronic technology.

(b) The excitation system shall have a minimum excitation ceiling limit of 1,6 pu rotor current, where 1 p.u. is the rotor current required to operate the unit at rated load and at rated power factor as defined in IEC 60034, IEEE421 or any other standard agreed to by the *ENTSO*.

6.2.8Reactive Capabilities (GCR6)

(a) *Generating Units* built after the implementation of the *ENTGC* shall be designed to supply rated power output (MW) for power factors ranging between 0.85 lagging and 0.95 leading as indicated in Section 6.1.8.1 (a) under Performance Requirements, or otherwise as agreed with the *ENTSO*. Power factor readings refer to the HV side of the *Generating Unit* step-up transformer.

(b) Gas Turbine *Generating Units* after the implementation of the ENTGC shall be capable of synchronous condenser operation, unless otherwise agreed with the ENTSO.

(c) Reactive outputs shall be fully variable between these limits under *AVR*, manual or other control.

(d) *Generating Units* shall carry out routine and prototype response tests to demonstrate reactive capabilities as described under Section 13.2.1 Commissioning Tests.

6.2.9Multiple Unit Tripping (MUT) Risks (GCR7)

(a) A *Generating Plant* shall be designed, maintained and operated to minimise the risk of more than one unit being tripped from one common cause within the time window and load limits described below. Two categories of multiple units tripping are used to categorise the impact as follows.

1. Unplanned disconnection or tripping of more than one *Generating Unit* instantaneously or within a one hour window, where the total maximum continuous rating (MCR) of those *Generating Unit* exceeds the largest credible multiple contingencies.
2. Unplanned disconnection or tripping more than one (1) *Generating Unit* instantaneously or within ten minutes, where the total MCR of those *Generating Unit* exceeds the largest single contingency.

(b) The *Generating Plant* shall be designed such that no MUT category 1 trip risk can occur and a MUT category 2 trip will not occur more than once in ten years.

(c) The *Generating Plant* shall calculate the minimum number of units required to trip for each category and identify potential common elements in the *Generating Plant* that can cause an MUT category 1 or 2 trip. The *Generating Plant* shall inform the *ENTSO* of these causes with corrective actions planned.

(d) Should the *ENTSO* determine that a *Generating Plant* presents an unacceptable MUT risk for the network, the relevant *Generation Licensee* and the *ENTSO* shall agree on the corrective action required to reduce the MUT risk and time frames within which to comply.

6.2.10 Governing (GCR8)

All *Generating Units* above 50 MVA shall have an operational governor capable of responding according to the minimum requirements of this section.

EAPP Section 6.1.4.1 describes frequency ranges and controllability issues. Chapter 15 Balancing and Frequency Control under Section 15.2 provides the requirements for maintaining normal system conditions.

6.2.11 Restart after Generating Plant Black-out (GCR9)

6.2.11.1 Thermal Power Stations

(a) A *Generating Unit* shall restart without unreasonable delay and be synchronised to the *ENTS* following a blackout and restoration of external auxiliary *AC* supply to the HV yard provided that the following is maintained at the point of connection for the duration of the unit start-up process

1. A stable supply of at least 90% of nominal voltage for *Generating Units* with on-load tap changers on the generator transformers, and a stable supply of at least 95% nominal voltage for *Generating Units* without on-load tap changers on the generator transformers
2. An unbalance between phase voltages of not more than 3% negative phase sequence
3. A frequency within the continuous operating range

Generators shall reasonably co-operate with the *ENTSO* in attempting to restart at lower voltage conditions.

(b) For the purposes of this Chapter, examples of unreasonable delay in the restart of a *Generating Plant* are:

1. Restart of the first unit that takes longer than 4 hours after restart initiation
2. Restart of the second unit that takes longer than 2 hours after the synchronising of the first unit
3. Restarting of all other units that take longer than 1 hour each after the synchronising of the second unit
4. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant *Generation Licensee*
5. The startup 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

6.2.11.2 Hydro and Gas Turbines

(a) A *Generating Plant* and a unit is to be capable of being restarted and synchronised to the *ENTS* following restoration of external auxiliary *AC* supply without unreasonable delay resulting directly from the loss of external auxiliary *AC* supply

(b) For the purposes of this Chapter, examples of unreasonable delay in the restart of a Generating Plant are:

1. Restart of the first unit that takes longer than 30 minutes after restart initiation
2. Restarting of all other units that take longer than 30 minutes each after the synchronising of the first unit
3. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant *Generation Licensee* and
4. 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

6.2.12 Black Starting (GCR10)

Generating Plants that have declared that they have a station black start capability shall demonstrate this facility by test. The procedure for the tests shall be determined by the *Generation Licensee*, in agreement with the *ENTSO*.

6.2.13 External supply disturbance withstand capability (GCR11)

Generating Plant equipment shall be designed with anticipation of the following voltage conditions at the point of connection:

(a) A voltage deviation in the range of 90% to 110% of nominal voltage
(b) A 3-phase voltage drop to zero for up to 0.2 seconds, to 75% for 1 second, or to 85% for 60 seconds provided that during the 3 minute period immediately following the end of the 0.2 second, 2 second, or 60 second period the actual voltage remains in the range 90% to 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) A Volt/Hz requirement of less than 1.1 p.u.
(e) A requirement to withstand the following Automatic Reclosing (ARC) cycle for single-phase faults on the transmission lines connected to the power station:

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. This only applies where synchronism is maintained

(f) A requirement to withstand the following ARC cycle for multi-phase faults (phase-to-phase or 3-phase) on the transmission lines connected to the power station:

3ph fault - 3ph trip - 3 seconds 3ph ARC dead time - 3ph ARC - 3ph fault - 3ph trip - lock out

Routine and prototype response tests shall be carried out to demonstrate capabilities.

6.2.14 On-load Tap Changing for Generating Plant Step-up Transformers (GCR12)

All *Generating Plant* step-up transformers shall have on-load tap changing with remote control capability. The range and mode of control shall be agreed between the organization(s) responsible for the planning, development, and operation of the *ENTS* and the *Generation Licensee*.

6.2.15 Emergency Unit Capabilities (GCR13)

All *Generation Licensees* shall specify their units' capabilities for providing emergency support under abnormal power system conditions, as described in Chapter 10 (Emergency Operations or OC 3).

6.2.16Facility for Independent Generating Plant Action (GCR14)

Frequency control under system island conditions shall revert to the *Generating Plants* as the last resort, and units and associated *Plant* shall be equipped to handle such situations. The required control range is from 49 to 51 Hz.

6.2.17Automatic Under-frequency Starting

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

6.2.18Testing and Compliance Monitoring

(a) A *Generation Licensee* shall keep records relating to the compliance by each of its units with each section of this Chapter applicable to that unit, setting out such Information that the *ENTSO* reasonably requires for assessing power system performance (including actual unit performance during abnormal conditions)

(b) Within one Month after the end of June and December, a *Generation Licensee* shall review, and confirm to the *ENTSO*, compliance by each of that *Generation Licensee*'s units with every GCR during the past 6 Month period

(c) A *Generation Licensee* shall conduct tests or studies to demonstrate that each *Generating Plant* unit complies with each of the requirements of this code. Tests shall be carried out on new units, after every outage where the integrity of any *GCR* may have been compromised, to demonstrate the compliance of the unit with the relevant *GCR*(s). The *Generation Licensee* shall continuously monitor its compliance with all the connection conditions of the *ENTGC*

(d) Each *Generation Licensee* shall submit to the *ENTSO* a detailed test procedure, emphasising system impact, for each relevant part of this Chapter prior to every test

(e) If a *Generation Licensee* determines, from tests or otherwise, that one of its units or *Generating Plant* is not complying with one or more sections of this Chapter, then the *Generation Licensee* shall:

1. Promptly notify the *ENTSO* of that fact;

2. Promptly advise the *ENTSO* of the remedial steps it proposes to take to ensure that the relevant unit or *Generating Plant* (as applicable) can comply with this Chapter and the proposed timetable for implementing those steps
3. Diligently take such remedial action as will ensure that the relevant unit or *Generating Plant* (as applicable) can comply with this Chapter. The *Generation Licensee* shall regularly report in writing to the *ENTSO* on its progress in implementing the remedial action
4. After taking remedial action as described above, demonstrate to the reasonable satisfaction of the *ENTSO* that the relevant unit or *Generating Plant* (as applicable) is then complying with this Chapter

6.2.19 Non-compliance Suspected by the *TSO*

(a) If at any time the *ENTSO* believes that a *Generating Plant* is not complying with this Chapter, and then the *ENTSO* must notify the relevant *Generation Licensee* of such non-compliance specifying the Chapter section concerned and the basis for the *ENTSO*'s belief

(b) If the relevant *Generation Licensee* believes that the *Generating Plant* (as applicable) is complying with the Chapter, then the *ENTSO* and the *Generation Licensee* must promptly meet to resolve their difference

6.2.20 Unit Modifications

6.2.20.1 Modification Proposals

(a) If a *Generation Licensee* proposes to change or modify any of its units in a manner that could reasonably be expected to either adversely affect that unit's ability to comply with this Chapter, or changes the performance, information supplied, settings, etc., then that *Generation Licensee* shall submit a proposal notice to the *ENTSO* which shall:

1. Contain detailed plans of the proposed change or modification
2. State when the *Generation Licensee* intends to make the proposed change or modification; and
3. 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 Chapter

(b) If the *ENTSO* disagrees with the proposal submitted, it may notify the relevant *Generation Licensee*, and the *ENTSO* and the relevant *Generation Licensee* shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement

6.2.20.2 Implementing Modifications

(a) The *Generation Licensee* shall ensure that an approved change or modification to a *Generating Plant* unit or to a subsystem of a unit is implemented in accordance with the relevant proposal approved by the *ENTSO*

(b) The *Generation Licensee* shall notify the *ENTSO* promptly after an approved change or modification to a unit has been implemented

6.2.20.3 Testing of Modifications

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

(b) Within 20 business days after any such test has been conducted, the relevant *Generation Licensee* shall provide the *ENTSO* with a report in relation to that test (including test results of that test, where appropriate)

6.2.20.4 Equipment Requirements

Where the *Generation Licensee* needs to install equipment that connects directly with equipment of the organization(s) responsible for the planning and development of the *ENTS*, for example in the high voltage yard of the organization(s) responsible for the planning and development of the *ENTS*, such equipment shall adhere to the design requirements of the organization(s) responsible for the planning and development of the *ENTS* as set out in this Chapter.

6.3 GENERATING PLANT CONNECTION CONDITIONS

Tables 6-6 and 6-7 define minimum requirements for *Generating Plants* connected to the *ENTS* and other *Generating Plants*.

Generator unit transformers, associated busbar ducts, and switchgears shall be equipped with well-maintained protection functions to rapidly disconnect appropriate plant sections should a fault occur within the relevant protection zones that may affect the *ENTS*.

Backup impedance requirement ensures the availability of an impedance facility with a reach greater than the impedance of the generator transformer. It operates 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. This requirement is considered for units 20 MVA or higher.

Generating Plants shall have reactive power capability for providing voltage support depending on the system requirement at Connection Point.

Table 6-6: Summary of the Requirements Applicable to Specific Classes of Units Other than Hydro

Grid Code Requirement		*Units* other than Hydro and Renewables (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR3	**Protection**						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of Field	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes

Grid Code Requirement		*Units* other than Hydro and Renewables (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
	- Trip to House Load	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Generator Transformer *HV* backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- *Unit* Switch-onto-standstill *Protection*	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Main *Protection* only	Yes	Yes	Depends on Sys Reqts	-	-	-
	- Main *Protection* (monitored) or main and backup	-	-		Depends on Sys Reqts	-	-
	- Main and Backup *Protection* (both monitored)	-	-	-		Depends on Sys Reqts	Yes
GCR4	Ability To Island	-	-	Depends on Sys Reqts	Yes	Yes	Yes
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Limiters	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GTCR7	Multiple Unit tripping	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 unit at station
GCR8	Governing	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR11	External Supply Disturbance Withstand Capacity	Depends on Sys Reqts	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GRC13	*Emergency unit* capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR14	Facility for Independent Generating Plant Action	-	-	Depends on Sys Reqts	Yes	Yes	Yes

Sys Reqts = System Requirements (factors such as power system configuration, variability of power generation with changing conditions, etc.)

Table 6-7: Summary of the Requirements Applicable to Specific Classes of Hydro Units

Grid Code Requirement		Hydro Units (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR3	**Protection**						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes

	- Loss of Field	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Generator Transformer HV backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- *Unit* Switch-onto-standstill *Protection*	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Main *Protection* only	Yes	Yes	Depends on Sys Reqts	-	-	-
	- Main *Protection* (monitored) or main and backup	-	-		Depends on Sys Reqts	-	-
	- Main and Backup *Protection* (both monitored)	-	-	-		Depends on Sys Reqts	Yes
GCR4	Ability To Island	-	-	-	-	-	-
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabilizer	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Limiters	-	Depends on Sys Reqts	- Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR7	Multiple Unit tripping	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 unit at station
GCR8	Governing	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	GCR10	Black Starting
GCR11	External Supply Disturbance Withstand Capacity	Depends on Sys Reqts	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on Sys Reqts	Yes	Yes	Yes	GCR12	On load tap Changer for generating *Unit* step up transformers
GRC13	*Emergency unit* capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR14	Facility for Independent Generating Plant Action	-	-	Depends on Sys Reqts	Yes	Yes	Yes

Sys Reqts = System Requirements

6.4 TRANSMISSION SYSTEM PERFORMANCE STANDARDS

Transmission system performance indicates system reliability. Monthly, quarterly, and annual evaluation shall be used to monitor transmission system performance and reliability. The Key Performance Indicators (KPI) as described in Table 6-8 shall be used to measure the transmission system performance for each *TNSP* in the *ENTS*. These KPIs are aligned with the EU Technical

Assistance Facility for the "Sustainable Energy for All" Initiative (SE4ALL) – Eastern and Southern Africa: Quality of Service Code, European Commission, 9 February, 2015.

Table 6-8: Transmission System Key Performance Indicators (KPI)

KPI	Definition	Calculation	Expected Range of Value (as per EEA QoS Code)
Transmission System Planned Unavailability Index	Planned Unavailability consists of planned outages required for maintenance	[Sum of all transmission circuits and number of hours in a given period in each circuit, which experiences planned outage/ {(Total number of circuits in the system)x(Number of hours in a given period)}]x100%	Between 2% and 8%
Transmission System Unplanned Unavailability Index	Unplanned Unavailability is due to outages occurring as a result of plant or equipment failure, i.e. outages required and taken at less than 24 hours' notice	[Sum of all transmission circuits and number of hours in a given period in each circuit, which experiences unplanned outage/ {(Total number of circuits in the system)x(Number of hours in a given period)}x100%	Between 0.1% and 1%
Transmission System Availability	Percentage of actual circuit hours available in relation to total possible circuit hours available; Circuit outages that result from both planned and unplanned unavailability are taken into account;	[Sum of all circuit hours available/{(Number of circuits)x (Number of hours in period)}]X100%	Greater than 90% for the transmission system

7 RENEWABLE POWER PLANT

This chapter contains requirements specific to both the EAPP IC and the *ENTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

7.1 EAPP IC REQUIREMENTS - RENEWABLE POWER PLANTS (RPP)

7.1.1 Introduction

EAPP IC requirements for RPP primarily address wind and solar resources.

7.1.2 Technical Requirements for Wind and Solar Power Generating Plants

The requirements for *Generating Plants* set out in section 6.1.8 in Chapter 6 (Connections) refer to synchronous units. *Wind Turbine Generating Plants* and *Solar Power Generating Plants* do not have the same characteristics as *Synchronous Generators* and alternative provisions are required. This section sets out the specific requirements for controllable *Wind Turbine Generating Plants* and *Solar Power Generating Plants*.

7.1.2.1 Fault Ride-through Requirements

A controllable Wind Turbine /Solar Power *Generating Plant* shall remain connected to the *EAPP* Interconnected Transmission System for voltage dips on any or all phases, where the system phase voltage measured at the *HV* terminals of the connection transformer remains above a level to be defined by the *TSO* and specified in the Connection Agreement.

In addition to remaining connected to the *EAPP* Interconnected Transmission System, the controllable Wind Turbine / Solar Power *Generating Plant* shall have the technical capability to provide the following functions:

(a) During a voltage dip, the controllable Wind Turbine /Solar Power *Generating Plant* shall provide Active Power in proportion to retained voltage and maximise reactive current to the *EAPP* Interconnected Transmission System without exceeding its declared limits. The maximisation of reactive current shall continue for at least 600 ms or until the voltage recovers to within the normal operational range of the *EAPP* Interconnected Transmission System whichever is the sooner

(b) The controllable *Wind Turbine / Solar Power Generating Plant* shall provide at least 90% of its maximum available Active Power as quickly as possible and in any event within one (1) second of the voltage recovering to the normal operating range

7.1.2.2 Power System Frequency Ranges

As displayed in Figure 7-1, controllable *Wind Turbine/ Solar Power Generating Plant* shall have the capability to:

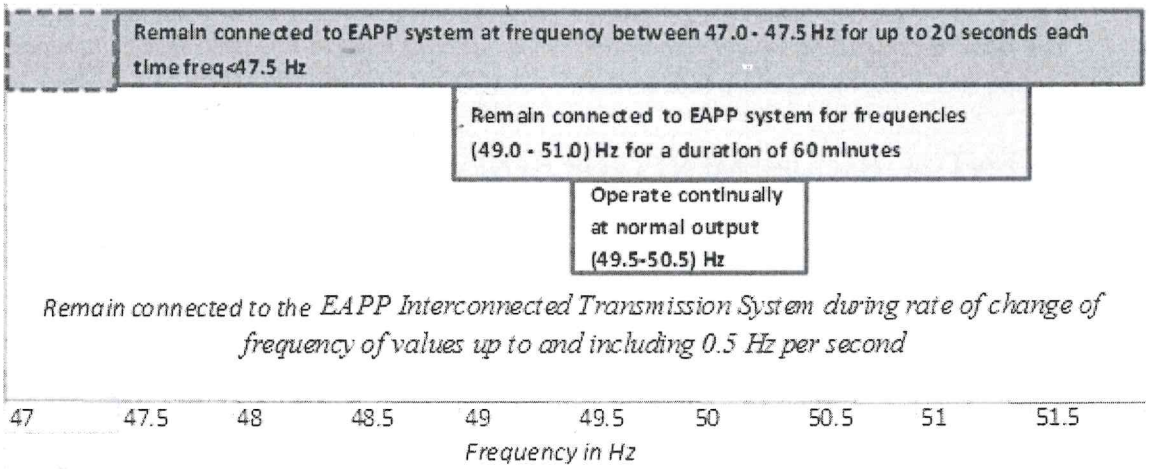
(a) Operate continuously at normal rated output at frequencies in the range 49.5 Hz to 50.5 Hz

(b) Remain connected to the *EAPP* Interconnected Transmission System at frequencies within the +range 49.0 Hz to 51.0 Hz for a duration of 60 minutes

(c) Remain connected to the *EAPP* Interconnected Transmission System at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds each time that the frequency is below 47.5 Hz, and

(d) Remain connected to the *EAPP* Interconnected Transmission System during rate of change of frequency of values up to and including 0.5 Hz per second

Figure 7-1: Frequency Ranges for Remaining Connected



7.1.2.3 Active Power Control

The *Wind Turbine / Solar Power Generating Plant* control system shall be capable of operating the *Generating Plant* at a reduced level if the Active Power output has been restricted by the *TSO*. The *Wind Turbine /Solar Power Generating Plant* control system shall be capable of receiving an on-line Active Power Control Set-point sent by the *TSO* and shall commence implementation of the set-point within 10 seconds of receipt of the signal from the *TSO*. The rate of change of output to achieve the Active Power Control Set-point should be no less than the maximum ramp rate settings of the *Wind Turbine/Solar Power Generating Plant* control system, as advised by the *TSO*.

7.1.2.4 Frequency Response

The frequency response system of *Wind Turbine /Solar Power Generating Plants* shall have the capabilities set out in the power frequency response curve agreed with the *TSO*.

7.1.2.5 Ramp Rates

The *Wind Turbine/Solar Power Generating Plant* control system shall be capable of controlling the ramp rate of its Active Power output with a maximum *MW* per minute ramp rate set by the *TSO*. There shall be two maximum ramp rate settings. The first ramp rate setting shall apply to the *MW*

per minute ramp rate averaged over one (1) minute. The second ramp rate setting shall apply to the *MW* per minute ramp rate averaged over ten (10) minutes. These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down.

It is recognised that falling wind speed or frequency response may cause either of the maximum ramp rate settings to be exceeded.

It shall be possible to vary each of these two maximum ramp rate settings independently over a range between one (1) and thirty (30) *MW* per minute. The *Wind Turbine Generating Plant* control system shall have the capability to set the ramp rate in *MW* per minute averaged over both one (1) and ten (10) minutes.

The *Wind Turbine /Solar Power Generating Plant* operator and the *TSO* shall agree a procedure for setting and changing the ramp rate control.

7.2 ENTGC REQUIREMENTS FOR RENEWABLE POWER PLANTS (RPP)

The renewable resources in the context of Ethiopia include wind, solar, geo thermal, hydroelectric, biomass, biogas, and landfill gas power plants. The requirements for conventional power plants in Chapter 6 cover large hydroelectric sources, geothermal, biomass, biogas, and landfill gas plants. Chapter 7 focuses on variable intermittent renewable resources (wind and solar) so that they will be able to contribute to the stability of the *ENTS*. Requirements for small hydroelectric power plants are addressed in this chapter as appropriate.

7.2.1 Objective

The primary objective of this section is to specify minimum grid connection technical and design requirements for variable *RPP* connected to or seeking connection to the *ENTS*.

7.2.2 Scope

The requirements in this section apply to all variable *RPPs* with a design capacity above one (1) MVA, connected or seeking connection to the *ENTS*, the *ENTSO*, and prospective *TNSPs*.

7.2.3 Technical Requirements

Tolerance and frequency of *RPP* voltage deviations shall be compliant with the following requirements. The *RPP* shall be able to:

(a) Withstand frequency and voltage deviations at the POC under normal and abnormal operating conditions described in this grid connection code while reducing the active power as little as possible.
(b) Support network frequency and voltage stability in line with the requirements of this grid connection code.

The following sections describe the normal and abnormal operating conditions for *RPPs* connected to the *ENTS*.

7.2.3.1 Normal Operating Conditions Normal Operating Conditions

(a) *RPPs* shall be capable of operating continuously within the POC voltage range (i.e., 0.9 p.u. - 1.0985 p.u.).

(b) *RPPs* shall only be allowed to connect to the *ENTS*, at the earliest, 3 seconds after the following condition are met:

1. The voltage at the POC is within the maximum and minimum allowable limits as established in item (a) above; and
2. The frequency in the *ENTS* is within the range of 49.0Hz and 50.2Hz, or otherwise as agreed with the *ENTSO*.

(c) The nominal frequency of the *ENTS* is 50 Hz and is normally controlled within the limits as defined in the *ENTGC*. The *RPP* shall be designed to be capable of operating for the minimum operating range illustrated in Figures 7-2 and Figure 7-3 (during a system frequency disturbance).

(d) When the frequency on the *ENTS* is higher than 51.5 Hz for more than 4 seconds, the *RPP* shall be disconnected from the *ENTS*. When the frequency on the *ENTS* is less than 47.0 Hz for longer than 200ms, the *RPP* may be disconnected. The *RPP* shall remain connected to the *ENTS* during rate of change of frequency of values up to and including 1.5 Hz per second, provided the network frequency is still within the minimum operating range indicated in Figures 7-2 and 7-3.

Figure 7-2: Minimum frequency operating range for RPP

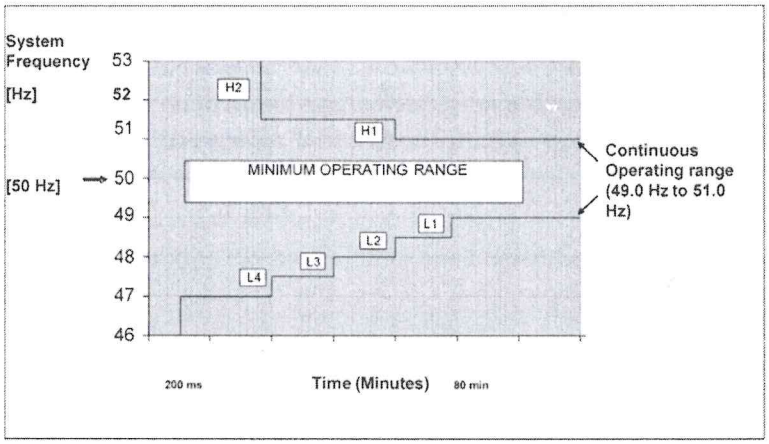
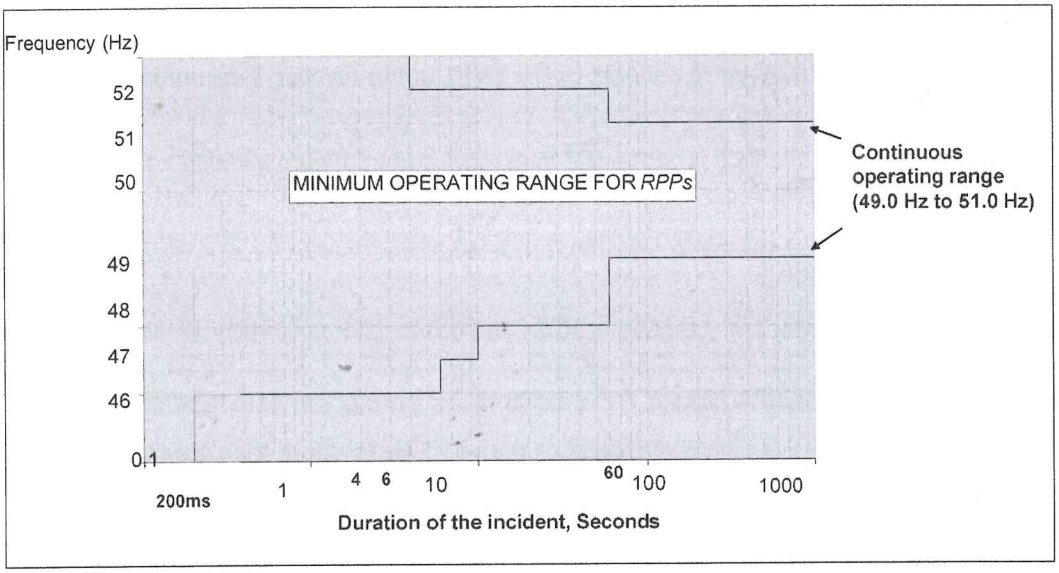


Figure 7-3: Minimum frequency operating range of RPP (during a system frequency disturbance)



7.2.3.2 Abnormal Operating Conditions

(a) *RPPs* shall be able to withstand sudden phase jumps of up to 20°at the POC without disconnecting or reducing its output. The RPP shall after a settling period, resume normal production no later than 5 sec after the operating conditions in the POC have reverted to the normal operating conditions.

(b) *RPPs* shall be able to withstand and fulfill, at the POC, voltage conditions described in this section and illustrated in Figures 7-4, 7-5, 7-6, and 7-7 below. The Area D is only applicable to RPPs 20 MVA and above.

(c) *RPPs* shall be able to withstand voltage drops and peaks, as illustrated in Figure 7-4, 7-5 and 7-6, and supply or absorb reactive current as illustrated in Figure 5 without disconnecting.

(d) RPPs shall be able to withstand voltage drops to zero, measured at the POC, for a minimum period of 0.150 seconds without disconnecting, as shown in Figures 7-4, 7-5 and 7-6 with exception for synchronous generators (of size 20 MVA or below) during symmetrical 3 phase faults.

(e) *RPPs* sized above 20 MVA shall be able to withstand voltage peaks up to 120% of the nominal voltage, measured at the POC, for a minimum period of 2 seconds without disconnecting, as shown in Figures 7-4, 7-5 and 7-6.

(f) Figures 7-4, 7-5 and 7-6 shall apply to all types of faults (symmetrical and asymmetrical i.e. one-, two- or three-phase faults) and the bold line shall represent the minimum voltage of all the phases

(g) If the voltage reverts to area A during a fault sequence, subsequent voltage drops shall be regarded as a new fault condition. If several successive fault sequences occur within area B and evolve into area C, disconnection is allowed as shown in see Figures 7-4, 7-5 and 7-6.

(h) In the area C (Figures 7-4, 7-5 and 7-6): disconnection of the *RPP* is allowed.

(i) In connection with symmetrical fault sequences in areas B and D of Figures 7-4, 7-5 and 7-6, the *RPP* (other than synchronous generating units) shall have the capability of controlling the reactive current, as illustrated in Figure 7-7. The following requirements shall be complied with:

1. Area A: The *RPP* shall remain connected to the network and uphold normal operation

2. Area B: The *RPP* shall remain connected to the network. Additionally,

    a. *RPPs* shall provide maximum voltage support by supplying a controlled amount of reactive current so as to ensure that the *RPP* assists in stabilising the voltage;

    b. Inverter driven *RPPs* shall have the capability of disabling reactive current support functionality at the request of *ENTSO*

3. Area D: The *RPP* shall remain connected to the network and provide maximum voltage support by absorbing a controlled amount of reactive current so as to ensure that the *RPP* helps to stabilise the voltage within the design capability offered by the *RPP*, see Figure 7-7.

4. Area E (Figure 7-7): Once the voltage at the POC is below 20%, the *RPP* shall continue to supply reactive current within its technical design limitations so as to ensure that the *RPP* helps to stabilise the voltage. Disconnection is only allowed after conditions of Figures 7-4, 7-5 and 7-6have been fulfilled.

(j) Control shall follow Figure 7-7 so that the reactive current follows the control characteristic with a tolerance of ±20% after 60 ms.

(k) The supply of reactive power has first priority in area B, while the supply of active power has second priority. Active power shall be maintained during voltage drops, but a reduction in active power within the *RPP's* design specifications is required in proportion to voltage drop for voltages below 85%.

(l) Upon clearance of fault each *RPP* shall restore active power production to at least 90% of the level available immediately prior to the fault within 1 second.

Figure 7-4: Voltage Ride through Capability for the RPPs utilising non-synchronous machines

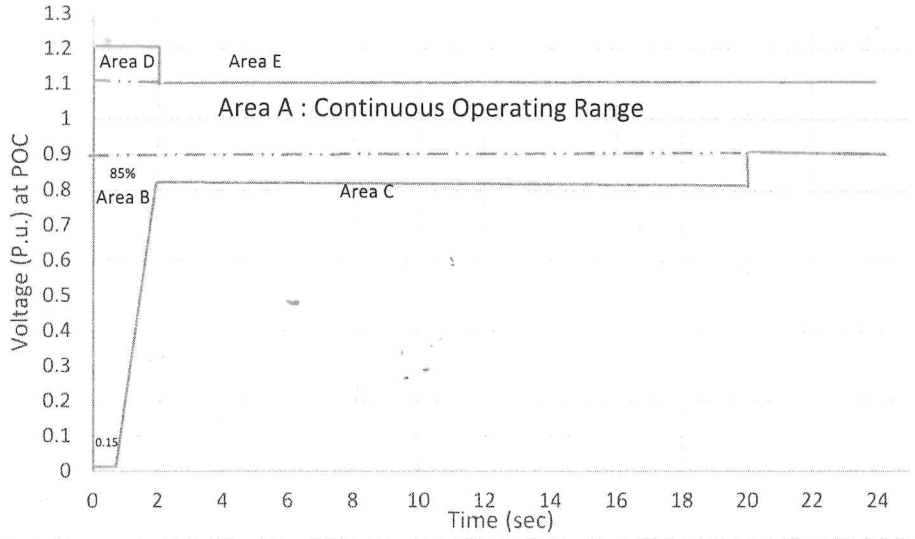


Figure 7-5: Voltage Ride through Capability for the RPPs utilising synchronous machines

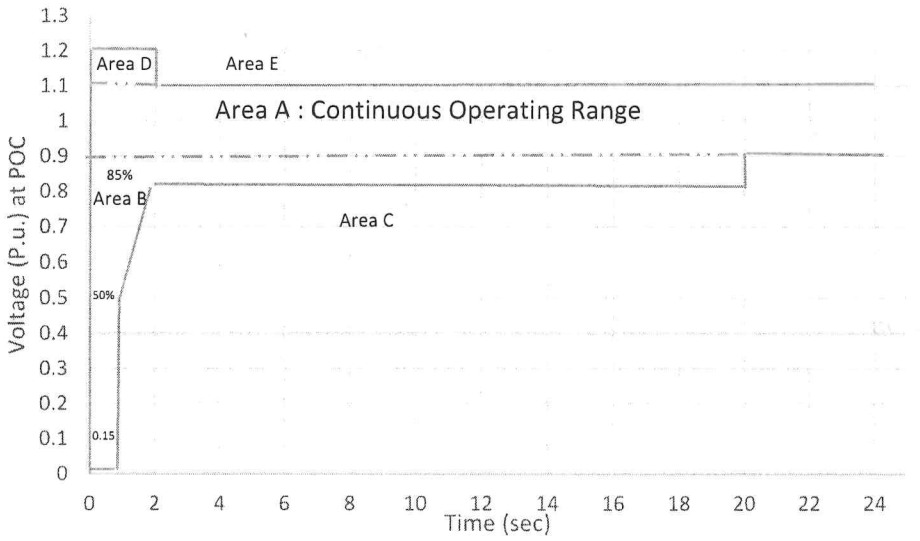


Figure 7-6: Voltage Ride through Capability for the RPPs (up to 20 MVA) utilizing synchronous machines (three phase faults only)

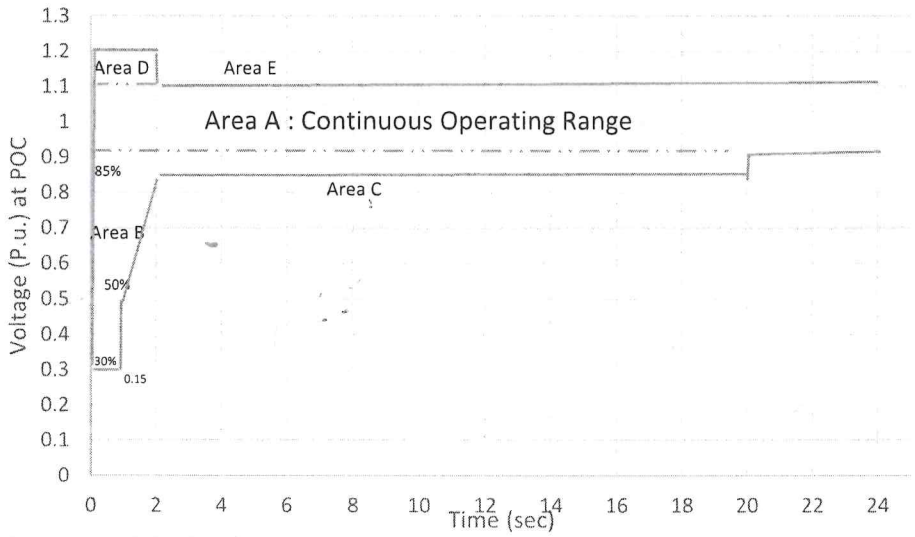
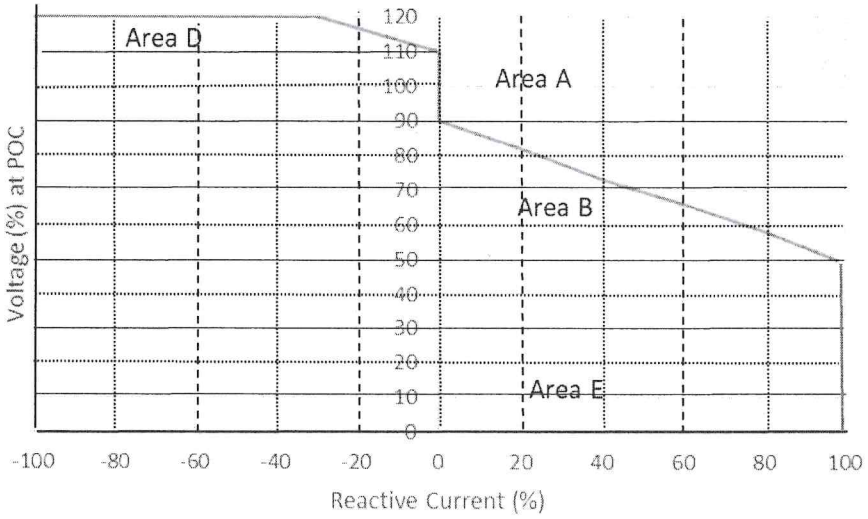


Figure 7-7: Requirements for Reactive Power Support, IQ, during voltage drops or peaks at the POC



7.2.4 Frequency Response

In case of frequency deviations in the *ENTS*, *RPPs* shall be capable of providing power-frequency response in order to stabilise the grid frequency.

Frequency response can be achieved through decreasing Generating Plant power output when frequency exceeds the upper bound of a specified acceptable frequency range, and by increasing Generating Plant power output when frequency falls below the lower bound of the specified range. Thus, an *RPP* must operate at a level below its instantaneous available capacity, if it is to provide both upward and downward frequency regulation capability.

The frequency response system of *RPPs* shall have the capabilities set out in the power frequency response curve agreed with the *ENTSO*.

7.2.4.1 Power Frequency Response Curve for RPP

RPPs shall be capable to provide power-frequency response in order to stabilise the grid frequency

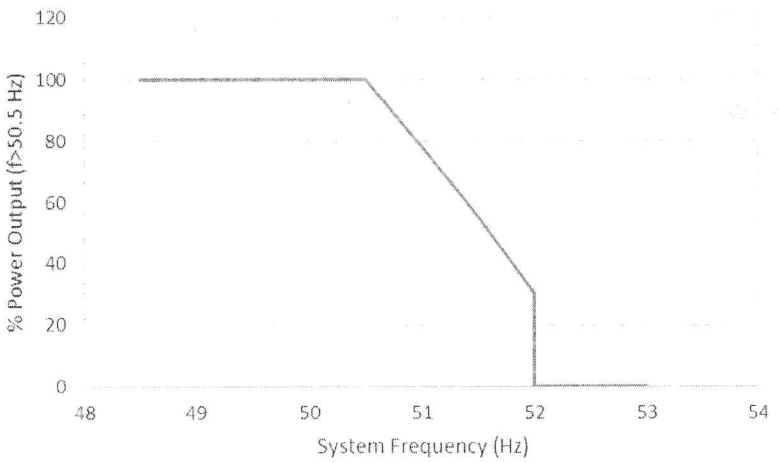
(a) During high frequency operating conditions, *RPPs* shall be able to provide mandatory active power reduction requirement in order to stabilise the frequency in accordance with Figure 7-8 below. The metering accuracy for the grid frequency shall be ± 10 mHz or better.

(b) When the frequency on the *ENTS* exceeds 50.5 Hz, the *RPP* shall reduce the active power as a function of the change in frequency as illustrated in Figure 7-8 below.

(c) Once the frequency exceed 51.5Hz for longer than 4 seconds the *RPP* shall be tripped to protect the *ENTS*.

(d) Although it is usually economically beneficial for RPPs to operate at their instantaneous available capacity, *RPPs* shall operate below their instantaneous available capacity, as and when instructed by the *ENTSO* accordingly.

Figure 7-8: Power curtailment during over-frequency for RPPs



7.2.4.2 Power Frequency Response Curve for RPP

RPPs with *Generating Plants* sized above 20 MVA shall be capable of providing power-frequency response as illustrated in Figure 7-9. Other requirements are:

(a) Except for the mandatory high frequency response (above 50.5 Hz), the *RPP* shall not perform any frequency response function including PDelta, dead-band and control band functions without having entered into a specific agreement with the *ENTSO*. PDelta is the amount of active power by which the available active power has been reduced in order to provide reserves for frequency stabilization.

(b) It shall possible to set the frequency response control function for all frequency points shown in Figure 7-9. It shall be possible to set the frequencies fmin, fmax, as well as f1 to f6 to any value in the range of 47 - 52 Hz with a minimum accuracy of 10 mHz.

(c) The purpose of frequency points f1 to f4 is to form a dead band and a control band for *RPPs* contracted for primary frequency response. The purpose of frequency points f4 to f6 is to supply mandatory critical power/frequency response.

(d) The RPP shall be equipped with the frequency control droop settings as illustrated in figure 7-9. Each droop setting shall be adjustable between 0% and 10%. The actual droop setting shall be as agreed with the *ENTSO*.

(e) The *ENTSO* shall decide and advise the *RPP* on the droop settings required to perform control between the various frequency points.

(f) If the active power from the RPP is regulated downward below the unit's design limit Pmin, shutting-down of individual RPP units is allowed.

(g) The *RPP* (with the exception of photo voltaic solar) shall have the capability of providing a PDelta of not less than three percent (3%) of Pavailable.

(h) It shall be possible to activate and deactivate the frequency response control function in the interval from fmin to fmax.

(i) If the frequency control set point (PDelta) is to be changed, such change shall be commenced within two (2) seconds and completed no later than ten (10) seconds after receipt of an order to change the set point.

(j) The accuracy of the control performed (i.e. change in active power output) and of the set point shall not deviate by more than ±2% of the set point value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

(k) The default settings for fmin, fmax, f4, f5 and f6 shall be as shown in Table 7-2, unless otherwise agreed upon between the *ENTSO* and the *RPP*. Settings for f1, f2 and f3 shall be as agreed with the *ENTSO.*

(l) The *ENTSO* shall give the RPP a minimum of 2 weeks if changes to any of the frequency response parameters (i.e. f1 to f6) are required. The *RPP* shall confirm with the *ENTSO* that requested changes have been implemented within two weeks of receiving the *ENTSO's* request.

Figure 7-9: Frequency response requirement for RPPs of size above 20 MVA

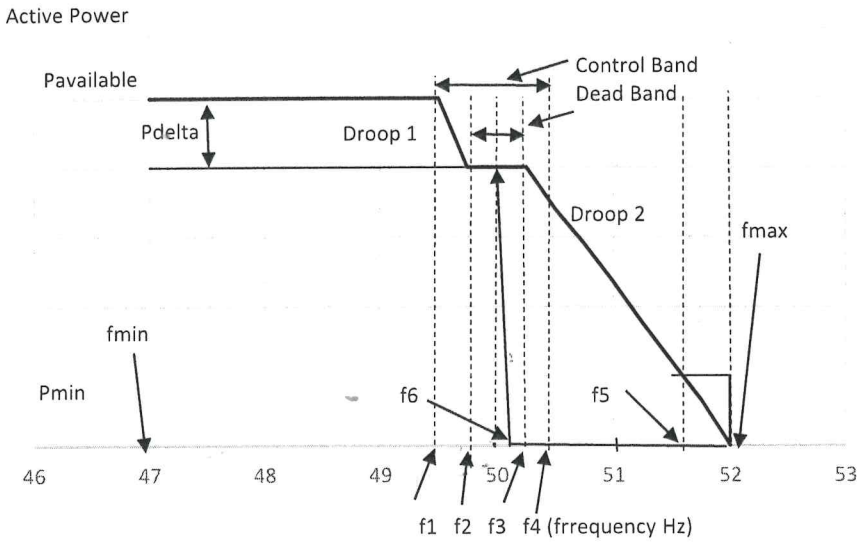


Table 7-2: Frequency Default Settings

(m)	Parameter	(n)	Magnitude (Hz)
(o)	fmin	(p)	47
(q)	fmax	(r)	52
(s)	f1	(t)	As per agreed with *ENTSO*
(u)	f2	(v)	As per agreed with *ENTSO*
(w)	f3	(x)	As per agreed with *ENTSO*
(y)	f4	(z)	50.5
(aa)	f5	(bb)	51.5
(cc)	f6	(dd)	50.2

(ee)

7.2.5 Reactive Power Capability

7.2.5.1 RPP Size up to 20 MVA

For *RPPs* sized up to and including 20 MVA, the following requirements are in effect:

(a) *RPPs* shall be designed with the capability to operate in a reactive power, power factor, or voltage control mode as described in section 7.2.7 below. The actual operating mode as well as the operating point shall be in agreement with the *ENTSO*.

(b) When operating between 5% and 100% of rated power Pn (MW) the *RPP* shall have the capability of varying reactive power (Mvar) support at the POC within the reactive power capability ranges as defined by Figure 7-10, where Qmin and Qmax are voltage dependent as defined by Figure 7-12.

(c) At nominal voltage, the required RPP reactive power capability measured at the POC shall be as shown in Figure 7-11.

(d) When operating below 5% of rated power Pn (MW), there is no reactive power capability requirement, however the *RPP* can only operate within the reactive power tolerance range not exceeding +-5% of rated power; that is within Area A,B,C and D in Figure 7-11.

Figure 7-10: Reactive power requirements for RPPs (size up to 20 MVA) at POC

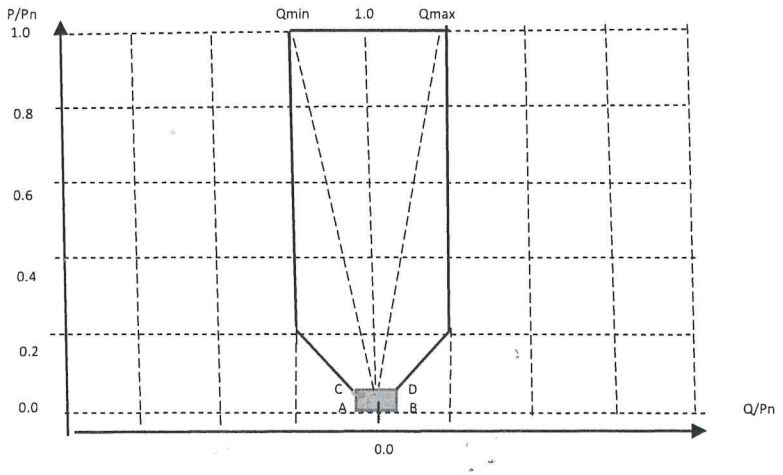


Figure 7-11: Reactive power requirements for RPPs (up to 20 MVA) at Nominal Voltage at POC

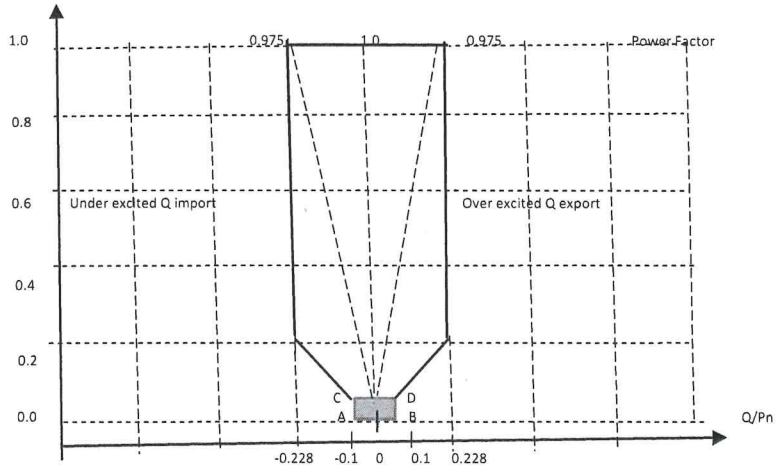
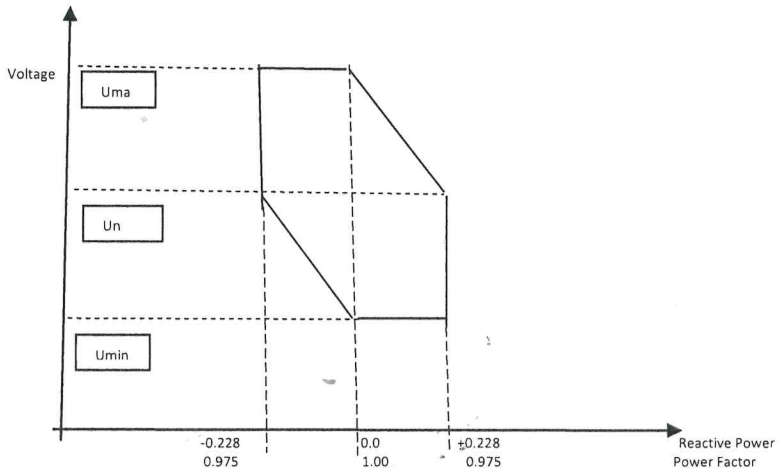


Figure 7-12: Requirements for reactive power and voltage control range for RPPs up to 20 MVA



(Umax and Umin are 10.985 p.u. and 0.9 p.u. respectively)

7.2.5.2 RPP Size up over 20 MVA

For *RPPs* sized above 20 MVA, the following requirements are in effect:

(a) *RPPs* shall be designed with the capability to operate in a voltage, power factor or, reactive power control modes. The actual control operating mode as well as operating point shall be as per agreement with the *ENTSO*.

(b) When operating between 5% and 100% of rated power Pn (MW) the *RPP* shall have the capability of varying reactive power support at the POC within the reactive power capability ranges as defined by Figure 7-13, where Qmin and Qmax are voltage dependents as defined by Figure 7-15.

(c) At nominal voltage, the required *RPP* reactive power capability, measured at the POC shall be as shown in Figure 7-14.

(d) When operating below 5% of rated power Pn (MW), there is no reactive power capability requirement, however the *RPP* can only operate within the reactive power tolerance range not exceeding +-5% of rated power; that is within Area A,B,C and D in Figure 7-14.

Figure 7-13: Requirements for reactive power and voltage control range for RPPs above 20 MVA

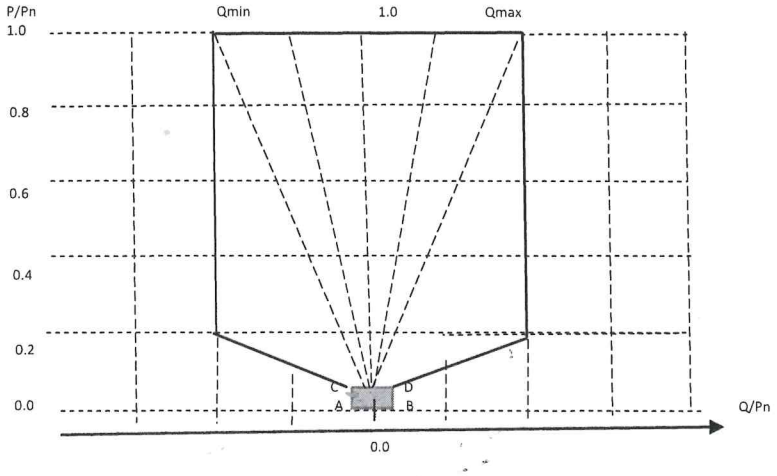


Figure 7-14: Requirements for reactive power and voltage control range for RPPs above 20 MVA (at nominal voltage at POC)

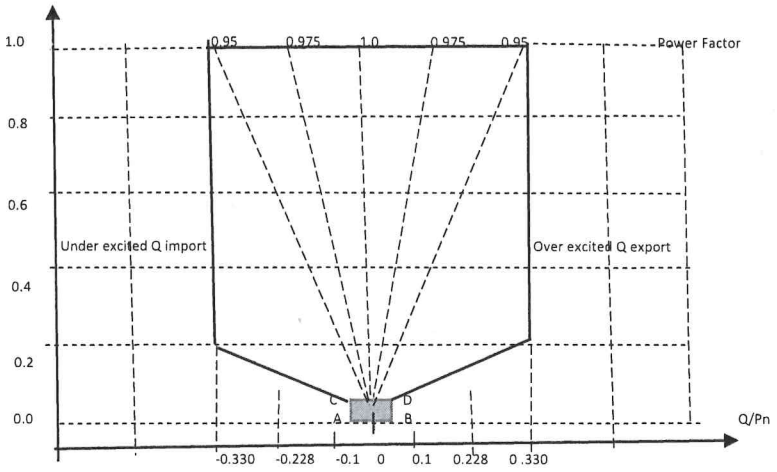
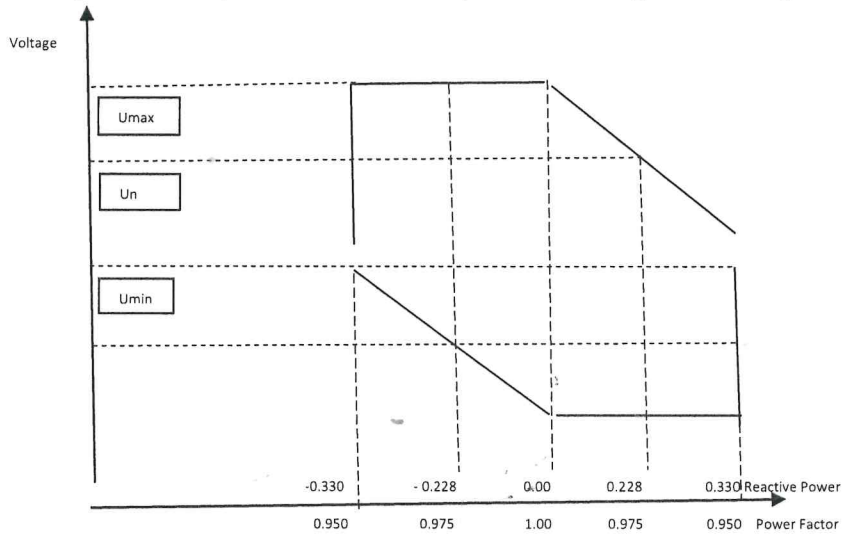


Figure 7-15: Requirements for reactive power and voltage control range for RPPs above 20 MVA



(Umax and Umin are 1.0985 p.u. and 0.9 p.u. respectively)

7.2.6 Reactive Power, Power Factor, and Voltage Control

The following requirements shall apply to those *RPPs* having contractual agreement with the *TNSP* for providing reactive power/power factor/voltage control:

(a) The RPP shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the RPP at the POC as well as a voltage control function capable of controlling the voltage at the POC via orders using set points and gradients.

(b) The reactive power and voltage control functions are mutually exclusive, which means that only one of the following three functions can be activated at a time.

1. Reactive Power Control
2. Power Factor Control
3. Voltage Control

(c) The control function and applied parameter settings for reactive power and voltage control functions shall be determined by the *TNSP* in collaboration with the *ENTSO*, and implemented by the *RPP*. The agreed control functions shall be documented in the operating agreement.

7.2.6.1 Reactive Power Control

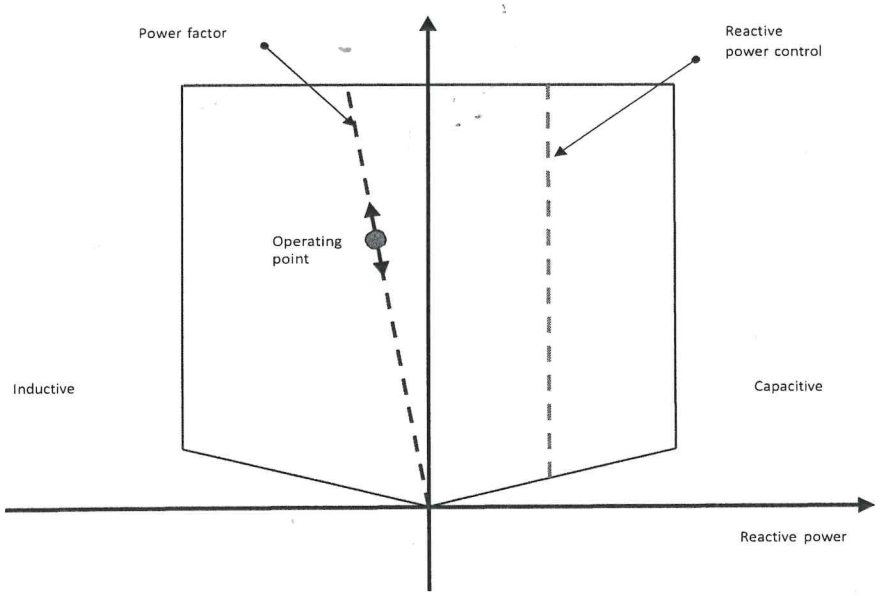
Reactive power control is a control function controlling the reactive power supply and absorption at the POC independently of the active power and the voltage. This control function is shown in Figure 7-16 as a vertical line.

(a) If the reactive power control set point is to be changed, the *ENTSO and* the *RPP* shall update its echo analog set point value in response to the new value within two (2) seconds. The *RPP* shall respond to the new set point within thirty (30) seconds after receipt of an order to change the set point.

(b) The accuracy of the control performed and of the set point shall not deviate by more than ±2% of the set point value or by ±0.5% of maximum reactive power, depending on which yields the highest tolerance.

(c) The *RPP* shall be able to receive a reactive power set point with an accuracy of at least one (1) kVar.

Figure 7-16: Reactive Power Control for RPP



7.2.6.2 Power Factor Control

Power Factor Control is used for controlling the reactive power proportional to the active power at the POC. The *RPP* shall comply with the following requirements:

(a) If the ENTSO issues a request to change the reactive power control set point, the RPP shall update its echo analog set point value in response to the new value within two (2) seconds. The RPP shall be able to respond to the new set point within thirty (30) seconds after receipt of an order to change the set point.

(b) The accuracy of the control performed and of the set point shall not deviate by more than ±0.02.

7.2.6.3 Voltage Control

Voltage control is for controlling the voltage at the POC. The *RPP* shall comply with the following requirements:

(a) If the voltage set point is to be changed, such change shall be commenced within two (2) seconds and completed no later than thirty (30) seconds after receipt of an order to change the set point.

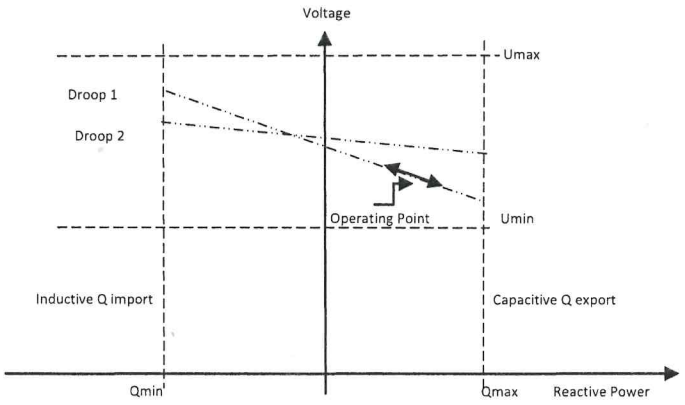
(b) The accuracy of the voltage set point shall be within ±0.5% of nominal voltage, and the accuracy of the control performed shall not deviate by more than ±2% of the required injection or absorption of reactive power according to droop characteristics as defined in Figure 7-17.

(c) The RPP shall be able to perform the control within its dynamic range and voltage limit with the droop configured as shown in Figure 7-17. In this context, droop is the voltage change (p.u.) caused by a change in reactive power (p.u.).

(d) When the voltage control has reached the RPP's dynamic design limits, the control function shall await possible overall control from the tap changer or other voltage control functions.

(e) The ENTSO shall be responsible for overall voltage coordination.

Figure 7-17: Voltage Control for RPP



(Umax and Umin are 1.0985 p.u. and 0.9 p.u. respectively)

7.2.7 Power Quality

(a) The *RPP* shall monitor the power quality parameters (i.e., flicker, harmonics, and unbalanced voltages) and provide report to the *TNSP,* the Regionl Control Center and/or the *ENTSO* as per agreement between the *RPP* and the *ENTSO*. The *RPP* shall use IEC standards for calculating harmonics (IEC 61000-4-7) and flicker (IEC 61000-4-15). The *RPP* shall follow IEC 61000-4-30 Class A power quality monitoring standard that defines the methods for measurement and interpretation of results for power quality parameters in AC power supply systems. The reporting s needed to prove compliance at the POC against the *TNSP* requirements as per the Purchase Power Agreement (PPA).

(b) Voltage and current quality distortion levels emitted by the *RPP* at the POC shall follow international standards such as IEC 61000-3-2:2018 (limitation of harmonic currents injected into the public supply system).

(c) The *RPP* shall also be compliant with IEEE 519-2014 (Recommended Practice and Requirements for Harmonic Control in Electric Power Systems), IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems), IEEE C-2 (Emergency Shutoff and National Electric Safety), IEC 62281 (Safety of primary and secondary lithium cells and batteries during transport), IEC 62897 (Stationary Energy Storage Systems with Lithium Batteries – Safety Requirements – under development), IEC 62932-2-2 (Flow Battery Systems For Stationary Applications – Part 2-2: Safety requirements), IEC 61850 (Communications networks and management systems), and IEC 60529 (Buildings, enclosures and protection from the elements).

(d) In addition, the *RPP* shall ensure that the *RPP* is designed, configured and implemented in such a way that the specified and agreed upon emission limit values are not exceeded.

(e) The *TNSP* will manage any voltage harmonic compatibility level exceedances due to the network harmonic impedance at the POC being more than 3 times the base harmonic impedance for the range of reference fault levels at the POC in line with its license conditions. The 3 times base harmonic impedance is calculated using the following equation: $\mathbf{Z(h) = 3*(v^2/s)*h}$, where h is the harmonic number, V is the nominal voltage (line-to-line) in kV, and S is the fault level in MVA. The angle of the network harmonic impedance is such that the impedance may range from fully inductive to fully capacitive

(f) In order to assist with the maximum resonance of 3 times as per item (e) above, no *RPP* may connect equipment (e.g. shunt capacitor banks) that will cause a resonance of more than 3 times at the POC at any frequency.

(g) The *TNSP* shall use reasonable effort to furnish the *RPP* with a reliable and continuous connection for the delivery of electrical energy up to the POC. The network operators do not guarantee that the continuity and voltage quality of the connection will always be maintained under all contingencies. It is therefore incumbent upon the *RPP* to take adequate measures to protect the *RPP* facility against any losses and/or damage arising from frequency deviations, connection/supply interruptions, voltage variations (including voltage dips), voltage harmonics, voltage flicker, voltage unbalance, voltage swells and transients, undervoltages and overvoltages in the connection. It is also incumbent upon the *RPP* to take such necessary measures so as not to cause any damage to the *ENTS*.

7.2.8 Protection and Fault Levels

(a) Protection functions shall be available to protect the RPP and to ensure a stable *ENTS*.

(b) The *RPP* shall be equipped with the necessary protection functions to protect itself against damage due to faults and incidents in the *ENTS*.

(c) The *RPP* shall be equipped with effective detection of islanded operation in all system configurations and capability to shut down generation of power in such condition within 2

seconds. Islanded operation with part of the *ENTS* is not permitted unless specifically agreed upon with the *TNSP*.

(d) The *TNSP* or *ENTSO* may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the *ENTS*. However, such change shall not result in the *RPP* being exposed to negative impacts from the *ENTS* lying outside of the design requirements.

(e) The *TNSP* shall inform the *RPP* of the allowable highest and lowest short-circuit current at the POC as well as any other information about the *ENTS* as may be necessary to define the *RPP's* protection functions.

7.2.9 Active Power Constraint Functions

RPPs may be subject to curtailment of active power output for reasons of system security as determined by the *ENTSO*. In case power curtailment, the *RPP* shall be capable of:

(a) Operating the RPP at a reduced level if active power has been curtailed by the ENTSO for network or system security reasons.

(b) Receiving a telemetered MW Curtailment set point sent from the ENTSO. Power curtailment actions shall be in agreement with all the parties involved.

(c) Being equipped with constraint functions (i.e. supplementary active power control functions) to avoid imbalances and/or overloading of the ENTS as indicated in Figure 7-18.The required constraint functions are: Absolute Production Constraint; Delta Production Constraint; and Power Gradient Constraint. Each of these are described in the following sections.

7.2.9.1 Absolute Production Constraint

An Absolute Production Constraint protects the *ENTS* against overloading by constraining the output active power from the *RPP* to a predefined power MW limit at the POC. This is typically used to protect the *ENTS* and *ENDS* against overloading. The *RPP* shall be capable of meeting the following requirements in implementing an Absolute Power Constraint:

(a) Changing Absolute Production Constraint set point shall commence within two (2) seconds and shall complete in no later than thirty (30) seconds after receipt of an order for changing the set point for all RPPs except the small hydro power plants.

(b) Accuracy of the control and set point for all *RPPs* (excluding the small hydro power plants) shall not deviate by more than ±2% of the set point value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

(c) Changes in the Absolute Production Constraint set point for a small hydro power plant shall be commenced within five (5) seconds and completed in the minimum time and to the highest accuracy achievable within its technical design limitations.

7.2.9.2 Delta Production Constraint

A Delta Production Constraint establishes a control reserve for control purposes in connection with frequency control. A Delta Production Constraint is typically used to establish a control reserve for control purposes in connection with frequency control. It constrains the active power from the *RPP* to a required constant value in proportion to the possible active power. The *RPP* shall be capable of meeting the following requirements in implementing a Delta Production Constraint:

(a) Changing Delta Production Constraint shall be commenced within two (2) seconds and completed no later than thirty (30) seconds after receipt of an order to change the set point.

(b) Accuracy of the control performed and of the set point shall not deviate by more than ±2% of the set point value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

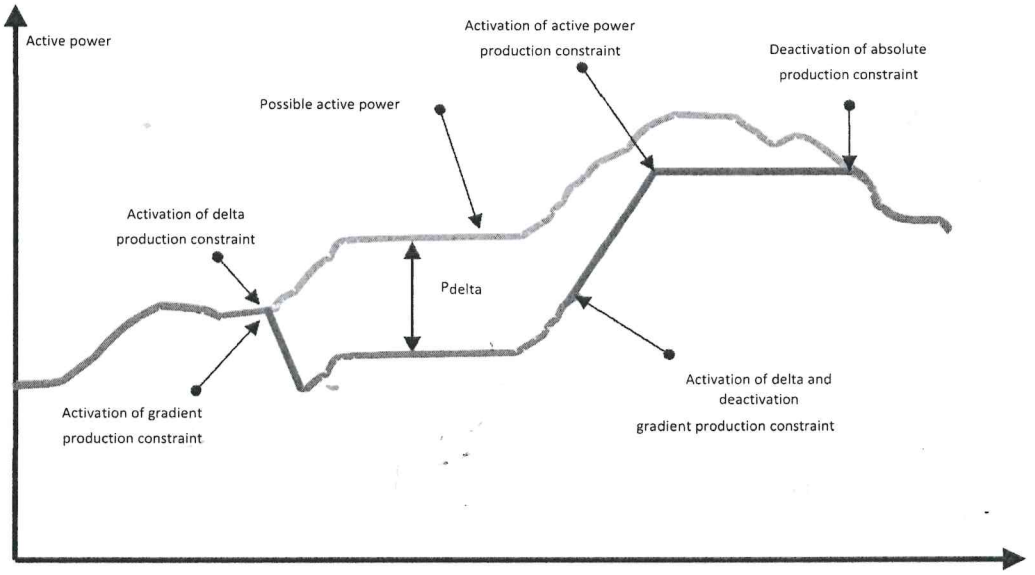
7.2.9.3 Power Gradient Constraint

A Power Gradient Constraint limits the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the set points for the *RPP*, taking into account the availability of primary energy to support these gradients. A Power Gradient Constraint shall be used for reasons of system operation to prevent changes in active power from impacting the stability of the *ENTS*. The *RPP* shall be capable of meeting the following requirements in implementing a Power Gradient Constraint:

(a) Changing Power Gradient Constraint shall be commenced within two (2) seconds and completed no later than thirty (30) seconds after receipt of an order to change the set point.

(b) Accuracy of the control performed and of the set point shall not deviate by more than ±2% of the set point value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

Figure 7-18: Active power control functions for a Renewable Power Plant



7.3 CONTROL FUNCTION REQUIREMENTS

RPPs shall be equipped with the control functions specified in Table 7-3. The purpose of the various control functions is to ensure overall control and monitoring of the *RPP's* generation. The *RPP* control system shall be capable of controlling the ramp rate of its active power output with a maximum MW per minute ramp rate set by the *TNSP,* and the *ENTSO.*

7.3.1 Ramp Rates

(a) The *RPP* control system shall be capable of controlling the ramp rate of its Active Power output with a maximum MW per minute ramp rate set by the Regional Control Centre.

(b) There shall be two (2) maximum ramp rate settings. The first ramp rate setting shall apply to the MW ramp rate averaged over one (1) minute. The second ramp rate setting shall apply to the MW per minute ramp rate averaged over ten (10) minutes.

(c) These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down. It is recognized that falling wind speed, rapidly changing cloud conditions, or frequency response may cause either of the maximum ramp rate settings to be exceeded.

(d) Power output of Solar Power Generating Plant has to be reduced in steps of 10% per minute, under any operating condition and from any working point to a maximum power value (target value) which could correspond also to one hundred percent (100%) power reduction, without disconnection of the RPP from the network.

(e) It shall be possible to vary each of these two maximum ramp rate settings independently over a range between one (1) and thirty (30) MW per minute. The *RPP* control system shall have the capability to set the ramp rate in MW per minute averaged over both one (1) and ten (10) minutes.

(f) The RPP operator and the *ENTSO* shall agree on a procedure for setting and changing the ramp rate control.

(g) The *RPP* shall not perform any frequency response or voltage control functions without having entered into a specific agreement to this effect with the *TNSP*.

Table 7- 3: Control Functions Required for RPPs

Control Functions	Generators 20 MVA and Below	Generators Above 20 MVA
Frequency Control	–	X
Absolute Production Constraint	X	X
Delta Production Constraint	–	X
Power Gradient Constraint	X	X
Reactive Power Control	X	X
Power Factor Control	X	X
Voltage Control	X	X

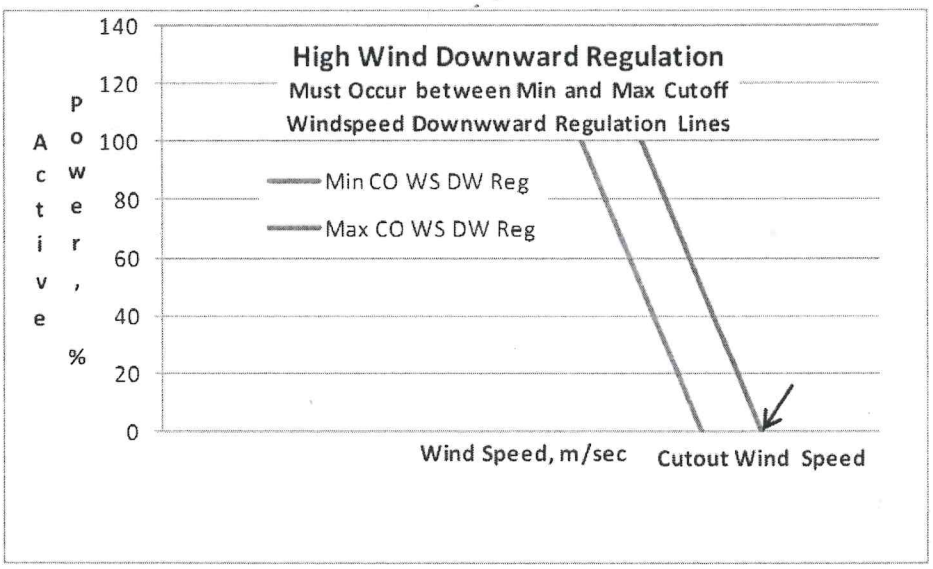
7.3.2 High Wind Curtailment

(a) The Wind Turbine Generating Plant shall stay connected to the *ENTS* at average wind speeds below a predefined cut-out wind speed. The cut-out wind speed shall as a minimum be twenty five (25) m/s, based on the wind speed measured as an average value over a ten (10)-minute period. To prevent instability in the *ENTS*, the wind power plant shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the Active Power production at wind speeds close to the cut-out wind speed.

(b) It shall be possible to continuously downward regulate the Active Power supplied by the RPP to an arbitrary value in the interval from one hundred percent (100%) to at least forty percent (40%) of the rated power. When downward regulation is performed, the shutting-down of individual *Wind Turbine Generating Plant* units is allowed so that the load characteristic is followed as well as possible.

(c) Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the area between the slanted lines shown in Figure 7-19 Illustrative High Wind Downward Regulation Chart. When downward regulation is being performed, the shutting down of individual *Wind Turbine Generating Plant* units is allowed. The downward regulation band shall be agreed upon with the *TNSP* upon commissioning of the *Wind Turbine Generating Plant* units.

Figure 7-19: Illustrative High Wind Downward Regulation Chart



7.4 SYSTEM RESERVE REQUIREMENTS

Increasing penetration of wind and photovoltaic generation, and to a limited extent other *RPPs*, can increase the need for various kinds of reserves. The variability of their output requires higher levels of both planning and operating reserves to offset the greater chance of being or going off-line when needed. They also contribute little or no inertia to the system, increasing the need for frequency regulation, which may lead to a need for higher levels of *Regulating and Spinning Reserve*. These factors shall be taken into account in establishing both planning and operating reserve requirements. In general, *RPPs* shall:

(a) Maintain as a minimum two different set levels of spinning reserve within the design margins.

(b) Maintain a spinning reserve set level within ±2% of the capability registered with the *ENTSO* and TNSP for at least one hour.

7.5 RPP HOURLY MW PRODUCTION FORECAST

Each *RPP* shall have the capability to produce and submit to the *ENTSO* the day ahead and week-ahead hourly *MW* production forecast as follows:

(a) Day ahead and week ahead available MW and forecast MW for each hour

(b) Available MW and forecast MW for the next 6 hours updated hourly 10 to 20 minutes before the hour

(c) Available MVar for the next 6 hours updated hourly 10 to 20 minutes before the hour

The above data shall be submitted as per the schedules described in Section 20.4.4.1 (b) and (c). Each *RPP* shall provide the forecast by means of an electronic interface in accordance with the requirements of the *ENTSO*'s data system.

7.6 RPP DATA REQUIREMENT

The *RPP* shall make the following signals available *ENTSO*:

(a) Actual MW at the POC

(b) Actual ramp rate of the generating plant

(c) Reactive power import/export at the POC

(d) Current sent out

(e) Power factor

(f) Voltage output

(g) Frequency

(h) Breaker status

(i) Isolator status

(j) Supervisory switch status

(k) Plant islanded

(l) Plant shutdown

(m) Plant trip on loss of grid detection

(n) Frequency Response System mode status indication (ON/OFF)

Other data requirements are described in the following sections.

7.6.1 Meteorological Data Requirements

RPP (excluding small hydro power plant) shall make the following signals available for the *ENTSO*:

(a) Wind speed (within 75% of the hub height) – measured signal in meters/second (for wind power generating plant only)

(b) Wind direction (within 75% of the hub height) – measured signal in degrees from true North (0-359) (for wind power generating plant only)

(c) Air temperature- measured signal in degrees centigrade (-20 to 50, for wind power generating plant)

(d) Air pressure- measured signal in millibar (800 to 1400, for wind power generating plant only)

(e) Air density (for wind power generating plant only)

(f) Diffuse Solar radiation (for solar power plants only)

(g) Direct Solar radiation (for solar power plants only)

The meteorological data signals shall be provided by a dedicated Meteorological Mast located at the RPP site or, where possible and preferable to do so, data from a means of the same or better accuracy. In the case of wind power generating plants, the Meteorological Mast shall be located at a position that optimizes the predictability of the output of the plant.

Energy resource conversion data for the facility (e.g. MW / wind speed) for the various resource inputs shall be provided to enable the *ENTSO* to derive a graph of the full range of the facilities output capabilities. An update shall be sent to the *ENTSO* following any changes in the output capability of the facility.

The meteorological data shall be provided from a number of individual Meteorological Masts (or where possible and preferable, from a source of the same or better reliability for groups of wind turbines), where the wind turbines are widely dispersed over a large geographical area and rather different weather patterns are expected for different sections of the *RPP*. Wind turbines within an individual group are expected to demonstrate a high degree of correlation in Active Power output at any given time. The actual signals required shall be specified by the *ENTSO*. There shall be at least one Meteorological Mast for every 10x10 square km area of the facility.

7.6.2 Active Power Constraint Data Requirement

The *RPP* shall make the following signals available to the *ENTSO*:

(a) Curtailment mode status (ON/OFF) as a single bit point

(b) Curtailment in progress as a single bit point

(c) Curtailment set point feedback

(d) Curtailment mode state (Not ready/Ready) as a single bit point

(e) Delta Production Constraint mode (ON/OFF) as a single bit point

(f) Delta Production Constraint set point feedback

(g) Delta Production Constraint mode (Not ready/Ready) as a single bit point

(h) Power Gradient Constraint mode (ON/OFF) as a single bit point

(i) Up Ramp rate set point feedback

(j) Down Ramp rate set point feedback

(k) Power Gradient Constraint mode (Not ready/Ready) as a single bit point

7.6.3 Reactive Power and Voltage Control Data Requirement

The *RPP* shall make the following signals available to the *ENTSO*:

(a) Reactive power control mode (ON/OFF) as a single bit point

(b) Reactive power control set point/raise or lower command

(c) Reactive power lower limit

(d) Reactive power upper limit

(e) Reactive power control mode (Not ready/Ready) as a single bit point

(f) Power factor control mode (ON/OFF) as a single bit point

(g) Power factor control set point/raise or lower command

(h) Power factor control set point feedback

(i) Power factor control mode (Not ready/Ready) as a single bit point

(j) Voltage control mode (ON/OFF) as a single bit point

(k) Voltage control set point/raise or lower command

(l) Voltage control mode set point feedback

(m) Voltage control mode (Not ready/Ready) as a single bit point

7.7 PROVISION FOR DATA AND ELECTRICAL DYNAMIC SIMULATION MODELS

(a) The *TNSP* and the *ENTSO* require suitable and accurate dynamic models, in the template specified by the requesting party applying for a connection to the *ENTS*, in order to assess reliably the impact of the *RPP* proposed installation on the dynamic performance and security and stability of the power system.

(b) The required dynamic models must be able to replicate the performance of the *RPP* facility or individual units for analysis of the following network aspects:

1. RPP impact on network voltage stability
2. *RPP* impact on quality of supply at POC
3. *RPP* switching transients impact on network performance
4. *RPP* impact on breakers transient recovery voltage
5. *RPP impact on network insulation co-ordination requirements*
6. *RPP* impact on network protection co-ordination
7. *RPP* Fault Ride Through (FRT) capability for different types of faults and positions
8. RPP response to various system phenomena that includes:
    a. Switching on the network
    b. Power swings
    c. Small signal instabilities

(c) Generic models can be accepted on condition that they represent *RPP* performance with frequency spectrum from 0 to 1kHz with accuracy level better that ±5%.

(d) Other models can be accepted as agreed upon by the *TNSP* and the *ENTSO*.

RPP data exchange should follow the steps as described in the sections below

7.7.1 Application for Connection

During application for connection, the *RPP* shall submit the following information to the *TNSP* and/or the *ENTSO*:

(a) Physical location (including the GPS coordinates)

(b) Site Plan

(c) Number of wind turbines or units to be connected

(d) MW output per turbine or unit

(e) Initial phase MW value

(f) Final phase MW value and timelines

(g) Any other information that the service provider may reasonably require

7.7.2 Detail Design

For the detailed *RPP* design, the *ENTSO* shall make available to the *RPP* the following information:

(a) Point of Connection and the Point of Common Coupling (PCC) including the nominal voltages

(b) Expected fault levels

(c) The *TNSP's* connection between the Point of supply and the *RPP*

(d) The bus bar layout of the Point of Common Coupling (PCC) and POC substations

(e) The portion of the *TNSP's* grid that will allow accurate and sufficient studies to design the *RPP* to meet the requirements of the *ENTGC*. This information shall include:

1. Positive and zero sequence parameters of the relevant *TNSP's* transformers, reactors, capacitors and other relevant equipment

2. The connection of the various lines transformers, reactors, and capacitors, etc.

7.7.3 Pre-Commissioning

After detail designing is complete, prior to commissioning, the *RPP* shall provide information such as:

(a) Selected *RPP* technology data

(b) Fault ride through capability and harmonic studies test report

(c) Generic test model and dynamic modelling data per wind turbine or unit as from the type approval and tests result

7.7.4 Post-Commissioning

After commissioning and optimization, the *RPP* shall provide the following information:

(a) A validated *RPP* electrical dynamic simulation model using commissioning test data and measurements

(b) Test measurement data in the format agreed between the *RPP* and the *TNSP/ENTSO* as applicable

8 OPERATIONS CODE NO. 1 – OPERATIONAL PLANNING

This chapter contains requirements specific to both the *EAPP IC* and the *ENTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

8.1 EAPP IC REQUIREMENTS

8.1.1 Introduction

To gain maximum benefit from the *EAPP Interconnected Transmission System*, outage requirements for generation and transmission facilities and other factors likely to affect the operation of the system shall be coordinated between *TSOs* and *EAPP CC* for a period of three (3) years ahead down to real-time. In formulating *Outage* placement proposals account shall be taken, where appropriate, of any commercial agreements entered into which impose constraints on *Outage* duration and or placement.

In accordance with the terms of the Planning Chapter 5 (Section 5.1 *EAPP IC* Requirements), the *TSOs* and the *EAPP Sub-Committee on Planning* are required to produce a *Power Balance Statement* and a *Transmission System Capability Statement* on an annual basis for the succeeding ten (10) years. The *Transmission System Capability Statement* forms the basis for individual *Users* of *National Systems* to determine the potential for power transfers within the *EAPP Interconnected Transmission System*.

OC 1 sets out a refinement of the planning process to take account of the following:

(a) *Outage* requirements for generation and transmission facilities whether for construction, maintenance or operational tests or *System Tests*

(b) Changes in the characteristics of generation or transmission facilities

(c) Changes in demand estimates

(d) Changes in *Generating Unit* availability caused by breakdown, fuel shortage or hydrological conditions

(e) Current and forecast weather conditions

(f) Anticipated commercial energy flows across the *EAPP Interconnected Transmission System*, and

(g) Other information supplied by *TSOs* or *Users*

The outcome of the Operational Planning process will be a definition of the *Power Balance* and *Transmission System Capability* over various timescales.

TSOs are responsible for liaison with the *Users* connected to their *National Systems* in respect of the Operational Planning process.

8.1.2 Objective

OC 1 specifies:

(a) The requirements for the exchange of information across the *TSO-EAPP* interfaces throughout the Operational Planning process, from *Outage* requirements identified up to three (3) years ahead for complex schemes and *EAPP Interconnected Transmission* and *National Systems* reinforcement to handover of the *Operational Plan* into the Control Phase

(b) The Operational Planning procedure including information required and a typical timetable for the coordination of *Planned Outage* requirements for *Generating Units* and transmission facilities including protection and associated communication channels that may have an effect on the operation of the *EAPP Interconnected Transmission System*, and

(c) The coordination of *Outages* to minimise as far as possible the number and effect of constraints on the *EAPP Interconnected Transmission System*

8.1.3 Scope

OC1 applies to *TSOs* and to *EAPP CC*. It should be noted that certain information and data may be required from individual *Users* and also from *External Systems*. It is the responsibility of individual *TSOs* to ensure such information and data is updated and made available.

8.1.4 Planning Cycle

The phases of the Operational Planning process are as follows:

(a) The Operational Planning Phase covering planning of the *EAPP Interconnected Transmission System* for the succeeding three (3) years

(b) The Programming Phase covering planning for the operation of the *EAPP Interconnected Transmission System* for the period of one (1) to eight (8) weeks ahead; and

(c) The Control Phase involving immediate operational planning for the day ahead

8.1.5 Outage Planning Process

There are four main inputs to be considered in carrying out the *Outage* planning process:

8.1.5.1 Demand Forecast

By the end of October each year, *TSOs* shall provide the *EAPP CC* with the projected maximum and minimum demands on their *National Systems* for the three (3) years ahead on a monthly basis. The demand forecast shall be specified for each substation of the *EAPP Interconnected Transmission System* within each *National System*.

By 10h00 Hrs each Friday, *TSOs* shall provide the *EAPP CC* with hourly demand forecasts for the following eight (8) weeks on each node of the *EAPP Interconnected Transmission System*. The demand forecasts shall include *Active* and *Reactive Power* requirements for each sub-station that is part of the *EAPP Interconnected Transmission System*.

The *EAPP* demand forecast shall normally be based on the aggregate of individual *TSO* forecasts. Nevertheless, the *EAPP CC* may carry out its own forecast using its own criteria if it has doubts on the validity of the individual *TSO* forecasts. If in the event there are significant differences between the aggregated *TSO* forecasts and the *EAPP* forecast, the *EAPP CC* shall prepare a report on the reasons for any discrepancies for presentation to the *EAPP Sub-Committee on Operations* to determine the matter.

TSOs shall provide the *EAPP CC* with estimates of the load, which could be disconnected if required. Details shall be given of the load shedding blocks and procedures required to implement load shedding in accordance with Chapter 12 (Demand Control, also known as OC 5 or DCC). Details shall also be provided of the *Automatic Load Shedding Scheme* installed in the *TSO's National System*.

8.1.5.2 Generating Unit Outages

Generating Unit Outages shall be planned such that any *Outage* shall not jeopardise the security of operation of the *EAPP Interconnected Transmission System*. Particular attention is required for large *Generating Units* and those having a major impact on the *Reactive Power* requirements of the *EAPP Interconnected Transmission System*.

By the end of October in each calendar year, the *TSOs* will provide the *EAPP CC* with:

(a) Draft *Provisional Generating Unit Outage Programme* for Years 2 and 3 for its centrally despatched *Generating Units*

(b) F*inal Generating Unit Outage Programme* for Year 1 for its centrally dispatched *Generating Units*

Between October and December of each calendar year, *EAPP CC* will consider the implications of the draft *Provisional Generating Unit Outage Programmes* submitted on the *Operating Margin* and the security of operation of the *EAPP Interconnected Transmission System* and request modifications if necessary. The *Final Generating Unit Outage Programmes* for Years 1, 2 and 3 shall be published on the *EAPP* Website at the end of December each year.

8.1.5.3 Transmission Outages

The planning of transmission *Outages* is dependent on the schedule of *Generating Unit Outages* and on the contracted energy transfers between *Control Areas*. *TSOs* shall plan transmission *Outages* required in Years 2 and 3 as a result of construction or refurbishment works. It is not anticipated that any detail of *Maintenance Outages* on the *EAPP Interconnected Transmission System* will be available 2 or 3 years ahead.

The planning of transmission system *Outages* in Years 0 and 1 ahead will, in addition, take into account *Outages* required because of maintenance and or operational or *System Tests.*

8.1.5.4 Net Transmission Capability

Certain *Users* may have pre-emptive rights over the use of *Transmission System Capability*.

This may occur where the *User* concerned has provided generation or transmission facilities as a consequence of a bilateral agreement. The *TSO* shall notify the *EAPP CC* of the existence and extent of such agreements for operational planning purposes.

In carrying out Operational Planning, the capacity rights shall be taken into account in the placement of generation or transmission *Outages*. However, the security of the *EAPP Interconnected Transmission System* shall be the overriding consideration.

The method of calculation of the Net Transmission Capability is set out in Section 14.1.3 (Chapter 14 or ISC 1).

8.1.6 Outage Planning Philosophy

Transmission system *Outages* and *Generating Unit Outages* shall be coordinated so that, in general, *Generating Unit Outages* shall take precedence over transmission system *Outages*.

The *EAPP CC* and each *TSO* shall seek to resolve any *Outage* placement conflicts through collaboration with each other, any relevant *Users* and *External Systems*.

The philosophy of *Outage* co-ordination associated with the *EAPP Interconnected*

Transmission System shall ensure that:

(a) *Maintenance* and construction *Outage* programmes of transmission *Plant* and *Apparatus* are co-ordinated to minimise the loss of *Transmission System Capability*

(b) *Planned Outages* of system voltage regulation equipment, such as automatic voltage regulators, synchronous compensators, shunt and series capacitors and reactors, shall be coordinated as required between *TSOs* by *EAPP CC*

(c) *Unplanned Outages* associated with transmission *Plant* and *Apparatus* are completed to restore normal operating conditions as quickly as possible. In the case of *Unplanned Outages*, *TSOs* shall consider the possibility of undertaking maintenance work during the *Unplanned Outage* such as to minimise subsequent *Outage* requirements or improve *EAPP Interconnected Transmission System* reliability

(d) Information is exchanged identifying maintenance work which has or could have a direct impact on the operation or transfer capability of the *EAPP Interconnected Transmission System*

(e) Risks of Trip of transmission elements and *Generating Units* are to be planned according to the same rules as for *Outages*, and

(f) Routine maintenance of metering, telemetering, control equipment and associated communication channels shall be coordinated between *TSOs* and *EAPP CC*

8.1.7 Data Requirements

The provision of a uniform data base of the *EAPP Interconnected Transmission System* and forecasts for interchange scheduling will allow each *TSO, EAPP Sub-Committee on Operations* and *EAPP CC* to perform power system studies for the simulation of:

(a) the effects of *Generating Unit Outages* on power flows, both on *National Systems* and on the *EAPP Interconnected Transmission System*, and

(b) load flows associated with the outage of lines or other elements of the *EAPP Interconnected Transmission System*, taking into consideration the influence of *Neighbouring* and *External Systems*

8.1.8 Operating Planning Phase

The Operational Planning Phase is concerned with the planning of generation and transmission *Outages* on the *EAPP Interconnected Transmission System* for the succeeding three (3) years.

By the end of October in each year, each *TSO* shall prepare a draft *Maintenance Plan* covering the period up to three (3) years ahead for discussion with *EAPP CC* and other *TSOs*. *TSOs* shall notify each *User* of those aspects of the draft *Maintenance Plan* that may operationally affect such *User* including, in particular, proposed start dates and end dates of relevant *EAPP Interconnected Transmission System Outages*. The *TSO* shall indicate to a *Generation Licensee* where a need may exist to impose restrictions on the operation of *Generating Plant Units* to allow the security of the *EAPP Interconnected Transmission System* to be maintained.

The development of the draft *Maintenance Plan* is an iterative process requiring frequent *EAPP CC* and *TSO* liaison. Each *TSO* shall review the draft *Maintenance Plan* on an ongoing basis and provide *EAPP CC* with *Outage* change requests, as they become known to that *TSO*, taking account of known or advised *User Outages*.

By the end of December in each year, the draft *Maintenance Plan* will be confirmed and will become the Annual *Maintenance Plan* for the immediate year ahead (Year 1).

8.1.9 Programming Phase

During the Programming Phase, *TSOs* and the *EAPP CC* shall refine, optimize, and update the Annual *Maintenance Plan* to accommodate essential changes, additional work and previously unconfirmed *Outages*, taking into account transmission and generation profile changes.

In the Programming Phase, operational planning is carried out on a rolling eight (8) week cycle. Each Friday *TSOs* shall update the Annual *Maintenance Plan* for the following eight (8) week period beginning at 00h01 Hrs on the following Monday.

The *Outage* Plan for the eight (8) week period ahead will determine the transmission constraints, which impact on the *Transmission System Capability*. Agreed final *Outages*, as published in the

Annual *Maintenance Plan*, are only to be amended if a changed requirement is brought about by an unplanned event on the *EAPP Interconnected Transmission System*.

Users shall give as much notice as reasonably practicable of any *Outages* affecting the *EAPP Interconnected Transmission System*. Any short notice *Outage* on the *EAPP Interconnected Transmission System, which could not be planned,* with ten (10) days' notice is considered an *Unplanned Outage. A Planned Outage* is an *Outage* for which at least ten (10) days' notice has been given.

Any variation in the planned return to service date or *Outage* start and completion times shall be brought to the notice of any other *TSO* involved and the *EAPP CC* immediately it is foreseen. The matter will be discussed between the respective *TSOs* and the *EAPP CC* in order to agree a new return to service date and or *Outage* start and finish times.

Where a *TSO* or the *EAPP CC* is obliged to cancel a *Planned Outage* in order to safeguard the operation of the *EAPP Interconnected Transmission System*, the *Outage* will be replanned to minimise any adverse impact on either the *User* or *TSO* concerned.

8.1.10Control Phase

Each day at 15h00 Hrs, *EAPP CC* and *TSOs* shall issue the final *Operational Plan* for use in real-time. This *Operational Plan* will cover the 24-hour period commencing at 00h01 Hrs on the following day. In the case of the *Operational Plan* issued on a Friday, the Plan will cover the three (3) days commencing at 00h01 Hrs on the Saturday. To minimise disruption to the existing programme and resources *Outage* changes in this period shall be limited to those deemed essential.

The *Operational Plan* shall contain details of any additional security studies, temporary protection settings and changes to operational arrangements to facilitate an *Outage* and agreements for operational actions including emergency return to service time, demand and *Generating Plant Unit* intertrip requirements and demand transfers. Any resource requirement for local switching shall be confirmed between relevant *TSOs*.

The *Operational Plan* will contain details of all *Outages* of *Generating Units* and transmission facilities, details of anticipated transfers, transmission constraints, *Contingency* plans and any other relevant information.

8.1.11Records

TSOs and *EAPP CC* shall keep records of:

(a) The availability of *Generating Units* and transmission facilities

(b) The duration and reasons for unavailability, whether planned or unplanned

(c) The changes requested for planned *Outages* in the Operational Planning process, and

(d) The cost of any constraint imposed by unavailability

These records shall be made available to the *EAPP Steering Committee* and to the *Independent Regulatory Board* upon request.

8.2 ENTGC REQUIREMENTS

8.2.1 Introduction

The Operating Policy Guidelines described here with the primary objective of ensuring an integrated operation of the Ethiopian National Grid and enhancing overall operational reliability and economy of the entire electric power network spread over the geographical area of the country and its interconnected system with neighbouring countries. Ethiopia's overall operation of the National / trans-national connections shall be supervised from the *National Load Dispatch Center (NLDC) by the ENTSO*. The Generation, Transmission, and distribution entities shall comply with the directions issued by the *ENTSO* as well as the Operating Policy Guidelines to ensure integrated grid operation most economically and efficiently. The Generation, Transmission and Distribution entities shall also cooperate with each other and adopt Good Utility Practice at all times for satisfactory and beneficial operation of the *ENTS*.

Operations planning for the *ENTS* shall include the following procedures wherever applicable.

8.2.2 Operating Procedures

(a) The *ENTSO* and *TNSPs* shall develop and maintain operating procedures for the safe operating of the *ENTS*, and for assets connected to the *ENTS*. These operating procedures shall be adhered to by Users when operating equipment on the *ENTS* or connected to the *ENTS*

(b) Each *User* shall be responsible for their own safety rules and procedures. The *ENTSO* and *TNSPs* shall coordinate to ensure the compatibility with regard to the safety rules and procedures of all Users

(c) In case of any equipment fault impacting the *ENTS*, *Users* must report such faults to the *ENTSO* immediately, or in the shortest possible time. Information on such faults shall be reported within seven (7) days of occurrence, and detail fault analysis shall be completed and reported within a maximum period of one (1) month. Details regarding the fault shall include such information as:

1. date, time, and location of fault
2. cause of fault
3. switching operation(s)
4. injuries/damages
5. interruptions and duration of interruptions; and
6. any other information, as appropriate. The *ENTSO* shall record and maintain all relevant information pertaining to all faults on the *ENTS*

(d) The *EAPP* operational agreements shall apply in the case of operational liaison with all international power systems connected to the *ENTS*

8.2.3 Operational Liaison, Permission for Synchronisation

(a) *ENTSO* shall sanction the switching, including shutting down and synchronising, of units and changing over of auxiliaries on all units

(b) If any *User* experiences an emergency, the other *Users* shall assist to an extent as may be necessary to ensure that it does not jeopardise the operation of the networks/plant

(c) A customer shall enter into an operating agreement with the *ENTSO*, if it is physically possible to transfer load or embedded *Generating Plants* from one point of supply to another by performing switching operations on his network. This operating agreement shall cover at least the operational communication and notice period requirements and switching procedures for such load transfers

8.2.4 Safety Coordination

(a) The *TNSP* shall authorize only competent staff to carry out any work such as network switching on the transmission grid and at the *Connection Point* for *Generating Plants* and non-embedded customers. The *TNSP* shall be the custodian of safety procedures and documents used when working on *Plant* and / or equipment on the transmission grid and at all points of connection with the *Users*. The *TNSP* shall not impose these safety requirements for work outside the transmission grid network and beyond the points of connection. The *TNSP* and customer both shall maintain clearly written switching logs in chronological order for all switching operations and document messages relating to safety co-ordinations. Repository of the switching logs and safety documents are maintained by the *ENTSO*

(b) The TNSP shall comply with the following guidelines for erecting any conductor of an overhead line that is accessible to pedestrians, urban areas and road/rail crossing, telecommunication lines and power lines at any part thereof be at a height not less than:

1. for 132kv: for pedestrians 7m, for urban areas and road/rail crossing 8.5m, for telecommunication lines 3m, for low voltage up to 1kv power lines 3m
2. for 230kv: for pedestrians 8m, for urban areas and road/rail crossing 9.5m, for telecommunication lines 4m, for low voltage up to 1kv power lines 4m
3. for 400kv: for pedestrians 9m, for urban areas and road/rail crossing 11.5m, for telecommunication lines 4.5m, for low voltage up to 1kv power lines 4.5m, and
4. For 500kv: for pedestrians 10.5m, for urban areas and road/rail crossing 12.5m, for telecommunication lines6.6m, for low voltage up to 1 kv power lines 6.6m

(c) A list of authorized personnel for transmission grid and for *Users* at points of connection with names, designations, and telephone numbers shall be made available to the *ENTSO* and the grid *Users*. The list must be updated and re-circulated as and when there is any change of information

(d) The designated and authorised person shall ensure that adequate safety precautions are established and maintained when any work is done on *Plant* and equipment. To ensure safety to commence work, the following steps shall be verified:

1. Source of power removed
2. Device physically disconnected from source of power with a caution notice attached to it
3. Safety testing completed satisfactorily
4. Proper connection to the earth ensured
5. Safety documents issued

The equipment shall only be considered suitable for return to service when all safety documents have been cleared and isolation points normalized.

(e) In the event of an accident during work on the *ENTSO* grid or at points of connection, the following steps shall be taken:

1. Stop work and attend to the injured if any
2. Notify designated authorised person for decision on whether work should continue or not
3. Designated authorized person notifies System Controller and Safety Officer
4. Designated authorized person produces a preliminary report and notify the *ENTSO* management, the *ENTGCRC* as soon as possible, but no later than seven (7) days
5. The *ENTSO* constitutes a committee for further investigation
6. The *ENTSO* produces a detailed accident report
7. The *ENTSO* circulates report internally and to key people in the *Users* systems

(f) Authorized switching personnel for *TNSP*(s) shall have to be recertified every year by the *TNSP(s)* designated personnel.

8.2.5 Communication

The Generation, Transmission and Distribution entities shall provide and maintain adequate and reliable communication facilities internally and with the *ENTSO* to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes.

8.2.5.1 Safety Conditions

To achieve a high degree of service reliability the *ENTSO* shall ensure adequate and reliable communications with the Users. Communication regarding safety coordination shall be made via normal operational channels. Additionally, the *ENTSO* and *Users* shall share their official business

contact telephone numbers at which operational personnel can be reached for use in operational purposes, if required. The *ENTSO* shall ensure proper recording and monitoring of all operational lines for future replay in case of any *Disputes* or incident investigation.

8.2.5.2 Outage Conditions

The *ENTSO* shall monitor and/or determine system conditions from time to time, and communicate these, or changes from a previous determination, to all *Users*.

The *ENTSO* shall be responsible for providing *Users* with operational information including planned and forced outages as agreed upon. Any changes or modifications to the existing transmission network and/or information regarding network condition that is likely to impact the short and long-term operation of the Users shall be communicated in a timely manner. Planned Outage shall be deferred if it will cause any of the following:

(a) Grid disturbances
(b) System isolation
(c) Partial blackout on the *ENTS*
(d) Any other event that may have an adverse impact on the system

Generation Licensees shall provide the *ENTSO*:

(a) A 52-weeks-ahead outage plan per *Generating Plant*, showing Planned Outage 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 *Generating Plant*, looking five (5) years ahead, showing the same information as above and issued by July 8 (updated by September for hydroelectric *Generating Plants)* each year

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

The *ENTSO* shall coordinate network *Outages* affecting unit output with related unit *Outages* to the maximum possible extent.

The objectives of the *ENTSO* in maintenance coordination are:

(a) Maintaining adequate reserve levels at all times

(b) Ensuring reliability where transmission constraints exist

(c) Maintaining acceptable and consistent real-time technical risk levels

The application for an equipment *Outage*, complete with duration of the Outage, work details, extent of isolation, switching programme and personnel to be involved, shall be made by the User to the *ENTSO* in a timely manner, but not later than seven (7) days prior to the due date of intended Outage. The *ENTSO* shall evaluate the request as per the established approval procedure for *Outages*. The information regarding the *Outage* request shall be communicated back to the applicant through established channels/modes of communication. Approved outages shall be entered into the appropriate log as an official record of planned system

Outages. Applicants shall be notified via the established channels of approval/rejection/deferment of *outage* applications.

The *ENTSO* shall also report daily demands, energies, losses, interruptions, etc. to *Users* and archive the information. The historical information shall be available to all Users on request.

8.2.6 System Logs

An operational message, instruction or a report sent/received on radio, telephone, cell phone or carrier by the *ENTSO*, *TNSPs*, or *Generation Licensees* shall be logged with all the necessary details, as listed below:

(a) Name of the station information is sent/received to/from

(b) Exact time information was sent/received

(c) Name of the person sending/receiving the information

(d) Exact time of completion of carrying out the instruction

8.2.7 Operational Planning

The demand estimation for both active and reactive power is required to be done on daily/weekly/monthly /yearly basis for current year load - generation balance planning. The *ENTSO* shall carry out system studies for operational planning purposes using this demand estimate. The Distribution entities shall develop methodologies/mechanisms for daily/ weekly/monthly/yearly demand estimation (*MW*, *Mvar* and *MWh*) for operational purposes (See *ENDGC* for details).

Procedure for scheduling energy from hydroelectric units shall be done as follows:

(a) After the end of rainy season around September, an annual declaration of energy shall be provided on a monthly basis, given the status of reservoirs and available energy taking projected evaporation and inflows into account

(b) Available energy shall be updated on a monthly basis

(c) Available energy shall be updated for the short rainy season in March and April

(d) Daily schedules for each dam shall be updated each month. Daily schedules shall also be updated as required in response to critical system conditions, including generator availability

(e) During the dry season between October and February, schedules shall be adjusted as needed to accommodate downstream water requirements from sugar plantations

(f) Generator operations shall be managed to meet the monthly energy targets

A daily generation dispatch shall be done as per the schedules described in Section 20.4.4.1 (b) and (c) following the procedure shown below:

A dispatch form is created by the *ENTSO* with the date/time of the dispatch and is archived. Expected half-hourly country demand is estimated using historical demands for the particular day. Available *Generating Plants* are scheduled in half hour increments to meet forecast demand based hydro energy targets, *Spinning Reserve* and other *Ancillary Service* system security and merit order requirements. The generation schedules is evaluated to determine if country demand, spinning reserve and other *Ancillary Service* system security needs, main hydro target and merit order requirements have been met.

If the requirements have not been met, the system shall be re-dispatched until requirements have been met. The *ENTSO* shall log the dispatch form, and customised copies of the dispatch forms shall be sent to relevant recipients.

8.2.8 Generation System Data Requirement

Generation outputs and equipment loadings shall be recorded on half-hourly basis for all *Generating Plants*. All *Generation Licensees'* fuel data and Energy meter readings shall be taken after every midnight. Machine loading/shutdown, trip or output limitations data/reports shall be done immediately after information is received at *ENTSO*. Data recording and reporting shall be done as described below:

(a) Meter reading of appropriate data (including *Plant* loading (MW, Mvar)/voltage levels, fuel storage, etc.) is taken in the field at pre-determined intervals of time, and logged

(b) Data is validated at the *Generating* Plant for accuracy/metering errors, and corrected; *Generating Plant* and all relevant equipment loading data are logged

(c) For hydrology data, dam levels received from hydro stations shall be recorded on hourly basis or appropriate intervals

(d) For *RPP*, ramp rate, power factor shall be made available as well

(e) For *Generating Plant* output/equipment loading data, half hourly outputs and relevant equipment loadings shall be logged

(f) For *Generating Plant* loading/shutdown time data, the *Generating Plant* loading/shutdown times shall be logged

(g) For system voltages, half hourly readings of system voltages from *SCADA* mimic display shall be taken and logged

(h) For *Generating Plant* capacity availability data, half hourly capacity availability for *Generating Plants* shall be logged

(i) For midnight energy Meter readings for *Generating Plants,* end of day Energy Meter readings shall be logged every midnight

(j) For fuel stock for *Generating Plants,* end of day fuel stocks for diesel plants shall be logged. *Generating Plants* shall pass the fuel stocks to the *ENTSO* after every midnight

(k) For *Generating Plant Outage/*Capacity reports, details of Outages or operation limitations shall be logged. Report forms shall be filled whenever a machine trips, is shutdown on emergency or it has operational limitations

(l) *The ENTSO* shall check to confirm that data received is correct and has been entered correctly in the log sheets

(m) Required corrections in data entries shall be made

(n) If no corrections are required, reports shall be processed and an accurate and complete daily analysis report prepared, archived, and printed

8.2.9 Transmission System Data Requirement

The capability of transmission system components for both normal and emergency conditions shall be established by technical studies and operating experience. System operation shall be co-ordinated among systems and control areas (national/regional). This includes coordination of equipment outages, voltage levels, *MW* and *Mvar* flow monitoring and switching that affects two or more systems of transmission components. When line loading, equipment 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 *ENTSO* 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. Please refer to Chapter 10 Emergency Operations) for more details.

9 OPERATIONS CODE NO. 2 – OPERATIONAL SECURITY

This chapter contains requirements specific to both the EAPP IC and the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

9.1 EAPP IC REQUIREMENTS

9.1.1 Introduction

OC 2 is concerned with security aspects in the operational planning and real-time operation of the *EAPP Interconnected Transmission System* and does not deal with long-term planning for which reference should be made to Chapter 5 (Planning). OC2 is not concerned with the commercial aspects of system operation.

System security and reliability are primary goals of the operation of the *EAPP Interconnected Transmission System*. Each *TSO* is responsible for the operation of its *National System* but the interrelationship between that system and the *EAPP Interconnected Transmission System* requires coordination by the *EAPP CC* at regional level.

Pending full interconnection between all countries of *EAPP*, the *EAPP Interconnected Transmission System* shall be operated in a number of *Control Areas*. A *Control Area* comprises various *National Systems* or parts of *National Systems* capable of regulating its *Generating Units* in order to meet its constantly changing demand and to maintain its interchange schedule with other systems or *Control Areas* and contributing its frequency bias obligation to the interconnection. Each *Control Area* shall have one of the *TSOs* designated as *Control Area Operator*. The designation of the *Control Area Operator* shall be agreed with the *TSOs* concerned and with the *EAPP CC*.

The *Control Area Operator* shall ensure that within its *Control Area* sufficient reserves of generation are available to allow for continuous generation and load balancing, frequency control and the maintenance of *EAPP* operational security standards as described in OC2. Any failure to meet these minimum requirements can lead to reduced security or to disturbances or events causing undesirable effects on the *EAPP Interconnected Transmission System*.

OC 2 specifies the technical requirements and standards for the operational security of the *EAPP Interconnected Transmission System* as they relate to the following issues:

(a) N-1 *Contingency* criterion

(b) Interchange scheduling

(c) Operating reserves for control of system frequency and interchange with other *Control Areas* or *External Systems*

(d) Voltage control

(e) Fault level control

(f) Protection coordination, and

(g) *Remedial Action Schemes*

9.1.2 Objective

The objectives of OC 2 are:

(a) To provide a framework of principles and requirements for achieving and maintaining the security and reliability of the *EAPP Interconnected Transmission System* during operation of the system under normal and emergency conditions, and

(b) To ensure that the *EAPP Interconnected Transmission System* is operated within the technical parameters set out in Chapters 5 and 6 (Planning, and Connection)

9.1.3 N-1 Criterion

The N-1 security criterion refers to the requirements placed upon the operation of the *EAPP Interconnected Transmission System* to maintain the security of the system during normal and disturbed conditions.

This criterion shall be applied by all *TSOs* in combination with appropriate choice of generation, transmission facilities, and sufficient active and reactive reserves. *TSOs* shall identify by means of operational planning potentially insecure situations in order to take appropriate measures in advance.

Control Area Operators are responsible for the application of the N-1 Criterion throughout their *Control Area*.

9.1.3.1 Contingency

The loss of any element of the *EAPP Interconnected Transmission System* shall not cause:

(a) A frequency deviation outside operating limits

(b) A voltage deviation leading to voltage instability

(c) Thermal overloading of equipment

(d) Islanding of any part of the *EAPP Interconnected Transmission System*

(e) Angular instability in the *EAPP Interconnected Transmission System*, and

(f) Cascading *Outages*

It is acceptable in some cases for *TSOs* to allow for loss of load on condition that its magnitude is compatible with secure operation and is predictable and locally limited. The following normal *Contingencies* shall be considered:

(a) A single transmission line

(b) A single *Generating Unit* or combination of *Generating Units*

(c) A single transformer

(d) a voltage compensation installation

(e) an HVDC link considered as either a *Generating Unit* or a large *User*

TSOs shall also take account of multiple *Contingencies* when such *Contingencies* may occur with sufficiently high probability to threaten the security of operation. Examples of such multiple *Contingencies* are:

(a) A double circuit line, which refers to two circuits on the same towers over a considerable distance

(b) A single busbar, during periods when the *TSO* assesses there is a significantly higher risk of *Outage*

(c) A common mode failure with the loss of more than one *Generating Unit*

The *Contingency* monitoring process includes the loss of single or multiple elements of generation or transmission equipment at any time. This monitoring shall also take account of temporary weather conditions or temporary limitation of transmission facilities.

9.1.3.2 Responsibilities

It is the responsibility of each *TSO* to monitor the N-1 Criterion on its own *National System*, to carry out computer simulations for *Contingency* analysis and to notify the *EAPP CC,* TSOs of *Neighbouring Systems* and *External Systems* of potential problems in the application of the criterion. *TSOs* concerned shall jointly verify the compliance with the N-1 criterion taking into consideration cross-border power transfers.

After a *Contingency*, each *TSO* shall return its power system to N-1 compliant condition as soon as possible and in case of a delay, it shall immediately notify the *EAPP CC* and all other *TSOs* affected.

9.1.4 Interchange Scheduling

The net amount of interchange scheduling between *National Systems* or *Control Areas* shall not exceed the mutually agreed transfer limits of the *EAPP Interconnected Transmission System*.

The entire *EAPP Interconnected Transmission System* shall be operated in such a way that sufficient transmission capacity is available for the delivery of reserve power for *Primary Response* for the *National Systems* or *Control Areas* which may be affected by the most severe single *Contingency*.

Requirements for interchange scheduling on the *EAPP Interconnected Transmission System* are set out in the Interchange Scheduling and Balancing Chapters 14 through 16.

9.1.5 Operating Reserves

TSOs shall continuously maintain adequate reserve generating capacity to control the frequency of the *EAPP Interconnected Transmission System* within the limits set out in Chapter 6 (Connection) , and to avoid unexpected loss of load following transmission or generation *Contingencies*. The reserve generating capacity is also required to maintain agreed interchange schedules following changes in demand or generation.

The requirements for operating reserve on the *EAPP Interconnected Transmission System* are set out in Chapter 15 (Balancing and Frequency Control).

9.1.6 Voltage Control

9.1.6.1 Basic Principles

To maintain the *EAPP Interconnected Transmission System* security and integrity, and avoid damage to transmission and *User's* equipment, each *TSO* shall maintain voltages within the limits set out in Section 6.1.4 in Chapter 6 (Connection) and shall contract for voltage control *Ancillary Services* in accordance with Chapter 16 (*Ancillary Services*).

Each *TSO* shall operate reactive resources within its *National System* to maintain system and interconnection voltages within limits. Each *TSO* shall maintain reactive resources to support its voltage under N-1 *Contingency* conditions and shall disperse and locate the reactive resources so that they can be applied promptly and effectively when *Contingencies* occur. The *TSO* shall direct corrective action, including load shedding, necessary to prevent voltage collapse when reactive resources are insufficient.

Reactive Power flows on the *EAPP Interconnected Transmission System* shall be maintained at a minimum level in order to limit voltage drop and to allocate the total *Transmission System Capability* mainly to *Active Power*. In the event that sufficient reactive resources are not available within a *TSO*'s *National System*, bilateral agreements may be made with *Neighbouring Systems* to transfer *Reactive Power* through cross-border connections.

9.1.6.2 Responsibilities

Each *TSO* individually and jointly with other *TSOs* and the *EAPP CC* shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and *Mvar* flows within their *National Systems* and with *Neighbouring Systems*.

Without limitation, the procedures shall include the following methods of voltage control:

(a) Adjusting *Generating Unit Reactive Power* output

(b) Transformer tap changing, cable switching, reactor and capacitor switching, and other control methods

(c) Tap changing on *Generating Unit* transformers

(d) Scheduling must-run generation, and

(e) Switching out of transmission lines

TSOs shall ensure that data on all generation and transmission *Reactive Power* resources, including the status of voltage regulators, tap changers and *Power System Stabilisers,* is available to neighbouring *TSOs* and the *EAPP CC*.

9.1.7 Fault Levels

The *EAPP Interconnected Transmission System* is subject to short circuits between phases or to earth mainly due to atmospheric conditions and to faults in equipment. Short-circuit protective devices are installed on all system equipment in order to promptly and effectively disconnect any fault with selectivity.

TSOs shall ensure that the setting and function of the protection equipment is checked regularly. If there are significant changes in operating conditions, the settings of protection devices shall be adjusted to suit the new conditions.

9.1.7.1 Standards

Each *TSO* shall operate its *National System* such that, at any node of the *EAPP Interconnected Transmission System*, short-circuit currents do not exceed the breaking capacity of the switchgear installed at that node, so that failure to clear a fault does not lead to cascading *Outages*. The *TSO* shall use an appropriate protection strategy as set out in Chapter 6 (Connection) to ensure selectivity and to provide backup protection in case of failure of the main protection system to isolate a fault.

9.1.7.2 Corrective Action

In the event of fault levels exceeding permissible levels at any particular location, *TSOs* shall take immediate action to manage the values within limits.

Each *TSO* shall calculate where appropriate the short-circuit currents at each node of its *National System* taking into account the contributions of *Neighbouring Systems* to the short circuit current. *TSOs* of *Neighbouring Systems* shall exchange the data required for short circuit calculations.

In order to limit fault levels in operational timescales, *TSOs* have a number of options including the switching out of lines and the operation of busbars in separate sections. However, *TSOs* shall take into account the operational security standards when considering such measures.

9.1.8 Protection Coordination

TSOs and the *EAPP CC* shall coordinate the application and maintenance of protection systems on the *EAPP Interconnected Transmission System*. Protection systems shall be used to detect abnormal system conditions and to trip selectively circuit breakers on generation and transmission facilities to prevent danger to persons or damage to equipment.

Each *TSO* and the *EAPP CC* shall ensure that its Control Centre personnel are familiar with the purpose and limitations of the protection system schemes applied in the *EAPP Interconnected Transmission System*. Power system protection procedures shall be made available to all appropriate system personnel and shall provide for instructions and training where applicable.

The procedures shall cover the following:

(a) Planning and application of protection systems

(b) Review of protection systems and settings

(c) Intended operations under normal, abnormal and emergency conditions

(d) Regular scheduled testing and preventive maintenance, and

(e) Analysis of the actual protection system operation

9.1.9 Requirements

Since protection systems in one *National System* can affect operations in *Neighbouring Systems*, all protection systems in the *EAPP Interconnected Transmission System* shall be co-ordinated between *Users* and the relevant *TSOs*. Protection systems on transmission interconnections with *External Systems* shall also be coordinated to prevent operational problems, which may impact on the *EAPP Interconnected Transmission System*.

Each *TSO* shall supervise the status of its protection system and notify all relevant neighbouring *TSOs* of every change in status.

Each protection device shall be recalibrated at least once a year. A review of the protection settings shall also be carried out whenever there is an expansion or change to the transmission or generation facilities. Any incorrect operation of a protection device shall be reported in accordance with the guidelines in Chapter 11 (Incident Reporting or OC 4), investigated immediately and corrective action implemented as soon as possible.

Neighbouring *TSOs* shall be notified in advance of changes in generating sources, transmission, load or operating conditions, which may require adjustments to their protection systems.

9.1.10 Remedial Action Schemes

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, generation units or transmission facilities under a set of carefully defined conditions. *RAS* are normally used in order to increase *Transmission System Capability* under specified conditions. They may also be used to permit higher loading levels on the *EAPP Interconnected Transmission System* in those instances where additional facilities cannot be built or have been delayed. Their application is specific to particular circumstances.

RAS installed on the *EAPP Interconnected Transmission System* shall be subject to agreement between the relevant *TSOs* and the *EAPP CC* unless the automatic actions following operation of *RAS* are confined to the area of a single *TSO*. *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 *TSOs* and *Users* involved.

TSO Control Centres shall monitor the status of all *RAS* and notify all relevant *TSOs* and the *EAPP CC* of any change of status.

9.1.11 Power System Monitoring

Each *TSO* shall maintain power system security by monitoring the status of its *National System* and of relevant parts of the *EAPP Interconnected Transmission System*. *TSOs* shall therefore ensure that their Control Centres and the *EAPP CC* are able, as a minimum, to monitor in real-time the following information:

(a) System frequency

(b) Transmission line status

(c) *Active* and *Reactive Power* flow on transmission circuits and across *User Connection Points*

(d) *Active* and *Reactive Power* from *Generating Units*

(e) Voltages at transmission and generation busbars

(f) Dynamic and static *Reactive Power* reserves, and

(g) Appropriate alarms including overload and protection alarms

Each *TSO* shall agree with neighbouring *TSOs* and the *EAPP CC* the real- time data to be exchanged on-line and its format.

In addition, each *TSO* shall provide computing facilities for:

(a) Evaluating *Contingencies* on the *EAPP Interconnected Transmission System*;

(b) Determining thermal, voltage and stability limits

(c) Evaluating reserves of both *Active* and *Reactive Power*, and

(d) Carrying out post event analysis of power system incidents in accordance with the guidelines in Chapter 11 (Incident Reporting or OC 4) with the aid of recorded data

9.2 ENTGC REQUIREMENTS

This chapter specifies the criteria and procedures to be applied by the *ENTSO* for operational security of the *ENTS*.

9.2.1 Additional Responsibilities

9.2.1.1 Auxiliary Supply

The auxiliary supply to all base-load *Generating Plants* shall be regarded as the most important load on the *ENTS*. The *ENTSO* shall regard all essential supplies as identified by the *DNSP* as having the same priority.

9.2.1.2 Supply Restoration

The *ENTSO* shall be responsible for efficient restoration of the *ENTS* after supply interruptions.

9.2.1.3 Continuity of Operation

The *ENTSO* shall ensure continuous operation of the *ENTS*.

9.2.1.4 Switchgear Operation

(a) Any time that switchgear in the *ENTS* is to be operated, the *ENTSO* shall issue the switching sequence for such operation including equipment identification. If the *TNSP* has no objections, the procedures for the switching sequence shall be followed

(b) The *TNSP* shall carry out switchgear operation as instructed as expeditiously as possible. Whenever switchgear interlocks exist, the *TNSP* shall carry out an operation to defeat interlocks before performing switchgear operation. Interlocks should not be defeated except under emergency or extreme circumstances and then only by designated operational crew

(c) The *TNSP* shall inform the *ENTSO* of completion of carrying out switchgear operation

(d) The *ENTSO* shall write down the exact time of operating the switchgear in the standard daily switching log sheet

(e) If the *TNSP* has objections to carrying out switchgear operations, the *TNSP* shall inform the *ENTSO*, and the *ENTSO* shall investigate the matter

(f) In case of stressed switchgear noticed through alarm or physical observation, the *ENTSO* shall be informed by the *TNSP*, and the *TNSP* shall follow appropriate actions as directed by the *ENTSO*

Switchgear standards are defined in the *ENDGC* under Section 6.1.5.5 (Substation Standardization) in Chapter 6.

9.2.1.5 Equipment with Dual Responsibility

For equipment and its auxiliaries falling under the responsibility of the *ENTSO* and/or the *Regional Control Center (RCC)* or the *DNSP*, the *ENTSO* shall identify need to operate in dual control mode, and coordinate with the representative of the respective *RCC/DNSP*, if any on the sequence of operation to be carried out.

The *ENTSO* shall check and determine if there are any communication problems in the co-ordination of the operations. If there are no communication issues, the *ENTSO* shall coordinate switching operation with the representative of the DNSP/*RCC*.

In case of any communication problems, the *ENTSO* shall delegate coordination of operations to the representative of the DNSP/*RCC*.

The representative of the *DNSP/RCC* shall co-ordinate the operations as delegated and notify the *ENTSO* when the required operation is completed. The *ENTSO* shall log the exact time of completion.

9.2.1.6 Generating Plant Operation

Where there is a need for plant regulation/plant shutdown/plant loading identified by the *ENTSO* from the system status as displayed by the *SCADA* system or from any other source, the appropriate *Generating Plant* operator shall be instructed to carry out the operational guidelines.

If there are no objections, the *Generating Plant* operator shall carry out required operation as instructed as expeditiously as possible. The *Generating Plant* operator shall inform the *ENTSO* of completion of carrying out required operation.

In case of any objections, the *Generating Plant* operator shall notify the *ENTSO*, and the *ENTSO* shall investigate the refusal to carry out the operation.

Both the *ENTSO* and the *Generating Plant* operator shall log the following information upon sending or receiving an operational message/instruction/report on radio/telephone/ cell phone/carrier

(a) Message, instructions, or report details
(b) Name of the station to/from information is sent /received
(c) Exact time information is sent/received
(d) Name of the persons sending and receiving information
(e) Exact time of completion of carrying out the instructions

Generating Plant *AVRs* and *VAR* limiter relays (where fitted) should be in service continuously. Whenever a *Generating Plant* is operating without its *AVR* or *VAR* limiter, the *ENTSO* must be immediately informed.

The times at which a *Generating t Plant* shall be synchronised and switched off the interconnected system and the output (MW and Mvars) of such plant shall be directed by *ENTSO*.

The *ENTSO* shall instruct the *Generating Plant* when to turn on and off and the Generating Plant shall comply. When the *Generating Plant* is on, it shall follow the ENTSO's instructions regarding output (MW and Mvars).

Generating Plants shall not be taken out of service or rendered unavailable without reference to the *ENTSO* except in cases of emergency when the *ENTSO* shall be informed as soon as possible of the action taken.

The *ENTSO* shall as soon as possible be notified of any factors, which may affect the output, efficiency or inflexibility of operation of any *Generating Plant*.

Free Governor Action must be allowed within the prescribed limits whenever practicable to assist frequency control.

9.2.1.7 Loss of System Neutral Earthing

Any missing system neutral earthing noticed by the *TNSP* shall be immediately notified to the *ENTSO*. The procedure shall follow as listed below:

(a) Upon noticing part of the system missing its neutral earthing, the *TNSP* shall immediately notify the *ENTSO* with details of information regarding the exact area missing the neutral earthing. The *ENTSO* shall determine whether it is possible to restore the neutral earthing or not
(b) The *ENTSO* shall issue necessary instructions to switch in system neutral earthing, if it is possible to restore the system neutral earthing

(c) The *TNSP* shall switch in system neutral earthing as fast as possible, and inform the *ENTSO* of completion of switching in neutral earthing

(d) If restoration is not possible, the *ENTSO* shall quickly co-ordinate activities with the *TNSP* to make that part of the system without neutral earthing dead and log the time

(e) The *ENTSO* shall log down exact time of switching in system neutral earthing

9.2.1.8 Protection Equipment

In case there is any need to work on the system protection devices (e.g., relays, power supply, fuses, miniature circuit breakers, communication channel), the *TNSP* shall coordinate with the *ENTSO* according to the operational guidelines below.

The *TNSP* shall inform the *ENTSO* of the intention to carry out work on the protective apparatus. The *TNSP* shall also provide details of work to be carried out.

The *ENTSO* shall assess the request and determine if work can proceed or not according to the following conditions:

(a) It is unsafe to work

(b) There will be no adequate protection

(c) There will be a disturbance in case of any tripping

If none of the three conditions is prevalent, the *ENTSO* shall approve the request and inform *TNSP* to proceed with work. The *TNSP* shall carry out the work accordance with a procedure for such kind of work.

If any of the above conditions exists, the *ENTSO* shall reject the request for work and inform the *TNSP* of the rejection.

9.2.1.9 Transmission Line Fault

The *ENTSO* shall develop and communicate formal procedures for correcting transmission line faults.

When a line fault causes breakers controlling the line to trip, the *TNSP* shall coordinate with the *ENTSO* as per operational guidelines listed below:

(a) The *ENTSO* shall notice the unexpected trip from the *SCADA* and check to confirm whether the line has auto-reclosed or locked out. If line has auto-reclosed, the *TNSP* shall note the relays operated and distance of fault from the distance fault recorder and pass them to the *ENTSO*. The *ENTSO* shall log the relays operated and the distance of fault along with other information such as location of fault, identified by station, if possible; exact time of event; name of person working on the event; and exact time the fault was cleared. The incident shall be logged and relevant personnel shall be informed

(b) If the line has locked out, the *ENTSO* shall evaluate impact of the trip on the system by observing system response to the trip. In case of serious impact – the *ENTSO* shall take relevant appropriate action to stabilise the system

(c) If the impact is not serious, the *ENTSO* shall make every effort to find the root cause of this issue as per the established procedure of the *ENTS* and document it. The *ENTSO* shall check to confirm with the *TNSP* if any work is being carried out on the line. If so, the *ENTSO* shall determine if the fault is caused by the *TNSP*. If fault is caused by the *TNSP*, The *ENTSO* shall instruct the *TNSP* to eliminate the cause of fault, and the *TNSP* shall notify the *ENTSO* of the completion of eliminating the fault

(d) If no work is being carried out on the line, The *ENTSO* shall check to confirm if line is from a manned substation or not. If the line is from a manned substation, The *ENTSO* shall issue instructions for reading and resetting relays and distance of fault from the distance fault recorder. If the line is from an un-manned substation, The *ENTSO* shall direct the *TNSP* to the relevant substation. The *TNSP* shall note down relays operated, reset them, and also record the distance of the fault from the fault recorder

(e) The *ENTSO* shall check to confirm whether breaker-operating commands are available or not, and if so, issue instructions for closing of line breakers. The *ENTSO* shall close breakers controlling the line by sending a closing command using *SCADA*

(f) If breaker-operating commands are not available, The *ENTSO* shall issue instructions to the *TNSP* for a reclosure. The *TNSP* shall try a reclosure on the line and notify the *ENTSO* of completion of carrying out a reclosure. If the line holds, the *ENTSO* shall check to confirm whether the line trips again or not, and if any *Customers* are interrupted because of the trip. If *Customers* are interrupted and there is alternative source of supply, the *ENTSO* shall transfer or co-ordinate activities to transfer *Customers* to alternative source of power

(g) If no *Customers* are interrupted or if they are interrupted and there is no alternative source of power, the *ENTSO* shall check to confirm whether there is a switch along the transmission line or not. If there is an isolator along the line, the *ENTSO* shall direct the *TNSP* to the isolator. The *TNSP* shall confirm arrival at the isolator, and the *ENTSO* shall issue instructions to open the isolator on the line. Instruction shall be issued keeping in mind Electrical safety rules. The *ENTSO* shall try a reclosure on the two line- sections one after the other. If there is no trip, The *ENTSO* shall issue instruction to close the isolator properly and normalise the line

(h) If there is no isolator along the line, the *ENTSO* shall issue instructions to isolate the faulty section. Isolation of the fault shall be done by the *TNSP*, who shall open isolators controlling the affected section and securing them in open position as instructed by the *ENTSO*. The *ENTSO* shall notify the TNSP about the faulty part of the system. The *ENTSO* shall log the incident.

(i) The *TNSP* shall patrol the line to determine the fault. The *ENTSO* shall wait for a report from the *TNSP*

(j) Upon finding the fault, the *TNSP* shall report to the *ENTSO* details of isolations required for repairs to be carried out, and the *ENTSO* shall issue instructions to isolate the location of the fault. The *TNSP* shall inform the *ENTSO* of completion of carrying out isolations

(k) The *TNSP* shall carry out repair of fault using appropriate tools and shall notify the *ENTSO* of completion of carrying out repairs. The *ENTSO* shall issue instructions to normalise the line and the system

(l) The *TNSP* shall normalise line and system as instructed by The *ENTSO*, and confirm of completion of normalising the system. The *ENTSO* shall normalise and log the incident

9.2.1.10 SCADA Equipment Failure

Upon detection of *SCADA* equipment failure, the following operational guidelines shall be followed:

(a) The *ENTSO* shall establish whether it is a total or partial *SCADA* failure
(b) For a partial failure, the *ENTSO* shall assess the effects the failure has on generation, transmission and sub-transmission systems
(c) In case of a total failure, the *ENTSO* shall inform the *TNSPs* and the *DNSPs/RCCs* of the failure, and instruct the *DNSPs/RCCs* to begin diagnosis, repair and restoration work. Upon the completion of the work, the *DNSPs/RCCs* will inform the *ENTSO*. The *ENTSO* shall issue instructions to normalise the sub system and report -back to the *ENTSO*
(d) The *ENTSO* shall instruct the *TNSPs* and the *DNSPs/RCCs* to monitor system parameters i.e. system Frequency and Voltage and report any significant variations/changes
(e) The *ENTSO* shall instruct all Generating Plants and *TNSPs* to report any trip of a machine or line
(f) In case of a major disturbance on the *ENTS* affecting *SCADA* equipment:
    1. An incident shall be reported to the *ENTSO* by the *TNSP* or *DNSPs/RCCs* as soon as possible with the following information: nature of incident; equipment affected; location of equipment; Customers affected; and actions to be carried out. The *ENTSO* shall evaluate whether incident has severe impact on the system
    2. If there is a severe impact, the *ENTSO* shall take the necessary appropriate action to ensure the integrity of the system, and determine if assistance is required or not
    3. If assistance is required, the *ENTSO* shall call relevant staff, inform them about the incident, and instruct them to call from desired locations
    4. The *ENTSO* shall check to find out if there are any casualties because of the incident. In case of any casualty, the *ENTSO* shall call and inform the safety officer of the affected installation; location of the equipment; cause of the incident; and damage incurred
    5. Depending on the impact caused, the *ENTSO* shall make sure whether the incident is newsworthy. If it is newsworthy, the *ENTSO* shall inform relevant communications officers of the following: nature of incident; affected installation; and affected Customers

The *ENTSO* shall direct work for the identification of fault and repair. Upon the completion of the work, the *ENTSO* shall normalise the system and log the incident.

9.2.1.11 Access Security

The *ENTSO* shall have a detailed plan and procedures governing security and access to the system *Users' SCADA*, computer, and communications equipment. The procedures shall allow for adequate access to the equipment and information by the *ENTSO* or its nominated representative for purposes of maintenance, repair, testing, taking of readings/measurements, and periodic checking as deemed necessary. Participants shall ensure reasonable security against unauthorised access, use, and loss of information and a backup storage strategy for the systems that contain the information.

9.2.1.12 Hydro Generating Plants

Hydro *Generating Plants* equipped with over frequency protection at a set value, shall not be set at a level likely to compromise the system security and safety.

While preparing the net injection schedule for hydro generation, the *ENTSO* shall consider the operating zone/technical constraints, to the extent possible.

9.2.1.13 Solar and Wind Power Generating Plants

The *ENTSO* shall ensure that Solar/Wind Power *Generating Plants* back down generation on consideration of the security of the *ENTS* or safety of any equipment or personnel. The *SCADA* facility shall provide appropriate information to the *ENTSO* in this regard.

10 Operations Chapter No. 3 – Emergency Operations

This chapter contains requirements specific to both the *EAPP IC* and the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

10.1 EAPP Requirements

10.1.1 Introduction

OC 3 is concerned with maintaining the security and integrity of the *EAPP Interconnected Transmission System* in emergency operating conditions. Experience has shown that even a simple incident can trigger a large-scale disturbance, which may have widespread implications for electricity supply to the population at large.

Although the *EAPP Interconnected Transmission System* may be designed and operated in line with the security standards set out in the PC and OCs, unexpected circumstances may arise where faults and disturbances outside the defined *Contingencies* may occur. Such circumstances require timely and decisive action to prevent further propagation of the disturbance. Disturbances can result from a number of causes but most typically may be due to the simultaneous loss of a number of *Generating Units* or transmission failures resulting from severe weather conditions or mal-operation of protection systems.

This is particularly the case where power systems today tend to be operated closer to the security limits due to environmental constraints and market pressures. The overriding principle is that the effects of faults and disturbances should be confined to as small a part of the *EAPP Interconnected Transmission System* as possible.

10.1.2 Objective

The objectives of OC 3 are to ensure that *TSOs* and the *EAPP CC*:

(a) Are able to identify insecure operating conditions on the *EAPP Interconnected Transmission System*

(b) Have procedures and plans in place to manage emergency conditions

(c) Have comprehensive contingency plans in place for the restoration of supplies in the shortest possible time using the most effective means

10.1.3 Identification of Risks

TSOs and the *EAPP CC* shall ensure that they are in a position to identify the risk of insecure operating conditions either on their own *National System* or on the *EAPP Interconnected Transmission System*. The risks to secure operation of the *EAPP Interconnected Transmission System* may arise from but are not limited to the following:

(a) Flows on parts of the *EAPP Interconnected Transmission System* exceeding security limits

(b) Lack of operating reserves (caused, for example, by *Outages* of *Generating Units*, by hydrological conditions or by restricted transmission capacities)

(c) Human error when carrying out switching operations on the *EAPP Interconnected Transmission System*

(d) Frequency excursions outside normal operating limits

(e) Significant *Reactive Power* constraints leading to critical high or low voltage conditions

(f) High *Reactive Power* flows giving rise to potential protection mal-operations

(g) Indications of instability such as voltage drop, undamped power swings or increase of phase angles

(h) Lack of reliable real-time data, and

(i) Adverse climatic conditions

10.1.4System Warnings

TSOs and the *EAPP CC* require common definitions for NORMAL, ALERT, and EMERGENCY conditions to enable them to act appropriately and predictably as system conditions change. They should have a common understanding of each other's functions, responsibilities, capabilities, and authorities under emergency or near-emergency conditions.

10.1.4.1 Normal State

In its NORMAL state, the *EAPP Interconnected Transmission System* is operating within its technical parameters. It has sufficient generation reserves, all transmission elements are operating within limits and voltage and frequency are normal.

In the event of identifying a risk of insecure operation, a *TSO* or the *EAPP CC* may issue an ALERT or an EMERGENCY warning in real-time. These warnings shall be issued to all *Users* within a *TSO*'s *National System* and to the *EAPP CC* and any *Neighbouring System, which* may be affected by the risk. Any warning issued by a *TSO* may be applied to the whole or part of its *National System* and by agreement with neighbouring *TSOs* to the whole of or part of their *National Systems*. The *EAPP CC* may also issue warnings when in its view there is a serious risk to the whole *EAPP Interconnected Transmission System*.

10.1.4.2 Alert State

In an ALERT state, a Contingency has occurred but the *EAPP Interconnected Transmission System* is stable and all operational reserves for both transmission and generation balance have been committed. *TSOs* and the *EAPP CC* may be uncertain as to when the EAPP Interconnected Transmission System can be returned to its NORMAL state due to system constraints and or low operating reserves and the situation is potentially dangerous.

10.1.4.3 Emergency State

In an EMERGENCY state the *EAPP Interconnected Transmission System* is in an unstable condition and phenomena such as cascade tripping, low frequency and or voltage, loss of synchronism, loss of supplies, whether partial or total, and islanding may occur. The security of the *EAPP Interconnected Transmission System* is endangered. Exceptional actions such as load shedding may be necessary to limit the spread of the dangerous phenomena and prevent the collapse of part of or the whole *EAPP Interconnected Transmission System*. In this state, the system passes rapidly towards dangerous conditions of operation with system parameters outside the limits fixed for secure operation.

10.1.5 Responsibilities of TSOs

TSOs and the *EAPP CC* shall draw up emergency plans and procedures and ensure that appropriate measures and resources are in place to enable the early identification of risks to secure operation of the *EAPP Interconnected Transmission System*.

TSOs shall act to alleviate emergencies and to implement emergency procedures in cooperation with neighbouring *TSOs* and the *EAPP CC*.

10.1.5.1 Real Time Data

TSOs shall provide a *SCADA* system giving a complete overview of *TSO*'s *National System* and of relevant parts of *Neighbouring Systems*. The *SCADA* system shall be of dual redundant design with a back-up system in a remote location away from the Control Centre. The back-up system shall be subject to periodic testing to ensure its functionality.

The Control Centre *SCADA* system shall also provide facilities for post-mortem review to enable a detailed analysis of events and disturbances to be carried out.

Each *TSO* shall make available real-time data of relevant parts of its *National System* to neighbouring *TSOs* and the *EAPP CC*. Details of the data to be exchanged in real time shall be agreed between the parties.

TSOs shall ensure the provision of a direct telephone line to neighbouring *TSOs* and the *EAPP CC*.

10.1.5.2 Security Analysis

TSOs shall make arrangements to carry out studies of the effects of various *Contingencies* on the behaviour of the *EAPP Interconnected Transmission System* within their *National System*. These studies shall cover load flow, constraint analysis, static and dynamic stability and voltage stability. As a minimum, such studies shall be carried out by each *TSO* in off-line mode on a weekly basis. In addition, real-time studies based on SCADA data should be carried out wherever possible.

The *EAPP CC* shall make arrangements to carry out a similar series of studies for the whole *EAPP Interconnected Transmission System*.

TSOs and the *EAPP CC* shall agree the list of *Contingencies* to be considered in carrying out the studies. The data required for the security analysis studies is contained in Section 19.8 of Chapter 19 (Data Exchange).

10.1.5.3 Coordination of Automatic Systems

TSOs shall ensure that procedures are in place for the coordination of automatic systems, including protection, having an effect on the system of a neighbouring *TSO* and shall agree on the type and the settings of devices for automatic tripping of cross-border connections.

10.1.5.4 Auxiliary Supplies

TSOs shall ensure that appropriate back-up auxiliary supplies are available at all substations and Control Centres. These back up sources shall not rely upon a supply being made available from the *EAPP Interconnected Transmission System* and shall have a resilience of at least 6 hours.

10.1.6Emergency Procedures

TSOs and the *EAPP CC* have a primary obligation to maintain the integrity of the *EAPP Interconnected Transmission System* and to prevent any unplanned disturbance to the system. However, once a large-scale disturbance does occur they must be prepared to react and adapt to the dynamic environment of restoration operations.

Fundamental to re-establishing the integrity of the *EAPP Interconnected Transmission System* is effective communications and coordination that enables *TSOs* and the *EAPP CC* to understand the nature of the disturbance as well as how one *TSO's* actions may impact on *Neighbouring Control Areas*. This communication and coordination is a continuous and evolving process tailored to the demands of the disturbance.

Each *TSO* and the *EAPP CC* shall develop, maintain and implement robust and comprehensive procedures for emergency situations and have a strategy and plans in place for the safe and prompt restoration of electricity supply. *TSOs* shall also ensure that their personnel and any of their *Users* involved in implementing the emergency procedures are fully aware of and trained and tested in their responsibilities.

TSOs shall provide copies of their emergency plans and procedures to neighbouring *TSOs*, *EAPP CC* and to relevant *Users* within their *National Systems*. These plans and procedures shall be coordinated with other *TSOs,* the *EAPP CC* and *External Systems*.

The emergency plans and procedures agreed between *TSOs*, *EAPP CC* and relevant *Users* shall include, but not be limited, to the following:

(a) The procedures for the dissemination of the system state warnings set out in Section 10.1.4 in Chapter 10 (Emergency Operations – System Warnings) to neighbouring *TSOs*, *EAPP CC* and relevant *Users* and the actions to be taken on receipt of a warning

(b) The requirement to establish and maintain reliable communications between all interested parties and the communications protocols to be used

(c) A list of personnel appropriately authorised to take action in emergencies together with their contact details

(d) Any requirement under national legislation to inform government and other public authorities of the existence of an emergency condition on the *EAPP Interconnected Transmission System* and the possible effects of the situation on population and infrastructure

(e) The requirement to ensure rapid information exchange between *TSOs* about system conditions particularly close to their common borders. This information should include the topology of the system and its weak points and the potential risks of tripping

(f) The possible need to arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used

(g) A contingency plan to continue safe and reliable operations in the event of total loss of a *TSO's* Control Centre or communications facilities

(h) The need to ensure that sufficient resources of trained, tested and authorized personnel are available in control rooms and for operation under all conditions

(i) The need to modify cross-border transfers to alleviate overloading

(j) The application of load shedding in some parts of the *EAPP Interconnected Transmission System* in order to limit the risk of cascade tripping

(k) The regular training of all personnel in operation under emergency conditions

TSOs shall make every effort to remain connected to the *EAPP Interconnected Transmission System* under emergency conditions. If a *TSO* however considers that its *National System* is endangered if it remains connected, it may implement any remedial action necessary to protect its own *National System*.

10.1.6.1 Review of Emergency Procedures

TSOs shall review and update their emergency plans and procedures every year or whenever significant changes are made to the *EAPP Interconnected Transmission System*. They shall also take account of deficiencies noted when carrying out simulations and exercises of the emergency plan and procedures and any recommendations arising from reports prepared under Chapter 11 (Incident Reporting or OC 4).

The *EAPP Sub-Committee on Operations* is responsible for the review of the emergency procedures annually to ensure that the emergency plans and procedures comply with Chapter 10 (Emergency Operations or OC 3).

10.1.7System Restoration and Black Start

The procedure necessary for a recovery from a *Total Shutdown* or *Partial Shutdown* is known as a *Black Start* Procedure. The main objective of a *Black Start* is the restoration of the *EAPP*

Interconnected Transmission System as an integrated whole in the shortest possible time using the most effective means following a *Total Shutdown* or *Partial Shutdown*.

The complexities and indeterminate nature of recovery from a *Total Shutdown* or *Partial Shutdown* require that any *Black Start* Procedure is sufficiently flexible in order to accommodate the full range of *Generating Unit* and *EAPP Interconnected Transmission System* characteristics and operational possibilities. This precludes the setting out of concise chronological sequences. The overall strategy may include the overlapping phases of establishment of isolated groups of *Generating Units* together with complementary local demand. These groups are termed *Power Islands*. The step-by-step integration of these *Power Islands* into larger sub-systems will eventually result in the re-establishment of the *EAPP Interconnected Transmission System*.

10.1.7.1 Responsibilities

TSOs are responsible for the preparation of the strategy and plan for system restoration and *Black Start* as part of the procedures set out in Section 10.1.6 (Emergency Operations – Emergency Procedures).

When a *Total Shutdown* or *Partial Shutdown* exists on its *National System*, the *TSOs* shall notify the *TSOs* of *Neighbouring Systems* and the *EAPP CC* and shall agree the initial steps in the restoration process.

Each *TSO* is primarily responsible for re-starting its respective *National System* after a *Total* or *Partial Shutdown* that disconnects its system from the *EAPP Interconnected Transmission System*.

Each *TSO* shall be responsible for ensuring *Generating Units* with *Black Start Capability* as specified in CC 8.6 (*Black Start* Units) are available within its *National System*. TSOs shall contract for *Black Start* capability in accordance with Chapter 16 (Ancillary Services ISBC3).

Appropriate tests and simulations shall be carried out on an annual basis to ensure that:

(a) *Black Start* Units are capable of starting up without any external power supply;

(b) the *National System* can be energised and loaded from the *Black Start* Unit(s), and

(c) the *National System* can be re-synchronised with the *EAPP Interconnected Transmission System*.

Black Start Tests may involve synchronisation of generation to the *EAPP Interconnected Transmission System* or connection of demand remote from the *Black Start* Unit.

10.1.7.2 Procedure

In the event that the systems of neighbouring *TSOs* remain de-energised after a *Total Shutdown* of the *EAPP Interconnected Transmission System*, *TSOs* shall determine, by means of tests or simulations, the amount of system and load that could be energised from their *National System*.

Whenever possible the *TSOs* affected by a *Total Shutdown* shall coordinate the restoration process. If they consider it necessary to re-configure the *EAPP Interconnected Transmission System* or disconnect some cross-border connections, they shall request the *EAPP CC* to coordinate the operation with all other *TSOs* that may be affected by the action.

Each *TSO* shall recover its *National System* and obtain the balance between generation and demand in coordination with its *Users*, handling the synchronization operations of their systems until complete integration with the *EAPP Interconnected Transmission System* is achieved. The *EAPP CC* shall be responsible for the overall supervision of the restoration process of the *EAPP Interconnected Transmission System*.

During the initial stages of restoration normal operational security standards may not be appropriate or possible and the *EAPP Interconnected Transmission System* or a *National System* may be operated outside normal voltage and frequency limits provided that it does not result in damage to *Plant* and or *Apparatus*, or a safety hazard to persons.

10.1.7.3 Power Islands

EAPP CC shall coordinate the formation of *Power Islands* where such *Power Islands* include the parts of more than one *National System*. The *EAPP CC* shall designate one *TSO* to act as the *Control Area Operator* for such a *Power Island* until such time as re-synchronisation with the *EAPP Interconnected Transmission System* has occurred.

The designated *TSO* of a *Power Island* shall ensure that the *Power Island* is managed in a secure and safe manner. Where possible a *Power Island* should be operated in accordance with the following frequency and voltage criteria:

(a) the frequency in the Island shall be nominally 50 Hz and shall be controlled within the limits 49.5 – 50.5 Hz

(b) the voltage on the Transmission System in the Island shall normally remain within -/+ 10% of nominal. Voltages of +20% and –15% should not prevail for more than 15 minutes

Close coordination between *TSOs* and *Users* is required to achieve and maintain these frequency and voltage levels.

10.1.7.4 Completion of Black Start and System Restoration

When the *Black Start* and system restoration are complete the *EAPP CC* shall formally notify *TSOs* that the *Black Start* is complete and normal operation has been resumed.

10.1.8Reporting of Emergency Conditions

The reporting of significant incidents during emergency conditions and or *Black Start* shall be in accordance with Chapter 11 (Operations Code No. 4 – Incident Reporting), or OC 4, Incident Reporting which also contains provision for the Joint Investigation of incidents.

10.2 ENTGC REQUIREMENTS

10.2.1 Introduction

This section specifies the criteria and procedures that are specific to the *ENTSO* internal system for emergency operations of the *ENTS*.

10.2.2 Emergency and Contingency Planning

The following emergency and *Contingency* planning actions are specific for the *ENTSO* and are elaborated where needed:

(a) The *ENTSO* shall develop and maintain *Contingency* plans to manage system contingencies and emergencies that are relevant to the performance of the Interconnected Power System (IPS). Such *Contingency* plans shall be developed in consultation with all *Users* shall be consistent with internationally acceptable utility practices, and shall include but not be limited to:

1. Under-frequency load shedding
2. Meeting Ethiopia's disaster management requirements, if any, including the necessary minimum load requirements
3. Forced outages at all points of interface, and
4. Supply restoration

(b) Emergency plans shall allow for quick and orderly recovery from a partial or complete system collapse, with least cost solution and minimum impact on customers

(c) Emergency plans shall comply with *EAPP* agreements and guidelines

(d) The *ENTSO* shall periodically verify *Contingency* and/or emergency plans by actual tests to the greatest practical extent possible. In the event of such tests causing undue risk or undue cost to a *User,* the *ENTSO* shall take such risks or costs into consideration when deciding whether to conduct the tests. Any tests shall be carried out at a time that is least disruptive to the *Users* and embedded *end-use customers*. The costs of these tests shall be borne by the respective asset owners. The *ENTSO* shall ensure the co-ordination of the tests in consultation with all affected *Users*

(e) The *ENTSO* shall specify minimum emergency requirements for distribution control centres, *Generating Plant* local control centres and substations to ensure continuous operation of their control, recording, annunciator and communication facilities

(f) It shall be ensured that other *Users* comply with the *ENTSO*'s reasonable requirements for *Contingency* and emergency plans

(g) The *ENTSO* shall set the requirements for automatic and manual load shedding. *Users* shall make available loads and schemes to comply with these requirements. If there are any loads in the *ENTS* with contract to provide ancillary services, can be activated before any generators. Under frequency load shedding shall be viewed as a last resort to mitigate generation load imbalance and shall be followed only after conventional generation and then RPP resources have been exhausted. When the *SCADA* system displays a sudden loss of generation accompanied by a drastic drop in system frequency without the operation of

under frequency scheme, the *ENTSO* shall monitor the system for a voltage collapse. If a voltage collapse is imminent, controlled load-shedding is initiated according to Ethiopia Power System Control procedure

(h) If a sudden loss of a large *Generating Plant* occurs on the system followed by an operation of under frequency scheme, the *ENTSO* shall initiate action as detailed in the Ethiopia Power System Control procedure

(i) The *ENTSO* shall be responsible for determining all operational limits on the *ENTS*, updating these periodically and making these available to the *Users*

(j) The *ENTSO* shall conduct load flow studies regularly as indicated in section 10.1.5 (Responsibilities of the *ENTSOs* - Security Analysis) to determine the effect that various component failures would have on the reliability of the system. At the request of the *ENTSO*, *Distribution Licensees* shall perform related load flow studies on their part of the network and make the results available to the *ENTSO*

(k) Studies shall be made on a coordinated basis to:

1. Determine the facilities on each system, which may affect the operation of the coordinated area

2. Determine operating limitations for normal operation when all transmission components are in service; and

3. Determine operating limitations of transmission facilities under abnormal or emergency conditions. In determining ratings of transmission facilities, consideration shall be given to thermal and stability limits, short and long time loading limits, and voltage limits

(l) 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 power system, which may affect the Emergency Transfer Capability

(m) Studies shall be made to develop operating voltage or reactive schedules for both normal and outage conditions

(n) Adequate coordination with the *Neighbouring Systems* to use uniform line identifications and ratings when referring to transmission facilities of a transmission system network shall foster consistency when referring to facilities and reduce the likelihood of misunderstandings

(o) The scheduling of *Outages* of transmission facilities which may affect *Neighbouring Systems* shall be co-ordinated with the appropriate authorities

(p) Any Emergency *Outage*, which may have a bearing on the reliability of the transmission system shall be communicated to all systems which may be affected

11 OPERATIONS CHAPTER NO. 4 – INCIDENT REPORTING

This chapter contains requirements specific to both the EAPP IC and the ENTS. If in any instance there is a difference in requirements, the more stringent requirement shall hold

11.1 EAPP IC REQUIREMENTS

11.1.1 Introduction

OC 4 sets out the requirements for reporting significant incidents that have caused, or could have caused, damage to persons, system equipment, or operation of the *EAPP Interconnected Transmission System* outside the standards set out in Chapter 9 ((Operational Security or OC 2).

OC 4 also describes the procedure for the joint investigation of significant incidents and for the technical audit of *TSO's* procedures and *Plant* and or *Apparatus* connected to, or forming part of, the *EAPP Interconnected Transmission System*.

11.1.2 Objective

The objectives of OC 4 are:

(a) To specify the roles and responsibilities of *TSOs* and *EAPP CC* with regard to significant incident reporting

(b) To provide for the joint investigation by *TSOs*, *EAPP Steering Committee* and the *Independent Regulatory Board* of any significant incident that has had, or could have had, a widespread impact on any part of the *EAPP Interconnected Transmission System,* and

(c) To make provision for the technical audit of a *TSO*'s procedures and *Plant* and / or *Apparatus* connected to, or forming part of, the *EAPP Interconnected Transmission System*

11.1.3 Reporting Requirements

Where a *TSO* becomes aware of a significant incident on its *National System* which, in the *TSO*'s view, compromised, or may have compromised the integrity or secure operation of the *EAPP Interconnected Transmission System,* the *TSO* shall notify the *EAPP CC* and other affected *TSOs* of such significant incident as a matter of urgency.

The *EAPP Steering Committee* and the *Independent Regulatory Board* may require the provision of a report on a significant incident, which in their view has compromised the secure operation of the *EAPP Interconnected Transmission System*.

Without limiting the requirements of OC 4, *TSOs* shall report any of the following incidents that have or could have adversely affected the security of the *EAPP Interconnected Transmission System* or the safety of persons or system equipment:

(a) Manual or automatic tripping under emergency conditions of system circuits and *Plant* associated with the *EAPP Interconnected Transmission System*

(b) An uncontrolled loss of generation of greater than 30 MW

(c) A loss of demand greater than 20 *MW* for more than 15 minutes from a single incident

(d) Load shedding of more than 20 *MW* implemented for local reasons

(e) The occurrence of a system separation or islanding

(f) Deviation of voltage and or frequency outside the limits of the CC

(g) System instability

(h) Implementation of *Black Start* procedures

(i) Sabotage, vandalism, terrorism and cyber-attacks affecting the security of the *EAPP Interconnected Transmission System*

(j) Major safety incident

The Report shall provide a detailed description of the incidents that occurred as well as the actions taken for the re-establishment of normal conditions on the *EAPP Interconnected Transmission System*.

11.1.4Incident Reports

11.1.4.1 Initial Report

The Initial Report shall be prepared immediately and shall be submitted to the *EAPP CC* within four (4) hours of the occurrence of the significant incident. The Initial Report shall include, in the format of Sample Report in Section 11.1.7 of this chapter, without limitation, the following information:

(a) A description of the significant incident detailing the sequence of events

(b) The time and date of the significant incident

(c) The location(s) of the significant incident

(d) *Plant* and or *Apparatus* directly involved and not merely affected by the significant incident

(e) A preliminary diagnosis of probable cause(s) of the significant incident

(f) The consequences on the *EAPP Interconnected Transmission System* (loss of load, unavailability of generating and transmission facilities, protection operations)

(g) Immediate actions performed to restore the system to a normal operative state; and

(h) Any other information available in relation to the significant incident

Those incidents that were not identified until sometime after they occurred shall be reported to the *EAPP CC* within four (4) hours of being recognised.

11.1.4.2 Interim Report

Depending on the severity or complexity of the significant incident, an Interim Report may be issued. This report shall be submitted to the *EAPP CC* within five (5) business days of the occurrence of the incident. It shall contain further analysis of the incident together with provisional recommendations for action to be taken, on an urgent basis, regarding procedures or facilities of the EAPP Interconnected

Transmission System. The purpose of the Interim Report is to alert the *EAPP CC* and other *TSOs* of the possible need to take immediate action.

11.1.4.3 Final Report

A Final Report shall be presented to the *EAPP CC* within thirty (30) business days of the occurrence of the significant incident. As a minimum the Final Report shall contain a description of the incident, the identification of its root cause, the conclusions reached and recommendations for corrective actions, if applicable, to prevent recurrence of this type of incident.

When a *TSO* requires more than thirty (30) business days to submit a Final Report, it may request additional time and agree a new timescale to carry out the relevant investigations.

11.1.4.4 Evaluation and Approval of Reports

All reports shall be circulated by the *EAPP CC* to the *EAPP Steering Committee*, to the *Independent Regulatory Board and to* other relevant *TSOs*.

The Final Report is subject to the approval of the *EAPP Steering Committee* and of the *Independent Regulatory Board*. If either body fails to approve the Final Report, the incident shall be subject to a Joint Investigation in accordance with Section 11.1.4 in this chapter.

11.1.4.5 Actions Arising from Incidents

When the Final Report of a significant incident concludes that action is required to implement the recommendations of the Report, *TSOs* concerned shall draw up an implementation timetable. The actions required as a result of incidents are likely to involve the following:

(a) Modification of operating procedures

(b) Modification of equipment (e.g. control systems or *Remedial Action Schemes*)

(c) Identification of any lessons learned

(d) Non-compliance with operational or technical procedures or any provision of the EAPP/EAC Interconnection Code or *ENTGC* or equivalent documents

The *EAPP Sub-Committees on Planning and Operations* shall track and review the status of all recommendations from Final Reports at least twice a year to ensure they have been implemented in due time. If any recommendation has not been implemented within two (2) years, or if the tracking and review process indicates at any time that the recommendation(s) are not being pursued with due diligence, the matter shall be bought formally to the attention of the *EAPP Steering Committee* and the *Independent Regulatory Board* for further action.

11.1.5Joint Investigation

Where an incident has occurred and a Final Report submitted under Section 11.1.3 in this chapter, the affected *TSOs* or the *EAPP CC* may request in writing that a Joint Investigation be carried out. A Joint Investigation shall also be carried out in accordance with the provisions of Section 11.1.3

where approval of the Final Report by the *EAPP Steering Committee* and or the *Independent Regulatory Board* has been withheld.

The composition of the Joint Investigation Committee shall be appropriate for the incident to be investigated and agreed by all parties involved. If an agreement cannot be reached on the composition of the Committee, the *EAPP Steering Committee* and the *Independent Regulatory Board* shall decide.

The terms of reference and all matters relating to the Joint Investigation shall be agreed by the parties in good faith and in a timely manner. The investigation shall begin within fifteen (15) business days from the request for a Joint Investigation.

11.1.6Technical Audit

Based on an analysis made by the *EAPP Sub-Committees on Planning and Operations* or the *Independent Regulatory Board* of all Final Reports, it may be decided to carry out a technical audit of the *EAPP Interconnected Transmission System* facilities or of the operational procedures used by *TSOs* and the *EAPP CC.*

These technical audits shall be carried out by experts nominated by the *EAPP Sub-Committees on Planning and Operations* or *Independent Regulatory Board* as the case may be. *TSOs* shall allow access for the inspection of their facilities, provide the required information, and accept and comply with the recommendations of the technical audit.

11.1.7 Sample Report

[Suggested Format of Reports]

SIGNIFICANT INCIDENT REPORT NO .....

REPORTING TSO .....

TYPE OF REPORT (CIRCLE) INITIAL / INTERIM / FINAL

TIME OF INCIDENT .....

DATE OF INCIDENT .....

LOCATION OF INCIDENT .....

.....

.....

PLANT OR APPARATUS DIRECTLY INVOLVED .....

.....

.....

.....

ESTIMATED TIME AND DATE OF RETURN TO SERVICE.....

.....

DESCRIPTION OF SIGNIFICANT INCIDENT .....

.....

.....

.....

.....

.....

.....

OTHER RELEVANT INFORMATION (Weather conditions, change in output of Generating Units etc.)

.....

.....

.....

CAUSE OF SIGNIFICANT INCIDENT where known at time of Report

.....

.....

.....

.....

.....

.....

RECOMMENDATIONS FOLLOWING INVESTIGATIONS

.....

....

11.2 ENTGC REQUIREMENTS

11.2.1Incidents for Reporting

A major incident is defined as an incident where (a) Load was interrupted for more than allowable time as determined by the *ENTSO*; and (b) Severe damage to *Plant* or system equipment has occurred. In case of a major incident, a Participant/*User* shall have the right to request an independent audit of the report, at their own cost, if they are not satisfied with it. If these audit findings disagree with the report, the Participant/*User* may follow the *Dispute* resolution mechanism. If the audit agrees with the report, the report recommendations shall prevail and be implemented within the time frames specified.

An incident is reported to the *ENTSO* by operators or regional controller when a major disturbance occurs on the national grid resulting in casualties, loss of supplies or damage to equipment. An incident shall be reported with the information on the nature of incident, its location, people/customers/installations affected, and corrective actions taken as soon as possible. Procedure for handling incident reporting shall be followed as per Ethiopia Power System Control procedure. Following are some guidelines regarding incident reporting, investigation, and analysis:

(a) *Generation Licensees* shall report loss of output and tripping of units and change of status of AGC and governor to the *ENTSO* within two (2) minutes of the event occurring

(b) In the event of a multiple unit tripping, the relevant *Generation Licensee* shall submit a written report to the *ENTSO* within seven (7) to fifteen (15) days identifying the root causes of the incident and the corrective actions taken.

(c) The *ENTSO* shall be responsible for developing and maintaining an adequate system of fault statistics

(d) Incidents shall be reported to the *Regulatory Authority* as defined in the license conditions

(e) A *User* may issue an incident report to the *ENTSO* on becoming aware of an occurrence. The *ENTSO* shall provide a reason for the incident, what has been done to address it, and, if appropriate, indicate what action it shall take to avoid such an incident(s) in the future

(f) The *ENTSO* may also issue an incident report to a *User*, where the *User* does not comply with necessary requirements. The *User* shall provide the *ENTSO* with reasons for the incident and, where appropriate, indicate the measures that will be taken to address the problem

(g) Incidents involving sabotage or suspected sabotage, as well as threats of sabotage on the power system shall be reported to the *ENTSO*

(h) Any incident that materially affected the quality of the service to a Participant/*User* shall be formally investigated. These include interruptions of supply, disconnections, under or over voltage incidents, quality of supply contraventions, etc. A preliminary incident report shall be available after three (3) working days and a final report within three months. The *ENTSO* shall initiate such an investigation, arrange for the writing of the report and involve all affected Participants/*User*s. All these Participants/*User*s shall make all relevant required information available to the *ENTSO*. The confidentiality status of information involved shall be maintained

11.2.2 High Risk Incidents

High-risk incidents include the ones causing any of the following events: Significant disruption of supply to customers; Substantial damage to equipment and switchgears; Fires in establishments; Adverse environmental consequences (e.g. bushfires, environmental pollution, etc.). The following information are also required to be provided:

(a) Sequence of events necessary for root cause analysis (includes loading and generation situation before/during/after the disturbance, and historical performance of the failed equipment)

(b) Details regarding the fault containing chronological description of the incident's occurrence, operations during the incident and the cause of the incident

(c) Any known facts such as: Protection malfunctions; Malfunction of Electrical *Plant* equipment; Malfunction of telecommunications and *SCADA*; Transport problems; Manpower problems

(d) Any of the following actions taken after occurrence of the incident: Emergency actions taken; Strategies taken to operate the system under fault condition; Operating procedures used during the disturbance; instructions issued, timings for execution; Restoration actions initiated

(e) Any conclusions/recommendations that include: Weaknesses found in the disturbance handling, equipment mal-operations performance; System response to the disturbance; Any mal-operations; Evaluation of all aspects of operation; Any modifications of disturbance handling procedures and why

(f) Any remedial actions taken to restore supplies and equipment

(g) Distribution of completed reports to the Operational Heads

Despite the urgency of the situation, careful, prompt, and complete logging of all operations and operational messages shall be ensured by all *User*s to facilitate subsequent investigation into the incident and the efficiency of the restoration process.

12 OPERATIONS CHAPTER NO. 5 – DEMAND CONTROL

This chapter contains requirements specific to both the EAPP IC and the ENTS. If in any instance there is a difference in requirements, the more stringent requirement shall hold

12.1 REQUIREMENTS FROM THE EAPP IC

12.1.1 Introduction

Demand Control (or OC 5) sets out the provisions to be made by a *TSO* in cooperation with the *EAPP CC* to permit reductions in demand in the event of insufficient generation capacity available to meet demand, or in the event of breakdown/ thermal overloading of any part of the *EAPP Interconnected Transmission System* leading to the possibility of unacceptable frequency or voltage conditions. Without limitation, the provisions of OC 5 may be used in the event of both a steady-state shortfall of generation and a transient shortfall following an instantaneous loss of generation.

TSOs shall, after taking all other remedial actions, disconnect customer demand rather than risk an uncontrolled failure of *Plant* and or *Apparatus* or cascading *Outages* of the *EAPP Interconnected Transmission System*.

12.1.2 Objective

The objective of OC 5 is to require *TSOs* to have procedures in place to enable a reduction in demand on the *EAPP Interconnected Transmission System* in order to avoid a breakdown or overloading of the system or in the event of generation shortage.

12.1.3 Methods of Demand Control

To preserve the security of the *EAPP Interconnected Transmission System,* OC 5 deals with the following types of demand control:

(a) *Automatic Load Shedding* activated by low frequency and low voltage relays

(b) Emergency manual load shedding, and

(c) Planned manual load shedding including voltage reduction and *rota disconnection*

The type of demand control utilised by the *TSO* in any particular circumstances will depend upon the amount of time between the *TSO* becoming aware of the need for implementing demand control and the time at which it needs to be implemented. In the event of a sudden and unexpected loss of generation on the *EAPP Interconnected Transmission System*, the requisite demand control will normally be achieved by means of *Automatic Load Shedding* but, occasionally, emergency manual disconnection may additionally be required. In all cases when demand control is necessary, the *TSO* shall use demand disconnection as the last option.

12.1.4Risk of Demand Reduction

The *TSO* and or the *EAPP CC* shall issue a notification of a risk of demand control whenever it is anticipated that there may be insufficient generating capacity available to meet demand or that there is a risk of serious disturbance to the *EAPP Interconnected Transmission System*.

Any such notification issued shall be provided as soon as reasonably possible after the *TSO* or the *EAPP CC* has grounds to believe that there is a risk of demand reduction. The notice shall include an estimate of:

(a) the required level of demand control in MW;

(b) the expected start time and duration of demand control.

Under the terms of Emergency Operations or OC 3 (Chapter 10), *TSOs* and or *EAPP CC* are responsible for the issue of ALERT and EMERGENCY warnings. The existence of a risk of demand reduction shall normally be included within one of these warnings.

12.1.5Automatic Load Shedding Schemes

Under generation shortfall conditions, the frequency graded *Automatic Load Shedding Scheme* is used to prevent frequency collapse on the *EAPP Interconnected Transmission System* and to restore the balance between generation output and demand.

Each *TSO* shall establish plans for *Automatic Load Shedding* for underfrequency and undervoltage conditions. The overall *Automatic Load Shedding Scheme* for the *EAPP Interconnected Transmission System* shall be coordinated by the *EAPP CC* in order to prevent excessive transfers across the *EAPP Interconnected Transmission System* and possible instability.

A *TSO* shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

TSOs shall coordinate *Automatic Load Shedding* in their *National Systems* with underfrequency isolation of *Generating Units*, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

12.1.5.1 Procedure

The following procedures are to be followed by a *TSO* in the implementation of the *Automatic Load Shedding Scheme* on its *National System*:

(a) Each *TSO* shall make available up to 60% of its annual peak demand for the *Automatic Load Shedding Scheme*

(b) Schemes shall be based on system dynamic performance where the greatest probable imbalance between demand and generation is simulated

(c) Schemes should be analysed to ensure that no unacceptable over-frequency, over- voltage or transmission overload will occur

(d) The demand on the *EAPP Interconnected Transmission System* subject to an *Automatic Load Shedding Scheme* will be split by the *TSO* into discrete blocks. The number, location, size and the associated low frequency or low voltage settings of these blocks will be as determined by the *TSO* in consultation with the *EAPP CC* and shall not unduly discriminate against or unduly prefer any one group of *Users*. The *TSO* and *EAPP CC* shall also take into account constraints on the *EAPP Interconnected Transmission System* when determining the size and location of demand reduction by *Automatic Load Shedding*

(e) If the *EAPP Interconnected Transmission System* is still in a critical condition following frequency or voltage recovery after the activation of the *Automatic Load Shedding Scheme*, a *TSO* may implement manual disconnection of additional demand to permit restoration of the previously disconnected demand;

(f) Demand disconnected by the *Automatic Load Shedding Scheme* shall only be restored on the instruction of the *TSO* with the agreement of the *EAPP CC* unless there are particular local circumstances

(g) The settings of under-frequency and under-voltage relays shall be coordinated with the emergency plans and procedures required by OC 3

(h) *TSOs* and *EAPP CC* shall review annually the settings of under-frequency and under-voltage relays and the levels of demand to be disconnected

12.1.6Planning and Emergency Manual Load Shedding

Planned manual disconnection is the procedure adopted when the *TSO* has reasonable notice that a generation shortfall and or *EAPP Interconnected Transmission System* problems may require demand control. *TSOs* may also initiate voltage reduction in lieu of demand disconnection as necessary.

Each *TSO* shall be responsible for maintaining *rota disconnection* plans for use where a shortage of generation is anticipated over a prolonged period. The *rota disconnection* plans shall provide for the disconnection and reconnection of defined blocks of demand on instruction from the *TSO*. In this way the *TSO* can instruct the necessary level of disconnection (and reconnection) required by the circumstances at the time. The *rota disconnection* plans of each *TSO* shall be coordinated by the *EAPP CC* to ensure that where the generation shortage is common to a number of countries of *EAPP* the resulting demand control is applied equitably.

Emergency manual disconnection is utilised by the *TSO* when a loss of generation or a mismatch of generation output and demand is such that there is an operational requirement to disconnect demand at short notice or in real time to maintain a margin between generation output and demand and in certain circumstances to deal with operating problems such as unacceptable voltage levels and thermal overloads. *TSOs* shall maintain emergency manual disconnection plans and procedures, coordinated with *EAPP CC*, to implement manual load shedding in a timeframe adequate for responding to an emergency.

TSOs shall ensure that, as far as practicable, demand reductions are deployed equitably. In the case of protracted generation shortage or transmission system overloading, large imbalances of generation and demand may cause excessive power transfers across the *EAPP Interconnected Transmission*

System. If such transfers threaten the stability of the *EAPP Interconnected Transmission System* or could damage generating and transmission facilities, the pattern of demand reduction shall be adjusted to secure the *EAPP Interconnected Transmission System*, notwithstanding the inequalities of disconnection that may arise from such adjustments.

12.1.7 Demand Restoration

When *EAPP Interconnected Transmission System* conditions have returned to normal, *TSOs* may, with the consent of *EAPP* CC, initiate demand restoration. Demand restoration will normally be instructed in stages as equitably as practicable. Two or more stages of demand restoration may be carried out simultaneously where appropriate. Procedures for demand restoration after a *Total* or *Partial Shutdown* shall be in accordance with Section 10.1.7 of Chapter 10 (Emergency Operations – System Restoration and Black Start).

12.2 ENTGC REQUIREMENT

12.2.1 Introduction

This section specifies the criteria and procedures to be applied by the *ENTSO* for demand control of the National Transmission System. Provisions of this section are to enable the *ENTSO* to implement demand reduction or demand addition in a manner that ensures the continued balance between supply and demand under normal or emergency conditions.

The objective of demand control is to achieve reduction in demand in the transmission grid in order to: (a) manage system security during low operating reserve; and (b) prevent system overload or voltage collapse.

Demand control shall, in general, apply to *Generation Licensee*, *TNSPs*, *Distribution Licensees*, and *End-use Users*.

12.2.2 Planned Demand Control

If a supply-demand mismatch is foreseen, the *ENTSO* will alert Users drawing power from the *ENTSO* grid in terms of the times and load quantum to be curtailed. The *ENTSO* shall consult the Users in producing a load-shedding programme that shall be followed when there is planned load demand control. During emergency, the *ENTSO* may curtail load in a manner that does not strictly follow the agreed load-shedding programme. Planned demand control is detailed under section 12.1.6 in this chapter.

12.2.3 Emergency Demand Control

Emergency automatic demand control occurs when there is a sudden loss of generation substantially in excess of spare *Plant* capacity. The *ENTSO* in consultation with grid Users shall prepare the plan for automatic load shedding during the low frequency conditions. For details on automatic load shedding, please refer to Section 12.1.5 in this chapter. During periods of low

frequency conditions, *Generating Plants* shall assist through the following: (a) Make every effort to assist the system frequency to rise to 50 Hz, by increasing generation whenever possible; (b) Not disconnecting manually from the transmission system unless there is definite evidence that a complete failure of generation would otherwise result. The *ENTSO* shall enforce demand control in such a manner that does not unduly discriminate against, or unduly prefer anyone.

If the *ENTSO* anticipates any generation shortfall based on the difference between projected maximum demand and available generation capacity from conventional *Generating Plant* and *RPP*, the *ENTSO* shall work with all relevant personnel following the operational guidelines below:

(a) The *ENTSO* shall inform *DNSPs/RCCs* of their required load rationing targets

(b) The *DNSPs/RCCs* shall coordinate with the *ENTSO* to determine the *End-use Users* and feeders to be affected

(c) The *DNSPs/RCCs* shall inform the *End-use Users* of their required load reduction magnitudes and the time period

(d) The *DNSPs/RCCs* shall be at the relevant End-use Users' premises before start of reduction period to ensure and confirm compliance by such Users

(e) The *DNSPs/RCCs* shall inform the *ENTSO* of *End-use Users'* compliance with load reductions

(f) The *ENTSO* shall evaluate system status and determine if this load reduction is adequate. If reduction is inadequate, the *ENTSO* shall instruct *DNSPs/RCCs* to carry out additional load shedding

(g) The *DNSPs/RCCs* shall carry out load shedding as instructed by the *ENTSO*. The *DNSPs/RCCs* shall instruct operators to carry out load shedding in places where there are no *SCADA* commands

(h) The *DNSPs/RCCs* shall notify the *ENTSO* of completion of carrying out load shedding

(i) The *ENTSO* shall evaluate system status. If load shedding is still inadequate, The *ENTSO* shall instruct *DNSPs/RCCs* to carry out further load shedding

(j) If load shedding is adequate, the *ENTSO* shall wait for the recovery of the system while monitoring system status parameters (voltage and frequency) on the *SCADA*

(k) The *ENTSO* shall determine if system has recovered from generation shortfall

(l) If system has not recovered from generation shortfall, the *ENTSO* shall wait for the recovery of the system while monitoring system status parameters (voltage and frequency) on the SCADA

(m) If system has recovered from the generation shortfall, the *ENTSO* shall instruct the *DNSP/RCCs* to restore *Customer* load through remote control. The *DNSPs/RCCs* shall instruct operators to restore *Customers* where there is no remote control. The *DNSPs/RCCs* shall also inform End-use Users who had reduced load to resume normal operation. Restoration of such Users shall be done systematically as directed by the *ENTSO*

(n) When the system returns to normal operation, the *DNSPs/RCCs* shall notify the *ENTSO* of the completion of load shedding, and the *ENTSO* compiles Load shedding detail report

13 OPERATIONS CHAPTER NO. 6 – SYSTEM TESTS

This chapter contains requirements specific to both the *EAPP IC* and the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

13.1 REQUIREMENTS FROM THE EAPP IC

13.1.1 Introduction

The Operations Code No. 6 (OC 6) sets out the arrangements and procedures across the *EAPP Interconnected Transmission System* for *System Tests* or operational tests including *Black Start* tests and *Power Island* tests.

System Tests are those tests, which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *EAPP Interconnected Transmission System*. In addition, they include commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out by a *User* and which may have a significant impact upon the *EAPP Interconnected Transmission System*.

System Tests or operational tests may involve single items of *Plant* and or *Apparatus* through to whole sections of the *EAPP Interconnected Transmission System* and may be proposed by *EAPP Sub-Committees on Planning or Operations* or a *TSO*.

To minimise disruption to the operation of the *EAPP Interconnected Transmission System* and or to other *TSO's National Systems*, it is necessary that these tests be subjected to central coordination by the *EAPP CC* in cooperation with the relevant *TSO*.

OC 6 also describes the data exchange and communication requirements between *EAPP* and the *TSOs* to facilitate planning, implementation and reporting of *System Tests* or operational tests.

13.1.2 Objective

The objectives of OC 6 are to specify procedures for central co-ordination and control of a *System Test* or operational test required by a *TSO* or the *EAPP Sub-Committees on Planning or Operations*, where such test will or may:

(a) Affect the secure operation of the *EAPP Interconnected Transmission System*

(b) Have a significant effect on the operation of the *EAPP Interconnected Transmission System* or a *National System*

(c) Affect the economic operation of the *EAPP Interconnected Transmission System,* or

(d) Affect the quality or continuity of supply of electricity from the *EAPP Interconnected Transmission System*

13.1.3 Procedure

13.1.3.1 General

Tests shall be planned to ensure all *Plant* and *Apparatus* remain within the applicable capability limits specified by the relevant *TSO* and carried out such that there is minimal impact on the *EAPP Interconnected Transmission System* or *TSOs' National Systems*. *System Tests* required by *TSOs* or *EAPP CC* shall include, but not be limited to the following:

(a) Tests involving the controlled application of frequency and or voltage variations aimed at gathering information on the behaviour of the *EAPP Interconnected Transmission System*

(b) *Black Start* and system restoration tests

(c) Testing of procedures and plans for system ALERT and EMERGENCY conditions

(d) Testing or monitoring of power quality under various system conditions and generation configurations

TSOs shall be responsible for obtaining the agreement of the relevant *User*(s) before tests proceed.

All *Outage* requests for Tests shall be progressed in accordance with the guidelines in Chapter 8 (Operational Planning).

The category of Tests shall be agreed by the *EAPP Sub-Committees on Planning and Operations* and relevant *TSOs*.

Major Tests are those considered sufficiently complex by either *Party* to require a detailed Test programme to be submitted in accordance with Test Proposal as described below.

OC 6 is not intended to deal with Tests categorised as minor or routine. Such tests do not require a detailed Test programme to be submitted.

Any *System Tests* on the *EAPP Interconnected Transmission System, which may affect an External System,* or tests on an *External System, which may affect the EAPP Interconnected Transmission System,* shall be carried out in accordance with the appropriate bilateral agreements.

13.1.3.2 Test Proposal

The level of demand on the *EAPP Interconnected Transmission System* varies substantially according to the time of day and time of year and, consequently, certain *System Tests, which may have a significant impact on the system,* can only be undertaken at certain times of the day and year. Other *System Tests*, for example, those involving substantial *Mvar* generation or full load rejection tests, may also be subject to timing constraints. It therefore follows that notice of *System Tests* should be given as far in advance of the date on which they are proposed to be carried out.

The *Test Proposer* shall provide a *Test Proposal* to *EAPP Sub-Committees on Planning or Operations* who shall be responsible for circulation to relevant *TSOs*.

Individual *TSOs* shall ensure that any of their *Users* who may be involved in or affected by the Test shall be provided with a copy of the *Test Proposal* and any updates thereof. Where practicable, the *Test Proposal* shall be submitted at least three (3) months prior to the proposed date of the Test. The *Test Proposer* shall ensure that sufficient detail is included in the *Test Proposal* to allow the affected parties to assess the impact of the Test on the *EAPP Interconnected Transmission System*, *TSOs' National Systems* and *Users' Systems*.

The *Test Proposer* shall be responsible for change control of the *Test Proposal* and shall issue a revised *Test Proposal* to *EAPP Sub-Committees on Planning or Operations*. *EAPP Sub-Committees on Planning or Operations* is responsible for liaising with any other affected *TSOs* who in turn shall notify any *Users* affected by the change.

EAPP Sub-Committees on Planning or Operations and the affected *TSOs* shall assess the implications and agree the category of the Test within a reasonable time. *TSOs* shall liaise with each affected *User, seek their agreement to the Test Proposal, collate,* and coordinate their responses to the *EAPP Sub-Committees on Planning or Operations.*

Following receipt of the *Test Proposal* and evaluation of the Test's likely impact, including discussions of test requirements with the *Test Proposer* and other affected parties, the *EAPP Sub-Committees on Planning or Operations* taking into account the criteria set out in this chapter will decide if approval for the Test is granted.

If the *Test Proposal* is not acceptable to the *EAPP Sub-Committees on Planning or Operations*, an affected *TSO* or *User*, *EAPP Sub-Committees on Planning or Operations* shall refuse the *Test Proposal* and shall immediately notify the *Test Proposer*. The *Test Proposer* may choose to revise and re-submit the *Test Proposal* in accordance with this procedure or raise a *Dispute* under the terms of section 3.11 of Chapter 3 (*Dispute* Resolution).

Any *Test Proposal* made by the *EAPP Sub-Committees on Planning or Operations* shall be subject to the prior approval of the *EAPP Steering Committee* and *Independent Regulatory Board* and shall otherwise be subject to the procedure set out above.

13.1.3.3 Detailed Test Programme

As soon as practicable after agreement to the *Test Proposal*, the *Test Proposer* shall provide an *Outage* request, in accordance with section 8.1.5 of Chapter 8 (Operational Planning – Outage Planning Process), to *EAPP CC* detailing the *Plant* and *Apparatus* involved.

The *Test Proposer* shall provide, within a reasonable time, a draft Test programme to a level of detail including, but not limited to, the content shown under Sample Report in Section A of this chapter.

The *Test Proposer* shall be responsible for change control of the draft Test programme and shall issue within a reasonable time, a revised Test programme where appropriate to *EAPP CC*. *EAPP CC* is

responsible for liaising with any other affected *TSOs* who in turn shall notify any *Users* affected by the change.

EAPP CC shall provide to each affected *TSO* a copy of the draft Test Programme and all updates thereof.

TSOs shall liaise with each affected *User* and seek their agreement to the Test Programme and collate and co-ordinate their responses to the *EAPP CC*.

EAPP CC and affected *TSOs* shall assess the implications of the Test programme on the safety, security, and reliability of the *EAPP Interconnected Transmission System*, individual *TSO National Systems* and *User Systems*.

When all issues raised have been addressed to the reasonable satisfaction of all parties and the draft Test programme agreed by all parties, the agreed Test programme shall be issued by *EAPP CC* to relevant *TSOs* at least fifteen (15) business days prior to the commencement date of the Test unless otherwise agreed.

In the event that that there is a *Dispute* regarding the acceptability or otherwise of a Test programme or associated *Outage*, the Test shall not take place until the *Dispute* has been resolved.

13.1.3.4 Operational Process

EAPP CC shall be responsible for operational liaison and obtaining agreement from any affected *TSO* for the Test to proceed and shall co-ordinate the Test.

When Tests have commenced, any change in System, site or Test conditions that could affect or invalidate the Test or have an *Operational Effect* shall be communicated to other parties as soon as reasonably practicable. The Tests shall be suspended until all parties involved have assessed the implications of the change in system, site, or Test conditions.

In the event of a failure of communications between *EAPP CC* and relevant *TSOs* or the Test location during the Test, then the Test shall be suspended until satisfactory communications are restored and agreement is reached to continue with the Test programme.

13.1.3.5 Other Considerations

Tests shall normally only be carried out by *EAPP CC* or a *TSO* on *Plant* and *Apparatus* in operational service when the results of off-load Tests would not be sufficiently rigorous in the reasonable opinion of either *Party* to confirm the continued satisfactory performance of the *Plant* or *Apparatus* involved.

13.1.3.6 Operational Intertripping

No Tests shall take place that could result in operation of an operational intertripping scheme unless this is the stated purpose of the Test and agreement has been reached with all affected *Parties*.

Where testing of an operational intertripping scheme is not the stated purpose of testing then no Tests shall take place involving a circuit associated with an operational intertripping scheme unless the operational intertripping scheme is not required in service. The scheme must be deselected from service by a means agreed with all affected *Parties*.

13.1.4 Reporting of System Tests

Within three (3) months of the completion of the *System Test* or operational test, the *Test Proposer* shall prepare a Final Report on the Test. The Report shall be submitted to the *EAPP Steering Committee*, to the *Independent Regulatory Board* and to all *TSOs* affected by the Test.

The Final Report shall include a description of the *Plant* and or *Apparatus* tested and a description of the *System Test* carried out together with the results, conclusions and recommendations as they relate to the *EAPP* and *TSOs*.

13.2 ENTGC REQUIREMENT

This section discusses those tests, which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *ENTSO*, not addressed in Section 13.1.

13.2.1 Commissioning Tests

The *TNSP* or *Users* shall perform all commissioning tests required in order to confirm that the *Plant* and equipment meet all the requirements of the *ENTGC* that have to be met before going on-line. The *ENTSO* may request relevant tests (or results of such tests) to be demonstrated in accordance with the *ENTGC* before accepting such *Plant* for operating. The party performing the test shall notify the *ENTSO* and the *Regulatory Authority* at least fourteen (14) days in advance of any such tests, so that they may witness the tests. For variable intermittent *RPP*, lead-time for notice will be coordinated between the involved parties.

In addition to the safety of the system as described under Section 13.1.3 (Detailed Test Programme) in this chapter, it is necessary to ensure that the safety of personnel or members of the public are not threatened while conducting system tests.

It is important to ensure that the test programme specifies switching sequence and proposed timings, list of staff involved in the test, and site safety responsible persons. If a *Generating Plant* fails the system test, the *Generation Licensee* shall:

(a) Promptly notify the *ENTSO* of that fact

(b) Promptly advise the *ENTSO* of the remedial steps it proposes to take to rectify the situation along the proposed timetable for implementing those steps

(c) Diligently take remedial action to ensure that the relevant *Generating Plant* can comply if there is any compliance issue

(d) Regularly report in writing to the *ENTSO* on its progress in implementing the remedial action

(e) Demonstrate to the reasonable satisfaction of the *ENTSO* that the relevant *Generating Plant* passes the test and is compliant

Work instructions for Commissioning of New *Generating Plant* shall be as follows:

(a) The *Generation Licensee* shall send to the *ENTSO* all necessary details of the equipment to be commissioned including a diagram of the high voltage connection points prior to the commissioning date

(b) The *Generation Licensee* shall also submit to the *ENTSO* protective relay settings for the new *Generating Plant* prior to the commissioning date

(c) Prior to the commissioning date, the *Generation Licensee* shall ensure that labels have been affixed to the equipment and its auxiliaries for the new *Generating Plant*

(d) Prior to commissioning, the *Generation Licensee* shall arrange for a training session for System Controllers/Operators of the *ENTSO* responsible for operating the new *Generating Plant*

(e) The *Generation Licensee* shall send a copy of the clearance certificate to the *ENTSO* before the commissioning date

(f) The *Generation Licensee* shall send to the *ENTSO* a copy of the commissioning programme, to connect the Equipment to the system, at least fourteen (14) days before the commissioning date

(g) The *Generation Licensee* shall provide notice of commissioning the new Generating Plant at least fourteen (14) days before the commissioning date

(h) The *ENTSO* shall check and determine if there are any problems with the commissioning. If there are any problems, the *ENTSO* shall discuss the matter with the *Generation Licensee* and mutually agree on an appropriate date when commissioning can take place

(i) The *ENTSO* shall log the commissioning date along with all other relevant information, and capture planned Outages in the Generation Dispatch schedule

(j) The *ENTSO* shall organize and coordinate switching personnel to assist during the commissioning

(k) Before commissioning, the *Generation Licensee* shall report to the *ENTSO* the position of all switchgears/circuit breakers, isolators, and earth switches, etc. that are included in the New *Generating Plant*

(l) The *ENTSO* shall be responsible for coordinating all commissioning

(m) After successful commissioning, the *ENTSO* shall declare the New *Generating Plant* to be under control of the *ENTSO*

Following commissioning, testing of new *Generating Plant* shall be carried out for compliance as per approved standards and ancillary services provision. Details of testing for a Generating Plant shall typically include Protection Integrity Tests. Trip testing of all protection functions, from origin (e.g.

Buchholz relay) to all tripping output devices (e.g. *HV* Breaker), shall be carried out and documented providing details of all trip test responses. Testing shall also include in specific:

(a) Excitation Response Test -With the *Generating Plant* 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, voltage response. With the *Generating Plant* connected to the network and loaded, carry out the small signal performance tests according to IEEE 421.2.1990. Also, carry out power system stabiliser tests and determine damping with and without Power System stabiliser. Document all responses

(b) Reactive Power Capability Test - Reactive output for a *Generating Plant* shall be fully variable between its rated limits under *AVR*, manual or other control. The duration of the test shall be for a period of up to 60 minutes, during which period the system voltage at the grid entry point for the relevant *Generating Plant* shall be maintained by the *Generating Plant* at the voltage specified by adjustment of Reactive Power on the remaining *Generating Plant* units, if necessary, for a period of 60 minutes. The *Generating Plant* shall demonstrate maintaining its reactive capability within plus or minus five percent (±5%) of its rated capability

(c) Governor Response Tests - Prove that the unit is capable of the minimum requirements required for governing frequency deviations

(d) Black Start Test - *Black Start* Units shall perform appropriate tests and simulations on an annual basis to ensure that the *Black Start* facility is available. Such tests shall be witnessed and approved by the *ENTSO*. A *Black Start* Station shall demonstrate that it can be synchronised to the system within thirty (30) minutes of the commencement of the *Black Start* procedure.

Other tests include:

(a) *Contingency/* Emergency plan Verification - Tests shall be periodically carried out to the greatest practical extent, as agreed by the parties, without causing undue risk or undue cost.

(b) Under - frequency load shedding (UFLS) Test - Test shall be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

14 ISCB CHAPTER NO. 1 - INTERCHANGE SCHEDULING

This chapter contains requirements specific to both the EAPP IC and the ENTS. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

14.1 EAPP IC REQUIREMENTS – INTERCHANGE SCHEDULING CHAPTER

The Interchange Scheduling and Balancing Chapters (ISBC) involve three Chapters: this Interchange Scheduling Chapter (ISC), the Balancing and Frequency Chapter (BFC), and the Ancillary Services Chapter (ASC).

14.1.1 Introduction

One of the objectives of the *EAPP* is to facilitate trading in electricity among the *EAPP Member Countries*. In its initial stages, such trading will consist of bilateral cross-border transactions between *Neighbouring Systems*. Once further infrastructure is developed, more complex arrangements including multilateral transactions with or without transit through *Neighbouring Systems* will become possible and a Regional Power Pool Market will be established. Accordingly, the provisions of the ISBCs will be modified to reflect any *EAPP/EAC* new electricity market rules.

To operate the *EAPP Interconnected Transmission System* and to facilitate bilateral trade between *EAPP Member Countries* it is necessary to schedule in advance the *Active Power* and *Active Energy* to be transferred between *TSO National Systems* and to be imported from or exported to *External Systems.*

The term Interchange Scheduling in the context of balancing power specifically refers to the intended delivery of *Active Power* and *Active Energy* from one *Control Area* to another *Control Area* within the *EAPP Interconnected Transmission System* or to be imported from or exported to *External Systems*.

This chapter deals with the following aspects of the scheduling process:

(a) Determination of the *Net Transmission Capability (NTC)* between *Neighbouring Control Areas* and or *External Systems* over the Operational Planning timescales

(b) Publication of *NTC* values to enable *TSOs* and *Users* to evaluate possible *Active Power* and *Active Energy* interchanges;

(c) Allocation of *NTC* to *TSOs* and or *External Systems* in accordance with predetermined rules and the issue of Interchange Schedules

14.1.2 Objectives

The objectives are:

(a) to enable *EAPP CC* and *TSOs* to establish and publish the *NTC* on the interconnections between *Control Areas* and or *External Systems* corresponding to the Operational Planning

Phase, Programming Phase and Control Phase respectively as set out in Chapter 8 (Operational Planning, or, OC 1), and

(b) to require *TSOs* to allocate the *NTC* to *Users* in accordance with certain rule

14.1.3 Determination of Transmission Capability

NTC relates to the physical capability of the interconnection between *Control Areas*, and with *External Systems* to transfer *Active Power* and *Active Energy* and shall be determined by the *TSOs* concerned. The determination shall be based on the operational security standards set out in OC 2 and on such current technical and operational factors as are of significance to the *NTC*. *TSOs* are individually responsible for assessing these factors within their own *National Systems* and will determine in conjunction with *EAPP CC* the method of calculation of *NTC* between *Control Areas* and or *External Systems*. In determining *NTC TSOs* shall also take account of the following factors:

(a) Deviations of *Active Power* flows resulting from the operation or functioning of *Primary Response* to frequency changes

(b) Emergency exchanges between *Control Areas* and or *External Systems* to cope with unexpected mismatch between generation and demand in real time, and

(c) Inaccuracies in data collection and measurements

14.1.4 Capacity Allocation

Certain *Users* may have acquired rights over the use of *NTC*. This may occur where the *User* concerned has provided generation or transmission facilities in accordance with a bilateral agreement. *TSOs* shall notify other relevant *TSOs* and the *EAPP CC* of the existence and extent of such agreements.

The *NTC* of the interconnection between *Control Areas* or with *External Systems* is firstly allocated to those *Users* with pre-emptive rights over the capability based on their bilateral agreements. After allocating *NTC* to *Users* who hold pre-emptive rights, *TSOs* may allocate the remaining capability of a particular interconnection in accordance with commercial agreements, which are not the subject of this chapter.

14.1.5 Interchange Scheduling Process

The Interchange Scheduling process is concerned with:

(a) Providing an indication of feasible electricity trading scenarios

(b) Determining *NTC* over various timescales

(c) The coordination of *Outages* to minimise the loss of trading benefit to *Users* and to the *EAPP Interconnected Transmission System*; and

(d) The evaluation of potential actions by *TSOs* to mitigate constraints on the *EAPP Interconnected Transmission System* as set out in Chapter 8 (Operational Planning, or, OC 1)

As part of the Operational Planning process under OC 1, *TSOs* are required to make an assessment over various timescales of the *NTC* available on the interconnections between *Control Areas* and

External Systems. This assessment is based on the commissioning of new facilities and on the *Outages* required for planned maintenance of generating and transmission facilities. *TSOs* are required to publish details of the *NTC* on the *EAPP* Website.

Where a constraint in the *NTC* is identified when carrying out Interchange Scheduling in any of the Operational Planning timescales, the *TSOs* concerned shall seek to reallocate the Interchange Schedule to *Users* in the following priority order:

(a) Lowest priority will be energy exchanged as compensation for *Inadvertent Deviations*

(b) Energy transfers scheduled on a commercial basis by *TSOs* over and above the pre-emptive rights

(c) Energy transfers scheduled as a consequence of pre-emptive rights, and

(d) Any agreements between *TSOs* for the provision of operating reserve

14.1.5.1 Annual Scheduling

By the end of September each year, *TSOs* shall exchange data on the cross-border *NTC* for the following year (Year 1). The data shall be copied for information to the *EAPP CC*. The data shall also indicate the pre-emptive rights over the *NTC* held by the *TSO* on behalf of a *User* connected to its *National System*.

By the end of October each year, *TSOs* shall agree on the allocation of transmission capability and shall publish an Annual Interchange Schedule. This Interchange Schedule is indicative only and is used to advise *Users* of potential availability of power trading opportunities over and above those pre-emptive rights held by the *TSO* on behalf of a *User* connected to its *National System.*

14.1.5.2 Weekly Scheduling

Interchange scheduling on a weekly basis is carried out on a rolling eight (8) week cycle in accordance with Section 8.1.9 in Chapter 8. Each Friday at 10h00 Hrs, *TSOs* shall agree the Interchange Schedule across their cross-border connections for the following eight (8) weeks, commencing at 00h01 Hrs on Monday of Week 1, including the following data:

(a) Its forecast of interchange *MW* profiles on an hourly basis, based on the preemptive rights held at the time of issue of the data to the *EAPP CC*

(b) Confirmation of pre-emptive rights currently held on behalf of *Users*; and

(c) Details of any changes to data included in the Annual Schedule issued under this section

EAPP CC shall develop the Weekly Interchange Schedule to achieve the operating reserve requirements as set out in the Balancing and Frequency Control Chapter, and shall finalise the *NTC* based on the data received from *TSOs.*

14.1.5.3 Daily Scheduling

On a daily cycle, *TSOs* shall carry out the process of revising progressively the Weekly Interchange Schedule. This process is phased and iterative to allow:

(a) appropriate interactions with *Neighbouring Systems, EAPP CC* and *External Systems*

(b) identification of changes to constraints on the *EAPP Interconnected Transmission System*

(c) forecasts of demand, and

(d) the *NTC* of all interconnections between *Control Areas*, *Neighbouring Systems* and *External Systems* to be determined and properly allocated

In accordance with OC 1.10 at 15h00 Hrs each day, *TSOs* shall finalise the *Operational Plan* for use on the following day commencing at 00h01 Hrs. The *Operational Plan* shall be issued and published by the *EAPP CC*. In the case of the *Operational Plan* issued on a Friday, the Plan will cover the three (3) days commencing at 00h01 Hrs on the Saturday. Apart from the information set out in Chapter 8 (Operational Planning, or, OC 1), the *Operational Plan* will contain the following:

(a) the *NTC* between each *Control Area*, *Neighbouring Systems* and *External Systems* and its allocation between *Users*

(b) the transfer in *MW* between each *Control Area*, *Neighbouring Systems* and *External Systems* on an hourly basis

(c) the Operating Reserve levels to be maintained within the *TSO*'s *National System* on an hourly basis

(d) the Operating Reserves contracted with other *TSOs* on an hourly basis and for which *NTC* has been reserved

Any additional information that may be reasonably considered to be of relevance to the daily Schedule for that *TSO* shall be included. This may include:

(a) Weather

(b) Voltage control issues

(c) System stability issues

(d) *System Tests* in accordance with OC 6 to be carried out in another part of the *EAPP Interconnected Transmission System* which may compromise security of supply

In real-time, neither the total of the schedules of individual *Users*, nor the actual power transfer between *Control Areas*, *Neighbouring Systems* and *External Systems* may exceed the *NTC* for that interconnection.

14.1.6Adjustments to the Interchange Schedule

After the completion of the scheduling process, and the issuing of the Interchange Schedule, a *TSO* may consider it necessary to make adjustments to the transfers as determined by the scheduling process. Such adjustments could be made necessary by any of the following factors:

(a) changes to *Generating Plant* availability or demand reduction

(b) changes to demand forecasts

(c) changes to *EAPP Interconnected Transmission System* constraints, emerging from the system security assessment

(d) changes to any conditions which in the reasonable opinion of a *TSO* or *EAPP CC* would impose an increased risk to the *EAPP Interconnected Transmission System* and would therefore require an increase in the operating reserves

14.2 ENTGC REQUIREMENTS

This section discusses *ENTSO* specific requirements relating to the interchange scheduling.

14.2.1 Interchange Scheduling

This section describes the *ENTSO*- specific interchange scheduling procedural requirements. These requirements are in addition to the *EAPP* requirements as described in Section 14.1.5. Where these requirements are mutually exclusive, both shall be satisfied. If there are redundancies between the *ENTGC* and *EAPP* requirements, the more stringent of the two requirements shall prevail.

14.2.1.1 Annual Scheduling

(a) Preliminary Interchange Schedules shall be mutually agreed upon between the parties annually

(b) The yearly energy schedule shall be distributed on a monthly basis

(c) The non-binding annual delivery schedules shall be determined at least 4 months before the beginning of the Calendar year

14.2.1.2 Quarterly Scheduling

The non-binding quarterly energy delivery schedules shall be determined at least 4 weeks before the beginning of the quarter

14.2.1.3 Monthly Scheduling

(a) Monthly energy delivery schedules shall be determined at least 4 weeks before the beginning of the month.

(b) Parties shall confirm the monthly energy delivery schedules as binding for the total energy for the month

(c) In exceptional situations (e.g., outage of major generation or transmission, shortage of water for hydro, total system blackout or significant partial system blackout, etc.) as mutually agreed between the parties, the parties can make changes to the confirmed delivery schedules

(d) During the rainy season between July and September, monthly energy schedules shall be determined one week before the beginning of the month

(e) During the rainy season, each party shall confirm the monthly energy delivery schedules on a weekly and daily basis

14.2.1.4 Weekly Scheduling

(a) Parties shall establish weekly schedules at the planning and operational levels through planning and operations working groups

(b) Aligned with EAPP process, weekly schedules with hourly granularity shall be submitted to the ENTSO each Friday before 10 am for the week starting following Monday at 00:01 hours and ending on the following Sunday at 24:00 hours.

(c) *ENTSO* shall confirm the schedules within one (1) hour of receipt

14.2.1.5 Daily Scheduling

Daily schedules shall be established to confirm weekly schedules. Parties shall submit schedules at 11am on the previous day for the period covering 24 hours from 00h00 Hrs until 24h00 Hrs on the operational day. The *ENTSO* shall confirm the schedule within 1 hour of receipt

14.2.1.6 Intra-day Scheduling

Parties shall agree to establish intra-day schedules to take into account events occurring in real time, such as:

(a) Generating units coming back on line earlier than expected

(b) Generating units staying off line longer than expected

(c) Network outages preventing available units to supply load

(d) Opportunity to set up a diversity schedule as defined and agreed by the Parties

15 ISBC CHAPTER NO. 2 - BALANCING AND FREQUENCY CONTROL

This chapter contains requirements specific to both the *EAPP IC* and the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

15.1 EAPP IC REQUIREMENTS

15.1.1Introduction

The frequency of a power system is an indicator of power balance between generation and the summation of demand and losses in the system. In the *EAPP Interconnected Transmission System*, this power balance is necessary to control system frequency and the power exchange between *Control Areas* and *External Systems*. In order to achieve this balance, each *TSO* shall ensure it has sufficient reserve capacity in order to maintain the interchange schedule within the *EAPP Interconnected Transmission System* and with *External Systems* and to control system frequency to meet the minimum standards under both normal and emergency conditions.

Balancing and Frequency Control Code (also known as ISBC2 in *EAPP*) sets out the procedure that the *TSOs* will use to direct frequency control. The frequency of the *EAPP Interconnected Transmission System* will be controlled by:

(a) Automatic response from synchronised *Generating Units*;

(b) The dispatch of *Generating Units* including *Automatic Generation Control (AGC)*;

(c) Response from interconnections with *External Systems*, and

(d) Demand control.

Frequency control is an Ancillary Service and *TSOs* shall contract for its provision in accordance with the Chapter 16 (Ancillary Services or ISBC 3).

15.1.2Objective

The objectives of ISBC 2 are to establish:

(a) Procedures to ensure adequate operating reserves are maintained by each *TSO* when connected to the *EAPP Interconnected Transmission System*;

(b) Procedures for the minimisation of *Area Control Error (ACE)*, and

(c) Procedures for the calculation and settlement of *Inadvertent Deviations* from scheduled interchanges.

15.1.3Operating Reserves

Operating reserves are the additional output from *Generating Units* or a reduction in demand, which are realisable in real-time operation to contain and correct any frequency deviation on the *EAPP*

Interconnected Transmission System. *TSOs* shall maintain at all times adequate operating reserves to control the frequency of the *EAPP Interconnected Transmission System* within the limits set out in Section 6.1.4 (Connection), and to avoid sudden, unexpected loss of load following transmission or generation *Contingencies*. Operating reserves are also required to maintain agreed interchange schedules following changes in demand or generation.

The control of the frequency of *EAPP Interconnected Transmission System* is a multi-stage process. For every stage of control, adequate reserves are needed. The Operating reserves have three components, which are realisable in the following distinct timescales.

15.1.3.1 Primary Response

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

Demand side 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.

15.1.3.2 Secondary Response

Secondary Response is a centralised automatic control that adjusts the *Active Power* production of *Generating Units* to restore the frequency and the interchanges with other *Control Areas* and with *External Systems* to their target values following a frequency deviation. *Primary Response* limits and arrests frequency deviations whilst *Secondary Response* restores the frequency to its target value.

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 *Generating Units* already synchronised to the *EAPP Interconnected Transmission System* and is normally controlled by the *TSO* by *AGC* where available.

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 *EAPP Interconnected Transmission System* target frequency.

15.1.3.3 Tertiary Reserve

Tertiary Reserve refers to *TSO* instructed changes in the dispatching and commitment of *Generating Units*. *Tertiary Reserve* is used to restore both *Primary* and *Secondary Response*, to manage constraints on the *EAPP Interconnected Transmission System* and to bring the frequency and the interchanges back to their target value when the *Secondary Response* has been depleted.

Where *Tertiary Reserve* is held on *Generating Units* not synchronised to the *EAPP Interconnected Transmission System*, the Units shall be capable of being synchronized within a specified time generally between fifteen (15) minutes and one (1) hour. Non synchronized *Tertiary Reserve* could consist of, for example, fast start hydro, gas turbine, and steam turbine *Generating Plants* on hot-standby.

Tertiary Reserve capability (i.e., hydro and gas turbines) in the *EAPP Interconnected Transmission System* is considered an Ancillary Service that is delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO*.

15.1.4 Distribution of Operating Reserves

Operating reserves shall be distributed evenly throughout the *EAPP Interconnected Transmission System* on *Generating Units* in operation. Possible *EAPP Interconnected Transmission System* constraints shall be taken into account by the *TSOs* and *EAPP CC* in the reserve calculation, in order to avoid a limitation in case of activation of operating reserves.

TSOs shall monitor operating reserves continuously, particularly after a loss of generation or demand and shall re-establish the required amount of reserve as soon as practicable, in order to protect against a further *Contingency* and to avoid endangering the *EAPP Interconnected Transmission System*.

15.1.5 Primary Response

The amount of Primary Response to be provided on the *EAPP Interconnected Transmission System* shall be equal to the capacity of the largest Generating Unit connected to the system.

In calculating the amount of Primary Response required the demand-frequency response within the Control Area or National System shall be taken into account. For initial calculations, the demand-frequency response can be assumed to be one percent (1 %)/Hz i.e. a load decrease of one percent (1%) following a frequency drop of one (1) Hz.

Each *TSO* is responsible for calculating its demand-frequency characteristic in response to a disturbance (loss of a Generating Unit), based on measurements of the system frequency and other key values and on a statistical analysis.

15.1.5.1 Control Area Contribution Coefficient

Each *Control Area* shall contribute to the correction of a frequency deviation in accordance with its respective contribution coefficient for *Primary Response*.

The Contribution Coefficient is the ratio of the energy generated within one year in the relevant *Control Area* to the total energy generated in the *EAPP Interconnected Transmission System.*

The contribution coefficients shall be determined by the *EAPP Sub-Committee on Operations* and published annually on January 1 for each *Control Area*. The contribution coefficients are binding for the corresponding *Control Area* for the following calendar year.

Each *Control Area* must contribute to the *Primary Response* as required. The respective shares are defined by multiplying the required *Primary Response* for the *EAPP Interconnected Transmission System* by the contribution coefficient of the *Control Area.*

The actual *Primary Responses* shall be monitored in real-time by *TSOs* and the *EAPP CC*.

15.1.5.2 Accuracy of Frequency Measurements

For *Primary Response* purposes, the accuracy of frequency measurements used in the primary controllers must be better than or equal to ten (10) mHz.

The insensitivity range of primary controllers shall not exceed ±ten (10) mHz. Where dead bands exist in specific controllers, these must be reduced as much as possible.

15.1.6Secondary Response

Each *TSO* shall operate sufficient *Generating Plants* under *AGC*:

(a) To continuously balance its generation and interchange schedules to its demand, and

(b) To provide its contribution to *EAPP Interconnected Transmission System Secondary Response* as specified below.

15.1.6.1 AGC Requirements

AGC shall continuously compare:

(a) Total net actual interchange adjusted for actual frequency and

(b) Total net scheduled interchange adjusted for target frequency, to determine the *ACE* and respond by adjusting generation output to reduce the *ACE* to zero.

Each *TSO* shall provide adequate *Secondary Response* by *AGC* to regulate interchange and frequency and shall operate its *AGC* in tie-line bias mode, unless such operation is adverse to the reliability of the *EAPP Interconnected Transmission System*.

Secondary Response shall only be used to correct an overall system deviation and shall not be used to minimize unintentional electricity exchanges or to correct other imbalances.

15.1.6.2 Data Recording

Each *TSO* and the *EAPP CC* shall have appropriate equipment installed for the recording of all values needed for monitoring the response of secondary controllers (*AGC*) and for analysis of frequency events in the *EAPP Interconnected Transmission System*.

15.1.7Tertiary Reserve

Tertiary Reserve is usually activated manually by *TSOs* in case of observed or expected sustained activation of *Secondary Response*. It is primarily used to release *Secondary Response* in a balanced system situation, but it is also activated as a supplement to *Secondary Response* after larger

frequency deviations to restore the frequency and consequently free the system wide activated *Primary Response*.

TSOs shall, therefore, immediately activate Tertiary Reserve in case of large imbalances between generation and demand and or for the restoration of sufficient Secondary Response.

Tertiary Reserve can include the following:

(a) That part of the reserve of *Generating Units* operating in parallel with the *EAPP Interconnected Transmission System* but which has not been included in the *Primary* and *Secondary Response*

(b) *Generating Units* that can be synchronised and loaded within specified timescales

(c) Demand control that can be implemented on the instructions of the *TSO* within specified timescales

(d) Standby capacity in other *TSO National Systems* that can be made available upon request and for which adequate *NTC* exists

The amount of *Tertiary Reserve* required at the day ahead and in subsequent timescales shall be determined by each *TSO* on the basis of historical trends in the reduction in availability of *Generating Units* and increases in forecast demand up to real-time operation.

As a minimum, each *TSO* shall arrange at least enough *Tertiary Reserve* to cover the loss of the largest *Generating Unit* on its *National System*.

15.1.8Accounting for Inadvertent Deviations

15.1.8.1 Introduction

During daily operation, the interchange schedules are followed by means of *AGC* installed in ach *Control Area*. Notwithstanding *AGC*, *Inadvertent Deviations* invariably occur in energy exchanges. For this reason, it is necessary to co-ordinate the interchange schedule between *TSOs*, observe in real-time *Inadvertent Deviations* from the schedules and co-ordinate accounting and calculate the compensation programmes to balance unintentional deviations.

Inadvertent Deviations in the *EAPP Interconnected Transmission System* shall be balanced by the import or export of an equal number of MWh at the same hours on the same day of the following week.

The measurement and accounting for *Inadvertent Deviations* shall be carried out using metering equipment installed in accordance with the metering codes as described in Chapters 17 (Ethiopia Metering) and 18 (Interconnection Metering).

15.1.8.2 Recording and Compensation Periods

The standard recording period comprises seven (7) days (one week), from Monday 00h01 Hrs to Sunday 24h00 Hrs.

The standard compensation period comprises seven (7) days (one week), from Thursday 00:01 Hrs to Wednesday 24h00 Hrs. In case of holidays or for other reasons, exceptions to this rule may apply. In any case, a compensation period shall last at least four (4) days and shall commence three (3) business days after the end of the corresponding recording period.

15.1.9 HVDC Interconnections

TSOs shall ensure that each *HVDC* interconnection is fitted with a fast acting control device to provide frequency response under normal and emergency operating conditions. The control device must be designed and operated to contribute to frequency control by continuous modulation of *Active Power* supplied to the *EAPP Interconnected Transmission System*.

The settings and other parameters of each HVDC Interconnection shall be determined by the relevant *TSOs* and the *EAPP Sub-Committee on Operations*.

15.2 ENTGC REQUIREMENTS

The *ENTSO* shall balance supply and demand in real time through the implementation of the energy schedules and utilisation of ancillary services based on the normal and abnormal conditions as described below.

15.2.1 Description of Normal Conditions

(a) The control area is considered to be under normal conditions when

1. The immediate demand can be met with the available scheduled resources, including any expensive *Contingency* resources; and
2. The *ACE* deficit does not exceed the available reserves for longer than ten (10) minutes; and
3. The frequency is not less than 49.8 Hz for longer than ten (10) minutes; and
4. The frequency is within the range 49.5 to 50.5 Hz; and
5. The interconnections are intact; and
6. There are no security and safety violations

(b) The control area is considered to be under abnormal conditions if it is not in a normal condition as defined above.

15.2.2 Requirements for Maintaining Normal Conditions

The *ENTSO* shall maintain the system frequency between 49.7 and 50.2 Hz. Excursions outside of this range will be permitted for no more than 1.25% of the time, to be checked on a quarterly basis. The *ENTSO* shall maintain voltage on the *ENTS* within +/- 10% of nominal.

15.2.3 Operation during Abnormal Conditions

(a) When abnormal conditions occur, corrective action shall be taken, until the abnormal condition is corrected.

(b) Possible corrective action includes both supply-side and demand-side options. Where possible, warnings shall be issued by the *ENTSO* on expected utilisation of any *Contingency* resources.

(c) Termination of the use of emergency resources shall occur as the *Plant* shortage situation improves and after frequency has returned to normal.

(d) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with agreed procedures prepared and published by the *ENTSO*.

(e) Automatic under-frequency systems shall be kept armed at all times.

Table 15-1: Operation during Abnormal Conditions

Condition for Usage	Resources in Default Order of Usage
Warnings	
When a shortfall in supply is expected to occur, issue warnings in sequence until sufficient capacity is obtained to cover the shortfall	*Emergency* generation warning Interruptible load shedding warning
Generation deficit foreseen with load shedding expected	Warning to *DNSPs/RCCs*
Gradual frequency decline – refer to merit order in control room for order of use	
CONDITION FOR USAGE	**RESOURCES IN DEFAULT ORDER OF USAGE**
If frequency falls below 50 Hz and an abnormal condition exists, the *ENTSO* shall apply resources in the order most suitable to ensure system security depending on the conditions existing at the time	a. Run all available units at *Maximum Continuous Rating* b. Dispatch emergency capacity according to the *ENTSO* equipment order, voltage profiles, and equipment loading
Rapid Frequency Decline - Automatic Operation by Under-frequency Relays – Apply in Order	
CONDITIONS FOR USAGE	**RESOURCES IN ORDER OF USAGE**
a. F < 48.6 Hz b. F < 48.0 Hz c. F < 47.75 Hz	a. Stage 1 loads shed on select feeders* at 207 MW b. Stage 2, 186 MW c. Stage 3 , 120 MW * Target loads based on current practice
Frequency Restoration after Rapid Decline	
By the *ENTSO*	Take restoration action as soon as possible after under frequency relays have operated

16 ISBC CHAPTER NO. 3 - ANCILLARY SERVICES

This chapter contains requirements specific to both the *EAPP IC* and the *ENTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

16.1 EAPP IC REQUIREMENTS – ANCILLARY SERVICES CHAPTER

The Interchange Scheduling and Balancing Chapters (ISBC) involve the Interchange Scheduling Chapter (ISC), the Balancing and Frequency Chapter (BFC), and this Ancillary Services Chapter (ASC).

16.1.1 Introduction

The Ancillary Services Chapter (ASC) deals with the provision of *Ancillary Services* used to describe those services that must be exchanged among generation resources, load customers, and *TNSPs* to operate the *EAPP Interconnected Transmission System* in a reliable fashion and allow separation of generation, transmission, and distribution functions.

The ASC defines those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the *EAPP Interconnected Transmission System* in accordance with *Prudent Utility Practice*. These *Ancillary Services* are required to ensure that *TSOs* meet the obligations and responsibilities under the Interconnection Code for a safe secure and reliable operation of the *EAPP Interconnected Transmission System*.

The ASC does not cover the commercial arrangements between *TSOs* and *Ancillary Service providers* for the provision of *Ancillary Services*. Such arrangements are the subject of bilateral agreements.

16.1.2 Objective

The objective of this section is to define the *Ancillary Services* to be provided by *TSOs* to support the transmission of energy across the *EAPP Interconnected Transmission System* and to maintain reliable operation.

16.1.3 Categories of Ancillary Services

The operation of *EAPP Interconnected Transmission System* requires the provision by *TSOs* of the following *Ancillary Services* grouped into three major categories:

(a) Frequency Control;

(b) Network Control, and

(c) System Restart Capability.

The above *Ancillary Services* are the traditional mechanisms to provide the required capability in relation to:

(a) Operating Reserves

(b) Demand Control

(c) Voltage Control

(d) Power Flow Control

(e) Stability Control; and

(f) Black-Start

The amount of each *Ancillary Service* required shall be determined by *EAPP CC* in conjunction with *Control Area Operators* in accordance with the *EAPP Interconnected Transmission System* security standards as defined in Chapter 9 (Operational Security or OC 2).

16.1.3.1 Frequency Control

Frequency control *Ancillary Services* are used by *TSOs* to maintain the frequency on the *EAPP Interconnected Transmission System* within the limits set out in Chapter 6 (Connection or CC). The *Ancillary Service* is necessary to provide for the continuous balancing of resources (generation and scheduled interchange) with load and to maintain the frequency of the *EAPP Interconnected Transmission System* at 50 Hz.

In general, frequency control action can be provided at any location within the *EAPP Interconnected Transmission System*. However, when transmission facilities are operating at or near their limits, sufficient control action is needed on each side of the limiting facility to prevent overloading of the facility.

TSOs are required to provide the following frequency control *Ancillary Services*:

(a) *Primary Response of Generating Units* in accordance with Section 6.1.8 of Chapter 6 (Connections, Technical Requirements for Generating Units) and Section 15.1.3 of Chapter 15 (Balancing and Frequency Control – Primary Reserve).This *Ancillary Service* is being delivered if the *Generating Unit* is responding to changes in frequency within ten (10) seconds and is able to sustain the response for a further twenty (20) seconds;

(b) *Secondary Response of Generating Units* in accordance with Chapter 9 (Operational Security or OC2), and Section 15.1.3 of Chapter 15 (Balancing and Frequency Control – Operating Reserve). This *Ancillary Service* is provided by *AGC* and is being delivered if the *Generating Unit's* output is correctly responding to signals sent from the *TSO's AGC* equipment in response to changes in frequency;

(c) *Tertiary Reserve* in accordance with Chapter 9 (Operational Security or OC 2) and Section 15.1.3 of Chapter 15 (Balancing and Frequency Control – Operating Reserve). This *Ancillary Service* is being delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO*;

(d) *Demand control* in accordance with the provisions of Chapter 12 (Demand Control or OC 5). This service is being delivered if: 1. Demand can be automatically disconnected in response to an under frequency condition (*Automatic Load Shedding*); or 2. Demand can be disconnected on request from the *TSO* (Emergency Manual Load Shedding). Emergency Manual Load Shedding *Ancillary Service* can be provided by industrial load, commercial load, residential load or hydro generating units operating as pumps.

Sufficient control range should be available at all times to control frequency within the limits specified in the CC under various circumstances including unexpected load and generation changes.

16.1.3.2 Network Control

Network control *Ancillary Service*s are primarily used to:

(a) Control the voltage at different points of the electrical network within the prescribed standards;

(b) Control the stability of the *EAPP Interconnected Transmission System*, and

(c) Control the power flow on network elements to within the physical limitations of those elements.

In accordance with the voltage standards set out in the CC, *TSO*s shall control system voltages within specific ranges. One method of controlling voltages on the *EAPP Interconnected Transmission System* is through the dispatch of voltage control *Ancillary Services*. Under these *Ancillary Services*, *Generating Units* absorb or generate *Reactive Power* from or onto the *EAPP Interconnected Transmission System* and control the local voltage accordingly. Voltage control requirements are location dependent because of technical limitations inherent in transporting *Reactive Power*.

Stability control services are required to prevent instability following a *Contingency*, which is more severe than defined for the purposes of determining *NTC*. Stability control can be achieved by *Generating Units* which can rapidly respond to a control signal to increase or decrease generation. This network *Ancillary Service* is being delivered if the *EAPP Interconnected Transmission System* remains stable after any *Contingency* (N-1) and oscillations are damped out. Remedial Action Schemes (RAS) are considered a network control *Ancillary Service*. Power flows on the *EAPP Interconnected Transmission System* shall be maintained within the *NTC* limits, as imposed by thermal ratings, stability, and voltage. In the event of a *Contingency* (N-1), equipment loadings should not exceed short-term ratings, but may exceed long-term ratings provided the loadings can be reduced to within the long-term ratings in an appropriate time period by either manual or automatic means. It is proposed to obtain network loading *Ancillary Services* by superimposing signals on the *AGC* and by emergency manual load shedding.

16.1.3.3 System Restart

Black-Start Ancillary Services are required to enable the system to be restarted following a Total or Partial System Shutdown. Following consultation with *EAPP CC, TSOs* shall arrange for appropriate *Generating Units* to provide this *Ancillary Service* in accordance with the provisions of Section 6.1.8. in Chapter 6(Connection - Technical Requirements for Generating Units) and Section 10.1.7 in Chapter 10 (Emergency Operations).

16.1.3.4 Ancillary Services Requirements

The amount and location of Ancillary Services will be determined by *EAPP CC* and *TSO*s as part of the Operational Planning Process in the Programming and Control Phases. The commitment of *Ancillary Services* in an operational situation, however, is the responsibility of individual *TSOs*.

TSOs may also contract for *Ancillary Services* with other *TSOs*. All such contracts shall be notified to *EAPP* CC.

16.2 ENTGC REQUIREMENTS – ANCILLARY SERVICES CHAPTER

The *ENTSO* shall follow the procedure as described in the ISBC for directing frequency control and power balance.

The *ENTSO* shall be responsible for the provision of all short-term reliability services for the IPS. These include restoration, the balancing of supply and demand, as well as the provision of quality voltages and the management of the real-time technical risk.

The *ENTSO* shall certify providers of ancillary services and keep a register of all certified providers.

The *ENTSO* shall determine reliability targets for the purposes of acquiring ancillary services in consultation with relevant *Users*.

The *ENTSO* shall be responsible for procuring the required ancillary services as appropriate, in accordance with the license and market rule. The *ENTSO* shall state opportunities for the provision of ancillary services as identified.

The various ancillary services that can be used by the *ENTSO* are described below:

(a) Reserves as defined in section 2.1 of this Chapter

(b) Black start and unit islanding

(c) Reactive power supply and voltage control from units

16.2.1Operating Reserves

Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten (10) minutes consistent with energy restrictions. Operating reserves shall consist of *Spinning Reserve*, *Regulating Reserve* and *Tertiary Reserve*. The total reserve make-up is described below.

16.2.1.1 Spinning Reserves

The provision of *Spinning Reserve* is a Primary Response.

The *ENTSO* shall ensure *Spinning Reserve* is available as needed to arrest the frequency at acceptable limits following a *Contingency*, such as a unit trip or a sudden surge in load.

16.2.1.2 Regulating Reserves

Regulating reserve is reserve that is under centralized *AGC* and can respond within ten (10) seconds and be fully active within thirty (30) seconds of activation, and be sustained for thirty (30) minutes.

This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore *Spinning Reserve* within ten (10) minutes of the disturbance.

16.2.1.3 Tertiary Reserve

Tertiary Reserve is consistent with *EAPP* definition of *Tertiary Reserve*. *Tertiary Reserve* is required to balance supply and demand for changes between the day-ahead and real time such as load forecast errors and unit unreliability. *Tertiary Reserve* is used to restore *Regulating Reserve* when required.

The amount of reserve required is to be calculated by the *ENTSO* and shall be based on *EAPP* minimum requirements, supplemental and emergency reserve availability, and other reserve considerations.

16.2.2 Black Start and Generating Plant Islanding

(a) Islanded *Generating Plants* shall be capable of running in the islanded state for at least two (2) hours before reconnecting to the network

(b) All *Generating Plants* capable of unit islanding are required to contract the service provision to the *ENTSO*. The *ENTSO* shall certify units capable of islanding

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

(d) The *ENTSO* shall determine the minimum requirements for each black start supplier and ensure that the contracted suppliers are capable of providing the service

16.2.3 Reactive Power Supply and Voltage Control from Units

Voltage control and the supply or consumption of reactive power are inter-related in the sense that the voltage is affected by changes in the reactive power flow. System stability depends on the voltage profile across the system. In view of these considerations, it is necessary from time to time to employ certain Generating Plants to supply or consume reactive power, provided that the unit is not required to operate outside of its effective capability diagram for the purpose of voltage control.

(a) The ENTSO shall control the amount of reactive power. This may be done directly through the energy management system or by telephone

(b) When a unit is generating or pumping, reactive power supply is mandatory in the full operating range as specified

17 ETHIOPIA METERING

17.1 ENTGC REQUIREMENTS

The metering requirements of the *EAPP IC* deal exclusively with the metering of each point of interchange of energy between *Control Areas*. The metering requirements for *ENTS* deal primarily with metering points that do not have exchanges between *Control Areas*. The metering requirements of *EAPP IC* and *ENTS* have many areas of similarity.

To avoid confusion regarding the two chapters that deal with metering, they have different names. The metering code, which is part of the EAPP IC, is described in Chapter 18 as the *EAPP IC Metering* Chapter (IMC), and the metering code, which is specific to the ENTGC, is described in Chapter 17 as Ethiopia Metering Chapter (EMC).

The IMC deals with metering of each point of interchange of energy between *Control Areas* and is not concerned with Metering of *Connection Points* between *Users* and *National Systems*.

The EMC deals primarily with metering entirely within Ethiopia, to which the IMC does not apply. The EMC also includes each metering point connecting Ethiopia's networks to a *Neighbouring Country*. The IMC applies to those inter-country connections.

17.1.1Introduction

The Ethiopia Metering Chapter (EMC) specifies the minimum technical, design and operational criteria to be complied with for the metering of each *Connection Point* of a *User* to the *ENTS*.

(a) This Chapter ensures a metering standard for all current and future *Users*. It specifies metering requirements to be adhered to, and clarifies levels of responsibility.

(b) The *ENTS* shall follow nationally adopted metering standards currently in place that includes *IEC 62052, IEC 62053, IEC 62054, IEC 62056, IEC 62059*, and/or any equivalent IEEE/local standards as appropriate.

17.1.2Scope

The Ethiopia Metering Chapter addresses the following:

(a) Application

(b) Principles and responsibility

(c) Installations and testing

(d) Database, data validation, verification and inconsistencies

(e) Data access and confidentiality

17.1.3Application of the Ethiopia Metering Chapter

(a) This Chapter shall apply to all Users in respect of any metering point of the *ENTS*

(b) This Chapter sets out provisions relating to:

1. Main metering installations and check metering installations used for the measurement of active and reactive energy
2. The collection of metering data
3. The provision, installation and maintenance of equipment
4. The accuracy of all equipment used in the process of electricity metering
5. Testing procedures to be adhered to
6. *Storage requirements for metering* data
7. Competencies and standards of performance; and
8. The relationship of entities involved in the electricity metering industry

17.1.4 Principles of the Ethiopia Metering Chapter

(a) The following points shall have a metering installation:

1. Each Point of Supply connecting a *Distribution Licensee* or *end-use customer* to the *ENTS*
2. Each *Connection Point* between a *Generating Plant* and a *Distribution Licensee* and/or the *ENTS*
3. Each point connecting *ENTS* to a *Neighbouring Country*

(b) Items 17.1.4 (a) 1 and 17.1.4 (a) 2 shall not be subject to the requirements of the IMC. Item 17.1.4 (a) 3 shall meet all metering requirements specified in the *EAPP IC*

(c) The type of metering installation at each metering point shall comply with *IEC 62053*, equivalent IEEE and/or local standards as appropriate

(d) Each metering point shall be installed with main and check metering where practical and economical. Customers with a maximum demand of at least five (5) MVA shall have main and check metering, with the same accuracy as of the main meter. There shall be at least one dedicated metering *CT* and *VT* core. All *CTs* and *VTs* installed after the implementation of the *ENTGC* shall have separate main and check *CT/VT* cores in order to keep the errors checked

(e) A metering point shall be located as close as practicable to the *Connection Point*. A metering point may be located at a point other than the *Connection Point* or the Point of Supply by mutual agreement between applicable *Users*

(f) Customers may request the installation of their own separate check meters. Any extra costs shall be borne by the requesting Party. The *Transmission Metering Administrator (TMA)* shall install and control such meters

17.1.5 Responsibility for Metering Installations

(a) The Generation Licensee is responsible for providing both primary and check meters, per *TNSP* specifications. The Generation Licensee will continue to be responsible for the primary meter. The check meter is to be transferred to the *TNSP*. the *TNSP* or the *Generation Licensee*, whoever is the owner of the meter, shall perform the role of the *Transmission Metering Administrator (TMA)*

(b) For the metering between transmission and distribution lines, the *TNSP* will place the primary meters on the outgoing lines on all HV substations. The *DNSP* will own and put check meters on the outgoing distribution lines. Each entity/owner of the respective meter shall be responsible for their meters and perform the role of the Transmission Metering Administrator (TMA)

(c) The *TNSP* shall be responsible for ensuring that all points identified as metering points in accordance with Sections 17.1.3 and 17.1.4 in this chapter have metering installations

(d) The *TMA* shall be responsible for managing and collecting metering information

(e) *Users* connected to or wanting to connect to the *ENTS* shall provide the *TMA* with all information deemed necessary to enable performance of its metering duties

(f) In case of a material difference in location between the metering point and Connection Point, an adjustment for losses between these two points shall be calculated and agreed upon by the *TMA* and the customer

(g) The *TMA* shall ensure that an adequate level of security is applied to the metering system with appropriate seals that will only be broken in the presence of the *TMA* unless agreed otherwise

(h) In the event of a metering installation between the *TNSP* and a *User*, the TNSP will provide the meter and shall be responsible for managing and collecting metering information as a TMA of the meter

(i) In the event of a metering installation being positioned between two *TNSPs*, the following shall apply:

1. Both *TNSPs* shall be responsible for installing and maintaining the metering installation in accordance with the requirements of this Chapter
2. All costs related to this metering installation shall be borne by both *TNSPs*
3. The *TNSPs* shall ensure that the *TMA* is given remote/electronic access to the metering installation. Should access to the metering installation compromise the Security of the installation, then metering data shall be supplied to the *TMA* on a daily basis in an appropriate format

17.1.6Metering Installation Components

(a) The following principles shall apply to all metering installations:

1. The meter(s) or recorder(s) shall be able to store data in memory for forty (40) days or more
2. Data stored in either a meter or a recorder shall be remotely (where possible) and locally retrievable
3. A meter shall be remotely interrogated on a daily basis where possible or as mutually agreed by the affected *Users*
4. A meter shall be visible and accessible, but such access shall be restricted to authorised access only. Data for customers shall be historical data situated on a secure server. As and when required, metering impulses shall be provided

5. A telecommunications medium shall be connected to the meter/recorder where possible
6. The meter data retrieval process shall be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories
7. The accuracy of meters and recorders shall be in accordance with the minimum requirements of *IEC 62053*
8. Commissioning of the metering installation and metering data supporting systems shall take place in accordance with the requirements of *IEC 62052, IEC 62058* and/or any other *IEC*, IEEE, currently existing local prevailing standards or equivalent as appropriate
9. Both active and reactive energy shall be measurable without compromising any requirements of this Chapter
10. The meters shall accurately measure both active and reactive energy flow in both directions in accordance with applicable IEC standards
11. The meters shall be configured to store/record metering data in half-hourly integration periods

(b) In the event of a metering installation being used for purposes other than metering data
1. Such use shall not in any way obstruct metering data collection and accuracy requirements
2. The secondary use shall be communicated to all *Users* who may be affected by the secondary use of the installation
3. No secondary *user* shall interfere with VT/CT circuitry

(c) Metering installations shall be audited in accordance with *IEC 62052* and/or any other *IEC*, IEEE, currently existing local prevailing standards or equivalent

17.1.7 Data Validation and Verification

17.1.7.1 Data Validation

Data validation shall be carried out in accordance with IEC *62056* appropriate sections.

(a) In the event of the electronic access to the meters not being possible, the following options may be resorted to by the TMA:

1. Manual meter data downloading
2. Estimation or substitution subject to mutual agreement between the affected parties;
3. Profiling
4. Reading of the meter at scheduled intervals

(b) In the event of an estimation having to be made, the following shall apply:

1. A monthly report shall be produced for all estimations made
2. No estimation shall be made on three (3) or more consecutive time slots, and if such estimation had to be made, the *TMA* shall ensure that the meter readings are downloaded for the billing cycle

3. Any logs on data estimation shall be kept for the entire period of data retention. As per *IEC 62056*, five (5) years' data retention shall be made available

(c) Not more than ten (10) slots may be estimated per meter point per Month. If such estimation had to be made, the *TMA* shall ensure that the meter readings are downloaded for the billing cycle.

(d) Meters needing three or more consecutive estimations or a total of ten (10) or more estimations in a month shall be tracked for problems needing attention.

17.1.7.2 Meter Verification

In addition to the *IEC 62052*, *IEC 62058*, and/or any other equivalent IEEE/local standards verification requirements, meter readings shall be compared with the metering database at least once a year.

17.1.8 Metering Database

(a) The *TMA* shall create, maintain and administer a metering database containing the following information:

1. Name and unique identifier of the metering installation
2. The date on which the metering installation was commissioned
3. The connecting parties at the metering installation
4. Maintenance history schedules for each metering installation
5. Telephone numbers used to retrieve information from the metering installation
6. Type and form of the meter at the metering installation
7. Fault history of a metering installation
8. Commissioning documents for all metering installations

(b) Information relating to raw and official values as indicated in *IEC 62056* shall form part of the metering database and shall be retained for at least five (5) years for audit trail purposes

17.1.9 Testing of Metering Installations

(a) Commissioning, auditing and testing of metering installations shall be done in accordance with the *IEC 62052*, IEC 62058 and/or Ethiopian equivalent specification as appropriate

(b) Any *User* may request the *TSO* for performance testing of a metering installation. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of the requesting *User* if the meter is found to be accurate and to the account of the TMA if the meter is found to be inaccurate. If errors are found with the metering after testing or auditing, the requesting *User*'s account will be adjusted according to the rectified Data

17.1.10 Metering Database Inconsistencies

In the event of testing revealing that data in the metering database is inconsistent with the data in the meter, the *TMA* shall inform all affected *User*s and corrections shall be made to the official metering data in all the impacted areas.

17.1.11 Access to Metering Data

(a) Metering data shall be accessed through a central database that shall store all customer information

(b) The *TMA* shall control access to all metering installations

(c) No electronic access to the meters shall be granted to the customer or any other Party unless special permission has been granted by the *Regulatory Authority*

(d) Schedules for accessing metering data from the central database shall be administered by the *TMA* in line with IEC 62056

(e) All Security requirements for metering data shall be as specified in IEC 62056

17.1.12 Confidentiality

Metering data and passwords are confidential information and shall be treated as such at all times.

17.1.13 Customer Query on Metering Integrity and Metering Data

If a *User* has a query or complaint related to metering, the relevant *TMA* shall comply with the applicable requirements as per IEC 62056.

18 INTERCONNECTION METERING

18.1 EAPP IC REQUIREMENTS

The metering requirements of the *EAPP IC* deal exclusively with the metering of each point of interchange of energy between *Control Areas*. The metering requirements of the *ENTGC* deal primarily with metering points that do not have exchanges between *Control Areas*. The metering requirements of the two Codes have many areas of similarity.

18.1.1Introduction

The Interconnection Metering Chapter (IMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each point of interchange of energy between *Control Areas*. The metering at the Interchange Point is required for real-time operation of *AGC* systems and for the accounting of *Inadvertent Deviations* in accordance with the Balancing and Frequency Control Chapter. The IMC also specifies the associated Data Collection and the related metering procedures required for the operation of the *EAPP Interconnected Transmission System*.

The IMC is not concerned with:

(a) Metering of *Connection Points* between *Users* and *National Systems,* and

(b) Metering for commercial purposes

These metering systems are subject to National Grid Codes or Regulations and or Power Purchase Agreements.

18.1.2Objectives

For the metering of the interconnections between *Control Areas* of the *EAPP Interconnected Transmission System* and between *Control Areas* and *External Systems*, the IMC specifies the conditions governing the following:

(a) technical, design and operational criteria

(b) accuracy and calibration

(c) approval, certification and testing, and

(d) meter reading and data management

18.1.3Technical Design and Operational Criteria

Metering equipment shall be installed and maintained to measure and record the hourly *Active* and *Reactive Energy* and *Active* and *Reactive Power* transferred to and from a *Control Area* at its interconnection point (IP) with other *Control Areas* and or *External Systems*. This Metering Equipment will be the primary source of data for *TSOs* to operate *AGC* systems in real-time and to account for *Inadvertent Deviations*.

TSOs are responsible for the maintenance and operation of the Metering Equipment at each *IP* and shall be responsible for the initial design, installation, testing and commissioning of the Metering and Check Metering Equipment.

Main and Check Metering Equipment procured, installed, operated and maintained for the purpose of the IMC shall meet the standards of accuracy and calibration in relation to meters and Metering Equipment as set out in this IMC.

18.1.3.1 General Technical Criteria

This section defines the general technical requirements for the Metering Equipment for the measurement and recording of electricity transfers on the interconnections between *Control Areas* and between *Control Areas* and *External Systems*. The provisions of the IMC shall apply equally to Main and Check Meters.

TSOs and the *EAPP CC* shall establish metering related policies, procedures and standards in support of the IMC including, but not limited to registration, testing and calibration, sealing, loss adjustments, data security, inspection, testing and audit of Metering Equipment and measurement error correction.

18.1.4 Metering Information Register

EAPP CC shall maintain a Meter Information Register of all meters at *defined metering points (DMP)*s. This register will contain, but not be limited to:

(a) A unique meter identification/serial number;

(b) Location of the Main Meters, Check Meters and Metering Equipment including metering data recording systems

(c) The identification of the *TSO* concerned

(d) Meter manufacturer, type and model

(e) The specification of Metering Equipment including accuracy class

(f) The adjustment factors including circuit losses to be applied

(g) Date of installation; and

(h) Calibration certificate

18.1.5Main and Check Metering

At all *DMP*s Main and Check Metering shall be provided. Main and Check Meters shall operate from separate Current Transformer (*CT*) and Voltage Transformer (*VT*) windings. All Check Meters shall meet the standards specified in the IMC as if they were the only Metering Equipment at the *DMP*.

CT and *VT* windings and cables connecting such windings to Main Meters shall be dedicated for such purposes and such cables and connections shall be securely sealed.

CT and *VT* windings and cables connecting such windings to Check Meters may be used for other purposes provided the overall accuracy requirements are met and evidence of the value of the additional burden is available for inspection by or on behalf of the *EAPP Independent Regulatory Board*.

The Main Meter, Check Meter and additional burdens shall have separately fused *VT* supplies.

18.1.6 Measurement Parameters

For each DMP, the Metering Equipment shall be capable of measuring the following parameters in both import and export directions: *MW, Mvar, MWh* and *Mvarh*.

18.1.7 Metering Equipment Standards

All Metering Equipment shall comply with the provisions set out in the IMC. These provisions may be revised from time to time in accordance with the provision set out in Chapter 3 (General Conditions or GC) to take account of changing technologies or new requirements of the electricity industry.

All existing *CT* s and *VTs shall conform to* IEC 60044 or IEC 61869 or equivalent as appropriate. Combined unit measurement transformer (*VT* & *CT)* shall comply with IEC Standard 60044 or IEC 61869 or equivalent as appropriate.

All meters shall include a non-volatile meter register for each measured quantity. The meter register(s) shall not rollover more than once within the normal meter reading cycle.

18.1.8 Equipment Accuracy and Error Limits

The accuracy of the various items of Metering Equipment shall conform to the relevant IEC standards or equivalent national standards where agreed between the *EAPP CC* and the *TSO* concerned. The accuracy limits set out in the IMC shall be applied after adjustments have been made to Metering Equipment to compensate for any errors due to secondary equipment and connections.

Meters shall be calibrated by an independent calibrating agency approved by the *EAPP Independent Regulatory Board* for this purpose. The agency shall provide a calibration certificate with expiry date of the calibration.

Where combined instrument transformers to IEC60044-3 are used, they shall meet the accuracy requirements of Chapters IMC 18.1.9.as stated for the *CT*s and *VT*s below.

18.1.8.1 Voltage Transformers (VT)

The *VT*s shall be of 0.2 Accuracy Class and comprise three (3) single-phase units, each of which complies with:

(a) IEC Standard 60044-2: Instrument Transformers - Part 2: Inductive Voltage Transformers, or

(b) IEC Standard 60044-5 Part 5: Capacitor Voltage Transformers for metering

The voltage drop in each phase of the *VT* connections will be such as to maintain the same accuracy and class and shall not exceed 0.2 Volts. The *VT* shall be connected through appropriate isolation and test facilities to the meter with a total burden that shall not affect the accuracy of measurement.

18.1.8.2 Current Transformers (CT)

The *CT*s shall be of 0.2 accuracy class and comprise three (3) units for a three phase set, each of which complies with the IEC Standard 60044-1: Instrument Transformers-Part 1: Current Transformers for metering.

The *CT*'s rated secondary current shall be either 1 or 5 Amperes. The neutral conductor shall be effectively grounded at a single point and shall be connected to the meter and other series technical equipment via separate "bridge type" isolation and test facilities with a total burden that shall not affect the accuracy of measurement.

18.1.8.3 Meters

Meters shall be of the three-element type independent for each phase, rated as appropriate and shall comply with IEC Standard 62052-11: Electricity Metering Equipment (*AC*)-General requirements, tests, and testing conditions for static watt-hour meter and other types of meters, and shall be of the accuracy class of 0.2 or better.

The meters shall measure and locally display at least the *MW*, *MWh*, *Mvar*, *Mvarh*, and cumulative demand, with additional features such as time-of-use, maintenance records and power quality monitoring. Meters shall be digital unless agreed otherwise by *EAPP CC*. A cumulative register of the parameters measured shall be available on the internal storage facilities of the digital meters for a minimum of thirty (30) calendar days with one (1) hour values. Bi-directional Meters shall have two such registers available.

The loss of auxiliary supply to the Metering Equipment shall not erase these registers. The meter registers shall be readable by both the *TSO's* SCADA and by the DCS of *EAPP CC*. Where data storage is not provided internally, it shall be provided externally to the Metering Equipment by way of a data logger, which summates the pulse outputs of the meters. The internal registers of these devices shall provide a register per measured quantity that can be interrogated by the *TSO's* SCADA system and by the DCS of *EAPP CC*.

18.1.9Inspection, Calibration and Testing

18.1.9.1 Initial Calibration

All new meters shall undergo relevant certification tests and initial calibration of meters shall be performed in a recognised test facility. These tests shall be performed in accordance with the relevant IEC standards and shall confirm that meter accuracy is within the limits stated in Section 18.1.9. A unique identifiable calibration record shall be provided before the connection is commissioned.

VTs and *CTs* shall be tested according to the relevant IEC standards prior to installation at the DMP. The *TSO* shall provide manufacturer's test certificates to *EAPP CC* to show compliance with the accuracy standards in this IMC.

18.1.9.2 Periodic Calibration and Testing

The TSO as owner of Metering Equipment shall undertake calibration testing upon request by the *EAPP Independent Regulatory Board* or another *TSO*. In addition, *TSOs* shall carry out routine calibration of the meters every three (3) years and connections for the *CTs* and *VTs* shall be checked every five (5) years. If the meters have been adjusted to compensate for errors in the *CTs* and *VTs*, then the *CTs*, *VTs* and their connections will be checked at the same periodicity as the meters.

Where, following a test, the accuracy of the Metering Equipment is shown not to comply with the requirements of this IMC, the *TSO* shall take such measures as are required to restore the accuracy of the Metering Equipment to the required standard.

The cost of routine testing shall be met by the *TSO* as owner of the Metering Equipment.

The cost of calibration testing shall be met by the *Party* requesting the test unless the test shows the accuracy of the Metering Equipment does not comply with the requirements of the IMC, in which case the cost of the tests shall be met by the *TSO*.

TSOs shall ensure that all Metering Equipment at DMPs is physically inspected and read by it or on its behalf not less than once in every three (3) months. The purpose of this reading is to reconcile cumulative register readings on site with readings collected remotely. Physical checks shall be carried out at the same time to identify such things as missing seals or damage or any other issues for concern.

Where a Metering Equipment is found to be faulty or to be non-compliant with the IMC, *EAPP CC* and the other relevant *TSO* shall be informed of the failure or non-compliance promptly. Such notification shall include the plans by the *TSO* concerned to restore the Metering Equipment to compliance with the IMC.

The *EAPP CC* shall in cooperation with the *TSOs* involved assess the duration of the period where the Metering Equipment has been faulty. For that period, recorded data from the Check Meter shall be used.

18.1.10 Data Collection

The TSO shall collect all data relating to the parameters measured by Metering Equipment at DMPs by remote or manual on-site interrogation in accordance with the terms of this IMC. For the purposes of remote interrogation, the *TSO* may use its own data communications network or failing this, shall enter into, manage and monitor contracts to provide for the maintenance of all data links by which data is passed to the *TSO* and to the *EAPP CC*. In the event of any fault or failure on such communication links or any error or omission in such data the *TSO* shall, if possible, retrieve such data by manual on-site interrogation.

18.1.11 Security

Each *TSO* as owner of the Metering Equipment at the *DMP*s shall ensure that the equipment itself is sealed and that any links and secondary circuits are sealed where practically possible. The seals shall only be broken in the presence of representatives of the *EAPP Independent Regulatory Board* and the *TSO* unless agreed otherwise by the parties involved.

18.1.12 Disputes

Disputes concerning this IMC will be dealt with in accordance with the procedures set out in Section 3.11 of Chapter 3 (*Dispute* Resolution).

18.1.13 Meter Data Confidentiality

Meter data may be commercially sensitive and confidential and appropriate measures shall be taken to ensure the meter data cannot be divulged to or obtained by third parties.

18.1.14 Operational Metering

An operational metering system is required to support real time operation of the *EAPP Interconnected Transmission System*. Because operational requirements differ from Interchange Metering requirements, the operational metering system does not necessarily have the same requirements for accuracy of measurement. However, timely operational metering data is critical for the efficient, safe, and timely operation of the *EAPP Interconnected Transmission System*. *EAPP CC* and *TSOs* shall agree on the types of operational data to be exchanged in real-time and shall ensure that appropriate systems are in place.

19 DATA EXCHANGE

19.1 INTRODUCTION

The Data Exchange Chapter (DEC) defines the system data to be exchanged between *TSOs* and *EAPP Sub-Committees on Planning and Operations* for the purpose of the modelling and analysis of steady-state and dynamic conditions for the *EAPP Interconnected Transmission System*.

The DEC sets out the information flows required between *TSOs* and *EAPP Sub-Committees on Planning and Operations* to produce *EAPP* system models for the various processes that require system studies to be undertaken.

These processes include those associated with System Planning as set out in Chapter 5 (Planning or PC), including the preparation of the *Transmission System Capability Statement*, and with Operational Planning as set out in Chapter 8 (OC 1).

19.2 OBJECTIVE

The objectives of the DEC are:

a) To detail how *EAPP* system models are produced and agreed

b) To address the methods of information management across the interface between *EAPP Sub-Committees on Planning and Operations* and *TSOs* to ensure consistency of the *EAPP* system model, and

c) To provide a basis for cooperation between *EAPP Sub-Committees on Planning and Operations* and *TSOs* in the field of power system analysis. The power system analysis studies are required in order to resolve balance and capacity problems and for secure exploitation of the advantages of the *EAPP Interconnected Transmission System*

19.3 POWER SYSTEM MODEL

Power System Model refers to the power system data that are needed in order to carry out load flow, fault, transient and dynamic studies on all or part of the *EAPP Interconnected Transmission System*.

The Model will characterise *Generating Unit* responses to system disturbances such as voltage and frequency deviations, and oscillations and control signals for power and voltage scheduling. The dynamic model will be part of the Power System Model used in the system studies to determine operating transfer limits and system reinforcements.

Power system studies are required for two distinct purposes:

19.3.1System Planning

System planning studies generally involve studies of the system from three (3) years to ten (10) years ahead. They identify deficient areas in the transmission and generation systems and solutions are proposed which may include facility additions, upgrades, or other modifications. Studies are performed for all projected seasonal periods. Generation output in the study case is based on the principles of economic dispatch. The combination of load and capacity studied is a snapshot of projected *EAPP Interconnected Transmission System* conditions and therefore subject to a degree of uncertainty. Additional studies may need to be performed to evaluate off-peak periods and study specific *Outages* of transmission and generation facilities.

19.3.2Operational Planning

Operational Planning studies are normally performed for conditions from three (3) years ahead down to real time. These studies identify *Contingency* related transmission deficiencies that may be encountered, and assist in formulating corrective measures in operational timescales to mitigate the deficiency.

19.4 PROVISION OF SYSTEM DATA

TSOs shall provide data of two types:

19.4.1Basic Data

The *EAPP Sub Committee on Planning* shall prepare the basic data for use in system studies. The data shall be prepared annually with input from *TSOs*. The basic data shall include the electrical characteristics and ratings of transmission facilities and the timing of new facilities maintained in a chronological database. Basic datasets shall be produced by the *EAPP Sub Committee on Planning* for each year up to ten (10) years ahead.

The system data to be provided by *TSOs* to the *EAPP Sub Committee on Planning* is set out in Section 19.8 of this chapter.

19.4.2Study Data

In order to carry out system studies in accordance with the PC or OCs, *TSOs* shall supply appropriate system data to the *EAPP Sub Committees on Planning and Operations*. This data includes, but is not limited to, the following:

a) The demand on the *EAPP Interconnected Transmission System* for the period under study. The distribution of demand across the nodes shall be consistent with the period under study

b) Generation indicative of the conditions under study - Generation in individual National Systems shall be based on that system's economic dispatch with base load units, hydrological factors, pumped storage and distributed generation given proper consideration

c) Evaluation of Transmission System Capability

d) Interchange with *External Systems* modelled as demand or generation as the case may be. Equivalents of the *External Systems* shall be used if studies other than load flow are being carried out

e) Ratings of transmission facilities based on appropriate ambient temperature and seasonal conditions

f) Timing of new facilities and outage schedules for existing facilities; and

g) A list of *Contingencies* to be considered during programme execution agreed between *TSOs* and *EAPP Sub Committees on Planning and Operations*

19.5 RESPONSIBILITY FOR SYSTEM MODELS

The *EAPP Sub-Committee on Planning* shall be responsible for the coordination and production of the *EAPP Interconnected Transmission System* models and shall define the software to be used in *EAPP* executed studies.

TSOs are responsible for the production of models of their own *National Systems* and they may determine the software to be used. If the software is different from that in use by *EAPP* then appropriate data format conversion shall be carried out. The data shall be the latest version available unless a specific version of the data is requested and in all cases, the data must be complete.

EAPP Sub-Committee on Planning shall perform data verification to ensure correct *TSO* model conversion, that the system configuration is maintained, and that the parameters for all lines, transformers, and reactors are properly converted. The *EAPP Sub-Committee on Planning* shall maintain a database of all problems encountered during data conversion and the solutions found.

19.6 EQUIVALENTS

An equivalent is a simplified version of the complete *EAPP Interconnected Transmission System* model. Equivalents can be supplied to and used by third-parties for their studies. The aim is that the characteristics of the equivalent at the *Connection Points* should be the same as those of the complete model in terms of load distribution, impedances, and dynamic response.

19.7 DATA CONFIDENTIALITY

Where the data exchanged between TSOs and EAPP Sub-Committees on Planning and Operations is not in the public domain in the country to which it refers, the data shall be considered confidential in accordance with Section 3.15 in Chapter 3 (General Conditions – Confidentiality).

19.8 BASIC DATA REQUIREMENT

List of Basic Data required by *EAPP* for use in the Power System Model

(a) **Substation:** name, nominal voltage, demand supplied (consistent with the aggregated and dispersed substation demand data supplied) and location

(b) **Generating Units (including synchronous condensers, pumped storage, etc.):** location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status

(c) ***AC* Transmission Line or Circuit (overhead and underground):** nominal voltage, impedance, line charging, Normal and Emergency Ratings, equipment status, and metering locations

(d) ***HVDC* Transmission Line (overhead and underground):** line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data

(e) **Transformer (voltage and phase-shifting):** nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings and equipment status

(f) **Reactive Compensation (shunt and series capacitors and reactors):** nominal Ratings, impedance, percent compensation, connection point, and controller device

(g) **Interchange Schedules:** Existing and future Interchange Schedules and/or assumptions.

Notes

a) Design data shall be provided for new or refurbished excitation systems (for *Synchronous Generating Units* and synchronous condensers) at least three (3) months prior to the installation date

b) Unit-specific dynamics data shall be reported for *Generating Units* and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment

c) Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained

d) The Interconnection-wide requirements shall specify unit size thresholds for permitting:
   i. The use of non-detailed vs. detailed models
   ii. The netting of small generating units with bus load, and
   iii. The combining of multiple *Generating Units* at one *Generating Plant*

e) Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible *AC* transmission systems, and static compensators

20 INFORMATION EXCHANGE

20.1 INTRODUCTION

The Information Exchange Chapter defines the reciprocal obligations of parties with regard to the provision of information for the implementation of the *ENTGC*. The information requirements, as defined for the Generation, Transmission, and Distribution entities, the *ENTSO*, the *Regulatory Authority* and *Users*, are necessary to ensure non-discriminatory access to the *ENTS* and the safe, reliable provision of transmission services.

The information requirements are divided into planning information, operational information and post-dispatch information.

Information criteria specified in the Information Exchange Chapter are supplementary to the other Chapters within the *ENTGC*. In the event of inconsistencies between other Chapters and the Information Exchange Chapter with respect to information exchange, the requirements of the Information Exchange Chapter shall prevail.

Requirements in this chapter apply to communications between the *ENTSO* and *Users*.

20.2 INFORMATION EXCHANGE INTERFACE

(a) The parties shall identify the following for each type of information exchange:

1. The name and contact details of the person(s) designated by the information owner to be responsible for provision of the information
2. The names, contact details of, and the parties represented by persons requesting the information
3. The purpose for which the information is required.

(b) The parties shall agree on appropriate procedures for the transfer of information.

20.3 SYSTEM PLANNING INFORMATION

(a) *Users* shall provide such information as the *ENTSO* may reasonably request on a regular basis for the purposes of planning and developing the *ENTS*. Each request shall specify the information sought and the requested frequency upon which it would be provided. *Users* shall submit the information within the specified time period without unreasonable delay. Such information may be required for the planning and development of the *ENTS*, monitoring current and future power system adequacy and performance, and fulfilling statutory or regulatory obligations. Reasons for any anticipated delay in providing the requested information shall be communicated for effective mitigation

(b) *Users* shall submit to the *ENTSO* and to all relevant *TNSPs* the following information for *Distribution Licensees* or end-use *Users*. The *ENTSO* may request additional information reasonably required

1. Hourly/daily/monthly load forecast data, and the source of the forecast

2. Transmission system losses data with indication of percent losses included in the load forecast
3. Identification of non-conforming load data
4. Demand response resources
5. Network topology, and capacity/rating data
6. Daily list of transmission reservations to and hourly increment of new reservations, if any
7. Transmission system connected transformer data
8. Shunt capacitor or reactor data requirements
9. Series capacitor or reactor data requirements
10. Phase shifting transformers
11. Flexible *AC* transmission system (*FACTS*) devices
12. High voltage direct current (*HVDC*) data
13. Information on customer networks
14. Overhead line data
15. Cable data

(c) *Generation Licensees* shall submit to the *TNSP* and/or *ENTSO* and to all other relevant *TNSPs* the following information for *Generating Plants*. The *ENTSO* may request additional information reasonably required

1. *Generating Plant* data including regulated bus, target voltage and actual voltage
2. *Generating Unit* data including unit owner and bus location in the model, seasonal ratings, PMIN, PMAX, QMIN, QMAX
3. Rules for sharing output between joint owners, if any
4. Station auxiliaries to the extent gross generation has been reported
5. Reserve capability
6. Unit parameters
7. Excitation system
8. Control devices and protection relays
9. *Generating Unit* step-up transformer
10. *Generating Plant* forecast data
11. Mothballing of *Generating Plant/Unit*
12. Return to service of mothballed *Generating Plant/Unit*
13. Decommissioning of *Generating Plant/Unit*

(d) *Users* shall submit to the *ENTSO* and to all relevant *TNSPs* their planning schedules, including a ten (10) year demand forecast and information on embedded *Generating Plant* larger than five (5) MVA

(e) The *TNSP* shall provide the *Generation Licensee* with information about equipment and systems installed in *HV* yards, including:

1. Circuit breaker

2. *Current Transformer* (CT) and *Voltage Transformer* (VT)
3. Surge arrestor
4. Protection
5. Power consumption
6. Link
7. Outgoing feeder
8. Transformer
9. Compressed air system
10. Fault recorder

(f) The *TNSP* and/or the *ENTSO* shall keep an updated technical database of the *ENTS* for purposes of modeling and studying the behaviour of the *ENTS*

(g) The *TNSP* and the *ENTSO* shall provide *Users* or potential *Users*, upon any reasonable request, with any relevant information that they require to properly plan and design their own networks/installations or comply with their other obligations in terms of the *ENTGC*

(h) The *TNSP* and/or the *ENTSO* shall make available all relevant information related to network planning

(i) *Users* shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *TNSP* and the *ENTSO* with information relating to the items in table 20-1 below:

Table 20-1: Required Information

Item	Description
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/nonfarm supply required as per Chapter 6 (Connections)
Location map	Upgrades: name of existing point of supply to be upgraded and supply voltage New connections: provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, co-ordinates of the *Connection Point* to be specified
Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed point of supply, and where applicable, the transmission line route from the facility boundary to the point of supply, clearly marked
Electrical single line diagram	Provide an electrical single-line diagram of the User intake substation

(j) The TNSP and/or *ENTSO* may estimate any system planning information not provided by a *User* as specified in items (b) and (c) above. The *ENTSO* shall take all reasonable steps to reach agreement with the *User* on estimated data items. The *ENTSO* shall indicate to the *User* any data item that has been estimated. The obligation to ensure the correctness of data remains with the *User*

(k) *Generation Licensees* shall submit weekly to the *ENTSO* all maintenance planning information requested with regard to each unit at each *Generating Plant* as well as transmission switching

(l) The *TNSP* shall provide the *Generation Licensees* with a monthly rolling maintenance schedule for all planned work in *HV* yards for a period of one year in advance. Log books on all vessels under pressure for receivers installed in *HV* yards shall be made available on request from the *Generation Licensees*

(m) Notification of all forced outages of both generation and transmission resources, shall be made immediately, not exceeding in any case beyond ten (10) minutes after they are identified if there are no emergency situations such as fire, communication failure, etc.

20.4 OPERATIONAL INFORMATION

20.4.1 Pre-commissioning Studies

(a) *Users* shall meet all system planning information requirements before the commissioning test date. (This will include confirming any estimated values assumed for planning purposes or, where practical, replacing them with validated actual values and with updated estimates for the future)

(b) The *ENTSO* shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified *Generating Plant* to the *ENTS*, using data supplied by *Users* in accordance with Section 3, to verify that all control systems are correctly tuned and planning criteria have been satisfied

(c) The *ENTSO* may request adjustments prior to commissioning should tuning adjustments be found to be necessary. The asset owner shall ensure that all system planning information records are maintained for reference for the duration of the operational life of the *Generating Plant*. Information shall be made available within a reasonable time on request from the *ENTSO* upon notification of such a request

(d) In case of *RPP*, each generating plant shall submit to the *ENTSO* a detailed test procedure with emphasis on system impact for each relevant part of the *ENTGC* prior to every test

20.4.2 Commissioning and Notification

(a) All *Users* shall ensure that exciter, turbine governor, *Flexible AC Transmission System* (*FACTS*) and *High Voltage Direct Current* (*HVDC*) control system settings are implemented and are as finally recorded by the *ENTSO* prior to commissioning

(b) *Users* shall give the *ENTSO* notice of the time at which the commissioning tests will be carried out. The *ENTSO* and the *User* shall agree on the most appropriate provision of operational data items

(c) Records of commissioning shall be maintained for reference by the asset owner for the operational life of the *Generating Plant* and shall be made available, within a reasonable time, to the *ENTSO* upon notification of such request

(d) The asset owner shall, before the equipment is returned to service, communicate to *ENTSO* changes made to commissioned equipment during an outage. *ENTSO* shall keep commissioning records of operational data for the operational life of the *Generating Plant* connected to the *ENTS*

(e) *Users* shall also provide notification on:

1. Planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments

2. Planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units

20.4.3 General Data Acquisition Information Requirements

The *ENTSO* shall have adequate observability to ensure reliable and safe operation of the *ENTS*. Users are to comply with reasonable requests from the *ENTSO* that are intended to ensure adequate observability. The *ENTSO* will ensure confidential treatment of data, as discussed in Section 3.15.

(a) *Users* and *TNSPs* shall agree on the formats to be used for the measurements and indications to be supplied to the *ENTSO*. Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information, such *User* shall report and restore or correct the signals and/or indications as soon as reasonable

(b) The *ENTSO* shall notify the *Users,* where the *ENTSO*, acting reasonably and in consultation with the *Users*, determines that additional measurements and/or indications in relation to a *User*'s *Generating Plant* and equipment are needed to meet *ENTS* requirement. The costs related to the *User*'s modifications for the additional measurements and/or indications shall be for the account of the providing *User.*

(c) On receipt of such notification from the *ENTSO,* the *User* shall promptly ensure that such measurements and/or indications are made available at the unit's communications gateway equipment

(d) The data formats to be used and the fields of information to be supplied to the *ENTSO* by the various *Users* shall be agreed among the parties

(e) The *TNSP* shall provide periodic feedback to *Users* regarding the transmission power flows, bus voltages, and status of equipment and systems installed in the substations where they are connected to the *ENTS*. The feedback shall include results from tests, condition monitoring, inspections, audits, failure trends and calibration. The frequency of the feedback shall be determined in the operating agreement, but will not exceed one year

(f) *Generating Plant* status reports provided by the *TNSP* shall also include *Contingency* plans where applicable

(g) The *ENTSO* needs to inform *Users* where in the network out-of-step relays are installed, and how the relays are expected to operate. Furthermore, the characteristics of such an islanded network shall be provided, based on the most probable local network configuration at such a time

(h) The cost of the installation of the *DTE* will be paid for by the *User*

(i) The *User* shall decide on the location of the *DTE*

(j) The *User* will be responsible for the maintenance of communications links between the *Generating Plant* gateway and the *DTE*

(k) The *TSO* shall be responsible for the maintenance, upkeep, and communications charges of the *DTE*

(l) *User*s shall exchange *SCADA* data that shall include:

1. Breaker statuses
2. Analog measurements (flows and voltages)
3. Generation *MW* and *Mvar*
4. Load *MW* and *Mvar*
5. *B*alancing area net interchange, operating reserve, and instantaneous demand

(m) Parties shall provide detailed *EMS* model data to the *ENTSO* once a year in a mutually agreed-upon electronic format with updates as new data becomes available as current and up-to-date representation of the *EMS* models become important for reliability coordination and market operations

(n) *User*s shall comply with all governing confidentiality agreements relating to information exchange

20.4.4 Data Acquisition Information Requirements for RPP

The *ENTSO* shall send control signals to the *RPP*. The *RPP* shall be capable of receiving these signals and responding accordingly:

(a) Connection Point CB Trip facility. A facility shall be provided by the *TNSP* to facilitate the disconnection of the *RPP*. It shall be possible for the *ENTSO* to send a trip signal to the circuit breaker at the *HV* side of the POC
(b) Primary frequency control ON/OFF
(c) Curtailment mode ON/OFF
(d) Curtailment set point command
(e) Stop command
(f) P-delta mode ON/OFF
(g) P-delta set point command
(h) Power gradient constraint ON/OFF
(i) Up ramp rate set point command
(j) Down ramp rate set point command
(k) Reactive power control mode ON/OFF
(l) Reactive power control set point command
(m) Power factor mode ON/OFF
(n) Power factor set point command
(o) Voltage control mode ON/OFF
(p) Voltage control set point

20.4.5 Unit Scheduling

20.4.5.1 Schedules

(a) The *ENTSO* shall arrange for the provision of sufficient energy and *Ancillary Services* to maintain system reliability

(b) *Dispatchable Resources* shall declare to the *ENTSO* their hourly unit available capacity or hourly load (in case of *Customers* participating as demand side resources) for the next day by 9h00 Hr each day

(c) The *ENTSO* shall provide final day-ahead power and *Ancillary Service* schedules to *Dispatchable Resources* by 15h00 Hr each day for the next day

(d) On the day, the *ENTSO* shall, at least 10 minutes before the hour, notify *Dispatchable Resources* of deviations in power and *Ancillary Service* schedules, subject to unit constraints

(e) In the event the *Dispatchable Resource* availability changes, the *Dispatchable Resource* shall notify the *ENTSO* promptly

(f) All information exchange requirements for *Ancillary Services* that are contracted annually shall be included in the contract between the parties

(g) If the *Dispatchable Resource* provides a schedule more than a day in advance and provides no update to the previously provided schedule by 11h00 Hr on the day-ahead, the *ENTSO* shall use the most recently provided schedule

(h) At the discretion of the *ENTSO*, the *Dispatchable Resource* will submit a daily energy schedule, which the *ENTSO* will use to determine the hourly power and *Ancillary Service* schedule of the *User*, subject to the unit and/or hydrological constraints

(i) Variable *Renewable Power Plants* shall provide forecasts as specified in Section 7.2.11

(j) See Sections 8.2.7 (Operational Planning) and 14.2.1 (Interchange Scheduling) for more details on units and interchange scheduling

20.4.5.2 File Transfers

The applicable *User* and *the ENTSO* shall agree on the format of the file used for data transfer. The data shall be made available in a secure but accessible, electronically protected directory. All file transfer data shall be fetched by the *ENTSO*. File transfer descriptions are detailed in Table 20-2

Table 20-2: File Transfers

File	Description	Trigger Event	Frequency
Dispatch schedule	The combined 24-hour day-ahead energy and ancillary services schedules. Hourly day-ahead contracts for different transaction categories that identify the unit with the next 24 hourly values for it.	Generation dispatch schedule	Daily
Dispatch cost curve	Daily cost curve with incremental costs and corresponding volumes	Generation dispatch schedule	Daily

20.4.6 Inter Control Centre Communication

(a) *Users* shall ensure that their control centres provide the *ENTSO* on request with network information that is considered reasonable for the security and integrity of the *ENTS*. The *ENTSO* shall communicate network information as requested to the *User* control centres, as required for safe and reliable operation. The information exchange between control centres shall be electronic and/or paper-based, and within the time frame agreed upon between the *Users*.

(b) The *Users* shall optimise redundant control centre facilities where required for the safe operation and control of the *ENTS*.

20.4.7 Communication Facilities Requirements

(a) The minimum communication facilities for voice and data that are to be installed and maintained between the *ENTSO* and *Users* shall comply with the applicable IEC standards for system control and data acquisition (*SCADA*) and communications equipment

(b) The communication facilities standards shall be set and documented by the *ENTSO*, acting reasonably, in advance of design. Any changes to communication facility standards impacting on *User* equipment shall be designed in consultation with *Users* and shall be informed by a reasonable business motivation

(c) For *RPP*, The IEC 60870-5-101 protocol shall be implemented on the Gateway for communication between the *RPP* and *ENTSO* when the *RPP* connects to the *ENTS*.

20.4.7.1 Telecontrol

(a) The *User's Plant* shall support data acquisition to and from the *Plant* gateway. The *ENTSO* shall be able to monitor the state of the *ENTS* via telemetry from the gateway connected to the *User's Plant*

(b) The signals and indications required by the *ENTSO* shall be agreed between the *ENTSO* and the *User*, together with such other information as the *ENTSO* may from time to time reasonably require by notice to the *User*

(c) *Users* shall interface via the standard digital interfaces, as specified by the *ENTSO*. Interface cabinets shall be installed in the *User's Plant* and equipment room if required. The provision and maintenance of the wiring and signalling from the *User's Plant* and equipment to the interface cable shall be the responsibility of the *User*

(d) *Users* shall comply with such telecontrol requirements as may be applicable to the primary control centre and, as reasonably required, to the emergency control centre of the *ENTSO*. Any changes to telecontrol requirements impacting on *User* equipment shall be designed in consultation with *Users* and shall be informed by a reasonable business motivation

20.4.7.2 Telephone/facsimile

(a) Each *User* 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. Scanned information sent via email may be accepted in place of facsimile at the discretion of the *ENTSO*

(b) The *ENTSO* shall use a voice recorder for historical recording of all operational voice communication with *Users*. These records shall be available for at least three (3) months. The *ENTSO* shall make the voice records of an identified incident in *Dispute* available within a reasonable time period after such a request from a *User* and/or the *Regulatory Authority*

20.4.7.3 Electronic Mail

The *Users* shall provide the *ENTSO* with the electronic mailing address of the contact person as defined in this Information Exchange Chapter and vice versa. The provider of this service shall be selected to meet the real-time operational requirements of the *ENTSO*.

20.4.8SCADA and Communication Infrastructure at Points of Supply

20.4.8.1 Access and Security

(a) The *ENTSO* shall agree with *Users* the procedures governing security and access to the *Users' SCADA*, computer and communications equipment. The procedures shall allow for adequate access to the equipment and information by the *ENTSO* or its nominated representative for purposes of maintenance, repair, testing and the taking of readings

(b) Each *User* 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 Chapter to third parties, and shall disclose that person's name and contact details to the *Regulatory Authority*. A party may, at its sole discretion, designate more than one person to perform these duties

20.4.8.2 Time Standards

All information exchange shall be *GPS* satellite time signal referenced. The *ENTSO* shall ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence.

20.4.8.3 Integrity of Installation

Where the electrical *Plant* does not belong to the *ENTSO,* the *ENTSO* shall enter into an agreement with the *User* for the provision of reliable and secure facilities for the housing and operation of *transmission* equipment. This includes access to, at no charge to the *ENTSO*, an uninterruptible power supply with an eight (8) hour standby capacity.

20.4.9Data Storage and Archiving

(a) The obligation for data storage and archiving shall lie with the information owner.

(b) The systems that store the data and/or information to be used by the parties shall be of their own choice and for their own cost

(c) All the systems must be able to be audited by the *Regulatory Authority*. The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the parties

(d) The information owner shall store the information in a manner that will allow for such information to be retrieved on request and shall ensure that the contents remain unaltered from its original state. The information shall be retained for a period of at least five (5) years (unless otherwise specified in the *ENTGC*) commencing from the date the information was created

(e) Parties shall ensure reasonable security against unauthorised access, use and loss of information (i.e. have a backup strategy) for the systems that contain the information

(f) Parties shall store outage planning information electronically for at least five (5) years. Other system planning information as defined in section 20.3 shall be retained for the life of the *Plant* or equipment concerned, whichever is the longer

(g) The *ENTSO* shall archive operational information, in a historical repository sized for three (3) years' data. This data includes:

1. *ENTS* time-tagged status information, change of state alarms, and event messages
2. Hourly scheduling and energy accounting information
3. Operator entered data and actions

(h) 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

20.5 DATA COMMUNICATION FOR RPP

(a) Active Power Curtailment or Voltage Regulation facilities at the *RPP* shall be tested once a month. It is essential that facilities exist to allow the testing of the functionality without tripping the actual equipment

(b) Test procedures shall involve a set point/raise or lower command being sent by the *ENTSO*, the set point feedback observed and the *RPP* responding to the set point. This shall be followed by return to normal set point/raise or lower command being sent to the *RPP* and the appropriate responses being measured

(c) Where signals or indications required to be provided by the *RPP* are unavailable or are not compliant with applicable standards due to failure of the *RPP* equipment or any other reason under the control of the *RPP*, the *RPP* shall restore or correct the signals and/or indications within 24 hours

20.6 POST-DISPATCH INFORMATION

20.6.1 System and Generating Plant Information

(a) The *ENTSO* shall provide relevant *Users* the following information:

1. Hourly system total *MW* loading
2. Hourly individual *Generating Plant MW* sent out
3. Hourly system constraints and constrained generation
4. Hourly international tie-line power flow
5. Predetermined system load flow data

20.6.1.1 Additional Unit Post-dispatch Information

(a) The *ENTSO* shall provide the following operational information regarding unit dispatch:

1. Unit high limit, *MW*
2. Unit low limit, *MW*,
3. Unit *Automatic Generation Control (AGC)* mode
4. Unit *AGC* status, Automatic/Off/Manual
5. Unit set-point, *MW*
6. *AGC* pulse
7. Unit sent out, *MW*
8. Unit auxiliary, *MW*
9. Unit contract, *MW*
10. Unit spinning, *MW*
11. 32-bit flag on AGC setting, 32 bits

(b) The *ENTSO* shall provide operational information regarding overall dispatch performance:

1. *Area control error (ACE)*, *MW*
2. Average *ACE* previous hour, *MW*
3. System frequency, HZ
4. Frequency distribution current hour, HZ
5. Frequency distribution previous hour, HZ
6. System total generation, *MW*
7. Control area total actual interchange, *MW*
8. Control area total scheduled interchange, *MW*
9. System operating reserve, *MW*
10. System sent out, *MW*
11. System spinning reserve, *MW*
12. *Automatic Generation Control (AGC)* regulating up, *MW*
13. *AGC* regulating down, *MW*
14. *AGC* regulating up assist, *MW*

15. *AGC* regulating down assist, *MW*
16. *AGC* regulating up emergency, *MW*
17. *AGC* regulating down emergency, *MW*
18. *AGC* mode
19. *AGC* status, On/Off
20. Area control error output, *MW*
21. System transmission losses, *MW*
22. International tie-lines, *MW*
23. *AGC* performance indicators

20.6.1.2 Hourly Demand Metering Data

The *ENTSO* shall provide *Users* with hourly-metered data pertaining to their installations.

20.6.2 File Transfers

(a) The format of the files used for data transfer shall be negotiated and defined by the supplier and receiver of the information. The file transfer media shall be negotiated and defined by both parties involved

(b) The parties shall keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures

Table 20-3: File Transfers

File	Description	Trigger Event	Frequency
AGC pulses	The total pulses sent to a unit by the AGC system to move the set-point up or down	Ongoing, file created at end of hour	Hourly
System near real-time data	Historical near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Unit near real-time data	Historical near real-time unit data files on readings as required for post-dispatch	Communication failure	To be agreed

20.6.3 Performance Data

20.6.3.1 Generating Plant Performance Data

(a) *Generation Licensee* shall provide the *ENTSO* monthly with performance indicators for each unit at each *Generating Plant* including those indicators listed below, and others as agreed between the *TSO* and the *Generation Licensees*.

1. Capacity factor
2. Equivalent availability factor
3. Equivalent forced outage rate
4. Equivalent planned outage hours
5. Start-up time
6. Successful start-up ratio

(b) *Generation Licensee* shall report significant events, such as catastrophic failures, to the *Regulatory Authority* within one (1) week of occurrence of such event.

(c) *Generating Plants* shall report Generating Plant Data and Service Performance Indicators as described in Table 20-4 below.

Table 20-4: Generating Plant Data and Service Performance Indicators

Ser. No.	Data filled	Indicator definition	To be reported for				Data to be presented	
			Interconnected system		Self -contained system		Monthly	Annual
			System level	Power plant level	System level	Power plant level		
A	Technical Indicators							
1	Capacity factor	The ratio of total energy dispatched to installed generation capacity	✓	✓	✓			✓
2	Load factor	The ratio of average load to peak load	✓		✓			✓
3	Reserve margin	Excess of available capacity over and above the capacity to meet demand	✓		✓			✓
4	Planned outage factor	Percentage of planned withdrawal of plant/unit for service for upgrade, maintenance and associated reasons from the total capacity		✓	✓			✓

Ser. No.	Data filled	Indicator definition	To be reported for				Data to be presented	
			Interconnected system		Self -contained system		Monthly	Annual
			System level	Power plant level	System level	Power plant level		
5	Forced outage factor	Percentage of forced withdrawal of plant/unit for service for upgrade, maintenance and associated reasons from the total capacity		✓		✓		✓
6	Availability factor	Available capacity as a percentage of installed capacity		✓		✓		✓
7	Water availability	The availability of water in the reservoir		✓		✓	✓	
8	Thermal efficiency	The ratio of total energy sent out to the heat value of fuel consumed (only for thermal plants)		✓		✓		✓
B	Personnel Indicator							
9	Labor productivity	The ratio of annual energy in GWh to average number of Generation employees	✓	✓		✓		✓
10	Average days lost due to sick leave	The ratio of total days lost due to sick leave to average total number of employees		✓		✓		✓

Ser. No.	Data filled	Indicator definition	To be reported for				Data to be presented	
			Interconnected system		Self -contained system		Monthly	Annual
			System level	Power plant level	System level	Power plant level		
11	Average days lost due to industry injury	The ratio of total days lost due to industry injury to average total number of employees		✓		✓		✓
12	Average days lost due to industry dispute	The ratio of total days lost due to industry dispute to average total number of employees		✓		✓		✓

20.6.3.2 Distribution Licensee and End-use User Performance

(a) The performance measurement of all *Distribution Licensees* and end-use *Users* shall be supplied to the *ENTSO*

(b) Distribution Data and Service Performance Indicators, and Customer/End User Data and Service Performance Indicators are described in the *ENDGC* Appendix A

(c) The *Parties* shall negotiate and agree on the details of acceptable levels of performance for *Distribution Licensees* or end-use *User* networks. Acceptable network performance principles shall include

1. Compliance with Quality of service Standards for Grid Supply-2019 or Latest Edition
2. Performance comparable with benchmarks for similar networks
3. Performance within the design or original equipment manufacturer (OEM) specifications of the *User* and transmission equipment
4. Performance at the *Connection Point* that complies with the *ENTSO* operating procedures
5. Performance consistent with the outcomes of the investment criteria
6. Performance that does not negatively impact on agreed levels of performance with other *Users*.

(d) If the *Distribution Licensee* or *End-use User* network performance falls below acceptable levels and affects the quality of supply to other *Users* or causes damage (direct or indirect) to the *transmission* equipment, the process for *Dispute* resolution as described in Section 3.11 of Chapter 3 (*Dispute Resolution*) shall be followed

(e) The *Regulatory Authority* shall determine criteria for the contracting of acceptable levels of performance.

(f) If *Distribution Licensees* or end-use *Users* 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 (e.g. by improving their line maintenance practices, improving protection and breaker operating times, if necessary replacing the said equipment, installing additional network breakers, changing operating procedures, installing fault-limiting devices if the number of faults cannot be reduced, etc.). These changes to their networks should be effected in consultation with the *ENTSO* regarding both the technical scope and the time frame

(g) Where *quality of service (QOS)* standards are not met, the parties shall co-operate and agree in accordance with *Regulatory Authority* power quality directives in determining the root causes and plans of action

(h) *Distribution Licensees* shall report periodic testing of under-frequency and under-voltage load shedding relays in the following format:

Table 20-5: Periodic Testing

Distribution Licensee:
Date:
Substation:
Fed from transmission substation (directly or indirectly):

	Activating Frequency/Voltage		Timer Setting	
	Required	As tested	Required	As tested
Stage 1				
Stage 2				
Stage 3				
Stage 4				
	Feeders Selected (required)		**Feeders Selected (as tested)**	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

20.6.3.3 TSO Performance

(a) The *ENTSO* shall make the Transmission Data and Service Performance Indicators available to the *Regulatory Authority* and *Users* at the periodicity indicated in Table 20-6 below:

Table 20-6: Transmission Data and Service Performance Indicators

Ser. No.	Data filled	Indicator definition	Data to be presented	
			Monthly	Annual
A	Technical Indicators			
1	Frequency of transmission line interruptions	The number of transmission line interruptions per 100 circuit kilometers (by voltage level and cause)	✓	☐
2	Duration of transmission line interruptions	The average duration of a transmission line interruptions in minutes (by voltage level and by cause)	✓	☐
3	Unserved energy (transmission line)	Annual Unserved energy (MWh) caused by transmission line interruptions		✓
4	Frequency of transmission substation interruptions	The average number of power transformer failures: (a) by voltage level and capacity; (b) by differentiating those which cause interruption to customers and those which do not cause interruption to customers	✓	☐
5	Duration of transmission substation interruption	The average duration interruptions caused by power transformer failures in minutes: (a) by voltage level and capacity; (b) by differentiating those which cause interruption to customers and those which do not cause interruption to customers	✓	☐

Ser. No.	Data filled	Indicator definition	Data to be presented	
			Monthly	Annual
6	Unserved energy (transmission substation)	Annual Unserved energy (MWh) caused by transmission substation interruptions		✓
7	Transmission loss	Annual transmission network losses	☐	✓
8				
B	Personnel Indicator			
8	Transmission line staff	Number of transmission line staff per circuit kilometer		✓
9	Transmission substation staff	Number of transmission substation staff per total substation capacity (MVA)		✓

(b) A transmission provider shall provide *Users* with all performance indicators at each point of supply.

20.6.3.4 System Operational Performance Information

The following *ENTS* operational information shall be published by the *ENTSO* to all *Users*:

(a) Daily:

1. The hourly actual demands of the previous day (*MW*)
2. The reserve amounts over the morning and evening peaks of the previous day (*MW*)

(b) Monthly:

1. *MW* generated, Imports, exports, available for distribution/sale and transmission losses.
2. *Generating Plant* availability
3. Regulating reserve Hours deficit over total hours
4. Number of frequency excursions > 50.05 or <49.5
5. For each abnormal network, condition the action taken by the System Operator to restore normal operations.
6. Network constraints (details to be defined by *Regulatory Authority*)

(c) Annually:

1. Annual peak (*MW*), date and hour
2. Annual minimum (*MW*), date and hour

(d) The *TNSP* shall make available all information collected via recorders installed at substations, to the *ENTSO* for analyses. The *ENTSO* shall make this information available to affected *Users* on request.

21 CYBER SECURITY

Cyber Security is the protection required to ensure confidentiality, integrity, and availability of the electronic communication system. With the two-way flow of electricity and information, the management and protection of the electrical communication system that includes information technology and telecommunication infrastructure, has become critical to the electric utility industry.

21.1 INTRODUCTION

With the increase in dependence on modern communication technology, power systems are vulnerable to cyber-attacks and hackers. In Ethiopia, the growth in the field of *information, communication, and technology (ICT)* makes it imperative to develop a sound Cyber Security strategy that will ensure confidentiality, integrity, and availability of public and private sector information across Ethiopia's *ICT* infrastructure.

Development of *ICT* framework in Ethiopia is dependent upon:

(a) Appropriate legal and regulatory frameworks
(b) Adequate telecommunications infrastructure and internet services
(c) Organized data and information resources, and easy accessibility to those that exist
(d) Skilled human resources coupled with low *ICT* literacy
(e) well-developed private sector

Ethiopia's *ICT* policy document last updated in 2009 covers major strategic focus on: (i) *ICT* infrastructure; (ii) human resource development; (iii) *ICT* legal systems and security; (iv) *ICT* for government administration and services; (v) *ICT* industry and private sector development, and (vi) research and technology transfer.

The *ICT* policy outlines the legislative instruments needed to govern cyber-related activities, such as data protection laws, cybercrime laws, and intellectual property laws. Ethiopia adheres to the cybercrime, personal data protection and electronic commerce law and policy set forth by the cyber convention adopted by the African Union (AU), which incorporates many of the provisions in the Council of European Convention on Cybercrime. Roadmap development for establishing Ethiopian Computer Emergency Response Team (Computer Security Incident Response Team or CSIRT) is in place as per African Union Convention.

Ethiopia's Information Network Security Agency (INSA) responsible for drafting Ethiopia's Cyber Security Law established in 2012 the Cyber Emergency Readiness and Response Team (also known as ETHIO-CERT). The Cyber Security Law drafted in 2014 contains internet law that addresses "unlawful interference", "unlawful interception", and "illegal access" to a telecommunication network.

Following the guidelines and best practices as described by the US DOE, National Institute of Standard and Technology (NIST – under US Department of Commerce), National Rural Electric

Cooperative Association (NRECA, from US), convention of African Union, Ethiopia's Cyber Security draft provisions, and some observations of Cyber Security best practices in India and Europe, this document provides guidance for developing Cyber Security controls that would help meet the *ICT* policy and potential security challenges for Ethiopia's power grid modernization.

This chapter addresses: (a) development of information security management controls and procedures; (b) development of Cyber Security systems with identity; (c) access management systems; and (d) developing skill set for defense against threats.

21.2 OBJECTIVES

Based on Ethiopia's *ICT* policy as well as cyber security & personal data protection initiatives set forth as per the African Union (AU) convention, the key objectives are identified as:

(a) Protect ion of Critical Information Infrastructure

(b) Building Skill Sets for Resource Development and Enhancing Cyber Security Awareness among Government/Private/Public Sector

(c) Development of a Comprehensive Governance Framework for Leveraging Resources, and Conflict Resolution,

(d) Facilitating Ethiopia's Cyber Security and *ICT* Implementation Strategy and Goals

21.3 SCOPE

The Cyber Security code of Ethiopia shall adhere to the cybercrime, personal data protection and electronic commerce law and policy set forth by the cyber convention adopted by the African Union (AU), which incorporates many of the provisions in the Council of European Convention on Cybercrime. The scope includes the following issues categorically:

(a) People and policy

(b) Operational issues

(c) Insecure software development life cycle (SDLC) risks

(d) Physical security

(e) Third-party relationship

(f) Network security

(g) Platform security

(h) Application security

21.3.1 People and Policy

Policies and procedures are the final protective or mitigating control against security breaches, and hence shall be examined closely to ensure its consistency with both the inherent business objectives

and secure operations. Policies and procedures shall be well- documented to ensure there is no deficiency that can lead to any security risks for the organization.

21.3.1.1 Security Policy

Security policies shall be well- structured in a practical, flexible, and easy to understand manner. Implementation and enforcement of the policies (e.g., through audits and disciplinary actions for noncompliance) shall be monitored periodically. Adequate flexibility shall be in place so improvements and modifications can be made easily as needed. Policies must be reviewed and approved by the designated authorities within the organization.

21.3.1.2 Security Policy Elements

The security policies must address the following elements:

(a) **Policy Management:** this shall address purpose, scope, and applicability, roles and responsibilities; implementation and enforcement procedures; exceptions, and policy reviews; approvals, and change management

(b) **Personnel and Training:** personnel risk assessment, security awareness program, and Cyber Security training for capacity building and from *Users*' perspective shall all be under the umbrella of this key element

(c) **Critical Asset Management:** methodology for identifying critical cyber assets; inventory and classification of cyber assets, information protection and data privacy; cyber vulnerability assessment, access control, monitoring, and logging; disposal or redeployment of assets; maintenance and change control of the asset inventory and classifications

(d) **Electronic Security Perimeter (ESP):** critical assets within the perimeter; cyber vulnerability assessment; access control/monitoring and logging, Configuration, maintenance, and testing; documentation maintenance to support compliance

21.3.1.3 Security Related Roles and Responsibilities

Roles of people responsible for maintaining security shall be defined and documented. These roles shall include:

(a) The governing body for the security policy (e.g., an oversight board comprising representatives of stakeholder groups)

(b) A designated information security manager who maintains the policy and provides guidance for implementation, training, and enforcement

(c) Department managers who "own" the critical cyber assets and are responsible for implementing the security policies and procedures to protect those assets

(d) Personnel with authorized access to critical assets who must review, provide feedback on, and comply with security policies

21.3.1.4 Privacy Policy

Insufficient privacy policies can lead to unwanted exposure of employee or customer/client personal information, resulting in both business and security risks. A privacy policy, that documents the necessity of protecting private/personal information to help ensure that data is not exposed or shared unnecessarily, shall be established.

21.3.1.5 Policy Exception

Reasons such as an overriding business need, a delay in vendor deliverables, new regulatory or statutory requirements, and temporary configuration issues may necessitate policy exceptions. The exception process must ensure that these circumstances are addressed in a manner to make all stakeholders aware of the event, the risks, and the timeline for eliminating the exception. Any event of policy exception shall be documented with date(s) in effect and date(s) of cancellation.

21.3.1.6 Personnel and Training

Training is required for everyone in the organization to get a clear understanding of the importance of Cyber Security. All employees shall acquire a level of security awareness training (with roles and responsibilities clearly defined), the degree of which shall vary based on the technical responsibilities and/or the critical assets.

Workshops shall be arranged periodically to provide training in such areas as Cyber Security for Critical Infrastructure, Threats and Attacks, Code of Conduct relating to computer resources/network/communication, Cyber Security Framework and Communications, Network and Information Security, Building Cyber Attack Resilience, Cyber Security Audit and Assessment, Data Protection and Privacy, and Cyber Security Assessment Project. Such workshops shall be aimed at providing exposure to the local utilities (Generation including IPP, Transmission, and Distribution), local Academia and R&D organizations as well as industry experts from overseas sharing with the best practices knowledge and experience.

21.3.1.7 Due Diligence in Hiring

Diligence in the hiring and personnel review process is crucial. It is important to define and document a risk assessment program for personnel with authorized cyber access or authorized unescorted physical access to critical cyber assets. The program must comply with applicable laws and existing collective bargaining agreements. The risk assessment must include, at a minimum, identity verification and criminal check. This information must be updated periodically at a frequency as determined by the local regulatory authorities. Similar checks must be enforced for the employees of third-party vendors.

21.3.1.8 Access Privileges

System access and information shall be granted only on an as-needed basis. System access needs to be managed, monitored, and enforced based on the individual's access requirements and the level of impact that uncontrolled access could have on the organization. In general, each employee shall

be granted the lowest levels of access to cyber assets and other privileges needed to do his or her job efficiently. A list of all personnel with authorized cyber access or authorized unescorted physical access to critical cyber assets shall be maintained. This list that contains each person's specific electronic and physical access rights to such assets shall be reviewed quarterly and updated within seven (7) days of any change in a list member's access rights.

21.3.1.9 Identity Validation, Background Checks

Identity validation/background checks shall be implemented based on an individual's area of responsibility, the physical facilities/hardware/systems, and the type of information authorized to access. The more sensitive information available to an individual, the deeper and more detailed the identity validation and background check process needs to be.

21.3.2Operational Security

Operational mistakes can break security policies. Although operational mistakes cannot be completely avoided, it is possible to reduce the risk of a mistake. Operational security acts as a deterrent against mistakes and deliberate misconfigurations. The ability to detect a mistake and trace it back to its source could also deter insiders from making malicious misconfigurations or to help quickly detect operator mistakes. The operational security shall deal with the responsibilities and authorization, as well as disciplinary actions in case of breaches. Industry compliance regulations require certain operational security measures. Network operators should check which regulation applies and verify that the required measures are in place.

It is often possible to provide additional security measures that are not fully dependent on operational mistakes. However, before implementing additional security measures a formal risk assessment needs to be performed to balance the cost of the additional measures with the cost of the risk incurred due to operational weaknesses. A Cyber Security program must be comprehensive—it is only as strong as its weakest link. Failure to develop appropriate controls in any category provides openings for attackers. This guide includes sections that describe common risks and mitigations in each category.

21.3.2.1 Risk Assessment and Mitigation

Security risks are fundamentally caused by people/policies/process/technology. An important part of the risk management process is to determine the severity of each risk as a function of its impact and likelihood. It is also important to understand the extent to which existing security controls completely or partially mitigate each risk. It is then possible to enumerate the gaps in protection and make an informed risk-based decision on next steps.

A risk assessment and mitigation strategy shall be implemented. Although a risk management strategy strives for risk prevention where practical, it also must balance the costs and benefits of security controls.

21.3.2.2 Access Control, Monitoring, and Logging

Access control that includes both technical and procedural control (e.g., logs, *user* account review, account management, restricting use of shared accounts, password use), enforces the authentication and accountability of all *user* activities. Access control requires not granting *users* access to network resources, before they are authenticated and authorized using their own individual (i.e., non-shared) credentials.

(a) Remote access to networks shall be limited to an absolute minimum

(b) When required, technologies like Virtual Private Networks (VPNs, IPSec) shall be used to create a secure tunnel after properly authenticating the connecting party using their individual credentials

(c) In addition to user name and password, also use an RSA ID-like device to provide an additional factor of authentication

(d) Access control shall be implemented for critical cyber assets by restricting authorized users and transactions

(e) A designated security team shall be in charge of access control and system logs. Access control shall be enhanced through perimeter security (e.g., security personnel, surveillance cameras and fences) wherever possible

(f) Use an access control model whose default setting is to deny access, thereby requiring explicit permission changes to enable access. Similarly, for all access points enable only the ports and services required for approved operations and monitoring

(g) Remote interactive access to a point within the perimeter typically must be accompanied by strong procedural or technical controls to enforce authentication of the authorized users

(h) Network access level that is needed for each individual or role at the organization shall be documented and only the required level of access shall be granted to these individuals or roles. All exceptions shall be noted

(i) All cyber assets, where technically feasible, shall include automated tools or organizational process controls to monitor Cyber Security-related system events.

(j) All automated mechanisms or processes shall be documented. The monitoring function shall log each detected Cyber Security incident and issue an alert. All such events shall be reviewed and logged. Logs shall be maintained for at least 90 days

21.3.2.3 Disposal or Redeployment of Assets

Formal methods, processes, and procedures for disposal or redeployment of cyber assets that are within an Electronic Security Perimeter (*ESP*) shall be documented and implemented in order to prevent any accidental release of sensitive and confidential information. This shall include, at a minimum, destroying or erasing the data storage media and maintaining records of asset disposition.

21.3.2.4 Change Control

Managing change is essential to maintaining a robust ongoing security posture.

(a) The state of the hardware, operating system must be monitored

(b) Change control mechanism shall ensure that new cyber assets and significant changes to existing cyber assets shall not adversely impact existing Cyber Security controls or the overall security posture of the system

(c) Change management processes shall also ensure an uninterrupted operation of the system

(d) All changes shall be logged and executed in a controlled way. The logs must be evaluated and checked for potential misconfigurations. The logs shall also be used to demonstrate a deliberate breach of the operational security policy

21.3.2.5 Patch Management Process

A patch management process must be in place to ensure that software and firmware are kept current to remediate against known vulnerabilities, or that a proper risk analysis and mitigation process is in place when patches cannot be promptly installed. Evaluation, installation, testing, and tracking process of Cyber Security patches, cumulative service packs, and version upgrades shall be implemented and documented.

21.3.2.6 Vulnerability Assessments

Cyber vulnerability is a gap or weakness in a system's security controls that a threat can exploit. Vulnerability assessments are necessary for generating awareness of threats, attacks, vulnerabilities, and ensuring the effectiveness of existing controls. They also establish baselines that future assessments can use to determine the need and effectiveness of planned improvement. A cyber threat is any entity or circumstance that has the potential to harm an information system along with its mission and goals.

Cyber vulnerability assessment of the access points to each *ESP* shall be done at least once a year to examine ways in which the security perimeter can be breached and existing security controls bypassed to compromise confidentiality, integrity, or availability of critical cyber assets.

21.3.2.7 Configuration Management and Maintenance

Improperly configured software/systems/devices added to existing software/systems/devices can lead to insecure configurations and increased risk of vulnerability. Configuration management processes must be in place to ensure that system configurations are governed appropriately in order to maximize overall system reliability.

A designated network team shall execute the following configuration actions.

(a) Adding vulnerable hardware

(b) Introducing tampered device to the system

(c) Failure to document changes made to the network configuration

(d) Not having a sign-off approval in the configuration management process

(e) Changing network configuration that reduces security profile shall be in the realm of responsibilities of the network team

21.3.2.8 Incident Management and Handling

An incident such as a breach of security or reliability protections can potentially cause loss of confidentiality, integrity, or availability of data, maintenance, and sustainment of any software or hardware product or operations. System reliability depends on the ability of participant organizations to quickly detect, report, and respond to incidents. Problems detected and correctly handled in a timely manner can prevent them from spreading to other entities. Knowledge gained from detecting and responding to computer security incidents provides insight into real risks and threats to the integrity, confidentiality, and availability of software and hardware products

A robust incident-handling capability shall be established with planning, documented procedures, and ongoing training and rehearsal for all personnel who might be required to report, analyze, or respond to incidents. This shall begin with a clear policy statement of incident- handling requirements.

21.3.2.9 Contingency Planning

Contingency planning shall include policy, plans, and procedures for disaster recovery and continuity of operations. Policy and plans must include preparation and training for responding to an emergency along with detailed procedures for executing defined strategies.

A disaster recovery plan applies to a major disruption to service that deny access to the primary facility infrastructure for an extended period of time. It includes the preparation (e.g., off-site storage of system backups), emergency facilities, and procedures for restoring critical cyber assets and infrastructure at an alternate site after an emergency.

A business continuity plan focuses on sustaining an organization's mission and business functions during and after a disruption. A business continuity plan shall be written for mission/business functions within a single business unit or it may address the entire organization's processes.

Continuity and recovery plans also define interim measures that increase the speed with which organizations resume service after disruptions. These plans must be tailored to each system. Creating specific measures requires a detailed understanding of specific scenarios.

The following key items shall be addressed in the *Contingency*- plan:

(a) Server backup and recovery

(b) Data backup and recovery

(c) Network backup and recovery; and

(d) Employee backup

21.3.2.10 Software Development Life Cycle (SDLC)

The software development shall have the objective to design, implement, configure, and support software systems to enable:

(a) Continuous operation even under most attacks by either restricting the exploitation of faults or other weakness in the software by the attacker, or tolerating the errors and failures that result from such exploits

(b) Isolation and containment of damage caused by any failures from attack-triggered faults that the software was unable to resist or tolerate, and

(c) Recovery from fault conditions as quickly as possible

Information gathered from incident handling shall be used at the beginning of the SDLC to help define better security requirements in products and provide a better understanding of the threat environment within which these products must operate. Knowledge gained from containing and mitigating computer security risks and threats shall also help identify auditing and recovery requirements for systems and software. Such requirements include: (i) building alerts when files and components that should not be changing are modified, (ii) establishing policy and configuration setting capabilities to identify and control specific software and hardware components that should not be changed during normal operations, and (iii) providing functionality for logging unauthorized changes or malicious attacks in a manner that would preserve evidence in a forensically sound manner.

Collection and sharing of information shall be smooth and successful if there is a well-defined and structured relationship between the software system developers and incident management staff.

Practices in SDLC shall include:

(a) Developing abuse cases to help refine requirements and build business cases

(b) Performing business risk analysis

(c) Implementing test planning (e.g., security functionality and risk-driven testing)

(d) Performing code review

(e) Performing penetration testing

(f) Deploying and operating applications in a secure environment

21.3.3Physical Security

Physical security is the protection of personnel, hardware, programs, networks, and data from physical circumstances and events that could cause serious losses or damage to an enterprise, agency, or institution. This includes protection from fire, natural disasters, burglary, theft, vandalism, and terrorism. A physical security plan, sponsored by senior management in the organization, must be documented, implemented, and maintained. The plan shall address the following among other things:

(a) The protection of all cyber assets within an identified physical security perimeter or by way of alternate measures if a completely enclosed border is not feasible

(b) The identification of all physical access points past the physical security perimeter and measures to control entry at those access points to make network links harder to compromise

(c) Processes, tools, and procedures to monitor physical access to the perimeter(s)

(d) Appropriate use of physical access controls

(e) Review of access authorization requests and revocation of access authorization

(f) A visitor control program for personnel without authorized unescorted access to a physical security perimeter

(g) Physical protection from unauthorized access and a location within an identified physical security perimeter for cyber assets that authorize or log access or monitor access to a physical or electronic security perimeter

(h) Documentation and implementation of operational and procedural control to manage physical access at all access points at all times

(i) Ensuring that all ports and services not required for normal and emergency operations are disabled

(j) Use of antivirus and malicious software prevention tools, where technically feasible

(k) Enforcement of restrictions on who can perform maintenance and repair, emergency procedures, and remote configuration and maintenance

Physical security can be implemented in the following levels:

(a) Multiple locks, fencing, walls, fireproof safes, and water sprinklers can be placed in the way of potential attackers and sites can be hardened against accidents and environmental disasters

(b) Surveillance and notification systems (such as lighting, heat sensors, smoke detectors, intrusion detectors, alarms, and camera) can be put in place as an alert

21.3.3.1 Monitoring, Logging, and Retention

The organization must document and implement the technical and procedural controls for monitoring physical security system at all access points at all times. Unauthorized access attempts must be reviewed immediately and handled in accordance with procedures. Logging will be sufficient to uniquely identify individuals and the time of access. Physical access logs should be retained for at least ninety (90) calendar days.

Routinely review network logs for anomalous / malicious behavior via automated and manual techniques.

21.3.3.2 Maintenance and Testing

Each physical security system must be tested at least once every three (3) years to ensure it operates correctly. Testing and maintenance records must be maintained at least until the next testing cycle. Outage records must be retained for at least one (1) calendar year.

21.3.3.3 Responsibilities of Different Entities

All Generation Transmission, and Distribution entities dealing with the *ENTSO* shall ensure and document cyber security protections such as: Performing regular malware scans; Patching vulnerable systems in a timely manner; and Enforcing a strong password policy. Responsibilities include:

(a) IPPs and the third party vendors shall be required to have a signed contract for such Cyber Security protections as stated above

(b) Third party vendors shall provide notification of known vulnerabilities affecting vendor-supplied, application, and third-party software within a pre-negotiated period after public disclosure. Vendors shall verify and provide documentation that all services are patched to current status. Vendors shall provide a configurable account password management system that allows for selection of password length, frequency of change, setting of required password complexity, number of login attempts, inactive session logout, screen lock by application, and denial of repeated or recycled use of the same password

(c) In the case of pre-existing contracts and relationships, it is crucial first to perform a full audit of these previous contracts to determine whether Cyber Security gaps exist, and then to determine how best to fill any gaps through contract renegotiation with the vendor. Vendors shall provide details on their patch management and update process

21.3.4Network Security

Network Security is the protection of all data that leaves or enters the local computer or server from the network. Controlled by a network administrator, network security involves the authorization of access to data in a network, and preventing and monitoring unauthorized access, misuse, modification, or denial of a computer network and network-accessible resources. Refer to Section 21.3.2.2, "Access Control, Monitoring, and Logging" for more on Network Security and access control. The following measures shall be taken to ensure network security:

(a) Intrusion Detection Systems (IDSs) shall be used to detect any anomalous behavior on network. If anomalous behavior is encountered, the potentially compromised nodes on the network must be isolated from the rest of the network

(b) All settings used on network hardware shall be set to their secure settings. Settings provided by each piece of hardware must be fully understood. Do not assume that default settings are secure

21.3.4.1 Network Connection Control

(a) User assigned devices shall be restricted to connection to specified network segments only, and shall be uniquely identified and approved for use

(b) Care shall be taken in granting authorized connections to network segments where information of a higher security classification is stored, processed, and/or transmitted and the user of that device has not been granted access to information assets of that classification

(c) Source of network time shall be accurate and that accurate time shall be reflected on all network nodes for all actions taken and events logged

(d) User devices shall be prohibited from cross-connecting (i.e., acting as a router) between any two networks. Unneeded network services shall be disabled

21.3.4.2 Firewall

Firewalls play an important role in establishing the first line of defense against cyber threats. Combined with anti-spyware, anti-virus and anti-spam software, strong passwords and safe online practices, a firewall adds a layer of protection that helps enhance Cyber Security. Firewalls protect the computer and information from: (a) hackers breaking into the system; (b) viruses and worms that spread across the Internet; and (c) outgoing traffic from the host computer created by a virus infection.

Firewalls and virtual local area networks (VLANs) technologies can be used to properly segment the network and to increase its compartmentalization (e.g., machines with access to business services like e-mail should not be on the same network segment as *SCADA* machines). Firewall rules shall be routinely reviewed and tested to confirm expected behavior.

Firewalls shall be configured in accordance with the organization's standards and policies, and deny any of the following traffic types:

(a) Firewalls and other boundary security mechanisms that filter or act as a proxy for traffic from one network segment to another of a different security level

(b) Invalid source or destination address (e.g., broadcast addresses, RFC 1918 address spaces on interfaces connected to public networks, addresses not assigned by *IANA* on interfaces connected to public networks)

(c) Those destined for the firewall itself, unless the firewall provides a specific service (e.g., application proxy, VPN)

(d) Source routing information

(e) Directed broadcasts that are not for the subnet of the originator (these can be used to create broadcast storms in denial-of-service attacks against third parties)

(f) Destined for internal addresses or services that have not been approved for access from external sources

(g) Requests for allowing additional services through a firewall or other boundary protection mechanisms must be approved by the information security manager

21.3.4.3 Flow of Electronic Communications

(a) Client systems shall communicate with internal servers. The internal servers shall communicate with the external systems via an intermediate system. The flow of traffic shall be enforced through boundary protection mechanisms

(b) Ensure channel security of critical communication links with technologies like Transport Layer Security (TLS). Where possible, implement Public Key Infrastructure (PKI) to support two-way mutual certificate-based authentication between nodes on the network

(c) Ensure that only standard, approved, and properly reviewed communication protocols are used on the network

21.3.4.4 Protecting Data in Transit

(a) When any non-public classified data transits a network and the confidentiality and integrity of that data cannot be guaranteed because of the use of protocols, which do not provide a mechanism for protecting the data payload, encryption shall be used to guard against disclosure and modification of the data

(b) Ensure availability, integrity, and confidentiality of data traversing the networks through use of digital fingerprints and signed hashes. If channel-level encryption is not possible, apply data-level encryption to protect the data traversing the network links. Time stamps to protect against replay attacks must be ensured. No actions shall be taken based on the data coming from network nodes that may have been compromised

(c) Ensure that proper certificate and key management practices are in place. Remember that cryptography does not help if the encryption key is easy to compromise. Ensure that keys are changed periodically and that they can be changed right away in the event of a compromise

21.3.4.5 Protecting Domain Name Service (DNS) Traffic

DNS provides a mechanism for resolving host names into Internet Protocol (IP) addresses in the internet. Due to its ability to map human memorable system names into computer network numerical addresses, its distributed nature, and its robustness, the DNS has evolved into a critical component of the Internet. Insecure underlying protocols and lack of authentication and integrity checking of the information within the DNS threaten the proper functionality of the DNS. The threats that surround the DNS are due in part to the lack of authenticity and integrity checking of the data held within the DNS and in part to other protocols that use host names as an access control mechanism.

(a) The DNS shall be deployed in a multitier architecture that protects internal systems from direct manipulation

(b) Internal client resolvers shall direct their queries to internal DNS servers, which forward all queries for external resource records to DNS server(s)

(c) The flow of traffic shall be enforced through boundary protection mechanisms

21.3.4.6 Network Routing Control /Use of Secure Routing Protocols or Static Routes

When exchanging routing information with external parties, secure routing protocols or static routes shall be used. If possible, network address translation shall be employed to prevent accidental leakage of internal routing information. Rules include:

(a) *Users* and devices shall not be allowed to specify the routing of network traffic. Development, test, and production environments shall be separated

(b) Sufficient redundancy shall be ensured to exist in the network links so that rerouting traffic is possible if some links are compromised

21.3.5Platform Security Risks

Platform security risk focuses on the operating systems and other software making up the software stack on top of which an organization's custom applications run. Each accessible host on an organization's network is a potential target for attack. Adversaries will try to compromise these hosts via methods that cannot be mitigated through network security controls alone.

Ensure that the platform software running on the hosts is secure, including (but not limited to) operating system software, database software, Web server software, and application server software. Together these form a software stack on top of which an organization's custom applications run.

21.3.6Application Security

In-house developed or custom-procured application software must be developed with security in mind from the get-go to help ensure that it does not contain any software security weaknesses that may be exploited by adversaries to compromise the system. The software development process therefore must to be security aware.

21.3.7Unique Security Requirements and Controls

This section describes unique security best practices and controls needed for the grid modernization and/or smart grid applications.

21.3.7.1 Advanced Metering Infrastructure (AMI)

The AMI network consists of various software & hardware components, and networks for communication. These include: (a) "head end" operating on the utility network; (b) wide area network (WAN) that provides communications from the utility head end out to the field; (c) field access or collection points on the edge of the WAN providing connections and/or consolidation for metering data access, and (d) mesh network known as a local area network (LAN) or neighborhood area network (NAN) providing sub-networks of meters, extending the reach to a larger meter population. Home area networks (HAN) are also used to provide interfaces into the home to support consumer awareness of energy consumption and to extend support for demand response functionality.

The security requirement for AMI begins with establishing fidelity of the meter data. Since smart meters in the field are readily available, with few if any physical security controls, an attacker

gaining physical access to the smart meter may "patch" their firmware, thereby compromising the smart meter. From this point on, any data supplied by the smart meter to the SCADA can no longer be trusted. If the attacker can repeat the same tactic on a broader scale, it may be possible for the hacker to generate incorrect actions for the *SCADA* system based on meter readings from compromised meters. Detection of a compromised meter through remote attestation and other state-of-the art techniques is therefore of utmost importance.

It is important to note that an attacker need not gain physical access to many meters. Since meters are networked together, gaining access to one smart meter, downloading its firmware, reverse engineering the firmware to look for software vulnerabilities (e.g., buffer overflow), and then creating a root kit that can exploit that vulnerability to modify the functionality of the smart meter is all an attacker needs to do. A worm can then be used to propagate that root kit from one smart meter to another via a network that connects them. An attacker may then have a botnet of compromised smart meters that he or she can activate at any time to achieve the attack goal (e.g., cause a blackout).

The following actions shall be taken in order to help mitigate this vulnerability:

(a) Verify with the software/hardware vendors (with embedded software) with proof of evidence (e.g., third-party assessment) that their software is secure and free of security weaknesses

(b) Perform remote attestation of smart meters to ensure that the firmware has not been modified

(c) Make use of communication protocol security extensions (e.g., MultiSpeak® security extensions) to ascertain the integrity, including the origin integrity, of smart meter data.

(d) Establish and maintain secure configuration management processes (e.g., when servicing field devices or updating their firmware)

(e) Ensure that all software (developed internally or procured from a third party) is developed using security-aware SDLC

(f) Apply a qualified third-party security penetration test to all hardware and software components prior to live deployment

(g) Ensure that the software running on the smart meter is free of software weaknesses, especially if they are remotely exploitable. Otherwise, an attacker may be able take control of a *user*'s smart meter to begin manipulating the climate in the *user*'s home. When done on a large scale, this may result in blackouts

(h) Implement physical security controls and detection mechanisms when tampering occurs.

(i) Ensure that a reliable source of network time is maintained

(j) Disable the remote disconnect feature that allows electricity to be remotely shut down using a smart meter

(k) To safeguard end user privacy, smart meter information shall be decoupled from end-user information. Meter identification shall be done through a generic number instead of a specific household address, GPS location, etc.

21.3.7.2 Meter Data Management System (MDMS)

Data imported in to MDMS must be thoroughly validated for syntax and semantic for both privacy and data security issues. The following actions must be ensured:

(a) Data received by MDMS does not come from a compromised meter

(b) Data received by MDMS undergoes validation, estimation, and editing (VEE) protocols to ensure data integrity and completeness

(c) Appropriate exception handling mechanism is available in place for compromised data

(d) MDMS has been designed and implemented using security-aware SDLC

(e) MDMS system has passed a security penetration test by a qualified third party

(f) Denial-of-service attempts (from compromised meters) are handled gracefully by MDMS

21.3.7.3 Communication System

Communication system security has been covered under Network Security Section earlier in this chapter. Following is a list of actions to be enforced for the communication system security:

(a) Ensure data integrity

(b) Ensure origin integrity

(c) Use proven communications protocols with built-in security capabilities

(d) Ensure confidentiality of data where appropriate

(e) Ensure proper network segmentation

(f) Have a third party perform network security penetration testing

(g) Implement sufficient redundancy

(h) Protect from man-in-the-middle attacks

(i) Protect from replay attacks

(j) Use proven encryption techniques

(k) Use robust key management techniques

21.3.7.4 Supervisory Control and Data Acquisition (SCADA)

SCADA system is a part of a utility's critical infrastructure and requires protection from a variety of threats that exist in cyber space. The following actions shall be taken to ensure Cyber Security of *SCADA* networks:

(a) Appoint a senior security manager with a clear mandate

(b) Establish policies to minimize the likelihood of inadvertent disclosure of sensitive information regarding *SCADA* system design, operations, or security controls by organizational staff

(c) Conduct personnel security awareness training

(d) Clearly define Cyber Security roles, responsibilities, and authorities for managers, system administrators, and *users*

(e) Apply basic network and system IT security practices (e.g., regular security patches, run antivirus software, etc.)

(f) Ensure that software running in the *SCADA* environment (e.g., either internal or external) has been built with security in mind and reviewed for security by a qualified third party.

(g) Enforce the principle of least privilege when it comes to granting *user* access to *SCADA* resources

(h) Conduct physical security surveys and assess all remote sites connected to the *SCADA* network to evaluate their security

(i) Disconnect unnecessary connections to the *SCADA* networks

(j) Document network architecture and identify systems that serve critical functions or contain sensitive information that need additional level of protection

(k) Establish a rigorous ongoing risk management process

(l) Conduct routine self-assessments

(m) Establish system backups and disaster recovery plans

(n) Test business continuity and disaster recovery plans

(o) Establish *SCADA* "Red Teams" to identify and evaluate possible attack scenarios

(p) Implement internal and external intrusion detection systems and establish 24-hours-a-day incident monitoring

(q) Perform technical audits of *SCADA* devices, networks, and any other connected networks to identify security concerns

(r) Perform monitoring and logging, and ensure that people can be held accountable for their actions

(s) Avoid taking critical control decisions without human confirmation

(t) Avoid taking critical control decisions based on too few data points

(u) Avoid taking critical control decisions based on data points from compromised field devices or based on data that has been tampered with

(v) Ensure proper network segmentation in the *SCADA* environment

(w) Ensure sufficient fault tolerance and redundancy in the *SCADA* environment

(x) Use individual (rather than shared) *user* login accounts with strong passwords

(y) Ensure that all hardware authentication settings have been changed from their default values

21.3.7.5 In-Home Display (IHD)

IHD provides customers with information on energy consumption. The security of this device is critical from the consumer's perspective in both preventing others from sneaking as well as preventing someone from using that device to manipulate household appliances. An attacker may

be able take control of a *user*'s IHD to begin manipulating the climate in the *user*'s home. When done on a large scale, this may result in blackouts due to overloads. Attacks could be launched wirelessly through AMI network, communication channel, or the internet.

Additionally, if utilities and third parties bundle internet access as a potential marketing hook, the device will also be subject to potential malware when a customer surfs the internet. It is therefore imperative to have a mechanism for frequent security patches. The following actions shall be taken to ensure security of IHD:

(a) Ensure that the software running on IHDs is free of software weaknesses

(b) Ensure the integrity of data shown on the *user*'s IHD.

(c) Ensure the integrity of data sent from the *user*'s IHD to the control center.

(d) Ensure the anonymity and privacy of data (where appropriate) pertaining to electricity usage patterns such that it cannot be tied back to the consumer.

(e) Perform remote attestation of IHDs to alert the control center when unauthorized firmware updates occur.

(f) Request third-party security penetration testing of IHDs

Tables 21-1 through 21-5 below provides at-a-glance summaries of risks, impacts, and mitigations for People and Policy Risks, Operational Risks, Thirds Party Risks, Network Risks, and Platform Risks.

Table 21-1: People and Policy Risks and Mitigation

Risk	Impact	Mitigations
Lack of security training and awareness.	Insufficiently trained personnel may inadvertently provide the visibility, knowledge, and opportunity to execute a successful attack.	All employees must undergo security training when hired and at least once a year thereafter. The degree and nature of security training for personnel shall vary based on their job function.
Inadequate technology & processes for identification/authentication	Online transaction and data/information privacy are vulnerable with identity fraud and theft	Identity proofing through appropriate background checks for all new hires must be done. Access to sensitive information and resources shall be given only after proper authentication and authorization.
Inadequate security policy	Inadequate policies that do not drive operating requirements and procedures lead to vulnerabilities in Cyber Security.	Security policies must adequately cover all aspects of maintaining a secure environment.
Insufficient privacy policy	Undesirable exposure of employee/customer/ client personal information could pose business and security risk.	Adequately defined privacy policies must cover all aspects of safeguarding access to private information.
Lack of management oversight for security.	Without sponsorship of senior management, it is not possible to successfully enforce a security program in the event of a policy compromised or abuse.	Assign a senior manager to be in charge of the overall security program who can make appropriate decisions in the event of the policies need to be modified.
Inconsistent action in revocation of employee access	Not revoking access of terminated employees could be a threat to Cyber Security that may lead to unauthorized access, and sabotage.	Employees shall have access to resources and systems only as needed to perform their job function for the duration as needed. All access for terminated employees shall be revoked before notifying them of termination.

Table 21-2: Operational Risks and Mitigation

Operational Risks	Potential Impact	Mitigation
Lack of patch management process.	Missing patches potential risks to the affected system.	Security patches shall be applied as appropriate, with automated alerts
Lax access control	Unauthorized users can obtain/modify/delete sensitive information	Periodically review the lists for each critical resource or system and the authorized users. Establish standards procedures and channels for granting and revoking employee access to resources or systems.
Inadequate change and configuration management.	Improperly configured software/systems/devices lead to insecure configurations and an increased risk of vulnerability.	All hardware and software must be configured securely. When unclear, seek further clarification from vendors as to secure settings and do not assume that shipped default settings are secure. Establish change management and approval processes for making changes to the configuration to ensure that the security posture is not jeopardized.
Lack of periodic security audits.	Failure to perform periodic security audits may lead to unidentified security risks and/or process gaps.	Periodic security audits shall focus on assessing security controls for (i) people and policy, (ii) operations, (iii) network, (iv) platform, (v) application, (vi) process, (vii) physical security, and (viii) third-party relationships.
Inadequate continuity of operations and disaster recovery plan.	Causes longer- than-necessary recovery from a possible plant or operational outage.	An associated cyber contingency plan and Cyber Security incident response plan shall be developed within the various plant/system disaster recovery plans in place. Disaster recovery plans shall highlight the need to determine if the disaster was created by or related to a Cyber Security incident. Steps shall be taken to validate, backup, and ensure devices being recovered are clean before installing the backups, incident reporting, etc.
Lack of adequate risk assessment process.	Inadequate understanding of the actual risk may lead to poor and ineffective decisions	A documented risk assessment process that includes consideration of business objectives, the impact to the organization if vulnerabilities are exploited, and the determination by senior management of risk acceptance is necessary to ensure proper evaluation of risk.
Inadequate risk management process.	Could result in major risks being unaddressed	A systematic approach of risk management process shall use the results of the risk assessment to initiate timely and appropriate risk mitigation in a fashion commensurate with their likelihood and impact. An executive dashboard shall be developed to show all risks where mitigations are past due.
Insufficient incident response process.	Time-critical response actions may not be completed in a timely manner, leading to the increased duration of risk exposure.	An incident response process is required to ensure proper notification, response, and recovery in the event of an incident.

Table 21-3: Third Party Risks and Mitigation

Risk	Impact	Mitigation
Failure to specify security requirements in RFPs.	Products/services will not meet security requirements of the system	Security requirements shall be reflected in the RFPs, and contract
Failure to request results of independent security testing of hardware and software prior to procurement.	Procurement may not meet standards of security requirements.	Hardware/software vendors must be required to have their products reviewed by third-party security experts and to share the reports.
Failure to request evidence from a third party vendor of its risk management and security practices.	Products/services will have insufficient security measures	Vendor's risk management and security practices shall be reviewed to ensure that they adhere to appropriate standards.
Failure to request information from a third party on its secure SDLC process.	A SDLC process that does not follow security development practices will likely result in insecure software.	Software vendor shall demonstrate a secure software development process.

Table 21-4: Network Risks and Mitigation

Risk	Impact	Mitigation
Unneeded services running.	Every service that runs is a security risk, because intended use of the service may provide access to system assets, and the implementation may contain exploitable bugs.	Perform analysis to identify all services that are needed, and only have these enabled. Establish a process for obtaining permission to enable additional services. Conduct periodic reviews to ensure that the services are running as expected.
Insufficient log management.	(i) Failure to detect critical events; (ii) Removal of forensic evidence; (iii) Log wipes	Events from all devices should be logged to a central log management server. Alerts should be configured according to the criticality of the event or a correlation of certain events. For instance, when the tamper-detection mechanism on a device is triggered, an alert should be delivered to the appropriate personnel. When a remote power disconnect command is issued to x number of meters within a certain time, alerts should also be sent.

Table 21-5: Platform Risks and Mitigation

Risk	Impact	Mitigation
Insufficient Authentication and authorization process for all components	Denial of service (DoS)/distributed denial of service (DDoS) attacks may overwhelm a software system by overloading it with data requests ultimately causing platform shutdown and data/assets stolen	Enforce multi-layer authentication. Institute sound key management practices. Ensure secure key exchange. Ensure that the authentication process cannot be bypassed.
Monitoring for unusual activities not performed	System may be vulnerable to fraudulent activities	Ensure dedicated senior management to rigorously enforce policies and procedures

22 SYSTEM OPERATOR TRAINING

THIS Chapter contains requirements specific to both the *EAPP IC* and the E*NTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

22.1 EAPP IC REQUIREMENTS

22.1.1Introduction

The *System Operator Training Chapter (SOTC)* sets out the responsibilities and the minimum acceptable requirements for the development and implementation of System Operator Training and Authorisation programmes. The *SOTC* shall ensure that System Operators throughout *EAPP* and the *EAC* are provided with continuous and coordinated operational training in order to promote the reliability and security of the *EAPP Interconnected Transmission System.*

22.1.2 Objective

The objectives of the System Operator Training Chapter are to establish mandatory continuing training and authorisation to improve and maintain System Operator capability and performance in their job tasks.

22.1.3 Responsibility

*TSO*s shall establish and authorise the System Operator positions that will have the responsibility in their Control Centres for the safe and reliable operation of the *EAPP Interconnected Transmission System* and *National System*. The *TSO* shall also be responsible for the ongoing training of their System Operators in accordance with the *SOTC*. In a *TSO's* Control Centre and in the *EAPP CC* at least one System Operator, authorised in accordance with the *SOTC*, shall be on duty at all times and shall be responsible for the operation of the *EAPP Interconnected Transmission System* and for complying with the *EAPP/EAC* Interconnection Code.

22.1.4 Scope

Reliable operation of the *EAPP Interconnected Transmission System* requires highly trained and tested System Operators who are able to evaluate information on the status of their *National System* and *EAPP Interconnected Transmission System*. They must evaluate possible risks to system reliability, and make near-instant decisions about actions necessary to protect the system in a safe and reliable manner under all conditions. When recruiting System Operators, each *TSO* shall ensure that they have basic qualifications and shall provide them with a continuous and coordinated training and authorisation. System Operators should be selected on the basis of their level of intellectual and reasoning ability and their capacity for working under stressful conditions. They should have good engineering, mathematical and problem-solving skills and communicate clearly both in writing and verbally. System Operators shall also have sufficient language skills to enable them to communicate with other *EAPP* Control Centres under operational conditions in English

language. System Operators must be able to deal with their peers in other Control Centres and also with regulators, *Generation Licensees*, and *End-use Users*. System Operators should be capable of supervising and training other operating personnel in their own *National System*.

22.1.5 Need for Training

System expansions, new technologies, and modifications of market and regulatory rules require changing functionalities in Control Centres. As the markets expand and the *EAPP Interconnected Transmission System* becomes more congested, operational reliability is crucial and requires more robust data acquisition, better analysis, and faster coordinated controls. To ensure smooth operation of the *EAPP Interconnected Transmission System* and *National Systems* under steady-state and disturbed conditions, a number of technical rules and recommendations also need to be followed. The functions and responsibilities set out above require qualified, skilled, and well-trained System Operators at the Control Centres to direct the operation of *EAPP Interconnected Transmission System* in a reliable and secure manner.

22.1.6 Authorization of System Operators

System Operators in the *EAPP Coordination Centre* and in the *TSO* Control Centres shall be authorised in accordance with the *SOTC*. The training and authorisation of System Operators is the responsibility of *EAPP* in the case of the *EAPP Coordination Centre* and individual *TSOs* in the case of their Control Centres. There are two levels of authorisation:

(a) Basic Authorisation: This level of authorisation is for new recruits to the System Operator function and requires the completion of the Initial Course and the passing of an examination. This authorization will be valid for three (3) years.

(b) Continuing Authorisation: This level of authorisation is for System Operators who are already performing the role. The Continuous Course to be followed involves the accumulation of credits. Sufficient credits must be obtained every three (3) years in order to maintain authorisation.

22.1.7 Training of System Operators

The training of System Operators consists of two courses. The content of the Initial Course is aimed at new recruits to the System Operator position and assumes a good knowledge of electrical engineering principles. It introduces the basics of system operation using the *EAPP Interconnected Transmission System* to illustrate the concepts and to instill knowledge on how the overall system operates at all times and under all conditions. The Initial Course is of six (6) month duration for trainees without experience in power system operation, including three (3) months for on-the-job and simulator training.

The Continuous Course is targeted at System Operators to enable them to maintain their proficiency and professional development throughout their career. The Continuous Course is required to be completed before expiry of the previous authorisation and will require the accumulation of a number of credits to be defined by the *EAPP Steering Committee*.

The training programme will introduce the basics of interconnected system operation and control practices including security analysis, stability studies, optimal power flow and system management. The deregulation processes adopted in *EAPP Member Countries* will be covered. Different restructuring models and technical problems in operation and control including congestion management, *Ancillary Services*, automatic generation control, demand forecasting, power systems security and state estimation will be discussed.

The detailed course material shall be reviewed periodically to account for changing requirements and developments in *Prudent Utility Practice*. *The EAPP Steering Committee* shall establish a Committee of experts to review the training needs to ensure that the content of both courses is relevant and covers all aspects.

22.1.8 Initial Course

22.1.8.1 Theoretical Modules

The Theoretical Module should provide advanced technical knowledge on the following main topics:

(a) Analysis of past system disturbances and 'near-misses'

(b) System operation including security analysis, optimal power flow, transient and dynamic stability and operation under emergency conditions

(c) New risks and conditions affecting system operation including new network elements or *Generating Units*

(d) Modifications to the EAPP/EAC Interconnection Code and National Grid Codes and other new technical and operational rules and procedures

The structure of the theoretical part of the Initial Course should provide a first level of competencies in the following main topics:

(a) Types of overhead lines and underground cables with their components

(b) Different types of *HV* and *EHV* substations, *HVDC* converters, circuit breakers, isolator-ground switches, power transformers, measurement and protection transformers, tap changers, reactors, capacitors, phase shifting transformers, other electronic regulators (*SVC*, *FACTS*), telecommunication systems, protection relays

(c) Types of *Generating Units* and their operational characteristics e.g. response times

22.1.8.2 Operation Modules

This will include all relevant national and international regulations and market rules as well as the knowledge and analysis of the necessary conditions for safe and reliable system operation. This category might include modules on the following aspects:

(a) Network behaviour, network operation, power flows and system frequency

(b) Basics of system protection

(c) Voltage and reactive power control

(d) Balancing (primary and secondary response and tertiary reserve), Automatic Generation Control

(e) *EAPP* Interconnection Code and National Grid Codes

(f) Other technical or operational policies of the *TSO*

(g) Emergency scenarios including manual and automatic remedial actions and system restoration philosophies

(h) Electricity Market operations

(i) Communication and reporting of system incidents

22.1.8.3 Practical Modules

Trainees should receive training in the following topics:

(a) Data collection and configuration of *SCADA* and *EMS*

(b) Models implemented for state estimation, system, *Contingency* analysis, automatic generation control, and demand forecasting

(c) System Operator's Human-Machine Interface

(d) Training on Power System Protection

22.1.8.4 Simulator Training

System Simulator based training bridges the gap between theory and practice and is also used to enhance the skills of experienced System Operators. Training on the System Simulator should be concerned with the 'play back' of system incidents and with the lessons to be learned from them. The training should also include 'live' interaction with Control Centres of Neighbouring Systems in the handling of cross-border incidents. During the Initial Course, trainees should use the Simulator to experience the following:

(a) Simulation of system performance under *SCADA* real-time conditions

(b) Restoration of the system following a blackout

(c) Use of the Control Centre User Interface

(d) Decision making under stress conditions

(e) Operation under emergency conditions

22.1.8.5 On Job Training

Training on shift in the Control Centre is a most important part of the Initial Course. The training should concentrate on the future position and responsibilities of the trainee and should cover all relevant operational aspects relevant to the position. On job training puts into practice all the topics of the Theory Modules and the trainees should be supervised by experienced System Operators.

22.1.9Continuous Course

The Continuous Course is an ongoing training programme aimed at System Operators who have already been authorized. It focuses on advanced theoretical and practical aspects of system operation as well as on cross-border issues. Each *TSO* should implement a Continuous Course with two modules.

22.1.9.1 Theoretical Module

The Theoretical Module should provide advanced technical knowledge on the following main topics:

(a) Analysis of past system disturbances and 'near-misses'
(b) System operation including security analysis, optimal power flow, transient and dynamic stability and operation under emergency conditions
(c) New risks and conditions affecting system operation including new network elements or Generating Units
(d) Modifications to the EAPP/EAC Interconnection Code and National Grid Codes and other new technical and operational rules and procedures

22.1.9.2 Simulator Training

Training on the System Simulator should be concerned with the 'play back' of system incidents and with the lessons to be learned from them. The training should also include 'live' interaction with Control Centres of *Neighbouring Systems* in the handling of cross-border incidents

22.1.10Combined Training

Cooperation and communication between System Operators in the National Control Centres and the *EAPP CC* is essential for the successful and coordinated operation of the *EAPP Interconnected Transmission System*. This cooperation can be fostered by joint training programmes between *TSO*s. These programmes could include:

(a) Exchange visits between Control Centres including periods on-shift
(b) Joint training workshops
(c) Common System Simulator training

22.2 ENTGC REQUIREMENTS

22.2.1 Operations Training Seminar

(a) The *ENTSO* will, at a minimum, annually host a training seminar. The purpose of the training seminar is to provide a forum for system wide problems to be effectively addressed. The training seminar should present information to maintain the consistency of operators across all of the *ENTSO* Region
(b) The seminar provides a forum for Generation, *TNSPs* and *DNSPs* and system operators. The *ENTSO* System Operators shall meet and analyze common topics and issues as well as participate in formal training sessions that impact all participants

22.2.2 Extreme Emergency Drill

The *ENTSO* shall conduct an extreme emergency drill each year. This drill will be used to test the scheduling and communication functions of the primary and/or backup centers and train operators in emergency procedures. The *ENTSO* shall participate in the drill. The *ENTSO* shall appoint a drill coordinator for developing and coordinating the annual extreme emergency drill. The *ENTSO* shall appoint a Working Committee to review and critique the results of completed extreme emergency drills that will ensure effectiveness and recommend changes as necessary. The *ENTSO* shall verify and report Entity participation to the appropriate authority.

22.2.3 Training Practices

Each *Licensee* shall establish a clear requirement, define and develop a systematic approach in administering the training, and provide the necessary feedback as a measurement of curriculum suitability and trainee progress. Each entity should recognize the importance of training and provide sufficient operator participation through adequate staffing and work-hour scheduling.

The *Regulatory Authority* shall certify the training practices established by each Licensee.

22.2.4 Operator Certification

The *ENTSO* Certification shall verify that an individual has knowledge of fundamental topics in electrical power and Ethiopia power system operations. The certification shall be achieved through self-study of the *ENTSO* Training Manual, followed by successful completion of an examination over the subject matter contained in the Manual.

23. Effective Date

This code shall enter into force as of the 2nd day of March 2021.

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FREHIWOT WOLDEHANNA (PhD)

BOARD CHAIRMAN, ETHIOPIAN ENERGY AUTHORITY

APPENDIX REVISION LOG

Chapter	Comments	Page	Action Taken	Date of Action

Chapter	Comments	Page	Action Taken	Date of Action